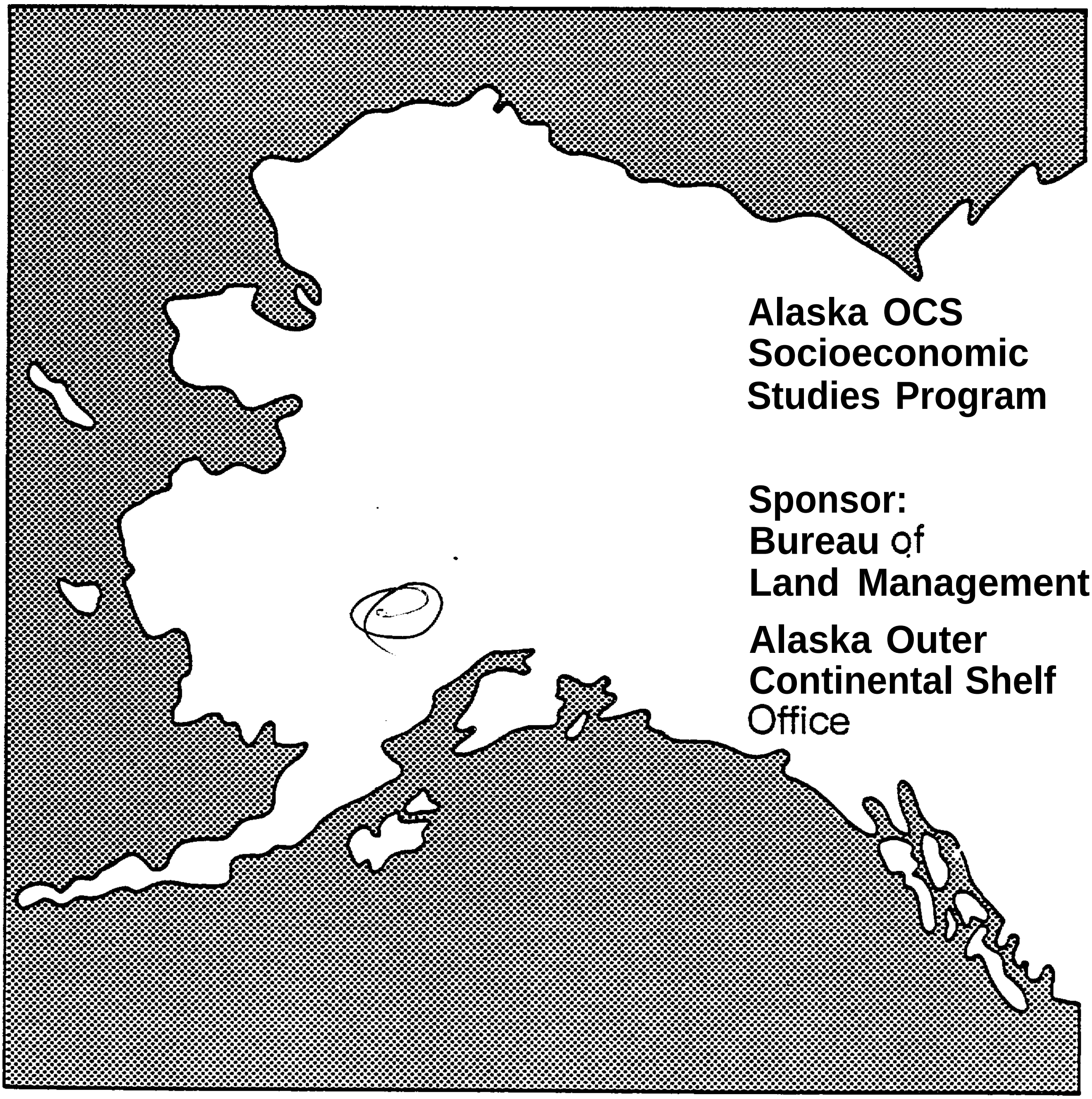
Technical Report Number 6



Alaska OCS Socioeconomic Studies Program

Sponsor:
Bureau of Land Management
Alaska Outer Continental Shelf Office

Beaufort Sea Region Petroleum Development Scenarios

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 various 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 (COAR), Socioeconomic Studies Program, Alaska OCS Office, P.O. Box 1159, Anchorage, Alaska 99510.

TECHNICAL REPORT NO. 6 CONTRACT NO. AA550-CT6-61

ALASKA OCS SOCIOECONOMIC STUDIES PROGRAM

BEAUFORT SEA PETROLEUM DEVELOPMENT SCENARIOS FOR THE STATE - FEDERAL AND FEDERAL OUTER CONTINENTAL SHELF

. FINAL REPORT

Prepared for

BUREAU OF LAND MANAGEMENT

ALASKA OUTER CONTINENTAL SHELF OFFICE

Prepared by

DAMES & MOORE

April 1978

Job No. 8699-009-20

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 final report is designed to provide preliminary petroleum development data to the groups working on the Alaska OCS Socio-economic Studies Program. The assumptions used to generate off-shore petroleum development scenarios may be subject to revision.

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 well spacing (acres).

ALASKA OCS SOCIOECONOMIC STUDIES PROGRAM
Beaufort Sea Petroleum Development Scenarios for the State - Federal and Federal Outer Continental Shelf, Final Report

Prepared by,

DAMES & MOORE

April 1978

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CHAPTER 1.0

INTRODUCTION

1.1 PURPOSE

In order to analyze the socioeconomic and environmental impacts of Beaufort Sea petroleum exploration, development, and production, it is necessary to make reasonable predictions of the nature of that development. The petroleum development scenarios in this report serve that purpose; they provide a "project description" for subsequent impact analysis. The socioeconomic impact analysis of the Beaufort Sea petroleum development postulated in this report is contained in another report of this study program.[1]

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 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.

It should be emphasized that this petroleum scenarios report is specifically designed to provide petroleum development data for the Alaska OCS socioeconomic studies program. The analytical approach is structured to that end and the assumptions used to generate scenarios

(1) Beaufort Sea Region Impact Assessment, Alaska OCS Socioeconomic Studies Program Technical Report No. 22, report in preparation for the Bureau of Land Management, Alaska OCS Office by Peat, Marwick, Mitchell & Co. et al., 1978.

may be subject to revision as new data becomes available. Within the study programs that are an integral part of the step-by-step process leading to OCS lease sales, the formulation of petroleum development scenarios is a first step in the study program coming before socioeconomic and environmental impact analyses.

This study follows an earlier evaluation of Beaufort Sea petroleum development for the Federal Outer Continental Shelf, which considered offshore development in isolation of future North Slope (onshore) development. The results of that study were presented in an interim report.[1] The current study involves a considerable expansion of scope although drawing upon some of the data and findings of the interim report.

1.2 SCOPE

The petroleum development scenarios formulated in this report are for the proposed joint State-Federal lease area and subsequent Federal Outer Continental Shelf (OCS) lease sale area in the Beaufort Sea (Figures 1, 2, and 3). These areas are located within that portion of the Beaufort Sea between Barter Island (144° W) and Point Barrow (156° W) from the shoreline to about the 20-meter (66-foot) isobath. The significance of the 20-meter (66-foot) isobath is that it is the water depth believed to be the limit of present or imminent technology for exploratory drilling and oil and gas production. This is because the 20-meter (66-foot) isobath marks the approximate landward boundary of significant ice movement and encroachment of the seasonal and polar pack ice.

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(1) Beaufort Sea Basin Petroleum Development Scenarios for the Federal Outer Continental Shelf, Alaska OCS Socioeconomic Studies Program Technical Report No. 3, Interim Report prepared for the Bureau of Land Management, Alaska OCS Office by Dames & Moore, Peat, Marwick, Mitchell & Co., and CCC/HOK, December, 1977.

Figure 1 - Location Map

Figure 2 - Beaufort Sea Study area - East Showing State-Federal and Federal Protraction Between Canning and Colville Rivers

Figure 3 - Beaufort Sea Study Area - West Showing Federal OCS Protraction

Current proposed OCS planning schedules indicate a joint State-Federal lease sale in December, 1979. In March, 1978, the State and Federal governments signed a memorandum of understanding on the details of the joint lease sale. A nomination map has been published identifying the tracts and area which has been put forward for calls for nomination (Figure 2). The area is located between the Canning River in the east and the Colville River in the west. It encompasses most of the area within the three-mile limit.[1] and a tier of adjacent federal tracts. Some of the tracts adjacent to the shoreline have already been leased by the State in previous North Slope lease sales and are, therefore, not included in the sale area. The area of call includes:

(1) 118 tracts containing a combination of Federal, State and disputed lands.

(2) 4 tracts containing only Federal 1 ands,

(3) 112 tracts containing only State lands, and

(4) 2 tracts containing only disputed lands.

Although over half of the area is contested, the sale will proceed according to the State-Federal agreement, which will no doubt involve the escrow of bids, royalties, and tax monies until such time that the dispute is resolved by court decision. For the purposes of the scenario analysis, it is assumed that a significant portion of the area nominated will be leased. The northern boundary of the State-Federal lease sale lies near the limit of the outer continental shelf considered "developable" in the near future. Consequently, other than a tier of Federal tracts that may be sold for drainage reasons, no extensive Federal leasing is considered in the scenario analysis seaward of the State-Federal lease sale area.

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(1) Since the three-mile state territorial limit has a legal definition, a metric (kilometer) equivalent or alternate is not given in the text.

This study also formulates petroleum development scenarios for the remaining Federal OCS located in the western Beaufort Sea between the three-mile limit and the 20-meter isobath. No sale data has been published by the Bureau of Land Management for this area which would have been available for nomination under Beaufort Sea OCS Lease Sale No. 50, which has been deferred.

Also considered in this report are future petroleum developments on the North Slope including Prudhoe Bay and current State leases between the Colville and Canning Rivers, the National Petroleum Reserve in Alaska (NPR-A), and Native corporation lands south and west of Prudhoe Bay. Additional oil reserves from discoveries in these areas are fixed by assumption (based upon the most current geologic estimates) and incorporated into the economic and transportation analysis. These resource projections for the North Slope were analyzed to assess the projected availability of oil and gas transportation facilities including the trans-Alaska pipeline, the Alcan gas pipeline, a twin trans-Alaska pipeline, a north-south oil pipeline in NPR-A and the western Arctic, and a petrochemical products pipeline.

The basis of the resource estimates used for development of the scenarios is the U.S.G.S. estimates of undiscovered recoverable oil and gas resources of the Beaufort Sea between the O- and 200-meter (656-foot) isobaths, as described in Circular 725 (Miller et al., 1975). The estimates prepared in 1975 for the Beaufort Sea are:

	Probability		Statistical
	95%	5%	Mean
Oil (Bbbl)	0	7.6	3.28
Gas (tcf)	0	19.3	8.2

In a subsequent working paper (Open-File Report 76-830, July, 1976), the U.S.G.S. provided an allocation of the resource estimate as follows:

40 percent - Federal waters between the 20- and 200-meter (66- and 656-foot) isobaths

51 percent - Federal waters between the 3-mile limit and 20-meter isobath

9 percent - State waters

A revision to the above estimates was contained in a U.S.G.S. memorandum (Memo EGS-214936, dated 11 October 1977; see Radlinski, 1977), which gave estimates for a sub-area of the Beaufort Sea -- out to the 20-meter (60 foot) isobath between longitudes 146° W and 150° W only. These estimates are:

	Low	High	Statistical Mean
Oil (Bbbl)	1.0	2.5	1.5
Gas (tcf)	1.75	6.25	3.25

1.3 METHODOLOGY

The construction of the petroleum development scenarios is based upon resource probability levels of the U.S. Geological Survey, allocated into four regions covering the Beaufort Continental Shelf out to 20 meters (66 feet) depth. An initial set of 24 scenarios is constructed for selection purposes utilizing favorable and less favorable sets of petroleum reservoir parameters, based upon U.S. averages and Prudhoe Bay experience described in Chapter 5.0.

The construction of the 24 skeletal scenarios involves the combination of resource probability levels, obtained from the U.S.G.S. estimates, with locational data produced from an independent geologic assessment of the oil and gas potential of the Beaufort Sea. The purpose of this assessment, which is presented in Appendix A, was to provide the geologic reality and geographic specificity to the location of the hypothetical oil and gas fields. The geologic analysis also provided ranges for certain oil field variables such as reservoir depths, fill factors, and oil-gas ratios. These scenario parameters are also presented in Chapter 5.0.

Each of the skeletal scenarios was subjected to a parametric economic analysis to establish approximate capital recovery after several combinations of parametric values for investment costs, tax status, transport costs, and market levels (Chapter 6.0). Procedures are developed to estimate minimum field sizes for development and transport system support. An alternative approach to scenario development used in an analysis of petroleum development for Beaufort Sea Federal OCS, presented in an interim report, is summarized in Appendix B.

Five scenarios, selected as representative of the range of geographic locations, and resource levels, were selected for detailing of the facility requirements and employment which can be generated in the circumstances of the scenarios.

The manpower framework of the scenarios is developed in Chapter 7.0 and the detailed manpower requirements and schedule of activities for each scenario are given in a series of tables in Appendix C.

The technical framework of the scenarios described in Chapter 8.0 is based upon the technology review presented in Chapter 3.0. The technical assumptions have been selected to be compatible with available and potential Arctic petroleum technology in the context of the dominant environmental constraints (sea ice, permafrost, etc.), and geologic knowledge established in available literature. The related cost data have been drawn to cover the wide range of cost experience published for the Arctic, and to permit allowance for uncertainty over future transport tariffs. Chapter 8.0 also details the equipment, materials and facilities requirements of the scenarios and discusses the logistical and locational considerations in the siting of onshore facilities for offshore petroleum development.

The report is concluded with a description of each of the selected (detailed) scenarios that includes scheduling, manpower, and facilities requirements (Chapter 9.0).

CHAPTER 2.0

REGIONAL ENVIRONMENT

2.1 PHYSICAL ENVIRONMENT

2.1.1 Physiography

To appreciate the physical setting of the petroleum region and potential State-Federal and Federal OCS lease sale areas 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 areas are located within the Arctic Coastal Plain physiographic region. For the most part this region is a smooth plain that rises gradually from the Arctic Ocean coast to an elevation of 180 meters (594 feet) in the foothills of the Brooks Range (Wahrhaftig, 1965). Located north of the Arctic Circle, the American or Alaskan 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 kilometers (380 miles). The shoreline is characterized by low relief; coastal bluffs are generally less than 3 meters (10 feet) high.

The Arctic Coastal Plain can be subdivided into two sections: the Teshekpuk section, which is a flat-lying lake-dotted plain, and the White Hills section, east of the Itkillik River, which is characterized by scattered groups of low hills. The coastal plain is at its narrowest (about 18 kilometers or 11 miles) near the Canadian border. It widens significantly to the west; at Point Barrow it is about 180 kilometers (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 Quarternary age (Black, 1964). These deposits, which are up to 45 meters (149 feet) thick, unconformably overlie Mesozoic sediments (shales, mudstones, and sandstones) west of the Colville River and Tertiary rocks east of the river.

The coastal plain is underlain by continuous permafrost up to 610 meters (2,013 feet) thick. This permafrost, coupled with the low relief, result in 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 plain is the thousands of lakes which cover an area of approximately 435,000 square kilometers (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. The major rivers have headwaters in the Brooks Range. The Colville is the largest of these rivers; it is over 690 kilometers (430 miles) long and drains about 30 percent of the Arctic Slope, intercepting much of the drainage and coarse sediments from the Brooks Range. East of the Colville many rivers also originate in the Brooks Range and transport coarse sediment. These rivers generally exhibit braided patterns and have numerous gravel and sand bars interspersed with continuously shifting channels. West of the Colville, the rivers on the coastal plain are generally shallow, poorly-integrated and have meandering channels.

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, including 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.

More detailed information on the physical features and environment of the North Slope and Beaufort Sea are available in such comprehensive references as Alaskan Arctic Tundra (Britton, 1973), The Alaskan Arctic Coast (Arctic Institute of North America, 1974), The Coast and Shelf of the Beaufort Sea (Reed and Sater, 1974), and Assessment of the Arctic Marine Environment: Selected Topics (Hood and Burrell, 1976). A detailed description of the geology and petroleum resources of the North Slope and Beaufort Sea is provided in Appendix A.

2.1.2 Climate

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 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 -35°F). Mean daily minimum temperatures for January along the Beaufort Sea coast, for example, range between -29°C (-20°F) and -32°C (-25°F). Record minimum temperatures at Barrow and Barter Island are -48.5°C (-56°F) and -50°C (-59°F) respectively. Moreover, persistently moderate (24-32 kph or 15-20 mph) to high (greater than 24 kph or 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 -73°C (-100”F) and more, during which times exposed flesh may freeze within 30 seconds. Summers are cool with average temperatures ranging from about -1°C to.7°C (+30°F to +45°F) although there are extremes of over 24°C (75°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 well insulated, which requires adding weight and bulk, which in turn restricts mobility and therefore efficiency. In summer, low clouds, fog, the tundra environment, and insects add to the decline in man's efficiency. Yet in the last three decades, civilization of the Arctic has been rapidly accelerated, first by the influx of the military (with construction and operation of the DEW line stations (1)), and more recently by the arrival of the oil industry.

2.1.3 Oceanography

Figures 4A, 4B, 5A, and 56 portray the major oceanographic conditions of the east and west portions of the Alaskan Beaufort Sea. The following discussions deal with conditions most likely to affect offshore petroleum development.

2.1.3.1 Waves and Storm Surges

Surface waves are restricted to the summer open-water season and are generally small; wind-generated waves have periods of 2 to 3 seconds and heights of less than 1 meter (3 feet). This is because of the limited fetch resulting from the offshore sea ice. Maximum swell heights of 1.5 to 2 meters (5 to 7 feet) with periods of 9 to 10 seconds have been reported during a summer storm (Wiseman et al., 1974).

The most severe wave conditions in the Alaskan Beaufort occur in summer during the passage of rapidly moving storms (provided ice conditions permit a significant fetch of open water). Maximum reported waves are over 9 meters (30 feet) and 6 meters (20 feet) near Point Barrow (Hufford et al., 1977).

Storm surges (storm-induced increases in sea level) have been recorded in the southern Beaufort Sea and may exceed 2 meters (7 feet) in height (Henry, 1975). These surges decrease to the west and are usually less than 1 meter (3 feet) near Barrow. In the southern Canadian Beaufort, hindcasting techniques have predicted the following storm tide

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(1) DEW = distant early warning (DEW line is a chain of Arctic radar Stations).

Figure 4A - Beaufort Sea
Oceanography - East

Figure 4B - Beaufort Sea

Oceanography - West

Figure 5A - Beaufort Sea
Ice Conditions - East

Figure 5B - Beaufort Sea
Ice Conditions - West

conditions for a 50-year return period. (A l-meter or 3-foot astronomical tide and 0.32-meter or l-foot pressure effect are included.) (Croasdale and Marcellus, 1977):

	Meters (Feet)	Meters (Feet)	Meters (Feet)
For These Water Depths:	2.4 (8)	6.1 (20)	12.2 (40)
Significant Wave Height is:	2.4 (8)	3.9 (13)	4.6 (15)
And Storm Tide is:	2.6 (8.5)	2.3 (7.5)	2.0 (6.5)

2.1.3.2 Bathymetry

The continental shelf of the Alaskan Beaufort Sea is narrow (no more than about 80 kilometers or 50 miles wide) and breaks at a depth of 70 to 75 meters (231 to 248 feet). The shelf remains shallow for considerable distances offshore; at Harrison Bay, for example, the 20-meter (66-foot) isobath lies as much as 72 kilometers (45 miles) offshore. The waters in the eastern Beaufort get deeper much more quickly; the 20-meter isobath at Camden Bay, for example, lies only 18.5 kilometers (11 miles) from shore.

Maximum water depths within Simpson Lagoon are about 2.0 to 2.3 meters (7 to 7.5 feet). East of Prudhoe Bay, maximum water depths shoreward of the barrier islands range from about 8.5 meters (28 feet) south of the Midway Islands to 2.3 meters (7.5 feet) south of Flaxman Island.

Numerous shoals extending west from Prudhoe Bay to Point Barrow occur at depths between 10 and 20 meters (33 to 66 feet). A relationship between these shoals and winter and summer ice conditions has been demonstrated (Reimnitz, Toimil and Barnes, 1977). Extensive shallows with water depths of less than 24 meters (79 feet) occur in the major bays: Harrison Bay, Smith Bay and Dease Inlet.

2.1.3.3 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. 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. 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,

Sea ice can be divided into four general zones: (1) fast ice zone, (2) grounded ridge zone, (3) seasonal pack ice zone, and (4) polar pack ice zone {Figures 5A and 5B). Several alternate classifications are shown on Figure 6. In general, only the fast ice zone will occur within the proposed developable region of the OCS lease sale areas, but even this region will experience frequent encroachment of the pack ice during the early period of ice growth (fall).

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-meter (66-foot) isobath.

Nearshore fast ice, or the inner belt, begins to develop during early October, growing in thickness to about 2 meters (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.

Figure 6 - Ice zones (Spring)

The outer fast ice belt of floating ice is topographically characterized by fields of ridges and hummocks. During the fall freeze-up, 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 which is generally thin and weak at this time. Ice movement may be significant at this time (hundreds of meters) but as the ice thickens during the winter, its movement decreases. During the winter, net ice movement is small (a few meters) within the barrier islands. Outside the barrier islands or at locations not protected by them, greater movement occurs and increases with distance from the coast (Barry et al., 1977). Typical landfast ice movements recorded in the southern Canadian Beaufort Sea in 1970 are shown below (Croasdale and Marcellus, 1977):

Water Depth In Meters (Feet)	First-Time Interval In Days	Gross Movement In Meters (Feet)	Second-Time Interval In Days	Gross Movement In Meters (Feet)
56 (185)	33	19 (63)	28	5 (15)
28 (92)	20	30 (97)	39	19 (62)
30 (99)	14	6 (20)	27	2 (7)

The seaward extent of the fast ice varies with the protection offered by the shoreline, water depth, time of year, and magnitude of pack ice forces along each section of the coast (Kovacs and Mellor, 1974). It has been demonstrated that during early winter the location of the boundary between undeformed fast ice and the westward moving polar pack ice is controlled by major coastal promontories (Reimnitz, Toimil and Barnes, 1977). The seaward fast ice boundary generally lies between the 10- and 20-meter (33- and 66-foot) isobaths. Grounded ice ridges protect the fast ice located shoreward, although at some locations during the winter and early spring the actual location of the fast ice edge may extend well beyond this zone (as in the vicinity of Cross and Narwhal Islands).

Initiation of breakup in May and early June occurs when river flow commences and open water forms near river mouths and extends offshore (Short and Wiseman, 1975). The fast ice becomes thinner and weaker and commences to break up in July. The open-water season generally lasts until late September. Based on 1973-75 data, the Beaufort Sea coast fast ice regime has been summarized as follows (Barryet al., 1977):

May 25	Rivers flooding estuarine ice
June 11	Incipient puddling
June 29	Openings in shorefast ice
July 7	End of period of stable ice
July 31	Coastal zone largely ice free to 10- to 15-meter isobath
October 1-5	New ice forming

Grounded Ridge Zone

The grounded ridge zone could be classified as part of the fast ice zone since it comprises linear pressure and shear ridges that are stabilized by grounding between the 10- and 20-meter (33- and 66-foot) isobaths (Reimnitz, Toimil and Barnes, 1977). This zone, which is termed the "stamukhi zone", forms the dynamic boundary between the fast ice and westward-moving pack ice. During the fall, fast ice grows seaward from the coast until it interacts with moving pack ice in the vicinity of the 10- to 20-meter isobaths. Pressure and shear ridges and hummock fields form along this boundary, and are stabilized by grounding. As winter progresses, intermittent slippage along this boundary forms new grounded ridge systems seaward of the older inshore ridges. The result is a widening zone of grounded ridges that, by the late winter, may extend out to the 40-meter (132-foot) isobath. Ice gouging of the shelf's surficial sediments is greatest within this zone.

There is a correlation between the areal distribution of linear ice ridge systems and shoals. (Reimnitz, Toimil, and Barnes, 1977). At the fast ice/pack ice boundary during the fall, pressure and shear ridges ground on shoals and coastal promontories, forming the innermost part of the stamukhi. Subsequent ridging and grounding increases the area of the stamukhi seaward through the winter. Shoals and small islands thus stabilize and protect the fast ice edge.

Seasonal Pack Ice Zone

The seasonal pack ice zone extends northward 95 to 160 kilometers (60 to 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. A gradual steepening of regional surface barometric gradients results in an onshore wind pattern. Severe onshore fall storms modify significantly the overall character of any first-year ice cover which might form, and it can introduce ice island fragments and multi-year flows floating off the periphery (slippage region) of the polar pack. Although seasonal pack ice becomes more compact as winter intensifies and, therefore, more resistant to penetration by the polar pack, it varies considerably from season to season and from year to year.

As discussed above, the interaction between the fast ice and seasonal pack ice results in the formation of pressure and shear ridges which become grounded between the 10- and 20-meter (33- and 66-foot) isobaths. Occasionally during the winter the ice in the seasonal pack ice zone will shift away from the edge of the fast ice, forming a lead (open water); a recurring lead 30 kilometers (18.6 miles) or more wide is a common phenomenon off Barrow.

Polar Pack Ice

The polar pack ice, consisting mainly of multi-year floe ice 2 meters (7 feet) and more thick, drifts westward 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). 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 kilometers or 30 miles) at the boundaries.

Ice thickness varies from first-year thin ice in leads and polynyas to multi-year floes 1.8 to 3.6 meters (6 to 12 feet) thick (or more) to ice island fragments and pressure ridges which can reach 45 meters (150 feet) or more in depth. The intensity of ridging varies, depending on the season, the area, and the year; it is generally 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); average height about 3 meters (10 feet); and the height ratio of keel to sail 3 to 1. Ridges can exceed 15 meters (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 inshore as the outer fast ice belt.

Ice Scour

The grounding of the pressure ridges and shear ridges that are formed in the stamukhi zone is responsible for many of the extensive gouges or scours that commonly occur in water depths of 15 to 45 meters (50 to 150 feet), and which have a maximum concentration at a 30-meter (100-foot) depth. (For a discussion of sea ice as a geologic agent in the Beaufort see Reimnitz and Barnes, 1974.) Table 1 summarizes scour zones in the southern Beaufort Sea.

Ice scour in the coastal shelf zone (less than 7 meters or 23 feet deep) is caused by fragments of broken ice islands or other

TABLE 1

BOTTOM ICE SCOUR ZONES SOUTHERN BEAUFORT SEA

Region	Water Depth In Meters (Feet)	Typical Scour Depth In Meters (Feet)	Maximum Scour Depth In Meters (Feet)	Frequency of Scour Tracks
Coastal Shelf	0-7 (0-23)	Less than 0.5 (2)	No data	Very frequent
Mid-Shelf	7-30 (23-99)	Less than 1.5 (5)	3-4 (10-13)	10-15 per kilometer (20-25 per mile)
Outer Shelf	30-80 (99-264)	No data	10 (33)	Slight beyond 45-meter (150-foot) depth

Source: Kovacs, 1972.

small pieces of ice; the scour may be very frequent but is generally shallow (less than 0.5 meter or 2 feet) (Kovacs and Mellor, 1974). In the mid-shelf zone (7 to 30 meters or 23 to 99 feet deep) considerable scouring is caused by the grounding of ice islands and/or pressure-ridge keels. The scours occur with a frequency of 10 to 15 per kilometer (20 to 25 per mile) and have an average depth of less than 1.5 meters (5 feet) . Scour relief up to 10 meters (33 feet) occurs in the outer shelf, which is 30 to 80 meters (99 to 264 feet) deep. However, there is a rapid decrease in frequency beyond the 45-meter (150-foot) depth. Most of the scouring in this zone is either relict or caused by ice islands.

2.1.3.4 Subsea Permafrost

Sub-seabottom permafrost exists over much of the Beaufort Sea shelf (Hunter and Judge, 1975; 'Hunter et al., 1976; MacKay, 1972). In the southern Beaufort Sea, permafrost thicknesses from 60 meters (200 feet) at shore to 100 meters (330 feet) offshore have been reported. At Prudhoe Bay, ice-bonded permafrost exists nearly up to the sea bed within 200 meters (660 feet) of the shore. At 3.2 kilometers (2 miles) from the shore, there is an unbended layer 45 to 70 meters (150 to 230 feet) thick (Osterkamp and Harrison, 1976). Subsea permafrost at Prudhoe is present to at least 3.4 kilometers (2.1 miles) offshore.

Seismic refraction studies at Elson Lagoon and in the vicinity of Point Barrow did not indicate bonded permafrost beneath the water, although it is possible that it exists beneath the lagoon below a plane dipping 30 degrees seaward (Rogers et al., 1975). There are little data available on the nature and distribution of offshore permafrost in the Beaufort Sea, and the three areas in which permafrost studies have been conducted differ significantly in their geologic and oceanographic settings. However, on a general level, the distribution of offshore permafrost on the shelf of the Alaskan Beaufort Sea can be predicted on the basis of bathymetry (Hopkins et al., 1977):

1) In the nearshore areas where the fast ice is grounded, ice-bonded equilibrium permafrost exists at depths of a few meters. Ice-rich permafrost must be anticipated wherever the water is less than 2 meters (7 feet) deep.

2) Since ice-bonded permafrost was once present beneath all parts of the continental shelf during the last low sea level of the most recent glaciation (the Alaskan portion of the shelf was for the most part free of glacial ice), relict ice-bonded permafrost must persist beneath any part of the shelf inshore from the 90-meter (290-foot) isobath. Observed depths of relict permafrost range from 10 meters (33 feet) near the present coast to 250 meters (825 feet) far off the Canadian coast.

3) *Seaward from the 90-meter (295-foot) isobath, ice-bonded permafrost is probably absent from parts of the Beaufort Sea shelf, although subsea temperatures are probably below 0°C (32°F) .

2.1.4 Comparison of State-Federal and Federal OCS Lease Sale Areas

This section summarizes the major physical contrasts between the State-Federal lease sale area and the Federal OCS of the Alaskan Beaufort Sea between the 3-mile limit and the 20-meter (66-foot) isobath. The engineering significance of these contrasts for offshore petroleum development is discussed in Section 3.2.

In addition to the seaward zonation of physical conditions in the Alaskan Beaufort, such as sea ice, subsea permafrost, and bathymetry, there are important east-west contrasts that should be noted. The major contrasts are:

1. With the exception of a narrow zone seaward of the Jones, Maguire and Stockton Islands, the State-Federal lease sale area lies within the fast ice zone. Formation of shear ice ridges occurs seaward of the barrier islands. In contrast, some of the Federal OCS lies within the shear ice zone (stamukhi) at some time during the winter between depths of 10 and 20 meters (33 and 66 feet). For example, a well-defined shearline occurs in Harrison Bay just seaward of the 10-meter isobath (Reimnitz, Toimil and Barnes, 1977). By mid-June, however, the limit of continuous fast ice lies near or seaward of the 20-meter isobath and therefore encompasses most of the Federal OCS (to the 20-meter isobath).

2. Grounded fast ice occurs in extensive areas within the 2-meter (7-foot) isobath and is thus restricted to the inshore zone of the State-Federal lease sale area. Grounded fast ice covers most of Simpson Lagoon and is continuous between the shore and the Maguire Islands east of Mary Sachs entrance.

3. Ice gouging is concentrated in the stamukhi zone. The gouges are generally less than 1 meter (3 feet) deep shoreward of the zone and are commonly more than a meter deep within and seaward of the stamukhi. Intense ice gouging does not occur, therefore, within the State-Federal lease sale area except locally seaward of the Jones, Stockton and Maguire Islands.

4. By definition, the potential Federal OCS lease sale area terminates seaward at approximately the 20-meter (66-foot) isobath. The outermost tracts of the State-Federal lease sale also straddle the 20-meter isobath. Minimum water depths at the 3-mile limit outside the State-Federal lease sale area occur off the Colville River delta and range from 0.5 to 1 meter (1.7 to 3 feet). Without a defined Federal OCS lease sale area to permit a direct comparison, only a general

statement can be made concerning bathymetric contrasts. Shallower water depths will be encountered in the State-Federal lease sale area, although maximum water depths in both State-Federal and Federal OCS lease sale areas are similar (about 20 meters or 66 feet). Also important are the east-to-west bathymetric contrasts, particularly with respect to the position of the 20-meter isobath and the inshore area encompassed by that water depth.

5. In the State-Federal lease sale area the barrier islands afford a degree of protection to the inner shelf from late summer and fall storms and encroaching pack ice. Some of the barrier islands such as Cross Island and Narwhal Island control the configuration of the stamukhi zone, absorbing much of the available marine energy.

6. Ice-rich subsea permafrost, which is anticipated at depths of a few meters below the sea floor in water depths of less than 2 meters (7 feet), is mainly confined to the inshore zone State-Federal lease sale area and landward of the 3-mile limit. The only area of the Federal OCS that may be underlain by ice--rich near-surface permafrost is southern Harrison Bay off the Colville River delta. Elsewhere, the Federal OCS lies within a zone in which ice-bearing subsea permafrost is probably widespread but generally below 50 meters (150 feet).

7. There are insufficient data to make a detailed comparison of the offshore sand and gravel resources between the State-Federal lease sale area and the Federal OCS. A contrast probably exists on a regional level from east to west in the Alaskan Beaufort and adjacent onshore areas in terms of gravel and sand availability (see Section 2.3.1). Preliminary data indicates that sandy bottom sediments occur from the Kavik River in the east to the Kuparuk River in the west, and seaward

to about the barrier islands; these deposits are therefore located within the State-Federal lease sale area. In contrast, sandy bottom sediments between Prudhoe Bay and the Colville River are located seaward of the Jones Islands (in the Federal OCS), while the bottom sediments in Simpson Lagoon are silts. Sand occurs offshore from the Colville River delta and extends into the Federal OCS. West of the Colville, bottom sediments are predominantly silts and clays. These observations concern surficial deposits; sand and gravel may be present or absent in subsurface horizons.

8. With respect to the "developable" OCS (the landfast ice zone to the 20-meter or 66-foot isobath that can be developed with current or imminent technology), it should be noted that the seaward boundary of the planned State-Federal lease sale area lies close to the 20-meter isobath and the limit of landfast ice. Since the barrier islands are included in the State-Federal OCS, the 3-mile limit is further offshore (from the mainland) in the State-Federal lease sale area, especially near Cross Island, than other sections of the Beaufort Sea coast where barrier islands are absent.

2.2 ECOLOGY

2.2.1 Terrestrial

The Beaufort Sea coast is a gently undulating tundra plain dotted with innumerable ponds and lakes interspersed with wet meadows. Sedges, rooted aquatics and riparian willows form the dominant plant cover west of the Sagavanirktok River; however, there is a gradual decrease in wet meadows to the east, and cottongrass tussock tundra becomes more prevalent. There is a profusion of flowering plants throughout the summer. The barrier islands, a few hundred meters offshore, reduce sea wave effects on the shore and result in quiet shallow lagoons on the leeward side. Figure 7 shows the major vegetation types and surface drainage in the study area.

The truly resident wildlife are few in number. Only the caribou, musk oxen, polar bear, wolf, Arctic fox, raven, snowy owl, Arctic hare, ground squirrel, vole, and lemming remain through the . winter period. However, from May through September the coastal fringe is invaded by hundreds of thousands of migrating waterfowl, shorebirds and terrestrial birds, including more than 150 species. Figures 8A through 8D show the major fish and wildlife patterns in the study area.

Birds from all four continental flyways nest on the shores of the Beaufort Sea. The most concentrated waterfowl use occurs in the rich estuarine waters, while shorebirds frequent gravel bars, ponds, and sedge-grass marshes. The sandpipers and phalaropes are the most abundant shorebirds (Bergman, 1974). Arctic loons, red-throated loons, oldsquaws, eiders, pintails, white-fronted geese, lesser Canada geese, and black brant are the most common waterfowl (Bergman, 1974; Gavin, 1974). There are also glaucous gulls, Ross gulls, Sabine's gulls, Thayers gulls, Arctic terns, and all three types of jaegers.

Raptors include snowy owls, rough-legged hawks, golden eagles, gyrfalcons and peregrine falcons. Willow ptarmigan are present through the summer. Lapland longspur and snow bunting are the most common passerine species between Point Barrow and the Canning River (Bailey, 1948) .

Terrestrial mammals found near the beach include caribou, Arctic fox, musk oxen, wolves, Arctic ground squirrels and occasional grizzly bears.

There are four caribou herds: the Arctic herd in the west, the Central Arctic herd near the Sagavanirktok River, the Porcupine herd

Figure 7 - North Slope Regional Vegetation and Surface Drainage

Figure 8A - Beaufort Sea and North Slope Major Fish and ~~Wildf~~ Wildlife Patterns - Birds, East

Figure 8B

Beaufort Sea and North Slope Major Fish and Wildlife Patterns - Whales and Birds, West

Figure 8C

Beaufort Sea and North Slope Major Fish and Wildlife Patterns - Mammals and Fish, East

Figure 8D

Beaufort Sea and North Slope Major Fish and Wildli

Patterns - Mammals and Fish, West

in the east, and a small resident herd between Teshekpuk Lake and the Colville River (Davis and Valkenburg, 1977; Hemming, 1971; Cameron and Whitten, 1976, 1977; White et al., 1975). At times each of these herds overlap in the vicinity of Prudhoe Bay.

Major caribou activity on the coast begins in May and June when the Porcupine, Central Arctic, and Teshekpuk herds move to traditional calving grounds near the beach. The Arctic herd calving area is well away from the coast at the headwaters of the Colville, Utukok and Ketik Rivers. The calving ground of the Central Arctic herd extends from Oliktok eastward to Bullen Point. However, since 1974 this herd has been displaced from the portion of their calving area that formerly included the Prudhoe Bay oil field (White et al., 1975; Hemming and Morehouse, 1976). The Porcupine herd also calves along the coast between the Katakturuk and Kongatut Rivers. In late summer, when biting insects increase in abundance, many caribou move onto river deltas where lower temperatures and nearly constant winds offer some relief from insect harassment.

Wolves are not common along the beach fringe, but they do follow caribou herds, particularly during the winter. Occasionally small numbers of caribou spend the winter along the coast between the Colville and Sagavanirktok Rivers. Musk oxen range in the western portion of the Arctic National Wildlife Range from Barter Island on the east to the Canning River on the west..

The coastal inshore zone is an important denning area for Arctic foxes. Beach ridges, river deltas and pingos are good denning habitat. Once dens are established, they tend to be used again each year. During the winter, when foxes gather in numbers at food sources, rabies epidemics can be expected. Animals are easily attracted to human use areas with improper garbage disposal and could easily spread the disease by biting other animals and humans. The customary procedure when a rabid fox is discovered is to shoot all foxes in the area.

2.2.2 Aquatic

More than 30 species of fish have been recorded in nearshore habitats of the Beaufort Sea (Outer Continental Shelf Environmental Assessment Program, 1977c). Arctic char and Arctic cisco are the most abundant and widespread (Bendock, 1976). Adult whitefish have been found only within the river systems, but shallow bays and lagoons are important feeding and migration areas for immature whitefish. Arctic cod ("Tom cod") are seasonally abundant. Each of these species is sought by local residents for both human and dog food.

Among the nearshore fishes, species diversity is low. Anadromous species migrate and concentrate along shallow coastal estuaries. Freshwater fishes are found in the rivers and occasionally in the estuaries when salinities are low. Most of the coastal streams freeze up each winter leaving only occasional unfrozen pools under the ice. These nonfrozen pockets are critical habitat for overwintering anadromous and resident fishes such as Arctic char, Arctic cisco, least cisco, grayling and round whitefish. These areas are extremely vulnerable to the effects of activities such as seismic shots, gravel mining, water removal, and chemical disposal.

Marine fish species such as the fourhorn sculpin, Arctic flounder and Arctic cod are found in brackish waters during the ice-free summer season, but apparently move farther offshore in winter (Outer Continental Shelf Environmental Assessment Program, 1977c). The waters surrounding nutrient-rich river deltas are critical habitat for larval and juvenile fish.

2.2.3 Marine

Summer marine and waterfowl habitats support a diversity of mammals, birds and fish, including commercial and subsistence resources for the villages of Wainwright, Barrow, 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 the shallower waters, bearded, ringed and spotted seals feed on bottom-dwelling invertebrates and fish. The belukha and endangered bowhead whales congregate in Wainwright, Barrow and Harrison Bays (Figure 8B) (Selkregg, 1975; Burns, 1978, personal communication).

Lagoons are nesting and molting sites for waterfowl, resting areas for migratory geese, nurseries for young waterfowl, and feeding grounds for many shorebirds.

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).

The bowhead whale is an endangered species, numbering 1500 to 3000 animals. Each spring in April and May these large cetaceans migrate northward from the Bering Sea through the flaw zone to the Beaufort Sea and Amundsen Gulf (Fiscus, Marquette and Braham, 1976; Alaska Department of Fish and Game, 1977). They pass very close to shore off Point Barrow. In September they return to their wintering grounds, passing near shore from Cape Simpson to Point Barrow. These large mammals feed on marine invertebrates. Recent sampling indicates that euphausids are a primary food item in the vicinity of Point Barrow (Fiscus, Marquette and Braham, 1976).

The belukha whale population off the Bering and Beaufort Seas is estimated to contain at least 5,000 individuals. They are gregarious mammals and occur in nearshore waters, including large rivers and areas above the tidal influence. Herds of 100 to 1000 animals have been observed during migration, but small groups of 2 to 15 whales are most common. Timing of migration is dependent on ice conditions, but belukhas usually arrive in the Arctic during April. Some groups return to the same ice-free area each summer. Young are born from May through July. As ice begins to form in the fall, the whales migrate south where leads are abundant or the area is ice-free. Belukhas depend on fish for food and often concentrate in estuaries when species such as smelt or salmon smelt are abundant (Alaska Department of Fish and Game, 1977).

Three species of ice-inhabiting hair seals occur regularly in the Beaufort Sea. Within nearshore waters, the ringed seal is the most abundant, followed by the spotted seal and bearded seal. Only limited information exists about these populations due to inadequate census technology and minimal research emphasis in the past but recent continental shelf studies are now increasing the data base (Alaska Department of Fish and Game, 1977; Lowry, Frost and Burns, 1977).

Species distribution commonly overlaps, but each seal species is usually found in distinct geographical areas. Adult ringed seals are found predominantly in areas of land fast ice in the winter and in broken floating ice during the summer. Spotted seals inhabit the outer edge of the pack ice in winter and remain near coastal areas or islands during the summer. Bearded seals prefer moving ice in the winter and broken floes of polar ice (over shallow water) in the summer.

Food requirements between seal species are quite different. Spotted seals utilize demersal, anadromous, and pelagic fishes. Ringed seal forage varies seasonally but predominant food items include zooplankton, shrimp, copepods, and other small marine organisms. Bearded seals are bottom feeders, relying mostly on crabs, mollusks, and small bottom fish.

Polar bears occur throughout Arctic waters and onshore areas of the Beaufort Sea. Pregnant females excavate dens in river banks, or on the ice where there is sufficient snow accumulation. Dens may be used from December until April. Present information indicates that some of the most important denning habitat on the Alaskan coast extends from the Colville River east to the Canadian border. This zone is about 80 kilometers (50 miles) wide and includes a corridor of land extending about 40 kilometers (25 miles) from the coast and the strip of adjoining shorefast ice (Outer Continental Shelf Environmental Assessment Program, 1977c). Males and nonpregnant females remain active year round on moving pack ice.

North of Point Barrow polar bears move east toward Barter Island where ice is more stable. The southern edge of the ice pack varies in position during summer, depending upon the winds. It can be lodged against the shore or can be as far as 160 kilometers (100 miles) offshore. Polar bears generally stay with the moving ice during the summer and concentrate on its southern edge where seals are abundant.

Polar bears are easily attracted to unburned garbage material at villages and exploration camps. This poses serious problems because these large bears are not. afraid of man and have been known to attack with essentially no provocation. Once bears become a nuisance they are usually killed (Stirling et al., 1975; Milke, 1977).

2.2.4 Hunting and Fishing

The coastal peoples of the Arctic harvest caribou, small game such as ptarmigan and owls, bird eggs, whales, seal and fish as part of their food resource. Spawning areas, overwintering fish sites, calving grounds, and nesting sites require special protection to assure long-term viability for food production. Figure 9 indicates the village subsistence hunting and fishing areas.

Fish and wildlife resources within a day's access of communities are used intensively. In the nearshore areas, spotted seals, ringed seals, and bowhead and belukha whales are taken. Ringed seals are the most common species taken by local village residents. Traditionally seals were used by coastal residents for food, oil, dog food, boat coverings, clothing and other practical items. Natives still depend on seals for some products, but a continuing shift to a cash economy has reduced this dependence.

Figure 9

Beaufort Sea and North Slope Hunting and Fishing Patterns

In the 1960's, harvests of the four species of hair seals in all Alaskan waters averaged about 18,000 per year. Declines in utilization from cultural changes and controls imposed by the Marine Mammal Protection Act have resulted in harvests of 7,000 to 9,000 animals per year since 1972 (Alaska Department of Fish and Game, 1977). Seals are usually hunted on foot, by boat, or a combination of both. Foot hunters usually walk to a suitable lead and wait for seals to surface, while boat hunters may pursue seals in open water or locate seals resting on ice or land. Although winter hunting has been popular, the majority of seals are presently killed in the spring during break-up or in the fall before freeze-up.

Harrison Bay is an important belukha whale 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 whitefish. The largest subsistence fisheries in the Arctic are conducted at Point Barrow, Kaktovik and Point Hope, mainly taking whitefish, cisco and Arctic cod (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 Coastal Plain 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 bears, Arctic foxes and other fur-bearing animals are sought for their commercially-marketable fur. Marine mammals, with the exception of the polar bear and walrus (which occur only rarely in the area;

Burns, 1970; Stirling et al., 1974), may be used for subsistence or commercial handicrafts only by Natives, as stipulated by the Marine Mammal Protection Act of 1972.

2.3 RESOURCES

2.3.1 Gravel

2.3.1.1 Onshore Deposits

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-A, 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 coastal plain are devoid of gravel deposits with the exception of the northwestern shore of Teshekpuk Lake, which has estimated reserves of 688,000 cubic meters (900,000 cubic yards) (Labelle, 1974). Gravel resources in the study area are shown on Figures 10A and 10B.

Within 40 kilometers (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). The Beaufort Sea shores of NPR-A, which are actively eroding by thaw action, have some sand and gravel resources, notably in the spit and barrier island

Figure 10A

Beaufort Sea and North Slope Gravel and Sand Resources - East

Figure 10 B -

Beaufort Sea and North Slope Gravel and Sand Resources - West complex that commences at Eluitak Spit and runs nearly as far east as Cape Simpson. Labelle (1976) estimates that this complex contains nearly 3 million cubic meters (4 million cubic yards) of fill material. Cooper Island, for example, located about 40 kilometers (25 miles) east of Barrow, contains over 1.5 million cubic meters (2 million cubic yards) of coarse material, while the remainder of the Plover Island chain contains only 530,000 cubic meters (700,000 cubic yards) of sandy gravel and gravelly sand.

Only small sporadic accumulations of coarse materials are found on the mainland shore. East of the spit/barrier island complex, between Cape Halkett and Drew Point, 1.2 million cubic meters (1.6 million cubic yards) of gravel and coarse sand exist along coastal beaches. In Smith Bay, the beaches are only composed of sand and mud, as are the few beaches in Harrison Bay. The Colville delta consists of only fine sand and mud.

The principal source of coastal sand and gravel is believed to be the Pleistocene Gubik formation, which is a mixed marine and alluvial deposit comprised of silt, sand and gravel that underlies most of the coastal plain. Coastal erosion and bluff collapse provide the sediment which is winnowed by currents and wave action, leaving behind the coarser sand and gravel fractions as lag deposits. These in turn are transported along the coast. by longshore drift forming beaches, spits, bars and barrier islands. Shoreline deposition by ice push and ice melt contribute minor amounts of the sediments deposited above sea level.

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 of NPR-A 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. The major rivers east of the Colville are generally braided gravel streams which have their headwaters in the Brooks Range.

Recent geologic investigation of the Beaufort Sea coast and barrier islands has provided new data on coastal gravel resources (Hopkins, 1977). This investigation revealed that the barrier islands originated from multiple sediment sources and were mainly derived from hillocks of Pleistocene sediments that have been partially drowned and left as tundra-covered islands. The source hillocks have been completely removed by erosion, and the present, residual islands are gradually migrating westward and landward from the original source areas. Hopkins (1977) concludes that if the islands were quarried for gravel, they would not be replaced by natural processes. There are, however, areas along the mainland coast where gravel is accumulating in spits and accretionary bars from which borrow could be removed with minimum adverse effects. From the Kuparuk River to the Canning River on the Beaufort Sea coastal plain, subsurface gravel deposits are ubiquitous at depths of 10 meters (33 feet) or less. Development of upland borrow sites in these deposits or by deepening thermokarst lakes may be an alternative to extraction from river bars and channels. Additional information on coastal gravel and sand deposits has been gathered in recent coastal geomorphology studies (Cannon, 1977; Lewellen, 1977).

2.3.1.2 Offshore Deposits

Few data are available on offshore sea floor and subsurface gravel and sand deposits. These possible deposits are particularly important with respect to potential demand for offshore aggregate for artificial island construction. On a regional scale, from the shoreline to the 20-meter (60-foot) isobath, east of the Colville River delta, the bottom sediments consist mainly of sands and gravels. West of the delta sediments are silts and clays (Outer Continental Shelf Environmental Assessment Program, 1977c).

The stratigraphy and thickness of offshore sediments in the inner shelf of the Beaufort Sea between the Colville River and Tigvariak Island have been mapped by the U.S. Geological Survey (Reimnitz, Wolf and Rodeick, 1972), using shallow seismic techniques. Holocene marine deposits, consisting predominantly of muddy sand, range in thickness from 25 meters (83 feet) in the eastern part of the area to 5 meters (16 feet) or less near the Colville River delta. A series of borings in Prudhoe Bay extending from the North Prudhoe Bay State No. 1 well to Reindeer Island indicated that the subsea soils are sandy gravel with some silt overlain by a thin layer of silty sand. This layer increases in thickness from a few meters nearshore to about 14 meters (46 feet) at 3.4 kilometers (2.1 miles) offshore. Seaward of the barrier islands bordering Simpson Lagoon, the sediments are generally less than 5 meters (17 feet) thick. A summary of current knowledge of Beaufort Sea sediments is contained in Arctic Project Bulletin No. 15 (OCS Environmental Assessment Program, 1977c). Sandy bottom sediments are generally confined to the shelf area east of Cape Halkett. Local areas of gravel, much of which is derived from erosion of coastal bluffs, occur with increasing abundance east of the Colville River delta. West of Cape Halkett clayey sediments predominate.

2.3.1.3 Environmental Problems

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 adjacent to NPR-A have been used as, gravel borrow sources by the U.S. Navy.

Arctic scientists have listed sources of fill material in increasing order of preference (OCS Environmental Assessment Program, 1977c):

1. Barrier island systems.

2. Beaufort Sea beaches and sea bottom inside the 5-meter (16-foot) isobath.

3. River beds.

4. Sea bottom outside the 5-meter (17-foot) isobath.

5. Terrestrial mining of the open pit type.

6. Abandoned artificial islands and causeways (recycling). This practice has already been adopted in the southern Canadian Beaufort Sea.

An unofficial list of suggested areas of environmental regulations reflecting scientists' concerns with respect to fill material extraction is contained in Arctic Project Bulletin No. 16 (OCS Environmental Assessment Program, 1977d).

The"gravel requirements of various facilities for Beaufort Sea petroleum development are given in Chapter 8.0.

2.3.2 Water

Water will be required for base camps, hydrostatic testing, reinfection into wells[(1)], mixing drilling mud, and 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

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(1) Injected water for reservoir pressure maintenance need not be fresh water; brackish or salt water may provide the necessary requirements depending upon reservoir conditions. At Prudhoe Bay, for example, a Cretaceus brackish water aquifer may be a suitable waterflood source (Beazley, 1978).

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 and 600 meters (594 and 1,980 feet). In addition, the water is often brackish and generally not suitable for industrial or 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).

2.4 LAND USE

2.4.1 Local Communities

Figure 11 indicates the land status of the study area. Two very large portions of the area are taken up by the Arctic National Wildlife Range, administered by the U.S. Fish and Wildlife Service, and the National Petroleum Reserve-Alaska, under the jurisdiction of the Department of the Interior. Almost all of the area is included in the domain[1] of the Arctic Slope Regional Corporation. Local government comes under the jurisdiction of the North Slope Borough. The following information comes from either Alaska Consultants (1978) or Alaska Planning and Management (1972), unless otherwise noted.

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(1) Domain here refers to the territory selected by the North Slope Eskimos (Arctic Slope Regional Corporation) under the Alaska Native Claims Settlement Act of 1971. Within this territory ASRC may select Federal lands not already patented to others -- such as the State of Alaska -- or already held in reserve -- such as NPR-A and the Arctic National Wildlife Range.

Figure 11

North Slope Land Status

There are five major North Slope settlements: Point Hope (to the west of the study area), Barrow, Wainwright, Kaktovik, and Anaktuvuk Pass (to the south of the study area). Three smaller communities are Point Lay (to the west of the study area), Nuiqsut, and Atkasook. There are also small groups of people at Lonely and Deadhorse, connected with DEW line and petroleum operations. All of the communities are primarily Eskimo and still rely to varying degrees on a subsistence lifestyle. Employment is primarily government- or military-related.

The largest community in the area is Barrow, which is a first-class city and serves as the borough seat. The 1977 population of Barrow has been estimated at 2,700, approximately 90 percent of which is Eskimo. This figure represents about a 30 percent increase over the 1970 population of 2,104. The current estimated annual average full-time employment is 915. Nearly half of those employed work for the North Slope Borough and over 100 work for the Naval Arctic Research Laboratory. Facilities in the community include a U.S. Weather Bureau station, U.S. Public Health Service Hospital, a community center, a bank, two hotels and restaurants, three churches, and five general stores. A DEW line station is nearby and there is a local airstrip. Water is supplied by two private hauling companies. Electricity and gas are available, but there is no community sewerage system (Alaska Division of Economic Enterprise, 1974).

The second largest community in the study area is Wainwright, with a 1977 estimated population of 398, of which 97 percent is Native. The population has been increasing since 1950, when it was 227. Employment is estimated at only 57 (annual average full-time), half of which is government-related. Wainwright has three stores, a movie theatre, a tank farm, and an airstrip.

Kaktovik’s population (88 percent Native) increased from 120 in 1960 to 134 in 1977. Employment is estimated at approximately 36, almost two-thirds of which is government work. In addition, 63 people live and work at the nearby DEW line station. Community facilities are very limited, but there is a local airstrip.

Nuiqsut and Atkasook are two traditional villages which have been resettled as part of the Native Claims Settlement Act. Atkasook had a population of 50 in 1967, zero in 1970, and 86 in 1977. Nuiqsut had a population of 86 in 1939, was not in the 1970 census, and had 157 inhabitants in 1977. 'Employment there now is estimated at 42, three-quarters of which is government-related. Nuiqsut has one store, a school, and a post office.

2.4.2 Existing Petroleum Development and Facilities

Beaufort Sea petroleum development should be considered in the context of existing petroleum development on the North Slope. The purpose of this section is to summarize that development and related infrastructure. For an overview of the status and future of Alaskan petroleum development, including the North Slope and Beaufort Sea, following completion of the Alyeska pipeline the reader is referred to an article by Wilson (1977). Figure 12 shows major petroleum facilities currently in the study area. As indicated in Appendix A, current exploration and production activity on the North Slope includes:

1. Prudhoe Bay.

2. NPR-A .

"3* Central-southern North Slope.

2.4.2.1 Prudhoe Bay

Exploration continues around the periphery of the Prudhoe Bay field, principally on a coastal strip between the Canning and Colville Rivers. The exploration is being conducted on state leases and includes

Figure 12

Existing North Slope Petroleum Development some leases which extend or are located offshore. Petroleum activities include development drilling in the Kuparuk formation to define the oil pool limits and assess the economic viability of Kuparuk production (Oil and Gas Journal, October 3, 1977). (Kuparuk production would use the spare capacity on the Alyeska pipeline, which could have a maximum 2 million bbl/day capacity with the addition of four pump stations.)

Prudhoe Bay has, to some extent, been both an overland and airborne staging area for exploration operations since a number of oil field services and suppliers are located there. However, some Prudhoe Bay facilities are devoted exclusively to the operation of that field. The extent to which Prudhoe Bay has served as a support base has varied considerably with exploration operators. The existing infrastructure will increase with the construction and operation of the Alcan gas pipeline. A full discussion of petroleum development logistics for the scenarios and the role of Prudhoe Bay is given in Chapter 8.0.

Generally, much of the well equipment, supplies and manpower for exploration activities are flown directly to the site from rear staging areas such as Anchorage or Fairbanks. Drill rigs, which take about 80 to 90 loads by Hercules C-130 aircraft to transport to the site, are mobilized from Anchorage, Fairbanks, Canada or the lower 48. Mobilization, installation of the drill rig, and drilling is usually conducted in winter. An airstrip, constructed of snow or ice, is located as close as possible to the well site. There are, however, a number of existing airstrips that can be used for support of exploration drilling if fortuitously located with respect to a given well site. These airstrips are listed in Table 2 (Arctic Institute of North America, 1974). Some exploration wells (e.g., Exxon’s Pt. Thompson well in 1977) have been drilled by rigs already located in Prudhoe and mobilized to the site overland by ice/snow road.

TABLE 2

NORTH SLOPE AIRPORT AND AIRSTRIP FACILITIES

Name	Location	Elevation (feet)	Operational Status	Runway Length	Surface	Runway Lighting	Fuel	Emergency Services	Approximate Distance From Coast (miles)	Tower or Airport Advisory Services or Unicom at Sites
Point Hope	68°21'N 166°43'W	20	Public	4100	Gravel	Yes	Emergency only	Emergency services and	On coast	No
Cape Lisburne	68°53' 166"07'	12	Air Force Base	5000	Gravel	Yes	--	equipment wholly inade-	On coast	--
Cape Sabine	69"02' 163°51'	50	Public	3000	Gravel	No	No	quate at all arctic	O" coast	No
Paint Lay DEW Station	69°44' 163°01'	20	Air Force	3500	Gravel	Yes	--	coastal airports. No	On coast	No
Icy Cape	70°20' 161"55'	48	Abandoned AFB	3200	Gravel	No	No	aircraft firefighting	On coast	No
Wainwright	70°38' 160°02'	55	Public	2200	Gravel	Yes	No	equipment at any	On coast	No
Wainwright DEW Station	70°37' 159"51'	88	Air Force	3500	Gravel	Yes	--	location. Doctors	On coast	--
Peard Bay	70"49, 158°16'	93	Private	1300	----	No	--	unavailable or only	On coast	No
Meade River	70°28' 157"25,	65	Public	2000	Gravel	No	No	available infrequently.	30	No
Point Barrow	71°20' 156"38'	9	NARL	5000	Steel plank	Yes	--	Other medical personnel	On coast	No
WileyPost/Will Rogers	71°17' 156"46'	44	Public	6500	Asphalt	Yes	No	present in limited	on coast	On request
Cape Simpson	71°03' 154"42'	--	Abandoned (Navy)	--	---	No	No	numbers. Aircraft not	On coast	No
Lonely DEW Station	70"55' 153"14'	29	Air Force	3800	Gravel	Yes	--	always available for	On coast	--
Kogru	70°35' 152°15'	--	Abandoned (Navy)	--	---	No	No	evacuation. Marginal	on coast	No
Itkillik River	70°04' 150"50'	36	Private	1700	---	No	--	weather conditions	25	No
Knifeblade Ridge	69°09' 154"45'	1380	Public	3600	Gravel	No	No	during winter and	135	No
Airport	69°01' 153"54'	--	Uncertain	--	---	No	No	lack of instrument	120	No
Prince Creek	69°22' 153"17'	1000	Public	3600	Gravel	No	No	landing systems may	95	No
Ai i-port	69"34' 153"16'	--	Uncertain	--	---	No	No	preclude arrival of	80	No
Umiat	69"23' 152°10'	352	Public	5400	Gravel	Yes	Ltd.	emergency supplies,	80	No
Anaktuvuk Pass	68"08, 151"44'	2100	Public	4400	Gravel	No	No	equipment and person-	160	No
Galbraith Lake Camp	68°28' 149°32'	2670	Private	2500	Gravel	No	--	nel for several days	150	--
Toolik Camp	68"38, 149"34'	2400	Private	2500	Gravel	No	--	to weeks.	140	--
Happy Valley Camp	69"09' 148"49'	975	Private	1500	Gravel	No	--		90	--
Sagwon	69°22' 148"42'	650	Public	5800	Gravel	No	Yes		75	Yes
Kavik River	69"41, 146 54'	640	Private	5900	Gravel	Yes	No	Pt. Barrow--doctor, fire	40	Yes
West Kavik	69°45' 147"11'	410	Private	5200	Gravel	No	--	equipment at NARL.	35	No
Oliktok DEW Station	70°30' 149"53'	16	Air Force	4000	Gravel	Yes	--	Happy Valley --medic?	on coast	--
Kuparuk	70°17' 149"04'	41	Private	1900	Gravel	No	--		12	--
West Kuparuk	70°20' 149"17'	41	Private	5000	Gravel	Yes	--		10	No
North Kuparuk	70°22' 149"02'	24	Private	2000	Gravel	No	--	Sagwon--medic?	5	--
Point McIntyre	70"24' 148"41'	15	Uncertain	1500	Gravel	No	--		On coast	No
Hull	70°15' 148"55'	67	Private	2000	Gravel	No	--	Prudhoe/Deadhorse--medics	12	No
Deadhorse	70"12, 148"28'	55	Public	5000	Gravel	Yes	Yes	and dry chemical fire	12	Yes
Prudhoe Bay	70°15' 148"210	45	Private	5500	Gravel	Yes	--	truck at ARCO.	4	--
Coastal	70°12' 148"10'	45	Private	2300	Gravel	No	--		10	--
Kadler	70"08, 148"04'	67	Private	2400	Gravel	No	--	Barter Island--medical	8	--
East Fork	70°12' 147°56'	20	Private	6000	Gravel	No	--	services.	5	--
Kad River	70"05' 141"38'	60	Private	5400	Gravel	No	--		8	--
Pingo	70"020 147"38'	118	Private	6000	Gravel	Yes	--		12	--
Drown Low-point	69°59' 144"50'	8	Private	2000	Gravel	No	--		On coast	--
Barter Island DEW Station	70"08' 143"35'	5	Air Force	4800	Gravel	Yes	Yes		On coast	No
Demarcation Bay	69"48, 142"20"	24	Public	1000	Gravel	No	No		011 coast	No

Source: Arctic Institute of North America, 1974.

Field Facilities

Current (March, 1978) oil production of 1.1 mill ion bbl /day at Prudhoe Bay comes from a total of 150 wells located on 15 pads averaging 10 wells per pad (Alaska Oil and Gas Association, 1978). Current well spacing is 160 acres but later in the production schedule, additional production wells will have to be drilled and extra well pads added, thus decreasing the well spacing.

At the maximum production of 1.5 million bbl/day, six separation plants known as gathering centers (on the Sohio/BP side of the field) or flow stations (on the ARCO side of the field) will be in operation, each capable of handling a maximum of 300,000 bbl/day. These gathering centers/flow stations take crude oil, which is fed from the wells via gathering lines, remove gas and water, and cool the crude (Bird, Blumeraus and Brown, 1976). After treatment, the water is reinfected at the gathering center/flow station into a porous sandstone formation at a depth of 1,500 meters (5,000 feet). The crude oil is sent by pipeline to Pump Station No. 1. Each of the gathering centers/flow stations has emergency flare facilities.

A gas compression plant, which is located on the ARCO side of the field, takes the gas separated from the oil at the gathering centers/flow stations and reinjects most of it into the reservoir gas cap at 4,300 psi. Ten injection wells are located 0.8 kilometer (0.5 mile) from the plant. Natural gas liquids produced during compression of the gas are reintroduced into the gas stream and reinfected. Some gas is used to fuel the central power plant and some is piped south through a 10-inch gas line to power Pump Stations 1, 2, 3 and through an 8-inch line to Pump Station 4 (from Pump Station No. 3).

A central power plant located on the Sohio/BP side of the field supplies electric power for field operations. The plant produces 154 megawatts which is distributed on two 69 kv powerlines.

A small topping plant, operated by ARCO/Exxon, produces diesel fuel and gasoline for field operations. The refinery has a crude oil capacity of 13,000 barrels per day, with a production of 2,600 barrels per day of useable products. The residue is reinfected into the reservoir.

Transportation Facilities

Prudhoe Bay is linked to the Yukon River and central Alaska by a 576-kilometer (346-mile) pipeline haul road. During pipeline and field construction, an average of 2.7 million kilograms (6 million pounds) of freight per month were transported over the haul road. The oil field is served by a 48-kilometer-long (29-mile) spine road with access roads leading to all facilities, totalling 208 kilometers (125 miles) of road for the field.

Two airfields capable of handling medium-sized jet aircraft serve Prudhoe Bay, the state-operated Deadhorse Airport and the private Prudhoe Bay airstrip (see Table 2).

Heavy equipment and bulk materials, including the modules for the oil field plants, are shipped by sealift to Prudhoe Bay. The original dock and staging area constructed by ARCO is located on the east shore of Prudhoe Bay and is linked to the field and airstrip by road. The facilities include a single gravel causeway, 330 by 9 meters (1,100 by 30 feet) and a 10.1-hectare (24.2-acre) gravel pad storage area. In summer, unloading is accomplished by placing four barges at the end of the causeway to provide a 3,240 square meter (35,640 square foot) unloading area. A new dock was constructed in 1972 on the west shore of Prudhoe Bay to which a 1,500-meter (4,950-foot) extension was added in the winter of 1975-76 to reach deep draft barges caught in the ice before they could be unloaded. The end of the new dock has a "T" shaped unloading area formed by sunken barges. With its extension, the new dock extends 2.4 kilometers (1.4 miles) into Prudhoe Bay, where the water is deep enough to accommodate ocean-going barges.

Support Facilities

Oil field operations are controlled at two operations centers, one on the Sohio/BP side of the field, accommodating 264 workers, and one on the ARCO side of the field, accommodating 440 workers. There are also three construction camps run by the field operators: two 500-man camps in the western section of the field and a 1,750-man camp near the ARCO operations center.

A number of oil field support services, equipment and material suppliers providing such services and materials as wireline services, mud logging, cement and mud are located at Deadhorse. These services have located here mainly in response to the requirements of the Prudhoe Bay field, although they are used by exploration operators throughout the central and eastern North Slope.

2.4.2.2 National Petroleum Reserve in Alaska (NPR-A)

A coordinated exploration program in the National Petroleum Reserve in Alaska (formerly Naval Petroleum Reserve No. 4) has been underway since 1975. An earlier program, conducted by the U.S. Navy between 1944 and 1953, resulted in several noncommercial oil and gas discoveries (U.S. Department of the Navy, 1977). The current program is managed by the Department of the Interior under the auspices of the U.S.G.S., with Husky Oil as the operator.

The base camp for the 1944-1953 program was established 6.7 kilometers (4 miles) northeast of Barrow. The principal base of operations for the ongoing program is Lonely, a DEW line station located on the Beaufort Sea coast at Pitt Point between Drew Point and Pogik Point. The facilites at Lonely have been expanded and improved for the exploration program and include a 1,580-meter (5,214--foot) airstrip, a camp with accommodations for up to 100 personnel, fuel storage, and sewer and water systems. Lonely serves as a barge-offloading area for the bulk equipment and materials used in the drilling program.

For exploration operations during the 1977-78 season in the western sector of NPR-A, a temporary staging area has been constructed at the old DEW line site (LIZ C) at Peard Bay on the Chukchi Sea coast (U.S. Department of the Interior, 1977a, 1977c). The facilities at the Peard Bay logistics base include a 25-man camp, a new 1,580-meter (5,214-foot) airstrip, fuel, pipe, and mud storage yards.

2.4.2.3 Central-Southern North Slope

There are a number of currently-held and expired oil and gas leases located between the Colville and Canning Rivers on state, federal and Native (Arctic Slope Regional Corporation) lands. Several gas discoveries have been made, including the noncommercial East Umiat gas field and Kemik gas field. The Gubik gas field, which straddles the border of NPR-A, is the largest known North Slope gas field (outside Prudhoe Bay), with estimated reserves of 295 billion cubic feet. No significant facilities are related to petroleum exploration in this area.

2.4.3 Permits and Regulations

Governmental requirements which must be met for development on the North Slope continue to change as more experience in the area is gained and more information is obtained. Table 3 lists the permits required and the regulations to be met if Beaufort Sea petroleum development were to begin in 1978.

TABLE 3

PERMITS AND REGULATIONS CONCERNING BEAUFORT SEA PETROLEUM DEVELOPMENT

AGENCY	PERMIT/ACTIVITY	AUTHORITY
STATE OF ALASKA		
Department of Natural Resources	Oil and Gas Leases	Alaska Statute 38,05.180
	Pipeline Rights-of-Way	Alaska Right-of -Way Leasing Act
	Gravel Permits and Sales	Alaska Statute 38.05
	Water Use Permits	Alaska Water Use Act; Alaska Statute 46.15.010
Department of Fish & Game	Water Use Permits	Fish & Game Act of 1959; Alaska Statute 16.05.870
	Hydraulic Permits	Fish & Game Act of 1959; Alaska Statute 16 .05.870
	Authority to Remove Nuisance Wildlife	Fish & Game Act of 1959; Alaska Statute 16.05.870
Department of Environmental Conservation	Water Quality Standards	Alaska Water Quality Standards 1973
	Ballast Water Discharge Permit	Alaska Statute 46.03.750
	Surface Oiling Permit	Alaska Statute 46.03.050
	Solid Waste Management Permit	Alaska Statute 46.03.050
	Air Quality Standards	Alaska Statute 46.03.050
	Burning Permit	Alaska Statute 46.03.050
FEDERAL GOVERNMENT		
Army Corps of Engineers	Permit to Work in Navigable Waters	Refuse Act; Rivers & Harbors Act 1899, Title 33 Code of Federal Regulations Part 209
	Permit to Discharge into Nav. Waters	Water Quality Improvement Act 1972; Title 33 Code of Federal Regulations Part 209
U.S. Coast Guard	Bridge Permits-Navigable Waters	Title 33 Code of Federal Regulations Part 114
Bureau of Land Management	Protection of Critical Habitat	Federal Land Policy Management Act 1976
	Special Use Permits:	
	Gravel Mining	Title 43 Code of Federal Regulations, Part 2920
	Construction Camps	Title 43 Code of Federal Regulations, Part 2920
	Timber Disposal	Title 43 Code of Federal Regulations, Part 5400
	Communication Sites & Right-of-Way	Title 43 Code of Federal Regulations, Part 2920
	Construction Disposal Areas	Title 43 Code of Federal Regulations, Part 2920
	Gravel Disposal	Title 43 Code of Federal Regulations, Part 3610
	Airport Leases	Title 43 Code of Federal Regulations, Part 2911
	Oil and Gas Leases	Mineral Leasing Act of 1920 and Revisions
	Right-of -Way Permits	Federal Land Policy and Management Act 1976
	Off-Road-Vehicle Permits	Sikes Act
Environmental Protection Agency	Wastewater Discharge Permit	Water Pollution Control Act 1972
	Oil Pollution Prevention	Water Pollution Control Act 1972
	Control Oil Spill Clean-up	Water Pollution Control Act 1972
Fish & Wildlife Service	Protection of Fish, Wildlife & Habitat	Fish & Wildlife Coordination Act 1973
	Outer Continental Shelf Development	Fish & Wildlife Coordination Act 1973
	Estuary Protection	Estuarine Study Act of 1968
	Special Use Permits -- Wildlife Ranges and Refuges	Title 50 Code of Federal Regulations
	Marine Mammal Protection	Marine Mammal Protection Act 1972 (Polar Bear, Walrus, Sea Otter)
	Endangered Species Protection	Endangered Species Act 1973
	Eagle Protection	Eagle Act of 1972
	Waterfowl Protection	Migratory Bird Treaty Act
National Marine Fishery Service	Protection of Anadromous Fish Habitat	Fish & Wildlife Coordination Act 1973
	Marine Mammal Protection	Marine Mammal Protection Act 1972 (Whales and Seals)
	Outer Continental Shelf Development	Fish & Wildlife Coordination Act 1973
Department of Transportation	Pipeline Safety & Valve Locations at Stream Crossings	Title 49 Code of Federal Regulations, Part 195

CHAPTER 3.0

TECHNOLOGICAL BACKGROUND

3.1 SIMILAR ARCTIC PETROLEUM EXPERIENCE

In order to fully appreciate the unique problems of development in the Beaufort Sea, some of the major contrasts with two other frontier petroleum areas, the North Sea and the Gulf of Alaska, are discussed below:

- The continental shelf of the Beaufort Sea is shallow and terminates at the 60-meter (198-foot) isobath. Initial exploration will probably take place in water depths of less than 20 meters (66 feet), as compared with very deep waters in the North Sea and Gulf of Alaska (over 150 meters or 495 feet).

- 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 in the Beaufort Sea throughout much of the year. Although sea-borne glacial ice drifts in some areas of the Gulf of Alaska, there are no ice-bound areas, and there are no sea ice problems in the North Sea.

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

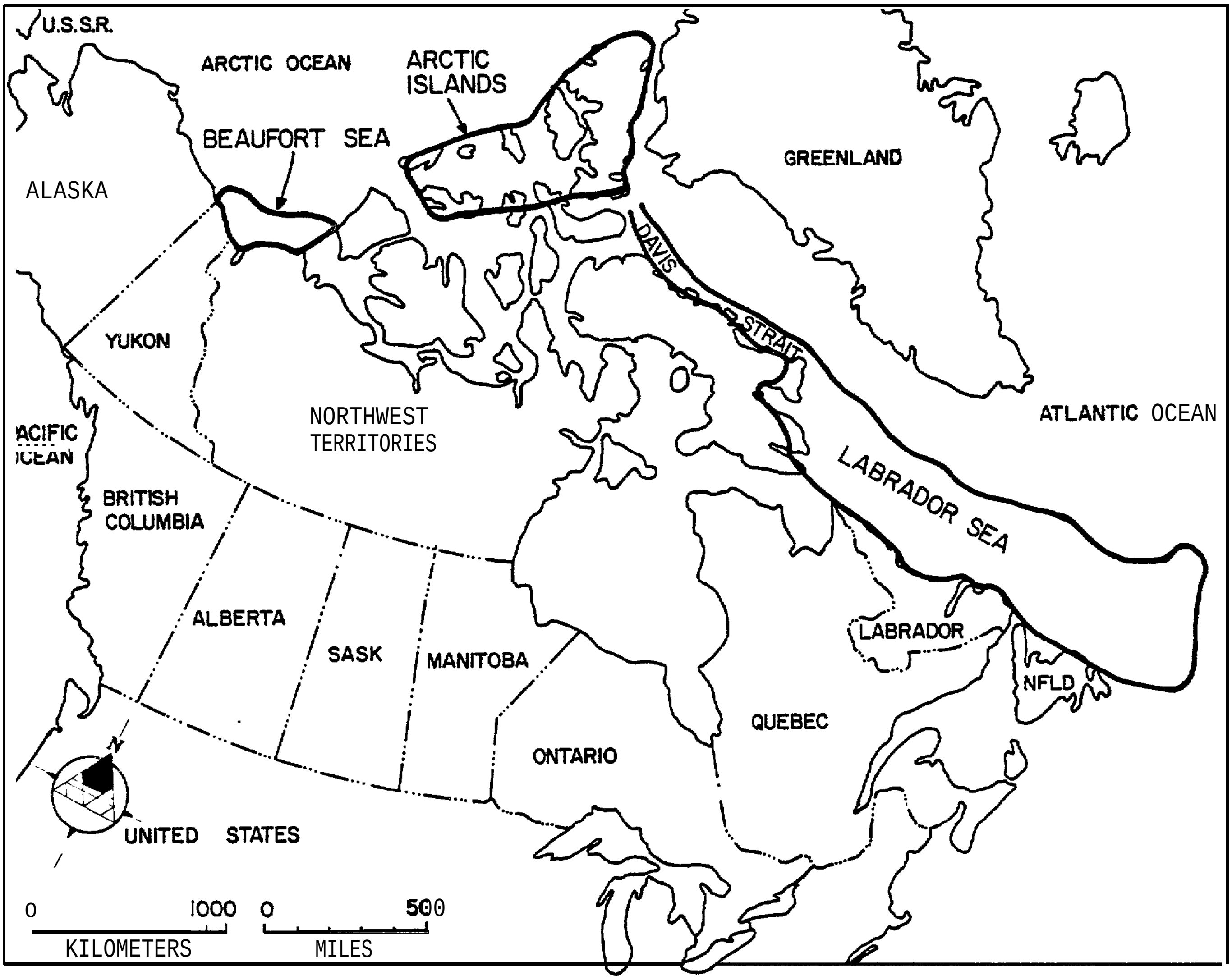
- Oil and gas markets are removed from the Beaufort Sea's potential oil and gas reserves by distances that are hundreds of miles greater than from similar areas in the Gulf of Alaska and the North Sea.

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

Significant exploration has not yet commenced in the Alaskan Beaufort Sea. Therefore, this study draws primarily on Canadian Arctic offshore experience in postulating the technologies to be used for Beaufort Sea development. Experience in the Canadian Beaufort Sea is the most applicable, but experience in the Canadian Arctic islands and Baffin Bay, Davis Strait and the Labrador Sea off eastern Canada and Greenland is also relevant. Figure 13 shows these arctic petroleum frontier areas. Drilling technologies used in all these areas are reviewed briefly below.

Offshore exploration drilling requires a stable platform. In conventional offshore areas there has been a technological progression and increase in depth capability of drilling rigs from bottom-founded mobile rigs such as jack-ups, semi-submersible rigs, and drill ships. Semi-submersibles and drillships can be kept. over the drill location by either mooring lines or thrusters (dynamic positioning). Typical depth capabilities for mobile offshore rigs are: jack-ups - 15 to 105 meters (50 to 350 feet); semi -submersibles - 45 to over 600 meters (150 to over 2000 feet); drillships - 120 meters (400 feet) plus. These conventional rigs can be used in the summer in ice-free areas, although short and variable ice-free periods and high standby costs detract from their efficiency.

Petroleum development in Cook Inlet in the early and mid 1960's established some precedents for operations in ice-covered waters.



SOURCE: CROASDALE , 1977.

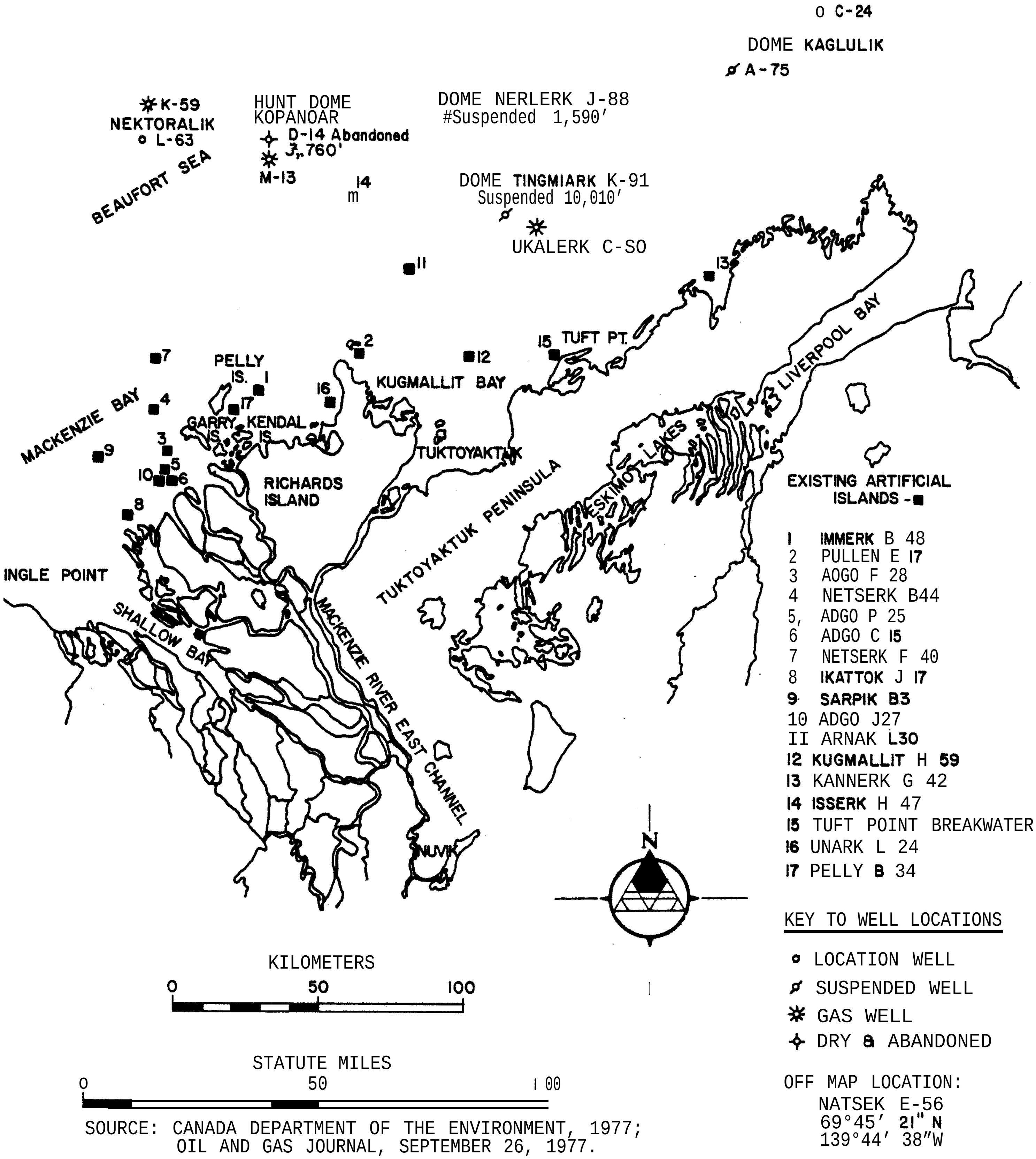
FIGURE 13 - ARCTIC PETROLEUM FRONTIERS

Strong tidal currents moving ice up to one meter thick, which can be present in the inlet from November to May, has necessitated the design of production platforms to resist lateral ice forces. This involved heavier vertical members, wells protected inside the legs, and cross bracing located below the zone of ice action. Exploration was conducted from conventional floating or jack-up rigs during the ice-free period. Of the 14 production platforms in Cook Inlet, one is a monopod type, a design which may have Beaufort Sea application (Visser, 1969).

Exploration drilling in the Canadian Arctic started in the Mackenzie Delta in the mid-1960's. After several years of extensive onshore exploration, which resulted in the discovery of commercial gas reserves, exploration extended offshore into the Beaufort Sea. The first well was drilled in the winter of 1973-74 from the artificial island, Immerk B-48, in 3 meters (10 feet) of water. Subsequently, 15 artificial ice islands have been constructed in the Beaufort Sea to a maximum water depth of 15 meters (50 feet). Figure 14 shows their locations.

Exploration drilling with ice-strengthened drillships started in deeper waters (over 30 meters or 100 feet) in 1976. Three drillships were operating in the Canadian Beaufort Sea in the summer of 1977. At the end of the 1977 drilling season, three gas discoveries and one oil discovery were made by the Dome ships; these await testing upon well re-entry in the 1978 drilling season (Figure 14).

In the Canadian Arctic islands, exploration drilling started in 1961. Off-ice drilling began in 1974 on the landfast ice that covers the seas between the islands for up to 11 months of the year. The first offshore well, Panarctic's Helca N-52, was successfully drilled from a reinforced ice platform in 130 meters (429 feet) of water, 13 kilometers (9 miles) from shore. Six gas fields have been discovered to date in the Sverdrup basin of the Arctic islands. Polar Gas has 'proposed a 48-inch, 5,330-kilometer-long (3,200-mile) pipeline, which would involve



SOURCE: CANADA DEPARTMENT OF THE ENVIRONMENT, 1977;
OIL AND GAS JOURNAL, SEPTEMBER 26, 1977.

FIGURE 14 - EXISTING ARTIFICIAL ISLANDS
AND DRILLSHIP WELL LOCATIONS
IN THE SOUTHERN BEAUFORT SEA"

crossing several deep inter-island channels, to transport the gas to southern Canadian and eastern United States markets. An LNG system has been proposed as an interim transportation system to take Arctic gas to market by Petro-Canada. That system would involve construction of a gas pipeline across Melville Island, an LNG plant and marine loading terminal, and an LNG shipping system employing ice-breaking tankers (World Oil, November 1977). A pilot project involving the first Arctic subsea production system and submarine pipeline will commence in 1978. An 18-inch, 1.3-kilometer-long (0.8 mile) pipeline will serve Panarctic's Drake F-76 gas well situated in 58 meters (185 feet) of water (Oilweek, September 12, 1977).

Exploration drilling has begun off the east coast of Labrador in Canada and in the Davis Strait between Greenland and Canada. Ice-free periods vary from 365 days per year in the south to about 100 days in the Davis Strait. These ice-free periods permit the use of conventional drilling platforms such as semi-submersibles and drillships. The main contrast with other ice-infested waters is the threat of icebergs. An average of 15,000 icebergs a year calve from west Greenland; some weigh over 3 million tons and have drafts over 260 meters (858 feet). Techniques for iceberg avoidance and handling have been developed which involve radar tracking and towing systems using support vessels. Because of the threat of iceberg collision and the need for rapid move-off, dynamically positioned drillships or semi-submersibles are better suited to this area than systems using mooring lines. Drilling on the Canadian portion of the Labrador Sea and Davis Strait started in 1971; exploration began on the Greenland (Danish) side in 1976. Because of the iceberg threat, only dynamically-positioned vessels are permitted to work in Greenlandic waters (Offshore, October 1977).

3.2 OFFSHORE DRILLING OPTIONS

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 engineering 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, Arctic islands and Davis Strait/Labrador Sea, since they are the only regions with significant offshore Arctic petroleum activity to date. This experience, discussed in Section 3.1, 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;

- Exploratory drilling from dynamically-positioned semi-submersibles and drillships in the iceberg-infested waters of the Davis Strait and Labrador Sea; and

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

In contrast, Alaskan Beaufort Sea 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.

As Croasdale (1977) has observed, there are essentially three options for exploratory drilling in ice-infested waters:

1. Drilling during the ice-free period from a floating vessel.

2. Drilling off the ice.

3. Drilling from a bottom-founded platform or vessels capable of resisting the external ice forces.

A fourth, limited option is directional drilling, a discussion of which commences the discussion of drilling options.

3.2.1 Directional Drilling

Directional drilling from land (mainland or offshore barrier islands) to reach targets in either the State-Federal or Federal OCS lease sale area 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.

A 3,050-meter (10,000-foot) deep target located about 5 kilometers (3 miles) from shore, would require a well with an envelope angle of 56 degrees to be drilled from shore and would involve a total well length of 5,455 meters (17,900 feet). However, the nominal average angle achievable in directional drilling is 45 degrees; thus a target such as the above example would be too shallow to reach with a 45 degree well. 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 on the maximum directional drilling angle (for a given horizontal distance to a target), there is a minimum depth above which targets cannot 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.

Within the 5-kilometer (3-mile) limit, a target at a depth of 3,050 meters (10,000 feet) and 3.2 kilometers (2 miles) from shore would require a directional well of 47 degrees (from the vertical), whereas the same target only 1.6 kilometers (1 mile) from shore would require a deviation of only 28 degrees. Shallower targets at the same distances from shore require greater deviations and thus longer wells.

For a target at a given depth, the length and deviation of a well will increase with distance from shore. Directional drilling, therefore, for targets of the same depth, would probably be more feasible and economic within the State-Federal lease sale area (within the 5-kilometer or 3-mile limit) than in the Federal OCS farther offshore.

Although a maximum deviation envelope of 45 degrees is cited in this report as the typical maximum of directional drilling, the maximum deflection from vertical developed in the bottom of the well is actually greater. An ultra high-angle well reaching 82 degrees (nearly horizontal) has been reported (Eberts and Barnett, 1976); however, the depth of the well was 1,325 meters (4,350 feet), which required a 3,750 meter (12 ,300-foot) total length, such that the average deviation was 68 degrees from the mudline. A comparable directional well (68°) required to reach a 3,050-meter (10,000-foot) offshore target would have a total length of 9,100 meters (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. Another factor to consider in directional drilling is that deviation is not generally commenced until a depth of about 610 meters (2000 feet) is attained. Deviation in North Slope wells is not commenced until the bottom of the permafrost has been penetrated (about 610 meters or 2000 feet).

Overall, if there were a significant oil deposit (requiring several wells) 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, and for which directional drilling would be feasible, it would be preferable to pay the directional drilling costs.

For exploration 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 installing 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 exploration efforts in frontier areas. On the other hand, production drilling, with up to 40 wells per platform, will commonly employ deviated wells.

3.2.2 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 exploration well or as a permanent production platform with long-term protection against ice and waves. In the southern Canadian Beaufort Sea off the Mackenzie Delta, artificial islands have been the favored technique for offshore exploration drilling in shallow waters. A total of 15 have been constructed there to date, mainly by Imperial Oil Ltd.

The factors which favor this type of structure are (Riley, 1975):

- Shallow water. The Imperial Oil Ltd. lease acreage extends to about the 20-meter (66-foot) isobath.

- Minimum sea ice movement. Most of Imperial's acreage lies within the landfast ice zone.

- Weather. Standby costs are very high for floating rigs during the winter due to the short working season (2-1/2 to 3 months).

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

- Cost. 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.

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

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

To date, artificial islands in the southern Canadian Beaufort Sea have been built in water depths of less than 15 meters (50 feet), although such structures may be feasible in water depths up to 20 meters (66 feet). Two islands were constructed in the summer of 1976, including one in a water depth of about 12 meters (40 feet). In the summer of 1977, an island was constructed in 15 meters of water (Croasdale, 1977).

3.2.2.1 Design and Construction Techniques

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 meters (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 1976). Croasdale (1977) reports a typical island diameter of about 100 meters (330 feet) at the working surface and 5 to 6 meters (17 to 20 feet) freeboard.

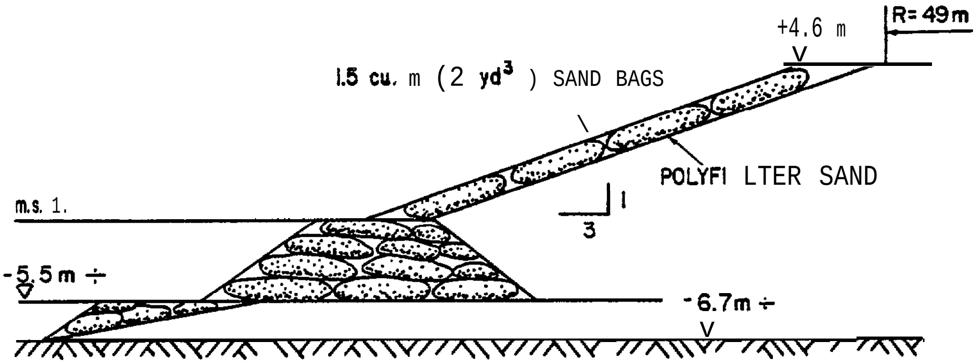
Island design is influenced by materials and techniques available for construction as dictated by location and season. The surface area is dictated by that required for drilling, and the freeboard by ice and wave conditions. These factors will therefore determine island size and fill requirements. Beach slopes, which also affect fill requirements, are decided partly by construction techniques and foundation conditions and partly by the requirement to protect the island against wave erosion.

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

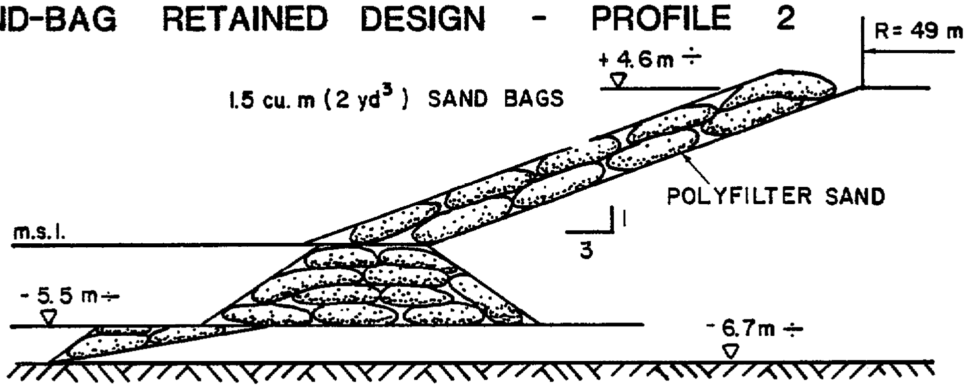
- Sand bags
- Gabions (wire mesh enclosures) filled with sand bags
- Sand-filled plastic tubes, and
- Filter cloth held down by wire netting

Typical island profiles are shown on Figure 15; a sandbag retaining wall was utilized for Netserk F-40, B-44, and Kugmallit N-59, while a sacrificial beach design was employed for Arnak L-30 and Kannerk G--4 (Croasdale and Marcellus, 1977). The sacrificial beach design protects the island through gradually sloping (1:20 underwater slope) beaches which force waves to break so that their energy is dissipated before they reach the island. The beach is thus sacrificed to protect the island. Since massive amounts of sand are contained in the beaches, the island will remain intact for several storms. If necessary, the beach material can be replenished by additional dredging.

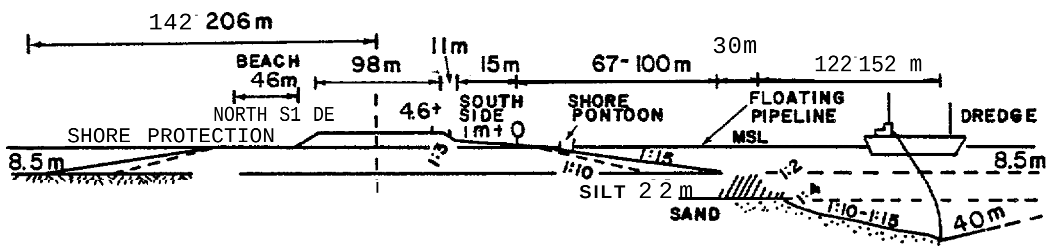
SAND-BAG RETAINED DESIGN - PROFILE 1



SAND-BAG RETAINED DESIGN - PROFILE 2



SACRIFICIAL BEACH DESIGN



CONSTRUCTION 40-45 DAYS

FILL 1.2 million cu. m (1.6million cu. yds.)

SOURCE: CROASDALE AND MARCELLUS, 1977; CROASDALE, 1977.

FIGURE 15 - TYPICAL ISLAND PROFILES

Three basic designs have been employed by Imperial Oil to date (Riley, 1976; de Jong, Steiger and Steyn, 1975):

- Immerk type. Granular fill was hydraulically placed by suction dredge, with 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 4.5 meters (15 feet) above sea level in 3 meters (10 feet) of water.

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

- Adgo type. Primarily silt 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 a mean sea level (MSL) of +1 meter (-I-3 feet) in 2 meters (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 meters (+10 feet) so that they could be used during the summer. In very shallow water in which barge-based equipment cannot operate, this construction method has to be adopted. In Prudhoe Bay in the winter of 1976-77, British Petroleum drilled an exploratory well from a gravel pad in one meter (three feet) of water using this construction method.

In the summer of 1976 Imperial Oil constructed two sacrificial beach islands, Anark L-30 and Kannerk G-42 (Engineering Journal, July/August 1977). The Anark Island, which was located in 8.5 meters (28 feet) of water, was constructed of local sand borrow using a 32-inch stationary cutter suction dredge. Sand was transferred to the island by floating pipeline.

In 1975, Imperial Oil's construction spread in the Beaufort Sea was comprised of (de Jong, Steiger and Steyn, 1975):

24-inch cutter dredge
34-inch stationary suction dredge
five 1,520-cubic-meter (2000-cubic-yard) bottom dump barges
three 228-cubic-meter (300-cubic-yard) bottom dump barges
four l ,500-horsepower tugs
two 600-horsepower tugs
one floating crane
four 5-cubic-meter (6-cubic-yard) clamshell cranes on spudded barges
a barge loading pontoon
floating pipelines

See Table 4 for a recommended 20-island, 10-year construction spread.

3.2.2.2 Construction Materials

The design of artificial islands in the southern Canadian Beaufort Sea has been determined in part by the availability and type of borrow materials. Because the sea bed west of 134°W longitude consists predominately of silt, for which the consolidation process is slow, use of local material is suited only to winter operations when the silt is frozen. Consequently, except in a few cases where local sand was available,

TABLE 4

ARTIFICIAL ISLAND CONSTRUCTION SPREAD

In order to construct and support a 20-island, 10-year program based primarily on caisson retained islands, Imperial Oil Ltd. suggest the following (Canada Department of the Environment, 1977):

1977	Stationary suction dredge Cutter suction dredge 4 - 1,500-hp tender tugs 3 - 2,200-hp tugs 2 - 4,000-hp dump barges 4 - 7,000-yd dump barges 3 flat barges 2 floating camps Supporting equipment
1978	Cutter suction dredge 3 - 1,500-hp tender tugs 4 - 2,200-hp tugs 5 - 4,000-yd dump barges 3 flat barges Floating camp Caisson Barge unloading dredge - caisson filled Support equipment.
1979	Add 1 - 2,200-hp tug 4 - 4,000-yd dump barges
1980	Add 1 - 2,200-hp tug 1 caisson 3 flat barges Caisson filling equipment
1981-1986	Same as for 1980

borrow material had to be hauled by barge for some distance for island construction. In the construction of Netserk B-44, for example, fill had to be hauled 32 kilometers (20 miles).

An example of the material requirements for a gravel island is provided by Sun Oil's Unark island, which was constructed in the winter of 1973-74 in 1.2 meters (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.

Kugmallit D-49, located in 5 meters (17 feet) of water, which was constructed of sand taken from a nearshore borrow deposit 37 kilometers (23 miles) from the site, required 287,000 cubic meters (375,000 cubic yards) of fill and 7,500 1.5-cubic-meter (2-cubic-yard) sand bags (Engineering Journal, July/August 1977). The fill requirements of a sacrificial beach island are significantly greater than those of a conventional sandbag-retained island.

In deeper water, say 10 meters (33 feet), a circular exploratory island with a freeboard of 5 meters (15 feet), a working area diameter of 105 meters (346 feet), surface side slopes of 1:3 and 1:2, and submarine slopes of 1:15, would require 278,650 cubic meters (364,438 cubic yards) of gravel or sand fill. A circular 7-acre production island using sheet piling or caissons for long-term protection and reduction of fill requirements at the same water depth with a freeboard of 7.6 meters (25 feet) would require 477,030 cubic meters (621 ,133 cubic yards) of gravel or sand.

3.2.2.3 Ice Action on Islands

The Canadian Beaufort Sea artificial islands have been located in the landfast ice zone. Landfast ice is relatively stable, although movements of several meters (feet) can occur. This amount of movement is sufficient to impose significant loads on fixed structures. Ice action on ice islands has been discussed in detail by Croasdale and Marcellus (1977) and Croasdale (1977), and will be addressed only briefly here.

Islands in shallow sheltered locations (less than 3 meters or 10 feet of water) are not subject to significant ice action since the ice becomes stable soon after freeze-up; subsequent movements are small and slow, with few observable cracks and ridges. Ice movements are believed to be small enough and slow enough to allow the ice to ‘flow’ or ‘creep’ around the island.

Ice around these islands during break-up generally melts in place. In summer, the threat of encroachment from the polar pack ice is minimal because the ice with its ridges tends to ground in deep water.

In deeper water at exposed locations in the fall, ice takes longer to become truly landfast, and freeze-up is characterized by large ice movements. This causes extensive ice rubble to form around the islands, although the ice is too thin to ride up. When the ice becomes landfast in November or December, ice movements are cyclical and occur on the periphery of the ice rubble which has refrozen in place to form a solid annulus around the island. Initially the ice fails by bending but as it becomes thicker it fails by crushing. At break-up the ice rubble surrounding the island rapidly melts away, leaving the island exposed to potential ice ride-up from large decaying ice sheets in the vicinity. However, to date this has not appeared to be a problem since the ice has been too weak to ride-up but instead forms rubble on the island beach. Within the landfast ice zone, therefore, ice movement does not appear to be a significant problem. Research into the problem continues since at exposed locations where polar pack ice may encroach, the potential exists for ice ride-up.

3.2.2.4 Cellular Sheet Pile Island and Caisson Retained Island

A cellular sheet pile island has been proposed as a feasible exploration or production platform for Arctic waters (Forssen, 1975). The concept involves a "cells-in-a-cell" arrangement of sheet piling which is filled with clean granular materials. To provide the requisite strength, the fill is allowed to freeze back and, in the case of a permanent production platform, is artificially refrigerated to maintain freezing. Thermopiles could be utilized to accelerate freeze-up of the internal mass.

The minimum size of an exploration island is dictated primarily by the minimum diameter acceptable to resist overturning, sliding or internal shear failure by ice loadings of up to 703,000 kilograms per square meter (1,000 pounds per square inch); this diameter was determined to be 60 meters (198 feet). In the case of a production island with only the peripheral cells and annular space between the peripheral cells and streamlined bulkhead containing frozen fill, a minimum of 150 meters (495 feet) was calculated. In both the exploration and production island designs, the interlocking cells would be 23 meters (76 feet) in diameter. A freeboard of 8 meters (26 feet) is estimated to be sufficient to resist overtopping by ice rafting.

For an exploration island, construction would take 40 to 50 summer days in one continuous operation. Fill would be dredged and barged in, and piling would be taken from onshore stockpiles. The construction spread would include a clamshell dredge, work barge, supply barge, and camp for about 50 men. Construction of a production island would take two seasons and would involve six crews with six driving templates and cranes. As much work as possible would be done on the island from completed cells.

The advantages of a cellular sheet pile island include:

- Reduction of fill requirements (over an artificial island).

- Strength against pack ice movement provided by cellular design and frozen fill.

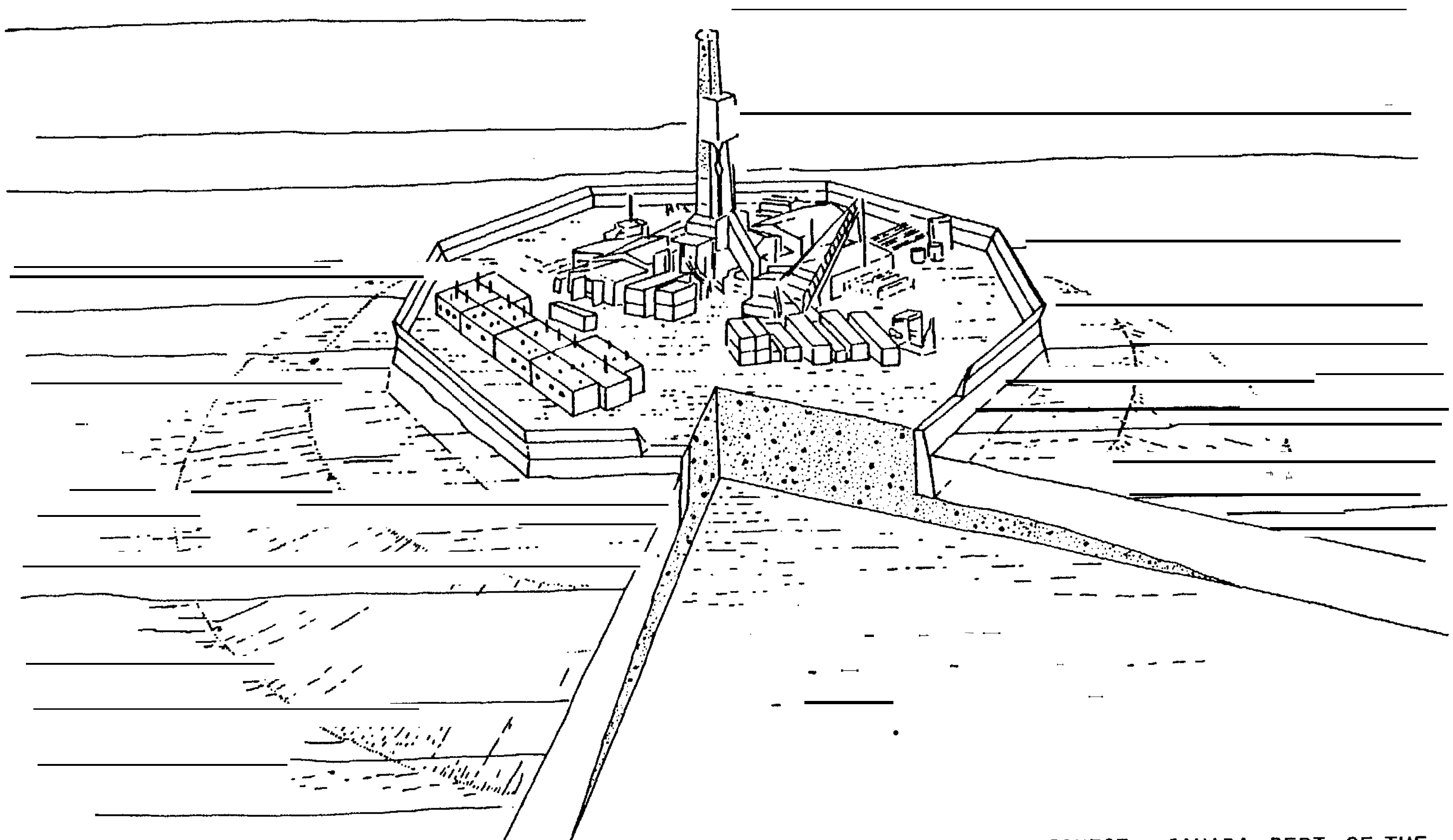
- Traditional construction techniques and readily available components (piling, soil, ice).

Imperial Oil Ltd. (Canada) has designed a similar island using steel caissons (Canada Department of the Environment, 1977). The retaining structure consists of eight caissons which are floated to the site, assembled into an octagon, and ballasted on the sea floor (Figure 16). In deeper water, a berm would be constructed of sand to support the caissons. Dredged fill would then be placed in the annulus of the caissons. Upon completion of drilling, the caisson could be deballasted and floated to a new location.

Imperial Oil has forecast a 1978 construction start of a 20-location, 10-year exploration program using mainly caisson contained islands. These islands would be used principally in water depths in excess of 8 meters (26 feet) or where there is a lack of suitable on-site fill to construct conventional artificial soil islands.

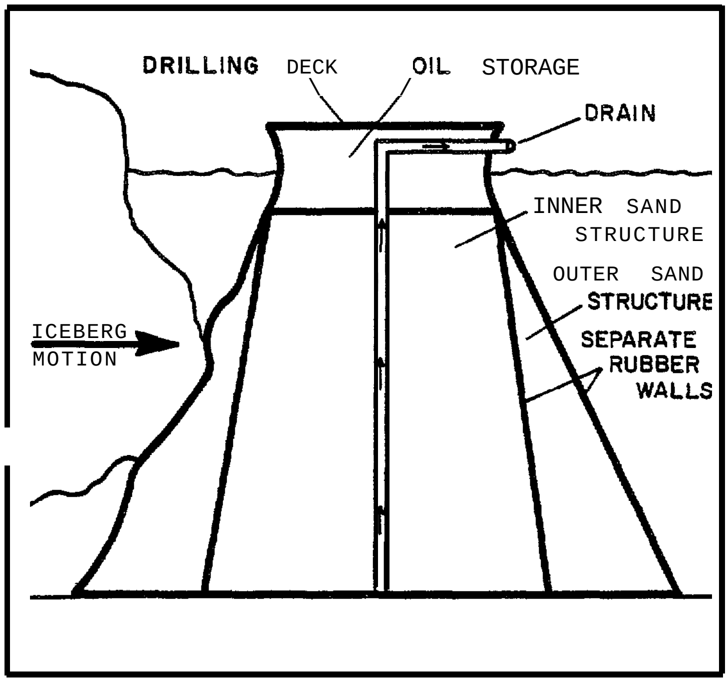
3.2.2.5 Membrane Contained Island

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, consists of an impermeable rubber membrane filled with hydraulically placed sand supporting a deck unit (Figure 17). The membrane and deck were fabricated on land and towed to the site (at a 15-meter or 50-foot water depth) where the fill was placed. Installation on site took less than 48 hours.

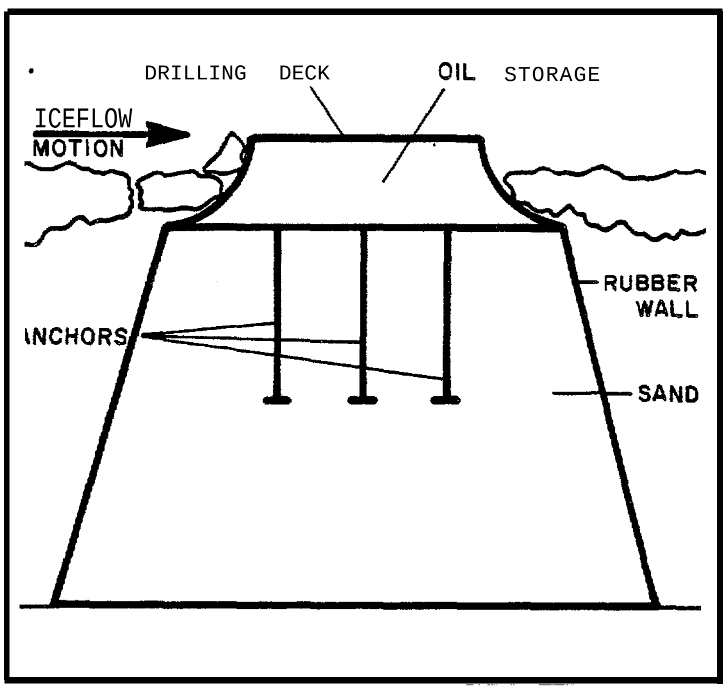


SOURCE: CANADA DEPT. OF THE ENVIRONMENT, 1977, ADOPTED FROM IMPERIAL OIL LTD., 1976.

FIGURE 16 - CAISSON RETAINED ISLAND



DOUBLE-WALL SANDISLE



CONCEPTUAL DESIGN FOR ICEFLOW CONDITIONS

SOURCE: OCEAN INDUSTRY, NOVEMBER, 1976.

FIGURE 17 - MEMBRANE CONTAINED ISLANDS

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 destroyed during a storm in October 1976, which brought 10.6-meter (35-foot) waves -- over 50 percent higher than the 6.4-meter (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.

3.2.2.6 Summary

Artificial islands have been used successfully for exploration drilling in the southern Canadian Beaufort Sea within the landfast ice zone. Although artificial islands in the Beaufort Sea have only been constructed as temporary platforms for exploration drilling, they can also be designed with sufficient reinforcement for long-term protection from waves and ice to serve as 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 meters (66 feet) with such protection as sheet piling. In addition to their restriction to the landfast ice zone, a major factor affecting 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 could make deeper water islands more economically feasible. It should be emphasized that the use of artificial islands for either exploration or production is essentially an extension of dryland drilling technology, since dryland Arctic drilling rigs and support facilities (storage, camp, etc.) are used.

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 15 meters (50 feet).

- Artificial soil islands with sheet piling are probably feasible to water depths of 20 meters (66 feet).

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

- Construction by suction or bucket dredging is normally conducted in the open water season; however, winter construction, consisting of ice removal and backfilling 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 Steyn, 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.

- Possible disturbance of marine mammals by marine construction traffic.

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

- Environmental stipulations.

3.2.3 Ballasted Barges

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 used successfully in construction of the Pelly artificial island located in 2.3 meters (7-1/2 feet) of water off the Mackenzie Delta (Brown, 1976). The Pelly island location consisted of a drilling barge, base camp, dredge and supply barges. The drilling rig was mounted on two rail barges, each 11 by 73 meters (36 by 241 feet), tied together with a superstructure to make a slotted barge 27 by 73 by 4 meters (89 by 241 by 13 feet). The artificial island was constructed with a gabion berm set on to the sea floor to form a rectangle 155 by 64 meters (512 by 211 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 (reuse) and extension of the drilling season beyond that provided by an ice or silt island. The Pelly island used conventional barges; their application is dependent upon their size and draft. Modified conventional barges are therefore restricted to a certain depth range which is probably on the order of 1.5 to 5 meters (5 to 17 feet). To use them closer to shore in shallower water would require the dredging of a channel.

The ballasted barge technique could have greater application through the development of a specially-designed drilling barge with a greater depth range capability and possibly, protection against ice movement that would obviate the need for a protective berm.

3.2.4 Reinforced Ice Platforms

There are two types of reinforced ice platforms that have been produced by thickening of the parent ice sheet through success"ive 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 or artificial ice island. In deeper water, this thickening technique has been used to gain the requisite buoyancy to support exploration drilling equipment.

3.2.4.1 Artificial Ice Island

The "ice island" concept involves the thickening of the parent ice sheet to produce a grounded ice island (MacKay et al., 1975). Factors limiting the usefulness of this concept include: 1) water depth, 2) movement and rate of movement of the parent ice sheet, 3) rate of "artificial" ice growth, 4) ice strength properties of artificially grown ice, 5) sea floor soil conditions, 6) winter access only for construction, and 7) maintenance required by a quasi-permanent structure. Advantages include minimum environmental impact, relatively low construction cost in comparison to alternative structures, and no removal or minimal restoration cost once the structure has completed its usefulness.

The key to the success of this concept is economical manufacture of high-strength ice at a rapid rate. Since the number of ice-making days is limited (40-50 days at 50 percent operating time during January through May), spraying or sprinkling of water has been suggested in order to increase growth rates (Fitch and Jones, 1974). However, in most ice growth concepts, the rate of ice growth appears to be inversely proportional to ice strength in that more brine, which degrades strength, is included in rapid growth.

The most useful offshore areas for this concept appear to be in the landfast ice zone in water depths shallower than approximately 10 meters (33 feet), where sea floor soils are capable of developing adequate resistance to shear forces. Use of an artificial ice island for exploration drilling appears to have more advantages than disadvantages. This seems particularly true for winter exploration inside the barrier islands. The cost of building an ice island (excluding development costs) has been estimated at less than $5 million (Fitch and Jones, 1974).

In the Alaskan 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 exploration well was drilled during the winter of 1976-77 (Duthweiler, 1977; Oil and Gas Journal, July 11, 1977) (Figure 18). The operational island was located about 19 kilometers (12 miles) north of Anachlik Island in Harrison Bay about 64 kilometers (40 miles) west of Prudhoe Bay. The island, which was located in 2 meters (8 feet) of water, consisted of an outer ice ring, 140 meters (462 feet) inside radius, and an inner rectangular drill pad, 60 by 120 meters (198 by 396 feet). Surface flooding by gasoline-powered pumps in augered ice holes was used to thicken the drill pad from the natural ice thickness of 1 meter to 4 meters (3 feet to 13 feet), i.e., an addition of3 meters (10 feet).

The outer ring was designed to protect the inner pad from ice movement and act as a containment barrier in case of an accidental spill. The rig was constructed by placing snow berms on both sides of the ring rim and then pumping water in the space to form ice. A 3.5-meter (lZ-foot) moat was cut around 70 percent of the containment ring and kept ice-free for the duration of drilling as further protection against ice movement.

The drilling rig equipment and supplies were brought. to the site by Hercules aircraft (total of 338 trips) which landed on a 2,000-meter (6,600-foot) ice strip 0.6 kilometers (1 mile) from the ice island The construction spread for both islands was minimal relative to the normal equipment demands of a land-based North Slope exploration well and included bulldozers, clamshell crane and ...

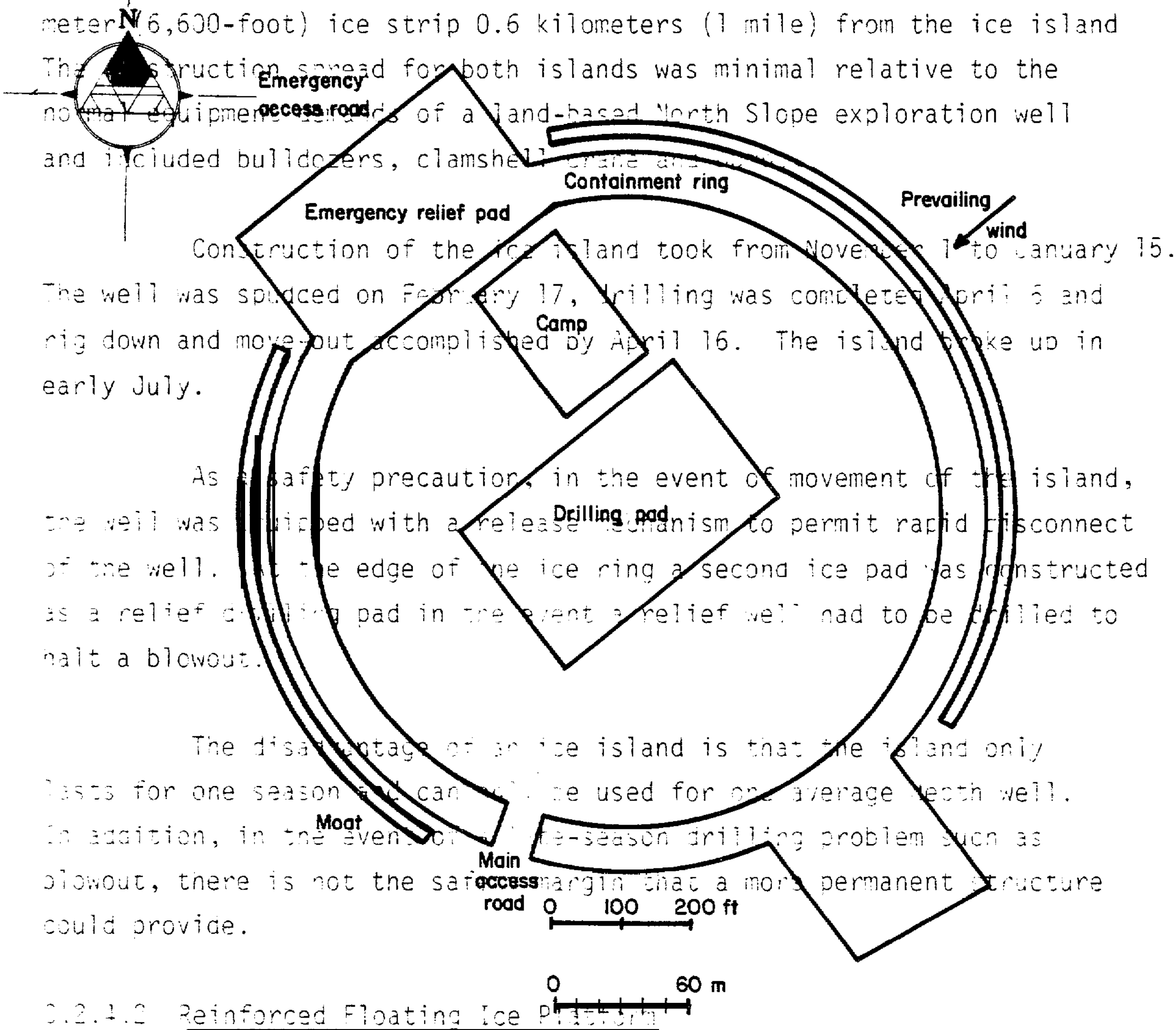
Construction of the ice island took from November 1 to January 15. The well was spudded on February 17, drilling was completed April 6 and rig down and move-out accomplished by April 16. The island broke up in early July.

As a safety precaution, in the event of movement of the island, the well was equipped with a release mechanism to permit rapid disconnect of the well. At the edge of the ice ring a second ice pad was constructed as a relief drilling pad in the event a relief well had to be drilled to halt a blowout.

The disadvantage of an ice island is that the island only lasts for one season and can only be used for one average depth well. In addition, in the event of a late-season drilling problem such as blowout, there is not the safety margin that a more permanent structure could provide.

3.2.4.2 Reinforced Floating Ice Platform

In the Canadian Arctic islands, the Arctic Ocean is covered with ice 10 to 11 months of the year. As of 1976, Panarctic Oils Ltd. had completed five wells in up to 286 meters (944 feet) of water there. Unlike the southern Beaufort Sea, this frontier region combines landfast ice and deep water. The Panarctic wells are up to about 23 kilometers ... miles) ... Dais, Watt... Masterson, ... The Panarctic program was pioneered ... the Hecla ... located ... Sabine Peninsula of Mel...



SOURCE: OIL AND GAS JOURNAL, JULY 11, 1977.

FIGURE 18 - ICE ISLAND PLAN (UNION OIL)

Island. It was drilled by a conventions'l dryland Arctic rig with a subsea blowout preventer (BOP) stack and riser (Baudais, Watts and Masterson, 1976). The ice sheet was art'ifically thickened from 2 to 5 meters (7 to 17 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. This can be explained by the fact that the 3-degree riser angle which is the maximum that can usually be tolerated in drilling operations corresponds to a lateral motion in 200 meters (660 feet) of water of 10 meters (33 feet) (Croasdale, 1977). By contrast, in 20 meters (66 feet) of water, the permissible maximum lateral ice motion would be only 1 meter (3 feet). Deep water, therefore, mitigates the effects of any fast ice movement. Conversely, drilling from a floating ice platform in shallow water, such as that which occurs in the proposed State-Federal lease sale areas of the Alaskan Beaufort, is generally not feasible.

The main disadvantage of the ice platform system in the Canadian Arctic Ocean around Melville Island and adjacent islands 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.

To produce the offshore gas reserves that have been discovered at Melville Island, a pilot project involving subsea completion and a subsea pipeline, is planned to commence in early 1978 (Oilweek, September 12, 1977).

3.2.5 Ice-Strengthened Drillships

Dome Petroleum currently has three ice-strengthened drillships 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 meters (19,800 feet) in water depths between 30 and 300 meters (99 and 990 feet) (Brown, 1976). The drillships are 115 meters (380 feet) long and 21 meters (66 feet) wide, with a light draft of 4 meters (13 feet) and a drilling draft of 7 meters (23 feet). Each have a dead weight of 5,486 metric tons (5,400 long tons). The drillships are 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.

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

- Length--63 meters (208 feet)
- Width--14 meters (46 feet)
- Draft--4.4 meters (14.5 feet)
- Cargo capacity--1,016 metric tons (1,000 tons)
- Horsepower--7,000 twin screw
- Speed--26 kph (14 knots)

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; McClure and Michalopoulos, 1977). A detailed description of a Beaufort Sea ice breaking drillship, including design and safety considerations and environmental parameters, is provided by Jones and Schaff (1975).

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

3.2.5.1 Drilling Program and Problems

A drilling season of about 112 days from July to October was planned for the Dome ships in 1976. However, in order to leave sufficient time to drill a relief hole in 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 was longer since the ships wintered in the area at Herschel Island, and drilling could commence immediately upon breakup without waiting for the freeing of the Point Barrow entrance to the Beaufort Sea.

By the end of the 1977 drilling season, Dome's drillships had drilled (completed or partially completed) six exploratory wells in the Canadian Beaufort Sea. In 1977, three wells were spudded: Kopanoar D-14, Tingmiark K-91 and Nektorolik K-59. The original plans required a work barge to install a 6-meter (20-foot) diameter caisson (for BOP protection) before the drillships arrived on location. However, due to problems experienced during preliminary work in 1975, Dome used 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, 1977).

The Hunt Dome Kopanoar D-14 well was drilled to a depth of 1,150 meters (3,795 feet) but was abandoned after a high-pressure water flow was encountered which rose to the sea floor outside the casing (OCS Environmental Assessment Program, 1977a). A well was drilled alongside the abandoned casing to the water-producing formation at 558 meters (1,840 feet); by the time the relief well had been drilled, the water flow had ceased of its own accord. Dome was required to reinspect the well, where a small water flow had started again, in the summer of 1977 prior to drilling at the new Kopanoar location (OCS Environmental Assessment Program, 1977b). A replacement well, Kopanoar M-13, was spudded 200 meters (660 feet) away and casing was set at 380 meters (1,254 feet) prior to suspension at the end of the 1976 drilling season (Oil and Gas Journal, June 13, 1977).

The Tingmiark K-91 well was suspended and shut in after a high-pressure natural gas zone was encountered. Subsequently, a leak of salt water was discovered issuing from a fissure in the sea floor 6 meters (20 feet) from the well head. The Canadian government has asked Dome to submit a plan to control the water flow (Oil and Gas Journal, September 26, 1977).

In 1977, drilling started again at the Kopanoar M-13 and Nektoralik K-59 wells, and a new well, Ukalerk C-50, was spudded. Gas was discovered at all three 1977 wells, and oil was discovered at a depth of about 2,590 meters (8,547 feet) at Nektoralik K-59 (Oil and Gas Journal, September 26 and October 10, 1977). A drilling extension beyond a September deadline for the Nektoralik well was granted prior to the oil discovery by the Canadian government in order to permit Dome to complete drilling through the gas zone and set casing. After operations for the 1977 season were suspended at the Kopanoar M-13 and Ukalerk C-50 gas discovery wells, the drillships were released to set surface casing at the Natsek E-56 and Nerlerk M-98 well locations (which had received preparatory work earlier in 1977 prior to the termination of the shallow drilling season at the end of October; Oil and Gas Journal, October 10, 1977). The 1977 discovery wells will be tested in 1978. The water depths at the three 1977 wells range from 27 meters (89 feet) at Ukalerk, 56 meters (185 feet) at Kopanoar and 63 meters (208 feet) at Nektoralik.

3.2.5.2 Application to the Alaskan Beaufort Sea

The use of ice-strengthened drillships permits exploration drilling in deeper water than do artificial islands. However, there is a minimum water depth (about 20 meters or 66 feet) in which drillships can operate due to limitations on lateral motion of the vessel that are dictated by the riser angle. The 20-meter water depth is the maximum that will be encountered in the State-Federal and Federal OCS lease sale areas. Therefore, drillships will be of limited application.

The use of drillships in the Alaskan Beaufort will also have to consider ice conditions, in particular the duration of the summer open water season and the position of the summer and fall pack ice boundary. In general, the summer pack ice boundary is further offshore in the southern Canadian Beaufort, especially east of the Mackenzie Delta, than in the Alaskan Beaufort. Therefore; the operational area of drillships beyond the 20-meter isobath is probably greater in the Canadian Beaufort.

As the Canadian program has demonstrated, it can take up to three seasons to drill and test (in the event of a discovery) an exploration well .

3.2.6 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 used 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 15 meters or 50 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.

3.2.6.1 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. The monopod design was employed successfully by Union Oil for a production platform in Cook Inlet in 1966 where seasonal ice moved by strong currents can be encountered from November to May (Oil and Gas Journal, March 2, 1970).' The platform was designed for 20 meters (66 feet) of water, a9-meter (30-foot)' tidal range, a design wave of 8.5 meters (28 feet) with a period of 8.5 seconds, steady force loads of 21,090 kilograms per square meter (43,200 pounds per square foot), and a bearing area based on a 2-meter (7-foot) ice thickness. The monopod consisted of a single column (in which the wells were located) resting on twin pontoons. The pontoons were connected by horizontal bracing members through which pilings were driven. The drilling deck and production deck, totalling 1,114 square meters (12,254 square feet), were 1 ocated 33 meters (109 feet) above the pontoons.

The advantages of the monopod are (Croasdale, 1977):

1. The amount of frontal area that is exposed to moving ice is minimized and· does not vary with water depth;

2. Ice action on the structure involves crushing failure, for which structures in Subarctic regions such as Cook Inlet have been designed;

3. An Increase in ice forces due to ice freezing to the structure will not be as great as that which might be expected with adfreeze on a sloping surface; and

4. There is no chance of ice-ride onto the platform's working surface.

Recent research on ice loading, which indicates that in water depths greater than 10 meters (33 feet) thick multi-year ridges might impose loads as much as 300 MN (67 x 10^6 lbf), coupled with research that indicates conical structures could resist such ice features better than cylindrical structures, would suggest that monopod structures may be of limited use in the Beaufort Sea. Canadian research emphasis has, therefore, been on conical structures.

Imperial Oil of Canada has designed a monopod platform for year-round exploration drilling in the southern Beaufort Sea (Brown, 1976). This monopod is a one-legged platform supported by a broad submersible base and is designed for the environmental and soil conditions existing out to 12-meter (40-foot) water depths. The monopod structure consists of three main components: the hull, 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 tanks contained in the hull. Beyond 12-meter (40-foot) 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 similar design described by Jazrawi and Davis (1975) is presented on Figure 19.

A mobile gravity structure such as the monopod provides operating flexibility for exploration 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.

3.2.6.2 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 1971). The conical shape reduces the ice force on the structure by causing the ice to fail by bending rather than crushing. This is particularly important in areas affected by multi-year ice ridges. In order to prevent excessive ice ride-up, the cone would recurve at the top beneath the superstructure. A cone structure could be of concrete construction designed to be ballasted on to the sea floor.

A hybrid design of the monopod and cone is the monocone which consists of a monopod within a conical collar attached at the ice line. The monotone configuration is expected to be less expensive in deeper water than a cone and also has a smaller diameter at the water line to keep ice friction [illegible] low.

Conside[illegible] model testing with ice, has been conducted [illegible] Oil Ltd. under a coordinated program of Arctic research sponsored by the Arctic Petroleum Operators Association (APOA). The reader is directed to papers by Croasdale (1975; 1977), Croasdale and Marcellus (1977), and Ralstan (1977) for discussions [illegible] ice interaction with offshore structures such as the cone.

A variant of the cone design is an "ice island" (not to be confused with a thickened ice sheet), which consists of a 76-meter (250-foot) tall hour-glass shaped steel-plated platform capable of operating in waters up to 20 meters (66 feet) deep (Oil and Gas Journal, September 14, 1970). The steel plate shell is supported by ice-filled tubes in compartments. The structure is floated to location during the open water season and ballasted to the bottom with seawater, which is then refrigerated to provide [illegible] resistance to ice forces. Refriger-

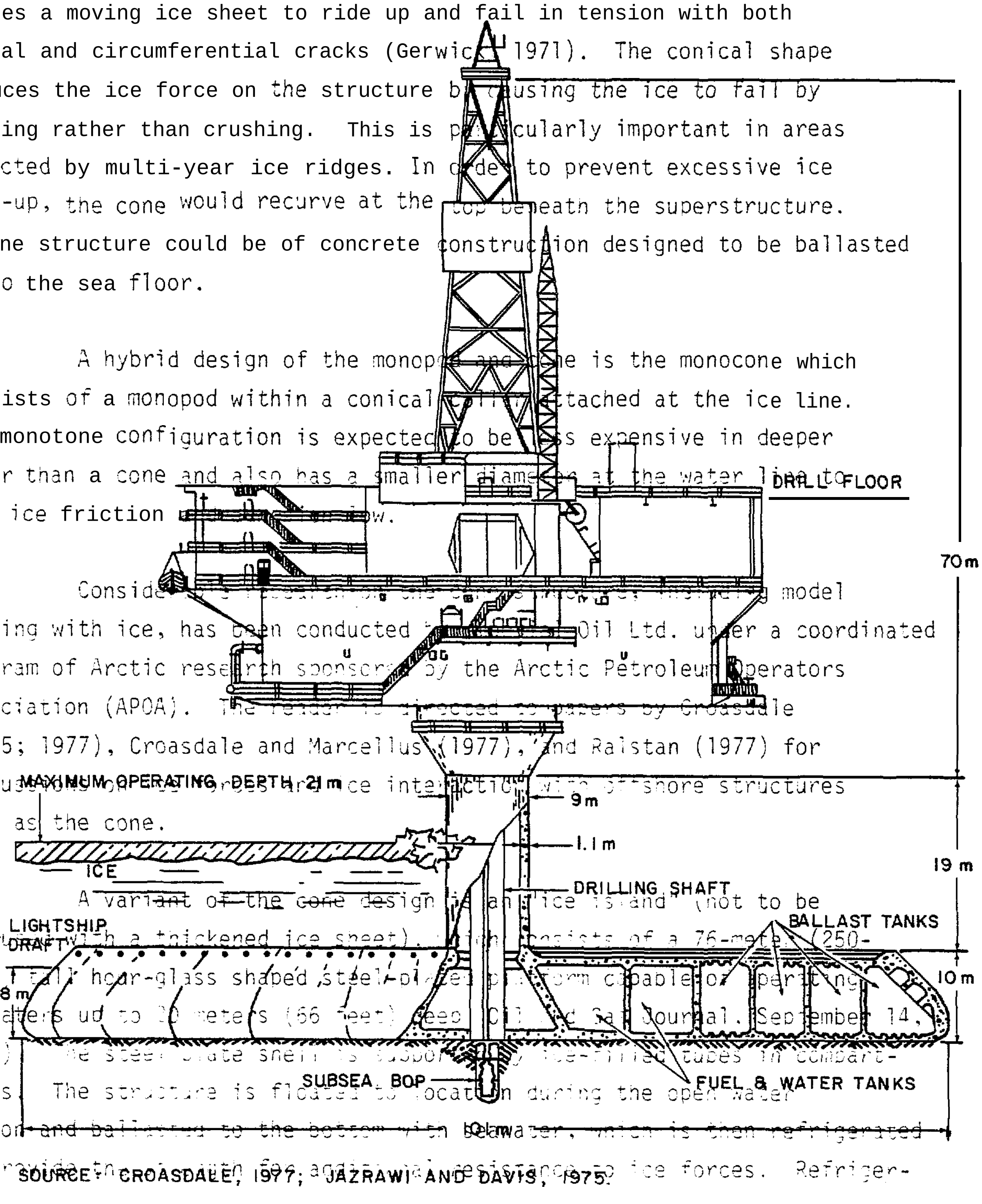


FIGURE 19 - CONCRETE MONOPOD

ation 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 is thawed, and the internal compartments emptied. The cost of this structure was estimated at $40 million in 1970.

The cone design, unlike many of the options described in this chapter, is one that is being considered for operations outside the landfast ice zone, in areas subject to ice ridge movement (i.e., ground ridge zone and seasonal pack ice zone).

3.2.7 Other Platforms

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 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 rig, 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 is a partially submerged steel tank in the form of a 32-side rhomb, 113 meters (373 feet) in diameter, and with a total height of 120 meters (396 feet) from the bottom of the tank to the top of the drilling derrick, which supports a deck and steel tower. A propulsion system with driving propellers set at the base of the tank 45 meters (149 feet) below water level, coupled with ballasting/de-ballasting capabilities, would provide the structure with ice breaking capability.

For operation in landfast ice areas, an air cushion drill barge (ACDB) has been proposed (Jones, 1977). The ACDB is a drill rig mounted on an amphibious air cushion platform which can be used on ice or in a lake previously prepared in the ice sheet by removal of ice blocks.

3.2.8 Offshore Tunneling

An offshore tunnelling and chamber system (OTACS) has been proposed as an alternative to offshore platforms, subsea pipelines and marine terminals (Lewis, Green and McDonald, 1977). A complete drilling and production system beneath the sea, comprised of two tunnels, a service tunnel (rail lines, access to drilling chambers, pipelines) and one for airflow, would be linked by cross-over ducts. The adit and surface complex would be located near the shoreline. To produce a reservoir covering 77 square kilometers (28 square miles) offshore in an area such as Prudhoe Bay, it is estimated that a 16-kilometer (10-mile) tunnel punctuated with drilling chambers every 2 kilometers (1.2 miles) would be required. Directional drilling from each of 8 chambers with 12 wells per chamber would be sufficient to access the 77-square-kilometer (28-square-mile) reservoir. Two depths were considered for OTACS: a shallow 300-meter (1,000-foot) level and a deep 600-meter (2,000-foot) level.

The advantages of such a tunneling system over more conventional offshore development are cited to be (Lewis, Green and McDonald, 1977):

- 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, which are more expensive than dryland facilities, are eliminated.

- Drilling conditions are more predictable and can continue year-round.

The need for strict safety requirements in OTACS is acknowledged by its proponents, but they 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 and oil spills may also pose serious problems and prove no less difficult to control than aboveground facilities.

Economics will be an 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. The capital costs of OTACS far exceed the individual field development costs (including pipelines) that are estimated in this report for the various petroleum development scenarios.

3.3 PLATFORM SELECTION CRITERIA

3.3.1 Engineering Constraints

The natural conditions which represent engineering constraints to platform design and selection include:

- Sea ice
- Bathymetry
- Tides and currents
- Winds and waves
- Soil mechanical properties of bottom sediments
- Subsea permafrost

Some of these factors have been described in detail in Section 2.1.3. Their relevant engineering constraints are summarized below. The various technological options for offshore drilling, specifically platforms and their application to the Alaskan Beaufort Sea, are summarized in Table 5.

3.3.1.1 Sea Ice

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. Although conventional semi-submersibles and jackup rigs could be used for exploration drilling during the open-water season, 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. Platforms, therefore, have to be designed to accommodate ice loading which varies spatially and seasonally. Landfast ice, although relatively stable, can have movement of several meters. Outside the landfast ice zone, the mobile pack ice, with its ridges, imposes significantly greater forces on structures.

TABLE 5

APPLICABILITY OF PLATFORM TYPES TO ALASKAN BEAUFORT SEA PETROLEUM DEVELOPMENT

Platform Type	State of the Art: Exploration	State of the Art: Production	Applicability to Alaskan Beaufort	Water Depths	Ice Conditions	Construction Techniques	Logistical and Drilling Considerations	Environmental* Concerns	Comments
Artificial Soil Island (Conventional Exploratory)	Proven	Not Suitable	Suitable; application may be locally limited by lack of nearby (within 20 miles) fill or environmental regulation.	1.5-15 meters (5-50 feet) (summer construction) 0.3-3.3 meters (1-10 feet) (winter construction)	Landfast Ice Zone Only	Floating construction spread with dredge. barges, etc. in summer or winter construction over ice by backfilling excavation in ice.	Dryland drilling rigs used; provides extended drilling season vs. ice island; support problems during freeze-up and break-up	fledging and construction activities; effects of increased marine traffic on marine mammals	Most suitable of platform options of currently proven techniques in landfast zone. provided suitable fill is available and no insurmountable environmental problems
Caisson/Sheet Pile Artificial Soil Island	Conceptual	conceptual	Suitable	1.5-18 meters (5-60 feet)	Landfast Ice Zone and Pack Ice Zone	Floating construction spread with dredge, barges, cranes. etc. in summer; caissons or cellular Piling prefabricated on shore.	Caisson/Sheet piles provide significant saving of fill and added protection	Dredging and construction activities; effects of increased marine traffic on marine mammals	Most suitable of platform options of currently proven techniques in landfast zone, provided suitable fill is available and no insurmountable environmental problems
Artificial Ice Island	Proven	Not Suitable	Suitable	0.3-9 meters (1-30 feet)	Landfast Ice Zone Only	Minimal construction spread; flooding of ice surface by pumps to thicken ice.	Dryland drilling rig used; time limitation on drilling; resupply over ice	Minimal; drilling has to terminate about 45 days before break-up as precaution in case relief well has to be drilled	Most environmentally compatible option but water depth and drilling time limitations; key to extension of range rests on ice thickening technology and ice preservation technology
Reinforced Ice Platform	Proven	Not Suitable	Not suitable due to limitation posed by shallow water, ice movement, riser angle	Variable with Ice movement, 100-400 meters (330-1300 feet)	Landfast Ice Zone Only	Minimal construction spread; flooding of ice surface by pumps to thicken Ice.	Dryland drilling rig used; resupply over ice; subsea BOP stack	Minimal; drilling has to terminate about 45 days before break-up as precaution in case relief well has to be drilled	Shallow water depths combined with ice movement would impose unacceptable riser angles.
Ballasted Barge	Proven	Conceptual	Suitable	1.5-4.5 meters (5-15 feet) for conventional barge	Landfast Ice zone Only	Floating construction spread with dredge. barges, cranes, etc. in summer; barge(s) ballasted to sea floor and berm constructed around periphery.	Dryland drilling rig used; provides extended drilling season vs. ice island; support problems during freeze-up and break-up	Dredging and construction activities; disturbance to marine mammals from increased marine traffic	Provides the mobility that soil islands lack but conventional barges restricted to narrow depth range. Specially designed drilling barges (self-contained drilling/production systems) could have greater application
Ice-Strengthened Drillship	Proven	Not Suitable	Limited; cannot operate in depths present in areas considered for leasing	11-300 meters (35-900 feet)	Open water summer Operations only unless ice breaking protection provided by support vessels	Fabricated outside Arctic; production variant may require on-site modular(?) installation in summer.	Requires support fleet; short drilling season; subsea BOP stack	See Footnote	Due to short drilling season, deep targets may take more than one season to drill and evaluate
Monopod	Proven (for limited ice loads)	Conceptual	Suitable	10-100 meters + (33-320 feet)	Landfast Ice Zone and Polar Pack Ice Zone (?)	Fabricated outside Arctic; production variant may require on-site modular(?) installation in summer.	Self-contained drilling system	See Footnote	Best suited to deeper waters of the State-Federal and federal OCS lease sale areas. Can either be a mobile exploration platform or fixed production platform.
Cone	Conceptual	conceptual	Suitable	10-100 meters + (33-320 feet)	Landfast Ice Zone and Polar Pack Ice Zone	Fabricated outside Arctic; production variant may require on-site modular(?) installation in summer.	Self-contained drilling system	See Footnote	Best suited to deeper waters of the State-Federal and Federal OCS lease sale areas. Can either be a mobile exploration platform or fixed production platform.
	Conceptual	Conceptual	Suitable	10-100 meters + (33-320 feet)	Landfast Ice Zone and Polar Pack Ice Zone	Fabricated outside Arctic; production variant may require on-site modular(?) installation in summer.	Self-contained drilling system	See Footnote	Best suited to deeper waters of the State-federal and Federal OCS lease sale areas. Can either be a mobile exploration platform or fixed production platform.
Conventional Semi-submersible	Proven (Summer Only)	Conceptual	Unsuitable; summer only operation; high standby costs; water too shallow in lease areas for operation.	30-610 meters (98-2000 feet)	Open water only	Fabricated outside Arctic; production variant may require on-site modular(?) installation in summer.	Self-contained drilling system; short drilling season; high standby costs	See Footnote	Has not been used in Beaufort Sea or Arctic islands and would require ice protection to operate in these areas.
Conventional Jack-up	Proven (Summer Only)	Not Suitable	Unsuitable; summer operation only with high standby costs.	15-45 meters (50-150 feet)	Open water only	Fabricated outside Arctic; production variant may require on-site modular(?) installation in summer.	Self-contained drilling system; short drilling season; high standby costs	See Footnote	Has not been used in Beaufort Sea or Arctic islands and would require ice protection to operate in these areas.

* A general environmental concern for oil spills and offshore drilling is assumed. Each platform type presents different spill and/or clean up problems, floating systems such as drillships with subsea BOP stacks are a particular concern. Artificial soil islands present fewer problems in case of a blowout though access to the island during freeze-up and break-up may be difficult. Drilling from ice islands or drillships has to terminate in sufficient time before break-up or freeze-up to permit sufficient time for drilling of relief wells if a blowout occurs.

In addition to ice stresses, platform design must consider the problems of ice ride-up and adfreeze to platform surfaces which, although relatively stable, can involve movements of several meters. In the landfast ice zone, the use of artificial soil islands, ice islands/thickened pads, and sunken barges is feasible and uses currently developed techniques. Platform designs for areas outside the landfast ice zone which are affected by the significantly greater ice loading of the seasonal pack ice and ice ridges are still in the conceptual or model stage. At present the Canadians have opted to use ice-strengthened drillships during the summer open-water season in the southern Beaufort Sea. However, the State-Federal lease sale area is for the most part limited to the landfast ice zone. In the near future in the Alaskan Beaufort Sea, the stamukhi zone will probably determine the seaward limit of petroleum development, thereby restricting activities to the landfast ice zone.

Another constraint imposed by sea ice on petroleum operations, including platform mobilization and support, concerns 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. As was proven in the 1975 Prudhoe sealift, when critical oil field equipment almost failed to reach Prudhoe Bay due to closure of the Barrow entrance by pack ice, marine transportation in the Beaufort Sea can be unpredictable.

3.3.1.2 Bathymetry

To some extent bathymetry and sea ice conditions are interrelated since the grounding of ice ridges in the stamukhi zone occurs between the 10- and 20-meter (33- and 66-foot) isobaths; the landfast ice zone terminates, therefore, at these depths. The shallow nearshore waters of the Beaufort Sea can be viewed as both an advantage and disadvantage to offshore petroleum development.

As indicated in Table 5, artificial soil islands have been constructed in water depths of up to 15 meters (50 feet); sheet piling or use of caissons could extend their feasibility to water depths of 20 meters (66 feet) in areas still within the landfast ice zone at these depths. While shallow water favors use of artificial islands and artificial ice islands, it does not favor conventional or ice-reinforced floating rigs such as semi-submersibles and drillships, since these generally cannot operate in water depths of less than 20 to 30 meters.

Construction of artificial soil islands by floating equipment is limited by bathymetry. Shallow-draft barges, dredges, etc., cannot operate in water depths of less than 1.5 to 2 meters (5 to 7 feet) without the dredging of channels, Consequently, artificial islands to be located in water depths of less than 2 meters are constructed during winter by dryland equipment through backfilling of an excavation made in the ice.

The ballasted barge drilling technique, if employing conventional barges, is also limited to certain water depths, about 1.5 to 4.5 meters (5 to 15 feet), due to draft and freeboard restrictions.

Design and installation of gravity structures such as the cone or monopod, whether mobile exploration rigs or fixed production platforms, will have to take the shallow water depths of the Alaskan Beaufort Sea into consideration. Designs for deep water production platforms in the North Sea, for example, are not applicable to the Alaskan Beaufort Sea.

3.3.1.3 Tides, Currents, Winds and Waves

Tides, currents, winds and waves are particularly important design considerations with respect to artificial soil islands. Erosion protection for island slopes and island freeboard in the southern Canadian Beaufort Sea, for example, are determined by the significant wave height, with allowance for storm tides and astronomical tides.

Standard hindcasting techniques based upon historical weather and ice data, supplemented in recent years by real-time wave data from buoys, have been used to predict significant wave heights and storm tide data for the southern Canadian Beaufort Sea (Croasdale and Marcellus, 1977). These data indicate that for a 50-year return period in a water depth of 2.4 meters (8 feet), the significant wave height would be 2.4 meters (8 feet) and storm tides 2.6 meters (8.6 feet). These conditions would require an island freeboard of about 7.6 meters (25 feet) in 4.6 meters (15 feet) of water. Imperial Oil Ltd. has used the 10-year recurrence interval of a 1.2 meter (4 feet) storm tide plus associated breaking wave (Riley, 1975).

For conventional offshore platforms, wind and wave conditions are not as significant a design consideration for Beaufort Sea operations as for the storm-stressed North Sea. An exception is the action of wind forces on ice surfaces which is an important consideration in the assessment of ice loading on offshore structures.

3.3.1.4 Soil Mechanical Properties of Bottom Sediments

The mechanical properties of offshore soils is an important consideration in the design of bottom-founded structures, including artificial soil islands, artificial ice islands and gravity structures.

With respect to artificial soil islands, the properties of sea bed soils are required to determine (de Jong, Steiger and Steyn, 1975):

- the bearing capacity and settlement of the island;
- the most suitable borrow area for silt or sand;
- the stability of shore protection; and

- the resistance of the island against ice forces.

Knowledge of these properties are needed to answer:

- The rate and method of island construction to ensure stability of the island and its slopes;

- The minimum dimensions required to resist ice forces and modes of failure of island (edge failure, failure through island fill, failure through sea bed); and

- The additional height of the island required to compensate for settlement of the subsoil and fill.

The stability of sea bottom sediments and their response to loading from gravity structures (including loading translated by moving ice) will be an important design consideration.

The seismic response of soils to earthquake shaking is not a major design consideration for bottom-founded structures in the Beaufort Sea, unlike the Gulf of Alaska, since the region is not subject to significant seismic activity.

3.3.1.5 Subsea Permafrost

The presence of subsea permafrost, its ice content, thermal regime and mechanical properties are important considerations in the design of bottom-founded structures. Essentially, evaluation of permafrost conditions is part of the assessment of the soil mechanical properties, as discussed above. A listing of permafrost-related problems of offshore petroleum development is contained in Arctic Project Bulletin No. 15 (OCS Environmental Assessment Program, 1977c). Some potential problems include:

1. Differential thaw subsidence of subsea permafrost and related foundation problems.

2. Difficult dredging operations in areas of near-bottom subsea permafrost; possible exposure of permafrost, modification of the thermal regime, and settlement or heave problems.

3. Thaw subsidence around well holes.

4. Frost heaving, including:

   (a) Bore casing co1 lapse due to freeze-back
   (b) Freeze-back of artificial soil islands and subsoils
   (c) Differential stresses on bottom-founded structures

At Prudhoe Bay, permafrost is found in thick unbended (non-ice-rich) layers at water depths greater than 2 meters (7 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 meters (7 feet), permafrost is found in ice-bonded layers. The presence of subsea permafrost is of greater concern to offshore pipelining than to offshore platforms and drilling (See Section 3.5.1.1).

3.3.2 Logistics

3.3.2.1 Available Technology

The technology available for Beaufort OCS offshore operations will in part depend upon the scheduling of the lease sale. As indicated in Tables 5 and 6, the systems that have been proven to date are artificial soil islands, thickened ice platforms, sunken barges and ice-strengthened drill ships.

TABLE 6

OFFSHORE 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	Yes	NA	2 Mos.	2 Mos.	NA	4 Mos.
Ice	Yes	Yes	NA	2 Mos.	2 Mos.	NA	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-submersib e	Conceptual	Yes	2 Yrs.	6 Mos.	1 Yr.	2-4 Mos.	45 Mos.
Drillship	Yes	Yes		1 Yr.	1 Yr.	2-3 Mos.	27 Mos.
F xed							
Protected Gravel	Yes*	Yes	1 Yr.	2 Mos.	6 Mos.	NA	20 Mos.
Gravity Platform	Conceptua	Yes	2 Yrs.	1 Yr.	1 Yr.	2-4 Mos.	51 Mos.

*Only in landfast ce.

SOURCE: E.S. Clarke, 976.

Caisson-retained islands may be constructed in the southern Beaufort Sea in 1978 (Canada Department of Environment, 1977). Existing technologies being used in non-Arctic areas, such as semi-submersibles, jack-up rigs, and gravity platforms, would have to be modified or adapted to the rigors of the Arctic environment, in particular sea ice. All of these systems will require certain design lead, testing and construction time (Table 6), which have to be evaluated within the framework of the lease sale schedule.

Experience gained in offshore operations in the southern Beaufort Sea in Canada will play an important role in selection of the technological options to be considered for offshore operations in the Alaskan Beaufort Sea. This is because:

- Environmental conditions are similar; and
- Canadian offshore activities are several years advanced of proposed American leasing schedules, and new equipment or technologies will already have been field tested by the Canadians.

Future Canadian plans include a proposal by Imperial Oil Ltd. for a 20-location, 10-year Beaufort Sea drilling program commencing in 1978 that calls for 14 caisson-retained islands, 4 “conventional” islands, and 2 sacrificial beach islands. The actual level of activity in this region will depend upon drilling success.

The State-Federal OCS can be explored and developed using currently developed techniques due to the great extent of landfast ice and area enclosed within the 20-meter (66-foot) isobath. The technological developments and offshore experience gained in the State-Federal lease sale area will influence the technology utilized to explore and develop remaining state lands offshore and federal OCS areas that may subsequently be leased.

3.3.2.2 Timing

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 soil islands do not have this problem and can be constructed and operated during either the winter or summer season. Summer construction of soil islands involves a significant floating construction spread which is idle for about 8 months of the year. Artificial ice islands are the most logistically attractive exploration platforms for the landfast ice zone, since they can be constructed with local materials (seawater) and a minimal construction spread. Figure 20 shows relative construction and drilling schedules for different kinds of platforms.

Another logistical problem concerns rig support during drilling. (A North Slope exploration well usually requires one Hercules flight a day for supply.) During freeze-up in the fall and break-up in the spring (which can total 3 to 4 months), access over ice or by sea to an offshore rig is difficult. In fall, over-ice transportation has to await sufficient thickening of the ice; boat transportation in the spring has to await ice melt. These delays can restrict the available drilling time, which can be critical in the case of a deep exploration target. A 3,050-meter (10,000-foot) exploration well may take 80 to 90 days to drill. An artificial soil island could have sufficient storage space, however, to minimize resupply problems. Air cushion vehicles such as those successfully tested in Canada by Artec Ltd. may provide all-season resupply capability to offshore rigs.

At this time it is difficult to speculate on the types and numbers of gravity platforms or other non-locally-constructed drilling systems that might be used and where they might be constructed. The actual time to utilization, as shown in Tables 5 and 6, includes much

Figure 20 -

Drilling and Construction Schedules of Some Platform Types in the Alaskan Beaufort Sea 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 might lead to a local concrete production platform fabrication industry which could subsequently serve other Alaskan OCS areas, including the Beaufort Sea.

3.3.2.3 Production Platforms

Whereas exploratory drilling can be conducted from temporary or mobile structures, production generally requires fixed platforms. The space demands for production platforms are greater since oil/gas/water separation equipment and oil storage may be required on the platform.

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 (8 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 exploration island. Temporary exploration islands that have been abandoned may be used as borrow sources for permanent production islands elsewhere (a recycling program). (In the southern Canadian Beaufort Sea, abandoned exploration islands have been used as borrow sources for new exploration islands.)

Gravity production platforms are probably more attractive economic options in deeper water, and may be the only option beyond the 20-meter (66-foot) isobath. Due to increasing borrow requirements with water depth, artificial islands become economically less attractive. Also, specially designed structures are required to resist the ice forces encountered seaward of the landfast ice zone. Ice islands are feasible (though unlikely) as permanent production platforms if appropriate measures (insulation, refrigeration, annual ice-thickening) are taken to minimize and/or replace summer ablation losses.

3.3.2.4 Resource Availability

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

Floating structures will probably be fabricated in the lower 48 states or overseas. In contrast, artificial islands are constructed on site with locally available construction materials and involve drilling with dryland Arctic rigs.

A major resource consideration is the availability of offshore and onshore borrow material for construction of artificial islands. The possible scarcity of onshore and offshore fill materials in the Federal lease area west of the Colville River may limit the use of artificial soil islands (unless long distance barge haul is conducted) and favor the use of ice islands, barges and gravity structures for exploration. The State-Federal lease sale area to the east has significant offshore and adjacent onshore sand and gravel resources.

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. Caissons and piling will be manufactured off site and shipped to the Beaufort Sea.

3.3.3 Environmental Stipulations and Impacts

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

Particular attention will 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. At present there are no specific state regulations pertaining to offshore gravel extraction. Rather, the state regulates borrow extraction on a case-by-case basis through the issuance of permits (Grundy, 1977).

A recent Canadian study has reviewed the potential environmental impacts of artificial islands in the southern Beaufort Sea (Canada Department of the Environment, 1977). While these findings may not be directly applicable to the Alaskan Beaufort Sea due to variations in oceanography and biology, the principal conclusions provide important indicators for the research that will have to be conducted on a site-specific basis in the Alaskan Beaufort.

The study, which pertains to the sixteen artificial soil islands constructed for oil and gas exploration off the Mackenzie Delta in the Beaufort Sea since 1972, concludes:

> "No significant environmental problems have yet been identified. As construction moves farther offshore and into the deeper and less turbid waters of the nearshore Beaufort Sea, some potential resource conflicts are foreseen.
>
> (1) It is not anticipated that the current rate of construction will have significant impact on the chemical and physical oceanography of the area.
>
> (2) Localized regeneration of nutrients from resuspended dredge spoils and hydraulic fill operations may result in short-term increases in phytoplankton production.
>
> (3) Increased turbidity resulting from construction activities may depress phytoplankton productivity. The impact will be localized and insignificant in terms of total production.
>
> (4) Localized destruction of benthos will occur as a result of direct burial at the island location or by fallout from the turbidity plume. The rate of recolonization and re-establishment of a stable' benthic community is unknown.

(5) No significant impacts on fish populations are anticipated.

(6) Increased support traffic through Shallow Bay and in the travel corridor from the Tuft Point materials site to construction areas may have significant impacts on beluga or white whales. The effects of a single barge tow through the Shallow Bay calving area were observed for 3 and as much as 30 hours[1]. Beluga have evolved a highly efficient underwater acoustic system to derive spatial information about their environment and as a mechanism for exchanging social information. Concern is expressed that underwater sounds emanating from operations on and in the vicinity of artificial islands could interfere with the animal's natural signals, affecting their navigation and communication processes and influencing their behaviour patterns. Any insidious effects of disturbance on calving beluga may take many years to manifest themselves as a population decline because of the longevity of the species and the lack of accurate popluation estimates. Strict measures must therefore be taken to regulate traffic through critical areas.

(7) Air traffic between onshore support bases and offshore construction areas can be routed to avoid passing over critical waterfowl areas. Erosion and deposition along the Tuktoyaktuk Peninsula resulting from granular material extraction may have detrimental impacts on both waterfowl feeding and staging areas. In the event that traffic through Shallow Bay is restricted because of potential disturbance to belugas, there may be pressure to permit traffic to proceed along river channels passing through the Kendal Island Bird Sanctuary. Because of the very low reproductive success of Snow Geese in the sanctuary over the past several years any disturbance to the colony may be critical. Since there may be no compromise solution to the problem of protecting both waterfowl and beluga populations, it may be necessary to prohibit barge traffic through both areas. Supplies could be stockpiled at an offshore staging area such as Garry Island and traffic routed via the East Channel of the Mackenzie River to Kugmallit Bay.

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(1) The observed effects were the avoidance of the marine traffic area by the whales and alteration of the whales normal distribution pattern and travel routes for a number of hours.

(8) Unless properly charted and marked, abandoned artificial islands may constitute a hazard to navigation.

(9) Artificial islands should be constructed so as to be readily destructed by wind and wave action following the removal of erosion control materials such as filter cloth and sandbagging."

The principal concern of the Canadian researchers is the impacts of the artificial island program on the white whale or belukha. Specifically, these concerns are:

(1) Disturbance due to construction activities to the extent that traditional calving areas, feeding areas and travel routes are avoided.

(2) Interference with whale movements from marine and air traffic associated with construction and support activities; and

(3) The actual physical presence of an artificial island, borrow pits or staging areas may interfere with calving or feeding areas or may block travel routes.

Impacts of sediment plumes and increased turbidity from dredging and hydraulic fill operations on benthic organisms and fish were not regarded as significant.

Impacts on the physical-chemical oceanographic environment from such activities as borrow extraction and island construction are not believed to be significant although the data base is still limited. Turbidity increases from dredging and island construction, for example, were observed to be significantly less than that resulting from a summer storm .

Possible impacts from construction of gravel islands, causeways, and onshore and offshore borrow extraction in the Alaskan Beaufort Sea have been summarized in Arctic Project Bulletin No. 15 (OCS Environmental Assessment Program, 1977c). The principal concerns are:

1. Borrow extraction, especially from the barrier islands, beaches, and nearshore bottom sediments (depths less than 5 meters or 17 feet);

2. Location of artificial islands within lagoons and bays, and between barrier islands;

3. Location of causeways inshore of the 5-meter (17-foot) isobath, between barrier islands, across bays and lagoons.

An unofficial list of suggested areas of environmental regulation with respect to the joint state-federal lease sale reflecting Arctic scientists' concerns is contained in Arctic Project Bulletin No. 16 (OCS Environmental Assessment Program, 1977d). These include length of the drilling season, types of offshore exploratory platforms, disposal of temporary facilities, and spill/blowout contingencies.

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 have to be considered.

Finally, the safety aspects of the operation of different types of offshore structures will have to be considered. For example, drilling from an ice island means that there is a definite time restriction on the length of the drilling season (due to breakup) that could present difficulties if late season drilling problems occur. An artificial soil island does not have these limitations.

3.3.4 costs

There are few 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. Sandbag-retained islands Netserk B-44, constructed in 4.5 meters (15 feet) of water, and Netserk North F-4, constructed in 7 meters (23 feet) of water, are reported to have cost $11 million and $15 million respectively (Riley, 1975; Cox, 1978). Sacrificial beach island, Anark L-30, built in 8.5 meters (28 feet) of water cost $5 million (Cox, 1978). Minter-constructed shallow-water islands such as Pullen E-17 (located in 1.7 meters or 5.5 feet of water) and Sarpik B-35 (located in 4.1 meters or 13.5 feet of water) range in cost from $2 million to $5 million.

The Helca N-52 offshore well (drilled in 128 meters or 422 feet of water) in the Canadian Arctic islands cost $2 million, which included about $0.5 million for construction of the ice platform and $1.5 million for drilling the well (Baudais, Watts, and Masterson, 1976).

Construction of an ice island to serve as a platform for an exploration well is estimated at between $2.5 million and $5 million (Dames & Moore, 1975a; Fitch and Jones, 1974). More recently a cost range of $1 million to $.2 million has been quoted for ice island construction (Hutt, 1978). The cost of an ice island is, in fact, probably less than that for site preparation (gravel pad construction, etc.) of an onshore exploratory well since minimal manpower, equipment and materials are required. No figures are available for Union Oil Company of California's ice islands. There is little doubt that ice islands represent the most viable economic option, especially in areas where gravel or sand cannot be readily obtained. A major cost factor in the construction of artificial soil islands is the haul distance from the borrow sources to the island site and whether that source is onshore or offshore.

While Canadian Beaufort Sea experience will be a major determinant in the selection of offshore platforms in the Alaskan Beaufort, there are certain contrasts between the two areas that should be considered in assessing the applicability of the Canadian experience. These contrasts can be summarized as follows:

- Shallow water generally extends for greater distances offshore in the 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-meter (66-foot) isobath are comparable (72 kilometers or 43 miles), a much greater area per kilometer of coastline is enclosed by that isobath in the 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 Canadian Beaufort, especially east of the Mackenzie Delta, than in the Alaskan Beaufort.

- Suitable offshore fill materials (sand and gravel) are scarce in the southern Canadian Beaufort Sea west of 134°W longitude (the principal area of exploration interest), necessitating barge haul for some distance of borrow materials. Preliminary offshore soils data for the Alaskan Beaufort indicates that for the area east of the Colville River delta, suitable offshore fill materials are present; west of the Colville delta, however, suitable offshore fill materials are probably scarce.

- U.S. environmental regulations, especially those concerning dredging operations, are expected to impose more stringent protection measures on U.S. development than Canadian regulations do in Canada.

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-meter (66-foot) isobath to the shore limits the application of artificial soil island and ice islands to a smaller area.

The more favorable open water conditions in the southern Canadian Beaufort Sea east of the Mackenzie Delta have encouraged the use of drillships for deep water drilling (>20 meters or 66 feet). In contrast, the summer pack ice generally lies closer to shore in the Alaskan Beaufort, thus restricting the area that can be explored by drillships.

3.4 OIL FIELD OPERATIONS

The purpose of this section is to provide a basic primer in oil field operations, specifically drilling and oil treatment, so that the equipment and material requirements of offshore petroleum development presented in Chapter 8.0 can be fully appreciated.

3.4.1 Oil Characteristics

In the Alaskan Beaufort Sea, oil and gas may be produced from several geologic formations which may have different reservoir characteristics and hydrocarbon properties (see Appendix A). To date oil has been produced commercially on the North Slope only from the Permo-Triassic Sadlerochit Group. Additional offshore reserves from the Sadlerochit Group or equivalent are expected and postulated in subsequent chapters of this report. Sadlerochit oil is anticipated to be a significant portion of the nearshore reserves in the central Alaskan Beaufort Sea.

As indicated in Appendix A, additional onshore and offshore oil and gas resources may be encountered in the Pennsylvanian-Mississippian Lisburne group and Cretaceus Kuparuk formation or younger Tertiary strata (e.g., Flaxman Island discovery). The scenarios developed in this report reflect the geologic diversity of the Beaufort Sea and postulate contrasting reservoir and oil characteristics. However, for the purposes of description, the following discussion of oil gravity, water impurities, etc. uses the Prudhoe Bay values (for which data is available) and are likely to be as close as any other projection, especially since a significant portion of the offshore reserves will probably be encountered in the Sadlerochit formation.

An analysis of Prudhoe Bay crude is presented in Table 7. The effects of alternative assumptions on oil characteristics are discussed below.

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 (5° to 15° API) may not flow from the reservoir unless they are warmed or diluted with a solvent. Crudes of very high gravity (35° to 45° API) flow readily from the reservoir, but are high in lighter fractions, which will tend to vaporize or evaporate in the atmosphere and in transport. The percentage of recovery of the light gravity oils in place 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.

TABLE 7

ANALYSIS OF A REPRESENTATIVE NORTH SLOPE CRUDE OIL

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	700.0	100.00
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		-10	----	----	+50
Water by distillation, Vol. %		1.5	----	----	----
Fraction of crude, vol. %		100	9.6	20.9	66.9

Source: "Character sties of World Crude Oi 1s". Petroleum Pub. Co. (Oil & Gas Journal), 1975, Tulsa, Oklahoma.

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 that, and a water layer further 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 cubic feet 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 sulfide gas, 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. It can be separated from the oil offshore at the platform or 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, in some situations it may be feasible to treat it onshore. Some trace sand content will remain in the oil until delivery to a refinery.

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

3.4.2 Lift and Reservoir Technology

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 increase drainage is to increase the underlying water pressure in the formation by injection of water. Direct lift of the oil by submersible pumps 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 drainage mechanism for the scenarios.

Maintenance of drainage 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.

3.4.3 Well Technology

A typical oil well drill has a bit which presents a cutting face or gear teeth 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 the 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 the 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. In the Arctic, typical well drilling time may be 45 to 60 days for wells 2,121 to 3,030 meters (7,000 to 10,000 feet) deep.

The flow of drilling fluid is an important control factor for oil drilling. Normal hydrostatic pressures will reach several hundreds of kilograms per square centimeter (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 up the well of high pressure formation fluids or gases 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 well head in case mud control fails. A hydraulically-operated blind ram seals off the casing if all other valves fail. High- and low-level alarms warn if the mud fails to return (indicating that a void or high permeability zone has been encountered) or if it returns faster than the injection rate.

Drilling downtime 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 and widespread public alarm.

For a well drilled on land, the drilling platform is immediately over the well head, 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 hundred meters, as with geotechnical coring of the ocean bottom. The drilling platform may be a stable platform standing on the ocean bottom, or it may be floating. At the present time, ocean drilling 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 well head. If wave roughness exceeds certain “window” conditions, the drill stem must be pulled out, the well head 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 outweigh those which are derived from materials consumed. Thus, nondrilling time due to weather or other interruption is nearly as costly as the drilling time. Well costs can be increased significantly by such down periods, sometimes as much as nine times in North Sea we'lls between calm and rough periods (A.D. Little, Inc., 197'6).

In the Beaufort Sea within the 20-meter (66-foot) isobath, use of stable platforms is probably the best method, most likely an artificial island constructed of gravel or ice, with or without concrete or steel skeletal reinforcement.

Wells may be directionally drilled from stable platforms at an angle of 45 to 50 degrees from the vertical, so that a considerable area of formation may be covered from a single platform location with 160-acre well spacing. The 45-degree cone permits 11 wells from a single point for a formation 1,500 meters (4,950 feet) deep; 45 wells at 3,000 meters (9,900 feet). A well may also be produced at more than one level throughout its life if it penetrates multiple layers of oil sand. Specifications of a typical well, equipment, and materials are presented in Chapter 8.0.

After a hole has been cut through some depth of rock, steel pipe is placed into the hole and cemented into place. Minimum casing programs may be specified by OCS regulations for particular areas. The steel casing and cement prevent high pressure fluids in 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.

Withdrawal from the well hole with a drill stem to change bits, to draw core samples, etc., and subsequent re-entry require care, but are done routinely. Gas pressure buildup may occur in the mud column while mud circulation is halted. Reentry techniques for underwater wells, where no conductor pipe is used, have been evolved using guide pins on the ocean bottom well head template to lead the drill stem through the ocean bottom well seal and into the borehole.

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

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 a 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 are 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.

To maintain the integrity of a hole in permafrost, many of British Petroleum's production wells at Prudhoe Bay have been equipped with about 600 meters (1,980 feet) of thermocasing (Oil and Gas Journal, June 7, 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 meters (149 to 198 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 used a specially developed nonfreezing fluid circulated into the annulus of the 9-5/8-inch casing through the permafrost interval to about 550 meters (1,815 feet). Sun Oil used a refrigerated surface string on its first two exploration wells in the southern Beaufort Sea (Brown, 1976). Thaw estimates for uninsulated wells at Prudhoe Bay and Mackenzie Delta indicate about one-meter (three-foot) radius due to drilling and 15 meters (50 feet) due to 20 year production (Goodman, 1977b). In addition to the problem of thaw-subsidence, well bore loading due to freeze-back when a well is shut-in is also considered in the permafrost completions. In addition to insulation, there are a number of well completion techniques to prevent thaw and freeze-back problems. These have been reviewed by Goodman (1977a, 1977b). The reader is referred to a series of articles on Arctic well completions in <u>World Oil</u> for an in-depth review of these problems (see Goodman, 1977b).

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, so such measures would not generally be required.

3.4.4 Gas Processing

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 mixture 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.

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 important 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 are then 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, assuming that the natural gas liquids are marketable. Natural gas liquids are not currently being stripped from the injection gas at Prudhoe Bay. If the gas is for direct pipeline sale, as it may be for delivery across Canada, 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 by the El Paso Alaska Company 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.

3.4.5 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 ami nes. 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 may be emitted ("tailed") into the atmosphere, where it may create a detectable odor.

Hydrogen sulfide is not necessarily a problem impurity at low levels of concentration at a few parts per million (ppm), although it may be present at up to 10 or 20 ppm. It is not a significant part of the total sulfur content of the oil. Chemically 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.

3.4.6 Sand and Water Removal

Sand and water removal, after the breakdown of the oil-water mixture, 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 is about 35 to 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.

3.5 TRANSPORTATION

This section discusses the technological aspects of the transportation requirements, specifically pipelines, for Beaufort Sea oil and gas production. An economic discussion of trans-Alaska pipelines and possible options is presented in Section 4.2. Emphasis in this section is placed on Arctic pipelining, although marine transportation options are briefly discussed. A brief review of certain logistical and supply options relating to North Slope and Beaufort Sea exploration drilling concludes the section.

The major transportation components for Beaufort Sea oil and gas are:

1. Gathering lines and/or trunk line to shore.

2. Onshore trunk pipeline to Alyeska pipeline.

3. Trans-Alaska oil or gas pipeline.

As indicated in Section 4.2, Beaufort Sea oil and gas resources, depending upon their size and location, could be transported to lower 48 markets by:

1. Using excess capacity on existing Alyeska or Alcan pipelines.

2. An Alyeska or Alcan twin pipeline.

3. A new north-south pipeline to tidewater (in a corridor separate from Alyeska), possibly in combination with transportation of other onshore reserves such as NPR-A.

A fourth option is marine transportation by tanker. Natural gas would require a LNG system.

3.5.1 Oil and Gas Pipelines

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. Proprietary Beaufort Sea pipeline studies have been sponsored by APOA in Canada and the Alaska Oil and Gas Association (AOGA) in Alaska. In addition, Arctic Gas had investigated the feasibility of a short offshore pipeline segment in the Beaufort Sea. There is, of course, 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 is envisaged. These would connect with an onshore trunk line that would transport the oil or gas to the Alyeska, or proposed Alcan pipeline. Our economic analysis indicates that there are insufficient oil and gas resources (based on current U.S.G.S. estimates) in the Beaufort Sea to justify a new trans-Alaska oil or gas pipeline. Another Prudhoe-size discovery is unlikely. Consequently, Beaufort Sea oil or gas will probably have to be transported by using spare capacity on existing pipelines. Pipeline specifications related to the petroleum development scenarios are presented in a series of tables in Chapter 8.0. "

3.5.1.1 Offshore Pipelines

Although several offshore drilling systems have been tested in the fast-ice nearshore 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-meter (33-foot) and 20-meter (66-foot) isobaths, but extending seaward as far as the 45-meter (149-foot) isobath.

A description of ice scour is presented in Section 2.1.3.3 and summarized in Table 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 State-Federal lease area lies shoreward of the stamuhki zone and that gouges greater than 2 meters (7 feet) are rare. The available scour data indicate that in water depths of less than 6 meters (20 feet), a burial depth of 1 meter (3 feet) may be sufficient, and in the mid-shelf zone with water depths from 7 to 45 meters (23 to 149 feet), 2 meters (7 feet) may be sufficient. Consequently, ice scour does not present an insurmountable problem for construction and operation of offshore pipelines.

Closer to shore in waters less than 7 meters (23 feet) deep, gravel causeways may be feasible to carry pipelines. The causeway concept would also overcome the potential for localized thaw stability problems of permafrost in the sea floor within a kilometer or two of the coastline. At greater distances from the shore, any subsea permafrost would probably be at depths sufficient to minimize thawing from a 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-inch) 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 one 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 is 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 (42- or 48-inch) 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 meters (990 feet). Although the physical conditions, particularly the 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 meters (149 feet), protection from scour will be required (Kaustinen, 1976). In these situations, Polar Gas proposes to use tunnels instead of trenches to carry the pipeline. A detailed description of the Polar Gas Project engineering and environmental research is provided by Hindle and Etchegary (1975) and Hindle and Palmer (1975).

In the spring of 1978, Polar Gas will commence a two-year pilot project to perfect a subsea production system suitable to develop the Arctic Island gas reserves (Oilweek, September 12, 1977). The project involves the subsea completion of Panartic's Drake F-76 well, located in 58 meters (191 feet) of water, and a 1.3-kilometer (0.8-mile) pipeline connection to an onshore test facility on the east coast of the Sabine Peninsula of Melville Island. The subsea portion of the pipeline will be 1 kilometer (0.6 miles). The offshore pipeline will be laid by a novel form of bottom pull from the ice and shore. Close to shore for protection from ice scour, the pipeline will be laid in a trench dug by an underwater trenching plough.

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 routes and offshore winter construction include:

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

Assuming the requirement for a Prudhoe Bay interconnection, there are several offshore discovery locations in the Alaskan Beaufort Sea from which the shortest distance would involve a major offshore segment, as opposed to a combined offshore (to the closest landfall) /onshore pipeline.

3.5.1.2 Onshore Pipelines

Onshore hot oil pipelines would probably be above ground (like Alyeska), except in areas of thaw stable soils and at some major river crossings. It can be assumed that construction and operation 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 will probably be below ground.

3.5.2 Marine Transportation

After the discovery of the Prudhoe Bay field in 1968, consideration was given to nonpipeline transportation options, including ice-breaking or ice-reinforced tankers. Interest in the tanker option was highlighted by the voyage of the S.S. Manhatten in 1969 through the Northwest Passage. Completion of the Alyeska pipeline and planning for the parallel (as far as Fairbanks) Alcan gas pipeline has firmly established a north-south transportation corridor with the possible effect of limiting future Arctic Alaska transportation options. However, the marine transportation option for shipping Arctic Alaska oil and gas and other minerals to southern markets has not been discounted. A series of papers on Arctic marine transportation and related problems were presented at the 1975 Third International Conference on Port and Ocean Engineering under Arctic Conditions (see Sandaes, 1975; Parker, 1975; and Gerwick, 1975). More recently, Arctic tanker transportation has been discussed at the 1977 Offshore Technology Conference (see Taylor and Montgomery, 1977; Windall and Levine, 1977).

The principal problem of marine transportation in the Beaufort Sea is sea ice, which covers the ocean for eight or more months of the year. In addition, a major disadvantage is the shallowness of the Beaufort Sea coast with the absence of any deep water port sites.

A nuclear ice-breaking tanker transportation system to move North Slope crude via the Northwest Passage to U.S. east coast markets has been evaluated (Windall and Levine, 1977). In this analysis a Beaufort Sea terminal 40 kilometers (24 miles) offshore in 30 meters (99 feet) of water in Smith Bay is postulated; oil production from NPR-A is transported via pipeline to an offshore loading tower terminal. An analysis of several tanker designs concluded that a nuclear-powered ice-breaking tanker (600,000 deadweight tons) is economically competitive and even superior to comparable fossil fuel-powered designs. Based on an estimated annual operating cost of $95 million and 10 to 12 trips per year between the North Slope and the U.S. east coast, the authors estimate a required freight rate of $5.43 per barrel which they believe is competitive with current pipeline tariffs.

A semi-submarine ice-breaking tanker (SSIT) has been proposed by Norwegian engineers to transport North Slope crude to markets on either side of the North Atlantic (Sandaes, 1975). Initially three concepts were considered: an ice-breaking tanker, a catamaran semi-submarine ice-breaking tanker, and a semi-submarine ice-breaking tanker. The SSIT was regarded as the most promising concept. The hull of the SSIT consists of a main, semi-submersible cargo section which is connected to the superstructure by a narrow transition section at the centerline of the vessel. Two ice-cutting edges are located at the fore and aft superstructures. A comparative economic analysis of a 250,000 deadweight ton SSIT indicate a crude oil transportation cost from Prudhoe Bay to Davis Strait of $0.66 to $0.96 per barrel. The study did not consider the problems or costs associated with a North Slope marine terminal.

A conceptual design of a nuclear submarine tanker system for transporting North Slope crude to the U.S. east coast has been formulated (Taylor and Montgomery, 1977). The system would include an undersea dock in about 150 meters (495 feet) of water (well below the depth of pressure ridge keels), connected to shore by a man-rated tunnel containing oil and ballast water pipelines, electrical and communication transmission facilities. The tanker would have an underwater displacement of 424,512 tons and carry 2 MMbbl of oil. To enable underwater docking, a sophisticated system of bottom-mounted sonar sensors would guide the tanker to the dock in a “control area” (similar to controlled air space) surrounding the dock. The analysis estimated that the required freight rates for direct shipment from the North Slope to the U.S. east coast would be $3.60 per barrel, somewhat less if the oil were transported to a conventional tanker in northern Norway. The submarine tanker system was believed to be economically competitive with ice-breaking tankers and pipelines.

3.6 SUMMARY

Prediction of the technology that will be used to explore and produce oil and gas in the Alaskan Beaufort Sea is difficult. While offshore exploration has started in several regions of the Arctic, as yet no oil and gas has been produced and transported. It is the production platform and pipeline technologies that are most difficult to predict, compounded by the uncertainty of environmental stipulations and regulations that will be imposed upon lessees of Beaufort Sea acreage. Reference should be made to Tables 5 and 6 which summarize offshore platform options.

The initial Beaufort Sea exploration efforts in the State-Federal lease sale area will be an extension of dryland technology, i.e., the use of dryland Arctic drilling rigs on locally constructed platforms rather than the introduction of specially equipped mobile platforms such as the monopod or cone.

Artificial soil islands, and to a lesser extent ice islands, will probably be the favored drilling platform options in the landfast ice zone. In areas where suitable fill materials are scarce and a long barge haul is deemed uneconomic, or in areas where artificial island construction is environmentally unacceptable, ice islands may be used instead of soil islands. In deeper waters (>12 to 15 meters or 40 to 50 feet) of the landfast ice zone, where economies in fill materials and/or extra protection from ice are required, caisson-retained islands and sheet pile islands will be used. In shallow waters (<5 meters or 17 feet), conventional barges, ballasted to the sea floor and protected by berms, may compete with artificial soil islands, although in the southern Canadian Beaufort this technique has only been used for one well. Close to shore in water depths too shallow for conventional barges or summer-constructed artificial soil islands, winter-constructed gravel pads and ice islands will be the favored techniques.

Due to water depth limitations, drillships will probably be of limited application in those areas of the Alaskan Beaufort which will be leased in the near future.

Oil and gas production within the landfast ice zone will most likely be conducted from a combination of artificial soil islands (reinforced for long-term ice and wave protection) and gravity structures such as the cone or monopod fabricated off site. Specially designed production barges may have limited application.

Beyond the landfast ice zone or in water depths greater than 20 meters (66 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 exploration drilling, and gravity structures probably the most suitable for production platforms.

The techniques, equipment and manpower to lay offshore pipelines in the Alaskan Beaufort Sea is less easy to predict than drilling options. A combination of summer barge lay and winter lay from ice (in inshore areas) is anticipated. The principal engineering problems will be the requirement to bury the pipeline with sufficient depth of cover to protect the pipeline from ice scour (about 2 meters or 7 feet maximum in the landfast ice zone). A second major problem will be the pipeline landfall where ice-rich permafrost approaches the sea floor and where shoreline erosion may be rapid; the pipeline will also have to be protected from the effects of ice push at the shoreline. While elevation of pipelines on short causeways at landfall may be the solution to these problems, there are significant environmental concerns about the construction of causeways.

The use of the barrier islands for drilling and the siting of production facilities is also a significant environmental concern and development there may be severely restricted.

3.7 OIL SPILLS

3.7.1 Control and Cleanup of Oil Spills

Concern about oil discharges into the Beaufort Sea is compounded by: 1) the lack of knowledge of the behavior and effects of spilled oil in Arctic waters, and 2) the difficulties of control and cleanup posed by ice. The weathering of spilled oil -- dissipation of the more volatile fractions of the crude -- is virtually suspended for spills floating under the ice. Natural degradation, which is promoted by bacterial action and light, is known to take place much more slowly in the Arctic environment, particularly during the winter darkness. The highest estimated rate of biological decay (21.4 grams per cubic centimeter per year) would be much too slow to rely upon as a method of cleaning up major oil spills (McLeod and McLeod, 1974).

Considerable study and experiments in oil spill control and cleanup have been conducted by the Canadian Department of the Environment and the Department of Fisheries under the auspices of Beaufort Sea project study program. Various skimmer devices have been tested, with rotating drums and oil mops showing some effectiveness with ice in the water (Ross, Logan and Rowland, 1977). Various booms have been tested, with some success in calm waters. However, no boom to withstand ice forces is ever anticipated.

Previous U.S. Coast Guard studies of cleanup methods for the Arctic considered a vortex type skimmer for picking up pools of floating oil surrounded by ice. The Coast Guard also conducted burning tests (Glaeser and Vance, 1971). Both U.S. and Canadian tests have concluded that burning is a viable means of reducing the volume of oil spilled into the environment, except for cases in which wave action has created an oil-water emulsion, and in which delay has permitted wet snow falling on the oil to create an oil-snow mush. Burn-off requires application of igniting agents, and sometimes wicking agents, to start and maintain the fire.

Canadian efforts have concentrated on the problems of oil trapped under the ice, since some of the Canadian" exploration prospects are being drilled from ships. A blowout near the end of the drilling season would leave the discharge uncontrolled during the period of ice formation, until personnel could be placed on a sufficiently firm ice sheet. Large volumes of oil would be trapped until after the spring breakup. Cleanup would be aimed first at reducing the volume of oil as it penetrates the melting ice -- while personnel, but only limited equipment, could work on ice floes -- then later trying to skim oil using floating equipment.

The areas considered in this study are in the landfast ice zones, and are projected as being drilled from bottomfast ice islands, sunken barges, or artificial soil islands. This presents less chance for discharge under the ice sheet. The dome type of containment device for holding oil from an under-ice blowout, which has received significant attention for Canadian drilling, is not likely to be applicable to the shallower Alaskan developments. Only a formation fracture type of blowout would result in discharge through the sea bottom under the ice. Drill scheduling would permit relief drilling. On permanent production platforms, drilling can be performed year-round. On sacrificial ice islands, the limiting factor in scheduling drilling is a margin of up to 45 days for relief drilling. However, maintenance of an ice island through the summer may also be a reasonable alternative in the Beaufort under such circumstances. The remaining accident situation in the Alaskan Arctic leading to under-ice oil discharge is the pipeline rupture. The chief means of control for pipeline spills is quick detection, and shut off of the line.

Oil spills during spring breakup and fall freeze-up will be difficult to clean up quickly due to access problems for men, materials, and relief drill rigs. The spring period may be more environmentally sensitive because the oil has more opportunity to spread, and because wildlife exposures are more likely or more imminent.

The behavior and characteristics of the ice zones with respect to oil spills in the Alaska Beaufort can be summarized as follows. The nearshore fast ice, or inner belt, begins to develop during early October. It becomes bottomfast in water depths of up to 2 meters (6 feet) by late February. The landfast ice is nearly, but not completely, static throughout the winter and is smooth and level except for small hummocks. Landfast ice is present until late June. The outer ice belt is also landfast, but not bottomfast. It extends from about the 2- to 20-meter (6.6- to 66-foot) isobaths in the southern Beaufort. The ice sheet is nearly stationary, but is topographically characterized by fields of ridges and hummocks, During freeze-up, areas of rafted rubble ice or hummock ice are generated by pressure from the seasonal and polar pack that pushes southward against the young (first-year) fast ice.

In the outer belt, the relatively rough bottom surface of the ice sheet will tend to consolidate and contain oil in pools and pockets. Oil floating on the water would probably be forced out onto the surface of the ice, to form oil-snow mush. However, not enough experience with this condition is available to predict this phase of the spreading behavior. Under-ice trapping, or trapped oil bubbles in the ice hummocks, could result from rafting of ice over oil pools.

Under-ice discharge in the inner belt will most likely spread outward from the rupture point (as a pipeline), forming a coherent slick across the bottom surface of the ice. The spreading is unlikely to be constrained by meso-form features (depressions or projections) or find open leads or cracks through which to reach the surface. Systematic drilling of the ice may prove to be a relief practice in this zone. Canadian experiments have also suggested air injection as a means of driving the under-ice oil to relief vents.

3.7.2 Probability of Oil Spills

The probability of oil spills can be projected for drilling blowouts, platform spills, and pipeline spills. The methodology of spill projection is based upon developing a risk rate (i.e., spills per million barrels of production, spills per year per 100,000 miles of pipeline, blowouts per 1,000 wells drilled, etc.) either from historical data, or from revision of historical data, based upon the conditions that which might apply in the Beaufort. The basis of projection comprises the number of wells, the production, the number of platforms, and the mileage of pipelines that have been determined for the scenarios.

The applicability of using historical rates of blowout, platform spills, and pipeline ruptures in OCS petroleum production in the U.S. has been questioned by the U.S.G.S. In U.S.G.S. Circular 741 (Danenburger, 1976), which" serves as an analyzed data source for Gulf of Mexico OCS operations, it is noted that "interchanging statistical information from many different sources can lead to unreasonable conclusions." The spill statistics are considered to "provide one means of evaluating offshore oil and gas operations," even though they may be "utilized to forecast discharges in frontier areas, despite the questionable applicability. " (Danenburger, 1976).

In spite of such caveats, spill projections based upon the historical record are developed here. One point developed in Circular 741 has been heeded, however. The discharge records prior to the 1970's should not be expected to provide an accurate reflection of future petroleum operations, and have not been utilized. More detailed statistics on U.S. OCS petroleum operations, spills and accidents can be found in Harris, Piper and McFarlane (1977) and U.S. Geological Survey (1975).

3.7.2.1 Drilling Blowouts

A drilling blowout refers to loss of control during the drilling and completion stages of constructing an oil well. Well completion involves attaching the wellhead hardware, such as control valves and piping connections, onto the production casing. U.S.G.S. statistics for 1971-75 show eight blowouts during that period, of which three were platform blowouts (loss of control hardware because of platform loss). Of the 5 drilling blowouts, only 1 was an oil blowout. Total U.S. OCS wells drilled during 1971-75 period were 3,695 (from a cumulative offshore total of 9,392 in 1971 to a cumulative total of 13,087 in 1975). The implied rate of drilling blowout would be 0.025 percent from the 1971-75 statistics, compared to the historical rate of 0.035 percent since the 1950's.

In studies of the Canadian Beaufort Sea exploration activities, a projected rate of 0.01 percent (one per 10,000 wells) was deduced from review of the geology and drilling practices. If such a rate can be achieved in the Canadian Beaufort, it should be achieved as well in the Alaskan Beaufort. The Canadian Beaufort drilling has experienced some difficulty with formation fractures and gas stringers, (small, shallow gas deposits), and a water outflow has already occurred (see Section 3.2.5.1). This does not count as an oil blowout, but portends possible drilling problems ahead. The Alaska Beaufort areas, on the other hand, are likely to reflect Prudhoe Bay field drilling experience, which has proven tame with respect to blowout potential.

Table 8 presents the probability and expectation of oil blowouts in the scenarios during drilling, based on a high rate of 0.025 percent and a low rate of 0.01 percent per well. The average size of a Beaufort Sea drilling blowout has not been estimated. Historical precedent on size is more likely to be misleading than historical precedent on frequency of occurrence.

TABLE 8

PROBABILITYOF DRILLING BLOWOUTS

Scenario		Wells	Blowout Expectation	Probability 0	Probability 1	Probability 2 or More
Rate of 0.025%						
Camden-Canning	1.3 Bbbl	520	0	87.8%	11.4%	0.8%
Offshore Prudhoe	1.9 Bbbl	290	0	93.0%	6.7%	0.3%
Offshore Prudhoe	0.8 Bbbl	330	0	92.1%	7.6%	0.3%
Cape Halkett	0.8 Bbbl	160	0	96.1%	3.8%	0.1%
Joint Production	4.0 Bbbl	970	0	78.5%	19.0%	2.5%
Joint Production	2.9 Bbbl	1010	0	77.7%	19.6%	2.7%
Exploration Only		52	0	'38 .7%	1.3%	--
Rate of 0.01%						
Camden-Canning	1.3 Bbbl	520	0	94.9%	4.9%	0.2%
Offshore Prudhoe	1.9 Bbbl	290	0	97.1%	2.8%	0.1%
Offshore Prudhoe	0.8 Bbbl	330	0	96.8%	3.2%	--
Cape Halkett	0.8 Bbbl	160	0	98.4%	1.6%	--
Joint Production	4.0 Bbbl	970	0	90.8%	8.8%	0.4%
Joint Production	2.9 Bbbl	10?0	0	90a 4%	9.1%	0.5%
Exploration Only		52	0	99.5%	0.5%	--

Source: Dames & Moore

3.7.2.2 Platform and Piping Spills

The accident statistics for 1971-75 show 872 minor spills and 20 major spills associated with platform operations and pipeline connections between platforms, and between the platforms and the shoreline. This includes provisioning operations for the platforms as well. The occurrence rate for major discharges was about 0.002 per year per platform, averaging 2,312 barrels per discharge. The discharge rate for minor spills was about 0.09 per platform per year, averaging about 4-1/2 barrels each. Based upon total production of 1.8 billion barrels over the period, the volumetric loss rate was 0.0028 percent, or 28×10^{-6}. Discharge projections for offshore platforms and lines are given in Table 9. Although the more severe environmental conditions in the Beaufort, compared to the Gulf of Mexico, tend to induce projections of higher accidental discharge rate, this should not necessarily be the case. It should be assumed that the failure rate due to environmental conditions will be no worse in the Beaufort than elsewhere -- for Beaufort design conditions. The wind and wave forces in the Beaufort present less severe extreme conditions both in magnitude and frequency.

The results of projection from Gulf of Mexico experience given in Table 9 are so divergent between the platform and volume bases that the application of any. validity to the projection seems doubtful. The divergence is due to the fact that the Beaufort Sea platforms (projected in the scenarios) contain many more wells than the average Gulf of Mexico platform. To the extent that the multiplicity of platforms contributes to the volumetric rate of discharge, then the overall volumetric rate that would be anticipated for the Beaufort production should be less than that in the Gulf of Mexico. On the other hand, since each platform is larger, and contains many more working units than a typical Gulf of Mexico platform, the incidence per platform per year may be expected to be greater.

TABLE 9

PLATFORM AND CONNECTING PIPELINE SPILL PROBABILITIES

SCENARIO		Platforms	GULF OF MEXICO RECORD		PROJECTION	
			Expected Number of Spills	Volume	Expected Number of Spills	Volume
Minor Spills, Platform Basis						
Camden-Canning	1.3 Bbbl	13	29	32		
Prudhoe Offshore	1.9 Bbbl	6	12	53		
Prudhoe Offshore	0.8 Bbbl	8	18	81		
Cape Halkett	0.8 Bbbl	4	9	41		
Minor Spills, Volumetric Basis						
Camden-Canning	1.3 Bbbl		626	2,800		
Prudhoe Offshore	1.9 Bbbl		915	4,100		
Prudhoe Offshore	0.8 Bbbl		385	1,700		
Cape Halkett	0.8 Bbbl		385	1,700		
Major Spills, Platform Basis						
Camden-Canning	1.3 Bbbl	13	7	1,500	2	4,500
Prudhoe Offshore	1.9 Bbbl	6	3	610	1	1,800
Prudhoe Offshore	0.8 Bbbl	8	4	920	1	2,800
Cape Halkett	0.8 Bbbl	4	2	460	1	1,400
Major Spills, Volumetric Basis						
Camden-Canning	1.3 Bbbl		14	33,400	5	11,100
Prudhoe Offshore	1.9 Bbbl		21	48,800	7	16,300
Prudhoe Offshore	0.8 Bbbl		9	20,600	3	6,900
Cape Halkett	0.8 Bbbl		9	20,600	3	6,900

Source: Dames & Moore

An envelope of projected spill incidence can be devised by increasing the platform base rate by three, and reducing the volumetric base spill rate by a factor of three. The resultant envelope is given in Table 9, and provides a reasonable expectation of spillage. It cannot, however, be supported from available data.

3.7.2.3 Pipeline Spills

Ruptures and joint leaks in offshore pipelines have been included in the estimates for the offshore platforms. There are no gathering systems -- i.e., connections between subsea well heads and platforms -- considered for the Beaufort inside the 20-meter isobath. Gathering lines mentioned in some portions of the report refer to inter-platform connections.

The remaining portion of oil transport system in the scenarios is the onshore line joining the Alyeska pipeline system. This amounts to line distances of 87 kilometers (54 miles) for the eastern scenarios, 14 kilometers (9 miles) for the central area, and 66 kilometers (41 miles) for the Cape Halkett area.

The rate of rupture projected for new U.S. systems is 50 ruptures per year per 100,000 miles, compared with a historical rate (1969-74) of about 120 ruptures per year per 100,000 miles (31 per year per 100,000 kilometers, compared to a historical rate of 75 per year per 100,000 kilometers) (U.S. Dept. of Interior, 1977b, annual summaries; Dames & Moore, 1975b) .

The probability of pipeline spills onshore for the scenarios over the estimated life of the fields (22 to 25 years) is given in Table 10. The average loss from a U.S. pipeline spill has been about 1,100 barrels in the base period surveyed for the spill data. Since the exposure base for pipelines is the length and time of use, the spills are considered equally likely at any point along the route. The results may be conservative for the isolated conditions of the Arctic, since many normal third party exposures (persons not part of the pipeline organization nor owners of the oil) are absent there.

TABLE 10

PROBABILITY OF ONSHORE SPILLS FROM PIPELINES

Scenario Location	Annual Spill Expectation	Lifetime Spillage	Percent Probability of Spills Over Project Life		
			0	1	2 or More
Camden-Canning	30 bbl	743 bbl	50.5	35.0	14.5
Offshore Prudhoe	5 bbl	109 bbl	90.6	9.0	0.4
Cape Halkett	23 bbl	564 bbl	59.6	31.2	9.2

Source: Dames & Moore

CHAPTER 4.0

FRAMEWORK FOR BEAUFORT SEA OCS PETROLEUM DEVELOPMENT

Scenario development for Beaufort Sea offshore development requires some assumptions or projections of projects which may be competing with it for essential equipment, manpower, and transportation facilities. This section outlines the related assumptions which have been selected as the framework for Beaufort Sea scenarios. For ease in reference, the existing Prudhoe Bay field is called Prudhoe Bay, and the scenario region offshore of Prudhoe is called Prudhoe Bay Offshore or Prudhoe Offshore.

4.1 NORTH SLOPE PETROLEUM RESOURCE PROJECTIONS

A discussion of the petroleum and gas horizons of interest on the North Slope is given in Appendix A. The competing areas considered with respect to Beaufort Sea development are:

- The Prudhoe Bay field.
- State leases east of the Prudhoe field, primarily at Flaxman Island and Point Thompson.
- The National Petroleum Reserve - Alaska.
- Native oil lands or state leases south of Prudhoe.

The Beaufort Sea offshore areas of concern are:

- State offshore leases west of Oliktok Point.
- The tracts covered by the joint State-Federal lease sale.
- Federal tracts between the joint State-Federal lease sale area and the 20-meter (66-foot) isobath.

- Federal offshore tracts between the 3-mile limit and the 20-meter isobath.

- Federal waters between the 20- and 200-meter (66- and 660-foot) isobaths.

4.1.1 Prudhoe Bay

A description of the Prudhoe Bay geology which is relevant to the offshore areas is discussed in Appendix A. In Section 2.4, a discussion of the facilities at the Prudhoe Bay field is given.

The reserves of the Prudhoe Bay field Sadlerochit group of reservoir formations have been estimated in several published articles at 9.6 billion barrels of oil, and from 24 to 26 trillion cubic feet of gas. In addition, an estimate of about 1 billion barrels has been made for the Kuparuk reservoir formation. Reserve estimates of the Lisburne group, underlying the Sadlerochit group, also approach 1 billion barrels. The designation of the Kuparuk and Lisburne resources as reserves, which implies that they are capable of economic recovery, is an assumption. The Kuparuk formation will be tested in a pilot program expected to place about 60,000 barrels per day onstream in 1981.

A preliminary reservoir analysis for the main Sadlerochit formation was made by H. K. van Poollen and Associates, Inc. (1976; addendum, 1977) for the State of Alaska for planning guidance. Various withdrawal and water injection programs were considered. Estimates of recovery from this formation (and formations considered connected with it, such as the Shublik) ranged from 6.05 to 8.18 billion barrels at an arbitrary end point of 100,000 barrels per day of oil production. The actual behavior to be demonstrated by the field under water injection programs will not be known for a few years. To project the output of the field, for this study, the profiles developed by van Poollen have been augmented during the declining period so that the total output follows a typical decline curve (beginning in 1986), but achieves an output of 9.6 million barrels.

Production from the Kuparuk group, beginning in 1981, and peaking in 1991, is assumed to involve the addition of a group of wells every two years until the potential for the formation is exhausted. Production from the Lisburne group is considered to be lumped in with the augmented Sadlerochit production.

4.1.2 Flaxman Island and Point Thompson

During 1977, oil discoveries in the Flaxman Island and Point Thompson tracts, which were leased by the state for exploration, were announced. A new exploration well, designated the Mikkelson, or East Mikkelson well, is to be drilled to test these discoveries. According to the U.S.G.S. estimates (presented in Chapter 5.0), this area is borderline. Those estimates were from the shoreline to the 20-meter (66-foot) isobath. If these two finds should belong to structures which trend offshore, then they are properly contained in the U.S.G.S. offshore estimates (which means they should be subtracted from the projections for the State-Federal and Federal offshore areas). If they are structures which are isolated, or trend landward, then they should be considered independent of the offshore estimates.

A compromise assumption has been adopted for the purposes of this report. The structures are considered isolated, even though they could be associated geologically with trends offshore, and the total production from them is assumed to total 400 million barrels. It is further assumed that production coincides with scenario production. The nominal peak production from a reserve of this level would be about 100,000 barrels per day. It is also assumed that transport facilities to the Prudhoe Bay junctions are shared with the Alyeska and Alcan lines.

4.1.3 National Petroleum Reserve - Alaska

Recent estimates of the petroleum potential of the NPR-A area have been placed at a most-likely value of 1 billion barrels over the entire reserve. It is assumed that there will not be sufficient resource discovery to permit a transportation link to existing facilities by the end of the Smith-Dease exploration scenario. Estimates of reserve levels are developed in Section 6.5

4.1.4 Native and Southern State Lands

Exploration is being conducted of some of the North Slope areas under Native corporation ownership. It is assumed for purposes of projecting pipeline throughput that such areas will not contribute more than 100,000 barrels per day if discoveries are made which could be joined into pipeline flow at a convenient pump station. This would limit the discovery to a field of 400 million barrels for the typical output potential of the area, or about 250 million barrels for areas of exceptionally good permeability (easy flow through the formation).

State leases granted onshore east of Prudhoe are included in this assumption. There are some leaseholds south of the Flaxman-Point Thompson leases which have not been drilled. The exploration rights in this area will soon expire under the current leases. If discoveries within the next year are made in this zone, it is assumed that the output (which can be joined to the scenario production for transport westward to Prudhoe Bay) does not exceed the 100,000-barrel-per-day envelope.

4.1.5 Western Offshore State Lands

It is assumed that no exploration or leasing of the state lands between the shoreline (which is mostly part of NPR-A) and the 3-mile limit is undertaken during the scenario period.

4.1.6 Joint State-Federal Lease Sale

The first areas to be explored in the scenarios are assumed to be related to the upcoming lease sale of the State areas between the current set of Prudhoe Bay leases extending offshore, a tier of adjacent Federal tracts, and all areas which have been contested by both the State and Federal governments (inclusive of the longitudes encompassing the area). The resolution of ownership, whether by demarcation or by formula, of any discovery in the joint sale will be resolved by court decision. No estimate of the outcome is necessary for scenario construction. However, the Federal royalty rate of one-sixth of production is used throughout. The year of the lease sale is assumed to be 1979. It will be conducted jointly by the State and Federal governments.

4.1.7 Federal Tracts Adjoining the Joint Lease Sale

A narrow band of Federal tracts lies between the Federal tracts covered by the joint State-Federal lease sale and the 20-meter (66-foot) isobath. This area is thus included in the resource estimates or probability curves applicable to the eastern Beaufort scenarios. It is assumed that if resource discovery should extend into this area, a limited drainage sale of the adjoining Federal tracts would be held. No change in the overall development schedule would necessarily result, since it is likely that the tracts could be drained from the platforms projected within the joint State-Federal area.

4.1.8 Western Federal Tracts

A lease sale for the Federal tracts west of the joint State-Federal area, within the 20-meter (66-foot) isobath, is assumed to occur in late 1983 or early 1984, permitting the start of exploration in 1984. This assumption is arbitrary, in that no sale date has been published by the Bureau of Land Management. The area is a part of offshore areas which would have been available for nomination under Sale No. 50. That sale has been deferred.

4.1.9 Deepwater Federal Areas

Activity in the Federal tracts between the 20- and 200-meter (66- and 666-foot) i sobaths is not considered. Water depths and ice conditions beyond 20 meters in the Alaskan Beaufort prevent exploration or production with present technological capabilities. If interest in this area should result in exploration during the period covered by the scenarios constructed in this study, the only competitive pressure foreseen might be found in the availability of Arctic exploration drill rigs. However, exploration in the eastern Beaufort is projected to be complete by 1988, and exploration in the western areas is minimal after that date. In addition, it is likely that the drill rigs used in the shallower water will not be suitable for the deeper areas.

4.2 AVAILABILITY OF OIL AND GAS TRANSPORTATION FACILITIES

4.2.1 Trans-Alaska Pipeline System (TAPS)

The Alyeska or TAPS pipeline is assumed to have a maximum capacity of 2 million barrels per day. This capacity would require a reduction of the average interval between pumping stations and, in some cases, an increase in the current average pump output pressure. Two million barrels per day in a 48-inch line corresponds to a flow speed of about 10 feet per second. This is double that typically used in cross-country pipelines, although loading pipelines may be operated at up to 30 feet per second.

The assumed output schedule from Prudhoe Bay operations is given in Table 11. Table 12 provides a summation of output from Prudhoe Bay the projected scenarios in Chapter 9.0, and the State eastern lease. It does not include the 100,000 barrels per day “margin of unknowns” provision for Native lands or Flaxman Island/Point Thompson onshore leases. The critical peak period occurs in 1993. If the additional 100,000 barrels per day should be present from Native lands, the peak load could be accommodated by adjusting the drilling during this period.

TABLE 11

PROJECTED PRUDHOE BAY FIELD OUTPUT SCHEDULE
(Thousand of Barrels of Oil per Day)

Year	Lisburne-Sadlerochit	Kuparuk	Total
1977	300		300
1978	1000		1000
1979	1600		1600
1980	1600		1600
1981	1600	64	1664
1982	1600	65	1665
1983	1600	130	1730
1984	1600	130	1730
1985	1600	185	1785
1986	1400	175	1575
1987	1200	215	1415
1988	1200	190	1390
1989	980	235	1215
1990	820	210	1030
1991	740	245	985
1992	700	220	920
1993	700	185	885
1994	600	155	755
1995	600	115	715
1996	550	85	635
1997	550	65	615
1998	500	45	545
1999	500	37	537
2000	450	20	470
2001	450	14	464
2002	450	7	457
2003	450		450
2004	400		400
2005	200		200
2006	100		100

Source: Dames & Moore

TABLE 12

PROJECTED TAPS FLOW SCHEDULE
(Thousands of Barrels per Day)

Year	Higher	Lower
1977	300	300
1978	1000	1000
1979	1600	1600
1980	1600	1600
1981	1664	1664
1982	1665	1665
1983	1730	1730
1984	1730	1730
1985	1785	1785
1986	1575	1575
1987	1415	1415
1988	1474	1390
1989	1515	1263
1990	1578	1219
1991	1772	1307
1992	1893	1416
1993	1996	1538
1994	1886	1603
1995	1801	1533
1996	1678	1511
1997	1745	1659
1998	1378	1346
1999	1227	1224
2000	1060	1067
2001	951	961
2002	840	860
2003	739	756
2004	611	630
2005	350	370
2006	196	214
2007	73	84
2008	54	63
2009	31	37
2010	16	17

		Higher	Lower
TOTALS :	Prudhoe Bay	10.5 Bbbl	10.5 Bbbl
	Flaxman Island/Pt. Thompson	0.4 Bbbl	0.4 Bbbl
	Camden-Canning	1.3 Bbbl*	1.3 Bbbl
	Prudhoe Offshore	1.9 Bbbl*	0.8 Bbbl
	Cape Halkett	0.8 Bbbl*	0.8 Bbbl

Source: Dames & Moore

*These are the four producing scenarios in this report.

One of the production schedules considered for the Prudhoe Bay fields was to use both Kuparuk and Lisburne group production early to bring the output in the 1980-85 period up to the 2-million-barrel-per-day capacity limit. This possibility should be considered a potential alternative. However, if it should occur, the augmented production schedule given here in the 1988-95 period would not be realized, and the peak projected in 1993 would be eliminated.

The end of Prudhoe Bay production in 2007 could be extended by Lisburne production and enhanced recovery operations which might be feasible under future conditions. However, this would have little impact on the present analysis.

4.2.2 Twin TAPS Line

The Alyeska pipeline bridges and right-of-way were designed so that a second line could be added. The amount of reserves necessary to justify this twin TAPS line, in addition to the reserves which can be accommodated in the present system, would be lower than those to be serviced by the present system (about 14 billion barrels in the scenarios and assumptions developed in this study). This results from the lower cost which would be expected for the second line.

The scenarios developed do not portend any need for a second TAPS line. The projected oil output of the scenarios and Prudhoe Bay lands in Table 12 do not exceed the Alyeska capacity. Even imposition of an additional flow up to 100,000 barrels per day in excess of the given flow projections would require minor cutback in only two years of the output schedule to accommodate the indicated total throughout.

4.2.3 Alcan Gas Line

The specific operating conditions -- line diameter, compressor discharge pressures, etc. -- have not been fixed for the proposed Alcan gas line from the Prudhoe Bay field to the U.S. midwest, with a distribution line to the U.S. west coast. The flow assumed for the line will be based upon an initial nominal peak capacity from the Prudhoe Bay field of 2.6 Bcfd, with the ability to expand the capacity to 3.4 Bcfd by increasing the system pressure and adding compressor stations. The average flow schedule for the line is a constant 2.5 Bcfd, which would pass the 24 to 26 tcf of the Prudhoe Bay field in 26 to 28.5 years. The Alcan flow is assumed to begin in 1983, and would be exhausted between the years 2008 and 2111.

The output schedule of gas assumed for the scenario development is:

- Camden-Canning, 3.25 tcf, 360 MMcfd, 25 years, 1990-2014
- Prudhoe Offshore-Large, 4.75 tcf, 520 MMcfd, 25 years, 1988-2012
- Prudhoe Offshore-Small, 1.6 tcf, 220 MMcfd, 20 years, 1989-2008
- Cape Halkett, 0.6 tcf, no production

An alternative gas production schedule, based upon limiting throughput from Beaufort Sea fields to 880 MMcfd, would extend the production life to 28 years, and be allocated for the two larger scenarios:

- Prudhoe Offshore-Large, 470 MMcfd
- Camden-Canning, 330 MMcfd

All Beaufort gas production is projected as being transported via the Alcan line assuming expansion of the nominal peak capacity of the line from 2.5 to 3.4 Bcfd by increasing system pressure and adding compressor stations as indicated above. No new lines would be considered for small additional reserves which could not be accommodated in the Alcan line. Thus, small reserves which may be discovered in the years 1990-2010 would have to be delayed in production until Alcan capacity became available. Exhaustion of the projected 3.4 Bcfd capacity of the Alcan line through combined maximum output of the scenario gas fields as indicated would represent an extremely unlikely event.

Small finds of gas found prior to 1990 would not be expected to pre-empt pipeline capacity from Beaufort Sea production because the reserves would be insufficient to pay for the installation of additional compressors and/or compressor stations.

4.2.4 NPR-A Western Line

An alternative pipeline system for oil produced in NPR-A has been suggested across the Seward peninsula to Nome. The Port of Nome has been projected as capable of year-round tanker operations (with occasional shut-ins) using ice-breaker support. It is assumed that the discovery of sufficient reserves to support such an oil transport route will not occur during scenario development. The projected level of discovery in NPR-A during the early exploration and construction phases in the eastern Beaufort has been estimated at the one billion barrel level, which is insufficient to support a western pipeline system.

4.2.5 Petrochemical Pipeline

The use of a separate pipeline to transport LP-gas and natural gas liquids (field condensates) into southern Alaska for use as a petrochemical feedstock has been proposed. The incentives and alternatives for petrochemical development in Alaska and the relationship of Beaufort Sea petroleum development to petrochemical potentials is discussed in Section 4.3. It is estimated from the potential volume of throughput in such a line, that its installation (in the 15 to 25 mmbbl per day volume in liquid throughput equivalent) would not affect the scenario development with respect to pipeline capacity.

4.3 PETROCHEMICALS AND PETROLEUM PROCESSING

A potential secondary impact which is usually raised with respect to proposed petroleum development is the stimulation or inducement of refinery and petrochemical manufacturing capacity. The conclusion of this study is that no petrochemical or refinery construction in Alaska could be directly attributable to Beaufort Sea petroleum development. The basis for this conclusion is that the Beaufort Sea output projections will not support a new transportation system for either gas or oil which could lead to inducement of new petrochemical capacity. In regard to refinery increases, local demand is generally considered to be the controlling factor, rather than the local crude supply. (Local demand also includes export markets where an edge in transportation economics may be present).

The operation of the Prudhoe Bay field for oil and gas production may lead to some petrochemical development in Alaska. To the extent that such development may occur, Beaufort Sea production could be considered to support it, primarily by maintaining the petroleum output levels in the period from 1992 to 1996. However, the economics of a project in the first five to seven years determine whether it is stimulating or inducing secondary development. Since Beaufort Sea output will not start for many years, it will not enter into present investment decisions concerning Prudhoe Bay production.

A secondary issue of interest to Beaufort Sea scenario considerations is the effect which petrochemical operations, should they be developed, might have upon the transportation facility capacities from the North Slope. Although some of the proposals for transport of petrochemical materials are mentioned here, any increased capacity as a result of them is not considered further in the transport analysis. It is assumed that such linkages would be small, limited to 15,000 to 30,000 barrels per day, and would not substantially affect the scenario projections.

Interest in petrochemicals development in Alaska stems from two sources. First, the production of natural gas in the Prudhoe Bay fields will create LP-gas feedstock (ethane, propane, butane) and field condensate liquids, which have traditionally been a major source of U.S. petrochemical feedstocks. (This changed when the U.S. domestic natural gas supply began to fall substantially short of meeting demand.) Alternate feedstock supply for olefins production includes naphtha and gas oils, which are obtained by crude oil refining. Second, the State is considering increasing the value of its share of royalty crude oil from the Prudhoe Bay fields by entering into downstream processing. Since the demand for local refined oil products is limited with respect to the volume of royalty oil available (and potential production from other Alaskan oil horizons as well), petrochemical refining or production is being explored.

4.3.1 Oil

A recent bid for processing Alaskan royalty oil (December, 1977) was based upon initial benzene production, and later expansion to a multi-product petroplex type of operation. Newspaper accounts of the various proposals indicated that olefins production had been considered with the oil, but that potential bidders had reconsidered their plans due to the present market conditions for ethylene. The markets for basic petrochemical materials (i.e., first tier materials such as olefins and aromatics) are the petrochemical centers of the U.S. -- the gulf coast and northeastern chemical centers -- and Japan-Taiwan plastics manufacture.

Economic advantages which might stimulate or induce petrochemical development include a market advantage (including the transportation to market), a feedstock advantage, a general market availability for by-product and co-product absorption, and labor or other cost advantages. For example, the U.S. gulf petrochemical complex advantage was originally a feedstock supply, and has been sustained by the strong co-product interrelationships between the differnt plants. If economic advantages are to be realized in Alaska, they would presumably be found in transport economics to the Japan-Taiwan manufacturers, or the U.S. west coast, relative to alternative supply sources.

If it is assumed that current petrochemical proposals are realized, the basic inducement would definitely be considered to be the presence of Prudhoe Bay oil, and not future additions to the supply stream. The current status of the petrochemical market is relatively soft, especially for ethylene, but the industry has been historically subject to cyclic variation in economic prospects. If current perspectives do not support the proposals, it is possible that they could be revived as market conditions change.

The transport of materials involved in petrochemical operations with the Alaskan royalty petroleum would be expected to follow a limited number of transport patterns. The oil supply could be tapped at one of the pumping stations along the southern portion of the Alyeska line, or in the terminus area. A water route (either boat or pipeline) to the center could be considered. Current interest is to tap the line in the Fairbanks area. An oil line once existed between Fairbanks and Haines, and Fairbanks is accessible to the Alaska rail corridor to water transport routes.

Diversion of the state royalty oil at Fairbanks might cause some changes in the pipeline tariff. Such changes would be expected to be slight since the royalty oil constitutes a small portion of the total throughput in the line and has not been considered in the projection of Beaufort Sea production transport. The current policy of the Alyeska Pipeline Company is that a single tariff should apply to each unit (of oil) entering the line. The State of Alaska and several consumer groups are contesting this policy.

4.3.2 Gas

The development of petrochemical processing of the LP-gas and gas liquids will depend strongly on transport economics, relative to the ethylene market. These components lead primarily to olefins, yielding over 80 percent (by weight) as ethylene. The transport methods proposed include a separate line, batched transport of the gases and gas liquids, and hitching a ride on the natural gas line to an extraction point in middle Alaska. The latter method may not be compatible with planned operating conditions and facility plans for the Alcan line. The volume requirements for a separate line, say 3 percent of 2.5 billion cubic feet per day, are about 15,000 barrels per day. Such a flow could be" accommodated in a 6- to 12-inch line, depending on the operating conditions selected and the proportion of the throughput devoted to gas flow.

Current market conditions for ethylene are probably not conducive to development of a separate transport system across Alaska for these LP-gas and condensate components. The Alaskan market in the southern portion of the state has nearby gas fields. Thus, Prudhoe Bay supplies are not expected to be competitive for the local market.

The ratio of resources estimates -- 24 to 26 tcf for the Prudhoe Bay fields, compared to about 8 tcf for Beaufort projections of high resource level discovery -- emphasizes the fact that the Beaufort cannot be expected to stimulate olefins production from natural gas components. In addition, the expected production schedule for natural gas from the Prudhoe Bay field is flat. Beaufort Sea production would not be used to sustain any decline after 7 to 10 years as it could with oil, but would be additional to the primary flow. If projected Beaufort gas is held until the Prudhoe Bay fields are in decline, then the production would not commence until well after the turn of the century.

In the absence of a separate line or accommodation on the natural gas line, the LP-gas would likely be carried away with the natural gas. The condensate liquid, mainly a mixture of C_5 to C_8 hydrocarbons, would be disposed of in local consumption as fuel, or returned to the formation. Current practice at Prudhoe Bay is to return it to the reservoir along with the produced solution gas.

Natural gas itself (methane) is an important petrochemical feedstock for ammonia production. An ammonia-urea plant is in operation on the Kenai Peninsula. Federally regulated natural gas is not expected to be available for feedstock use in Alaska, and is assumed to be designated primarily for residential domestic fuel distribution.

CHAPTER 5.0

SKELETAL PETROLEUM DEVELOPMENT SCENARIOS

5.1 METHODOLOGY

5.1.1 Current Analysis

Preliminary technological, environmental and socioeconomic factors have been evaluated and 24 skeletal development scenarios established for potential petroleum development in the Beaufort Sea. The scenarios 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.

These skeletal scenarios are limited to consideration of resource estimates, field sizes, related production characteristics, and drilling facilities. In subsequent chapters, technical, operational, and economic assumptions will be developed and applied to the skeletal scenarios in order to arrive at the detailed scenarios. Included in the items to be discussed later are: equipment and material requirements; logistics; manpower and construction activities; pipeline and transportation requirements and specifications; onshore facilities and structures; and time schedules for exploration, development, production, and shutdown.

In order to project the number of platforms and wells, field acreage production output, and so forth, average values for parameters characteristic of oil fields and oil production have been calculated. The inputs used for the calculations are:

- Resource Size: Determined by developing a resource discovery probability curve and selecting a value from the curve.

- Surface Fill Factor: Estimated from geologic data or" assumed from average values, giving the areal density of the reservoir and fixing the field size.

- Well Spacing: Extrapolated from Prudhoe Bay experience, giving the surface expression of the area covered by an individual well and fixing the estimate of primary producing wells.

- Reservoir Depth and Cone of Directional Deviation: Estimated from geologic data and current oil field practice, respectively, giving the area covered by a single platform and the number of wells required.

Using the above inputs, the simplistic formulas for developing the scenarios are:

$$\frac{\text{resource size}}{\text{surface fill factor}} \rightarrow \text{field acreage}$$

$$\frac{\text{field acreage}}{\text{well spacing}} \rightarrow \text{number of wells}$$

$$\text{surface fill factor} \times \text{well spacing} \rightarrow \text{average output per well}$$

$$\Sigma \text{ wells} \times \text{average output per well} \rightarrow \text{field output}$$

$$\frac{\text{number of wells}}{\text{platform capacity}} \rightarrow \text{number of platforms}$$

The number of wells is modified to include water and gas injection wells, and to allow for overlap between oil and gas production and dry holes. Although this analysis has not included them, dual level completions expected in a field can be treated by splitting the resource by level and using a separate surface fill factor for the overlapping zones. In addition, the parametric values of impurities can be extrapolated from experience in similar oil horizons, or in some cases by somewhat arbitrary estimates of high and low values taken from worldwide experience.

In formulating the field output from the typical output curve of a well or group of wells, the timing of production must be estimated. The field output curve is calculated over the life of production as a summation each year over the individual wells or groups of wells. A shorter alternative method was used preciously in order to estimate investment costs over a wider range (see Appendix B). The output profile of the Prudhoe Bay field, which is similar to the projected fields and already incorporates the timing effects of well production, was used proportionately to estimate individual well output. The projected field output is simply the product of the profile and the number of wells.

5.1.2 Similar Studies

The set of parameters used in this current analysis are not unique. However, other petroleum scenario projections have varied in their treatment of various parameters, according to the detailed scenario definition and kinds of information desired. Still other scenarios have dealt only with manpower and/or production value, excluding field characteristics. A brief synopsis of some of the petroleum development studies most similar to this current one is included below for general information purposes.

- Western Oil and Gas Association: Environmental Assessment Study, Proposed Sale of Federal Oil and Gas Leases, Southern California OCS. October 1974.

  A single reserve estimate covering five prospective areas was used. The number of producing wells was estimated from a projection of the average ultimate production per well and the production curve. Platform capacity was estimated similarly, based upon 100-acre well spacing, a 45-degree cone of deviation, and the projected producing depths. The surface fill factor was not specifically determined, but could have been deduced from the other parameters assumed. The field output curve was developed by summation of well groups.

- Resource Planning Associates, with La Rue, Moore, and Schafer: The Exploration, Development and Production of Naval Petroleum Reserve 4. May 1976.

This projection used the Monte Carlo technique of probabilistic modelling of drilling success to obtain the equivalent of the resource estimate and surface fill factor. The assumed parameters were the estimate of oil "hidden" in place, and the success ratio of finding it in exploratory drilling. The field output was projected from the average initial flow rate and the present value factor of the ultimate output. Oil and gas were considered separately.

- Resources Planning Associates: Onshore Impacts of Oil and Gas Development in Alaska, November 1975.

A single reserve estimate was considered for the Beaufort Sea. The number of wells and output were based upon an average per well output curve. For most of the wells, initial flow was about 4,000 barrels per day (b/d), compared with rates of 2,000 to 2,500 b/d used in the present study. Well spacing was 320 acres for oil and 640 acres for gas. Platform count was not projected.

- U.S. Dept. of Interior, Alaska Outer Continental Shelf Office: Draft Environmental Impact Statement, Lease Sale 46, Western Gulf - Kodiak. 1976c.

This scenario construction stated well schedules, but did not consider field area parameters. The methodology was not discussed, but from the information developed, it can be inferred that well count was estimated from the average ultimate production per well. Production schedule per well followed a 25-year curve, with initial output at about 1,800 bpd. The number of service wells (injection wells) was based on a 1:3 ratio with production wells, which is characteristic of a pattern flood production method. A peripheral flood method was assumed in the present study, which usually gives a service to production well ratio of 1:10.

- U.S. Dept. of the Interior, Alaska Outer Continental Shelf Office: Final Environmental Impact Statement, Lower Cook Inlet. 1976d.

This scenario construction used the average well output to evaluate the number of wells, similar to the Lease Sale 46 procedure. The output curve, however, had an initial peak average of 2,800 b/d and cumulative production was weighted towards a greater fraction of total output in the initial years. A service to production well ratio of 1:4 was used. Average gas well output was 23 million cubic feet per day (MMcfd), at the lower end of the 20 to 50 MMcfd typical of most U.S. gas wells.

5.2 SELECTION OF PARAMETERS FOR SKELETAL SCENARIOS

5.2.1 Resource Estimates

The basis of the resource estimates used for development of these scenarios is the U.S.G.S. estimates of undiscovered recoverable oil and gas resources of-the Beaufort Sea between the O- and 200-meter (660-foot) isobaths, as described in Circular 725 (Miller et al, 1975). The estimates prepared in 1975 for the Beaufort Sea are:

	Probability		Statistical
	95%	5%	Mean
Oil (Bbbl)	0	7.6	3.28
Gas (tcf)	0	19.3	8.2

The U.S.G.S. estimates that there is a 95 percent probability that at least the lower value of resources will be discovered, but only a 5 percent (1 chance in 20) that the high estimate will be discovered. The statistical mean given is defined as the arithmetic mean of the low, high, and most likely estimate. Hence, a most likely estimate (modal value) of 2.24 billion barrels of oil is implicit in the values above, although the probability of discovering the most likely value is not specified.

The U.S.G.S. estimate is constructed from summation of the individual petroleum provinces within the region, each province typically (with a few exceptions) distributed log-normally in probability with respect to resource size. The summation is not strictly log-normal, but can frequently be taken as log-normal in attempting to reconstruct the distribution from the information that the U.S.G.S. is permitted to provide. (The U. S.G.S. is required to protect certain information it may receive on prospective areas for specific periods of time.)

In the case of frontier areas lacking exploration information, and in particular the Beaufort Sea, a marginal or conditional factor has been applied which specifies a chance that no discoveries will result. This factor produces the zero value for the low estimate, and also alters the probability distribution of the smaller resource deposits. The truncation factor for the Beaufort Sea was estimated at 25 percent.

In a subsequent working paper (Grantz et al., 1976), the U.S.G.S. provided an allocation of the resource estimate as follows:

40 percent -	Federal waters between the 20- and 200-meter (66- and 660-foot) isobaths
51 percent -	Federal waters between the 3-mile limit and 20-meter (66-foot) isobath
9 percent -	State waters

The allocation of the 3,28 Bbbl statistical mean among these three areas would be approximately 1.3 Bbbl, 1.7 Bbbl, and 0.3 Bbbl, respectively. However, the U.S.G.S. has recently provided an estimate for a sub-area of the Beaufort Sea -- out to the 20-meter (66-foot) isobath only between longitudes 146°W and 150°W. This estimate (Radlinski, 1977) gives a low estimate of 1.0 Bbbl for the sub-area should resources be found, but estimate a 25 percent dry hole risk.

The Radlinski memo gives the following estimates:

	Low	High	Statistical Mean
Oil (Bbbl)	1.0	2.5	1.5
Gas (tcf)	1.75	6.25	3.25

Thus, the area between 146°W and 150°W longitude is assigned 1.5 Bbbl of the 2.2 Bbbl mean estimate of the entire Beaufort region out to the 20-meter (66-foot) isobath.

The resource estimates are referenced to a recovery of 32 percent of the oil in place (in reservoirs). In Appendix A, an independently derived estimate, referenced to 45 percent recovery, was given as 3.65 Bbbl . On the basis of 32 percent recovery, this latter value is reduced to 2.6 Bbbl. This is slightly more optimistic than the 2.2 Bbbl given by the U.S.G.S. The estimates in Appendix A provide a basis for allocating the statistical mean value of 2.2 Bbbl to four hypothetical discovery areas in the Alaskan Beaufort within the 20-meter (66-foot) isobath:

0.70 Bbbl - Camden Bay-Canning River

0.93 Bbbl - Prudhoe Bay Offshore

0.38 Bbbl - Cape Halkett area

0.19 Bbbl - Smith Bay-Dease Inlet

A log-normal probability distribution has been developed for the Beaufort Sea sub-area, including these four regions and allocated on a geological basis among the four regions. In the format discussed by Gumbel (1958), the distribution can be expressed with Parameters m and s, such that the cumulative probability can be referenced to the standard normal probability distribution by a variable:

$\frac{1}{s} \ln \frac{x}{m}$ where: - s is the probability dispersive index (related to the variance);
m is the resource level of the median probability;
- in is the natural logarithm

Reasonably close fit is obtained for values of s about 0.4 to 0.6. The resulting resource estimate probabilities for the aggregate areas are given in Table 13. The gas resource estimates average about 2,000 cubic feet per barrel of oil, ranging from 1,700 to 2,500 cubic feet per barrel for developable fields.

5.2.2 Distribution of Resources and Tracts

There is a distinct chance, which increases with resource discovery size, that the resource deposit associated with a given discovery probability may consist of more than a single reservoir. Fields which are reasonably close together, i.e., 16 kilometers (10 miles) compared to a total transportation distance of about 80 to 113 kilometers (50 to 70 miles), would vary little in investment cost over that of a single field of the same total volume. To illustrate this, at least one detailed scenario will be separated into two fields.

The size of the fields is determined from the resource size and the effective or average surface fill factor. Thus, a field of 0.8 Bbbl and a fill factor of 40,000 barrels per acre will cover 20,000 acres, or 80 square kilometers (31 square miles). The axes for a typical ellipse field pattern could then be 16 by 6 kilometers, 19 by 5 kilometers, 13 by8 kilometers (10 by 4 miles, 12 by 3.3 miles, 8 by 5 miles), etc.

TABLE 13

RESOURCE ESTIMATES EXTRAPOLATED FROM U. S.G. S. ESTIMATES[1]

(Bbbl Oil)

Probability	Total Beaufort	Beaufort Sub-Area to 20 Meters	Sub-Area to 20 Meters Between 146″ - 150°	Allocation of Sub-Area Resource Estimates			
				Camden-Canning	Offshore Prudhoe	Cape Halkett	Smith-Dease
Low (95%)	1.0	1.0	1.0	0.4	0.6	Nil	Nil
Modal	2.2	1.85	1.4	0.6	0.8	0.3	0.15
Mean (50%)	2.8	2.2	1.63	0.7	0.93	0.38	0.19
High (5%)	7.6	3.76	2.5	1.1	1.4	0.80	0.40
(1.0 %)	11.7	4.98	3.2	1.3	1.9	1.18	0.60

Note: Gas averages 2,000 cubic feet per barrel of oil, in a range from 1,700 to 2,500 cubic feet.

[1] The quantities in the total Beaufort, Beaufort sub-area to 20 meters and the sub-area to 20 meters between 146° - 150°W longitude are estimated from a probabilistic distribution. The quantities in the four regions are allocated somewhat arbitrarily on a geological basis. Given a 5% chance of finding at least 2.5 Bbbl of oil in the sub-area to 20 meters, between 146° and 150°W longitude, it would be reasonable to assume that 1.4 Bbbl of oil may be in the offshore Prudhoe area.

Source: Dames & Moore

For such elliptic patterns, the ratio of filled area to that of the tracts overlying the field is about 50 percent, representing a "packing ratio" of 2:1. The same ratio applies whether the fields are multiple or single, so long as the fields are markedly larger than a single tract (roughly 23 square kilometers or9 square miles for Federal tracts; 10 square kilometers or 4 square miles for tracts in the joint State-Federal sale area).

The location of tracts for the scenarios has been chosen to be consistent with the structural patterns presented in Appendix A. There are two or more structures in the eastern and western regions of the Alaskan Beaufort, and a single dominant structure in each of the two central regions of the Alaskan Beaufort (off Cape Halkett and Prudhoe Bay). For the detailed scenarios, specific tracts have been selected, and are given in Chapter 9.0.

In Appendix B, a much broader approach was taken to construct scenario resource size distributions in the absence of the allocations which have now been made for the four Beaufort regions. A procedure was developed by which the resource discovery was allocated 60, 30, and 10 percent to three geographic regions (splitting the Cape Halkett zone between the Prudhoe and western zone), and then field sizes distributed within each region such that:

32 percent of the resource was in large fields (1 Bbbl or more);

43 percent was in medium fields (500 MMbbl to 1 Bbbl); and

25 percent was in small fields (100 to 500 MMbbl).

Because the geographic distribution was considered arbitrary, the individual fields had to be permuted among the three regions, which allowed for the estimation of a single, very large deposit. As a result of the later estimate provided by the U.S.G.S. (with the benefit of two additional years of information), the chances of discovery have been increased, but the expectation of finding single deposits of greater than 2 Bbbl has been diminished.

5.2.3 Corollary Assumptions

5.2.3.1 Exploration

Current leasing procedures in the OCS stipulate that the period of exploration shall be 5 years (43 CFR 3302.2a states -- "all oil and gas leases shall be issued for a term of 5 years and so long thereafter as oil or gas may be produced from the leasehold in paying quantities, or drilling or reworking operations . . . .are conducted thereon"). Discussions with representatives of the petroleum industry indicated that the 5 year period was insufficient because of the severe operating conditions in the Arctic (Alaska Oil and Gas Association, 1977). In this study, a 10 year exploratory period has been assumed. Such a period could arise either through staggering the assumed tract purchases over two leasing periods, or through legislative amendment of the regulation to provide a 10 year leasehold in the Beaufort and similar areas. State of Alaska competitive oil and gas leases are issued for a primary term of 10 years (see Appendix A). The assumption of a 10 year term for the Beaufort OCS does not, however, reflect any presently known plan or commitment by the government to alter present leasing procedures.

The level of exploration in developed areas is assumed to be proportional to the number of tracts held for development -- one well per tract -- although the wells are not considered to be coincident to the tracts developed. The basis for this assumption is that while discovery reduces the need for further exploration, and the tracts to be ultimately developed, it stimulates nearby exploration. The western area, which has a low probability of near-term development, has relatively shallower strata depths of interest, and expected continuing discovery of deposits which are individually too small for development. Therefore, a higher exploration level -- a total of 12 holes -- has been postulated for the Smith-Dease scenario.

5.2.3.2 Schedule

In addition to a 10-year exploration period, it has been assumed that the two eastern areas will be leased before the western area. If the reservoir discoveries in the joint State-Federal sale area should extend into Federal waters, it is assumed that a drainage sale will ensue, permitting development of the reservoir with a schedule identical to that projected.

A critical scheduling criterion is that the production output be compatible at all times with transport availability, as discussed in Chapter 4.0. The economic aspects of scheduling, 'and its effect on investment cost and return, are discussed in Chapter 6.0.

5.2.4 Selection of Field Parameters

The parameters which have been selected to vary in the skeletal scenario construction, besides the resource size, are those which distinguish between fields of high density and those of low density or concentration with respect to development. These include the fill factor; whether the gas in the region is formed in an associated gas cap or is to be considered as a separate, detached pocket; the well spacing; individual well production period; and so forth. Factors associated with reservoir concentration or favorable density always produce a higher rate of return on investment. The contrast between high and low concentration is intended to produce a set of skeletal scenarios which display some of the variability in return which may be found in different fields of the same general size and location.

5.2.4.1 Depths

Field depths are expected to decrease east to west, from about 4,242 meters (14,000 feet) in the Camden-Canning area, to about 1,818 to 2,424 meters (6,000 to 8,000 feet) in the western areas. The coverage at a 4,242-meter depth in a 45-degree cone is about 14,000 acres. Over

80 production wells at 160-acre spacing could be reached. However, the maximum number of production wells assumed for a single platform is about 50. In the western area, the coverage at 1,818 meters in a 45-degree cone is about 2,600 acres, which would permit only 32 wells on 80-acre spacing, or 22 wells on 120-acre spacing. However, at a 55-degree cone, which may be achievable with some difficulty, 5,300 acres can be reached, permitting 44 wells on 120-acre spacing. The depths for the Prudhoe region are assumed to be about 3,660 meters (12,078 feet), and for the Cape Halkett region, 3,050 meters (10,065 feet).

5.2.4.2 Fill Factors

A study by Arthur D. Little (1976) of U.S. oil field potential cites an average fill factor for U.S. giant fields of 56,000 barrels per surface acre. However, the fill factor for Prudhoe Bay is on the order of 50,000 barrels per acre. The average of all U.S. giant fields includes some basins of very high intrinsic productivity, such as the Los Angeles Basin. If one considers that the North Slope is intrinsically less productive, then fill factors of 30,000 to 50,000 barrels per acre should be considered. A minimum factor of 20,000 barrels per acre can be considered.

5.2.4.3 Well Spacing

The basic spacing currently expected for the Prudhoe Bay field is 160 acres, although original estimates had been for 320 acres. It is also conceded that final well spacing in some portions of the field may be at 80 acres. The primary target adopted for well spacing on the North Slope is 160 acres. Reduction of the average to 150, 140, etc., acres will occur due to normal field irregularities. However, thin strata and tighter formations may require 80-acre spacing.

Allowance for waterflood injection is about 1:10 for concentrated fields and 1:5 for less concentrated fields. A 1:10 ratio is typical of a field well suited to peripheral flooding patterns. For fields in which local areas must be flooded individually, a 1:3 ratio may be required.

5.2.4.4 Gas-Oil Ratio

The gas-oil ratio is applied here to the resource values, and not to the output flow of hydrocarbons. Based upon the U.S.G.S. estimate for the eastern half of the area, the gas resource discovery will range from 1,700 cubic feet to 2,500 cubic feet for each barrel of oil (Grantz et al., 1976). Some gas will be produced with the oil, but the scenarios are distinguished by assuming either associated or separate gas reservoirs. Gas wells are assumed to produce about 20 to 50 million cubic feet per day, for the purpose of determining well allowances. In the western areas, the gas-oil ratio is projected to decline, not withstanding the already-discovered shallow Barrow gas field. Gas-oil ratios of 700 to 1,500 are assumed.

5.2.4.5 Production Characteristics

The production curves for a well are assumed to decline logarithmically, following an initial plateau. The basic curve used is a 14-year individual well curve with a 4-year plateau. As an alternate (for considering tighter formations, and also enhanced secondary recovery), an 18-year curve with a 6-year plateau is considered. These production curves are given in Table 14, in terms of percent of nominal peak well annual output. The capital recovery factors (present worth factors) associated with these are discussed in Chapter 6.0.

5.2.5 Skeletal Scenario Construction

The 24 scenarios encompassing this parameter selection are enumerated in Table 15. The tracts considered in the eastern areas (Camden-Canning, Prudhoe Offshore) are “State sized” (1,036 hectares or 2,560 acres), those in the western area are “Federally sized” (2,330 hectares or 57,600 acres).

TABLE 14

OIL WELL INDIVIDUAL OUPUT PATTERN
Percent of Nominal Peak Output

Year	14-Year(1) Pattern	18-Year(2) Pattern
1	50%	50%
2	95	95
3	95	95
4	95	95
5	70	95
6	52	95
7	41	72
8	31	60
9	24	46
10	18	38
11	14	30
12	11	24
13	8	19
14	6	15
15	--	12
16	--	10
17	--	8
18	--	6
	610%	865%

Source: Dames & Moore

(1) Corresponds to 32 percent recovery.
(2) Corresponds to 45 percent recovery.

TABLE 15

SCENARIO CHARACTERISTICS

Area		Oil (Bbbl)	Gas Ratio	Gas Location	Fill Factor (bbl/acre)	Well Spacing (acres)	Acreage	Producing Wells	Well Allowances	Total Wells	Platforms	Tracts
Camden - Canning	1	0.6	1.2	Assoc	40,000	140	15,000	107	13	120	3	12
	2	0.6	1.2	Assoc	30,000	100	20,000	200	30	230	6	16
	3	1.1	2.2	Assoc	40,000	140	27,500	196	24	220	6	22
	4	1.1	202	Sep	30,000	100	37,000	367	73	440	11	29
	5	1.3	3.25	Assoc	50,000	140	26,000	186	24	210	5	21
	6	1.3	3.25	Sep	30,000	100	43,000	433	87	520	13	34
Prudhoe Offshore	7	0.6	1.2	Assoc	40,000	150	15,000	100	15	115	3	12
	8	0.8	1.6	Sep	30,000	100	27,000	270	60	330	8	21
	9	1.4	2.8	Assoc	50,000	150	28,000	187	23	210	6	22
	10	1.4	2.8	Sep	40,000	120	35,000	292	68	360	9	28
	11	1.9	4.75	Assoc	50,000	150	38,000	253	37	290	6	30
	12	1.9	4.75	Sep	40,000	120	47,500	396	84	480	13	37

TABLE 15 (Cont.)

		Oil (Bbbl)	Gas Ratio	Gas Location	Fill Factor (bbl/acre)	Well Spacing (acres)	Acreage	Producing Wells	Well Allowances	Total Wells	Platforms	Tracts
Cape Halkett	13	0.3	0.2	Assoc	40,000	140	7,500	54	6	60	2	3-4
	14	0.3	0.2	Assoc	30,000	120	10,000	83	17	100	3	4
	15	0.8	0.6	Assoc	40,000	140	20,000	143	17	160	4	7
	16	0.8	0.6	Sep	30,000	120	27,000	222	48	270	7	10
	17	1.2	1.2	Assoc	50,000	140	24,000	171	19	190	4	8-9
	18	1.2	1.2	Sep	30,000	120	40,000	333	67	400	10	14
Smith - Dease	19	0.15	0.1	Sep	40,000	120	4,000	32	8	40	1	2
	20	0.15	0.1	Sep	20,000	80	7,500	94	21	115	3	3-4
	21	0.4	0.4	Sep	40,000	120	10,000	84	21	105	3	4
	22	0.4	0.4	Sep	20,000	80	20,000	250	50	300	8	7-8
	23	0.6	0.9	Sep	40,000	120	15,000	125	25	150	3	6
	24	0.6	0.9	Sep	20,000	80	30,000	375	85	470	11	11-12

Source: Dames & Moore

CHAPTER 6.0

ECONOMIC CONSIDERATIONS

6.1 SCOPE AND METHODOLOGY

The scope of the economic analysis that is sought along with scenario construction is designed to achieve as reasonably and succinctly as possible an approximation of the economic factors which will govern future development of Beaufort Sea petroleum resources. Some of the typical questions which can be addressed by the analysis include:

- What are the minimum size fields that could be expected to be developed in the Beaufort Sea?

- What level of resource discovery would be required to support (or justify) a new transport system?

- What would be the economic impact of Beaufort Sea development on existing transport systems?

- What market prices are necessary to economically justify production of Beaufort Sea oil and gas?

The approach adopted in this study to explore these questions has been formulated in as simple a model as could be expected to produce credible quantitative results. The development of the model focuses upon two basic parameters, which themselves summarize a very broad range of economic and physical situations:

1. A present worth factor for the revenue stream represented by the projected resource production.

2. The average investment per unit of resource output.

The projected investment costs, and the corollary expenses of operating, transport, and other costs such as per barrel duties and taxes incurred in production, are developed in Section 6.2.

The present worth factor is defined as follows: if a rate of return i is to be realized from an output stream of N_k units in the kth year, the present worth factor of the stream is:

$$\frac{\Sigma_k N_k/(1 + i)^k}{\Sigma_k N_k}$$

The use of present worth is essential for consideration of investments and revenues incurred at different points in time. All values are discounted backward in time, or escalated forward in time to a common instance. This instance (day 0) is taken at the start of production for each field. The cost escalation forward is equivalent to the inclusion of capitalized interest in the project construction price. Construction phases that occur after the start of production, which includes much of the well drilling, are discounted back to the reference date.

The use of discounted values is straightforward in the analysis, once the present worth factor is obtained. Alternative formulas, such as using the midpoint of each year instead of the endpoint, could be applied, but would not enhance the efficiency of the scenarios.

If a market price of $10 is associated with a unit output (i. e., a barrel of oil), and the present worth factor is 0.4, then the present worth of a unit output, averaged over the life of the project, is $4, at a rate of return or discount rate of i. Since the present worth factor is summed over the output stream, it depends on the shape of the output curve, which is to say, the timing of the output. Projects that return output early have higher present worth factors than those which produce a greater portion of the output later in time. Thus, oil well present worth factors tend to be higher than those for gas wells, since the bulk of the oil comes early -- in the first third of the life of the well. A gas well is more likely to be produced in an even output, until the final years of the well life.

The inverse of the present worth factor is a capital recovery factor. If the average unit investment is $2, and the present worth factor is 0.4, then dividing the unit investment by the present worth factor gives $5, the portion of the market price which provides capital recovery -- profit (or interest) and amortization of the investment. The cost formula used to develop the market price necessary to achieve a rate of return i is:

(1) $\dfrac{\text{unit investment}}{\text{present worth factor}} \div (1 - \text{royalty rate}) = \text{capital recovery costs}$

(2) capital recovery costs + operating costs + transport costs + ad valorem taxes = necessary market return.

The market return here refers to the market used by the owners of the oil (delivered to the refiner's receiving terminal) and not the consumer price.

The inclusion of the royalty factor is necessary to account for the royalty oil which has been included in the investment base. A royalty of 1/6 is used in the analysis, including leases in the joint State-Federal areas. This may be contrasted to the royalty rate of 1/8 used by the State of Alaska. Ad valorem taxes are those which are imposed on each barrel of oil, such as a severance or sales tax, rather than on the return or profit generated by the oil sale.

The rate of return may reflect after-tax return if the rate is adjusted for income taxes. If an investor pays an effective rate R on his income, then the rate of return he must have on his investment to realize a return i after taxes is i/(1-R). Thus, an investor paying an overall 40 percent on his income (which is not the same as the graduated 40 percent tax bracket, the latter referring only to the income falling within that bracket) and who wishes to realize 10 percent return after taxes must seek investments which will return about 16.7 percent.

This simple model is adequate to assess minimum field sizes necessary to support transport systems. Inflationary effects are not accounted for directly in the model, nor are incremental investment differences considered. The latter would arise in considering the differences in costs for varying levels of secondary recovery.

A similar model of costs can be applied to pipelines, although this model is only an approximation for pipeline tariff construction. A complex set of rules applies to pipelines, governing depreciation schedules, allowable return, etc. The rate of return used for pipelines in this study is the average interest rate charged by the bondholders, which may be at a higher rate of return than that permitted to the line owners. In using the interest rate, it is assumed that a major portion of the total line cost will be financed, and that interest will be the predominant cost overall. However, the interest cost is treated as a pre-tax return. The royalty rate is not applicable to pipelines, since royalty oil owners will pay a pipeline tariff equitably with other users.

Following the discussion and development of the cost parameters and present worth factors in Section 6.2, market prices for oil and gas in the skeletal scenarios are estimated in Section 6.3 as a function of arbitrary return on investment, i.e., parametric values of 0 percent, 5 percent, and 10 percent. (The rationale for selection of these values is discussed on page 195.) Minimum developable field sizes are assessed from these estimates.

The market prices associated with the detailed scenarios are constructed in Section 6.4, and the impact of production from the detailed scenarios upon the tariffs of the Alyeska and Alcan transport systems is considered.

The estimation of the level of reserves needed to support new transportation systems is discussed in Section 6.5.

Considerable variability can be attached to the two basic parameters of the economic model -- the present worth of the output and the mean investment per unit of resource -- and an effort has been made in the scenario constructions to explore the range of this variability. In Section 5.6 a sensitivity analysis is presented to determine the assumptions and costs in the model that weigh more heavily in market return.

The question of market price adequacy for Beaufort Sea oil and gas is never directly addressed. The market price construction gives a price (in fixed dollars) which would return O percent, 5 percent, 10 percent, etc., to an investor with either of two effective tax rates on the income generated. The inverse assessment, what rate of return would be assigned to a particular market value, can be estimated by interpolation between these constructed values. The adequacy or attractiveness of the return has to be judged by the investor relevant to his needs for oil and his available alternatives. The results of the study are not reasonably adapted to answering questions of the type: "How much stimulus will increased oil and gas prices have upon exploration and development of the Beaufort?" The assumptions-of these scenarios are logically contrary to this latter question. The level of discovery is determined by probability, rather than the intensity of exploration. The discovery of the resource in place has been assumed to be efficient, and the intensity of further exploration became dependent upon discovery. This assumptive framework is permitted by the expected geology of the area, namely, a few large structures.

The determination of a minimum field size requires selection of a necessary rate of return at which an investor would elect to proceed with development of the field. The rates used in the examples of this study are zero percent and five percent, with 35 percent effective rate. This selection is arbitrary, and alternative viewpoints could also have been elected; in particular that no investor would be willing to enter development unless his prospective return were greater than the prime interest rate, say eight percent. However, the adequacy or attractiveness of the return has to be judged by the investor relevant to his perspective of future returns, and also his alternatives. The rate of return itself is relevant to a specific market price. Thus a zero rate of return with respect to a $13 per barrel market value could be viewed by a particular investor as a $16 per barrel market (even in constant dollars) in terms of his future supply sources. This is especially true for petrochemical operators, who are viewing a more complex market than just crude oil. The amount of premium (i.e., rates of return less than the prime alternative interest rate to industry), which should be attached to development projections, is beyond the scope of economic analysis appropriate for this study, just as analysis of the future price behavior for petroleum is also not appropriate. Neither of the selected rates is intended to represent the better premium; the point of emphasis is that the point of minimum field size should be projected slightly lower than the break-even point relative to current conditions.

6.2 ESTIMATION OF PARAMETERS FOR ECONOMIC ANALYSIS

The parameters used in the economic analysis are the costs of developing Beaufort Sea oil and gas, construction costs of the transport systems, operating costs of the fields and transport systems, and the present worth factors applicable to the various output streams and revenue streams.

This information was also developed in a preceding interim study[1], a portion of which is presented in Appendix B. The investment values used in Appendix B were based upon a fixed set of unit costs -- per platform, per well, per mile of pipeline, etc. -- so that all of the

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(1) Beaufort Sea Basin Petroleum Development Scenarios for the Federal Outer Continental Shelf, Alaska OCS Socioeconomic Studies Program Technical Report No. 3, prepared for the Bureau of Land Management, Alaska OCS Office by Dames & Moore; Peat, Marwick, Mitchell & Co., and CCC/HOK, December 1977.

variation in unit investment costs arose from locational and resource size differences. All fields were attributed with a similar output schedule and construction schedule. The development drilling was costed as being completed in advance of all production, and the output curve of an individual well was identical with the field average. Insofar as estimating rate of return and market price, these approximations tend to introduce offsetting errors.

In the scenario construction of the present study, costing is structured to permit greater latitude between similar types of efforts, in order to provide a clearer representation of the variability to be encountered in the economic parameters. The investment schedule used generally permitted production to begin early, with most of the development drilling accomplished after the start of production. The field output pattern is thus influenced by the drilling program, and the latitude available from this scheduling is also reproduced.

Some of the basic cost parameters have been revised. The estimate of the average drilling cost of development (production) wells has been revised downward over that used in Appendix B. A reduced per-mile cost of offshore pipelines has been used, reflecting a more optimistic assessment of the difficulties to be encountered with sub-bottom permafrost. The unit investment costs and present worth factors developed are lower than those constructed previously for Appendix B.

6.2.1 Present Worth Factors

The present worth factor of a set of revenues f_k in the kth year at a rate of return i (interest rate, discount rate) has been defined as:

$$\frac{\Sigma_k f_k / (1 + i)^k}{\Sigma_k f_k}$$

To clarify the use of this factor, a textbook example will be constructed. Suppose that $100 is paid for say, 57 crafted items that are to be delivered according to the unit schedule given below, and for which the investor desires to earn 10 percent on his invested capital. For the example:

$$\Sigma_k \,'_k = 57 \text{ units}$$

$$\Sigma_k f_k / (1.1)^k = 40.489$$

Present worth factor = .7103

A unit market price of $2.47 is calculated from an average unit cost of $1.75 (=$100/57) divided by the factor .7103.

Year	Units	Market Revenue	Capital Bal ante	Earnings
1	10	24.70	85.30	10.00
2	10	24070	69.13	8.53
3	10	24.70	51.34	6.91
4	8	19.76	36.71	5.13
5	6	14.82	25.56	3.67
6	4	9.88	18.24	2.56
7	3	7.41	12.65	1.82
8	3	7.41	6.51	1.27
9	2	4.94	2.22	.65
10	1	2.47	0	.25
	57	$140.79		$40.79

This example illustrates how the amortization of the original investment occurs directly according to the revenue stream. Alternative forms of investment recovery which enter into bookkeeping methods are proportional amortization (each of the units is expected to contribute equally to the capital recovery, in this case $1.75 each) or scheduled depreciation. However, if the capital recovery is fixed, either the rate of return or market revenue must be allowed to vary, or a sinking fund must be devised to equalize the difference between the direct capital recovery and that which might be desired for regulatory reasons. Bookkeeping problems of this type arise in tariff analysis for pipelines.

The rate of return which is of interest for oil fields is that received after income taxes have been paid. Inquiries with some banking officials (Chase Manhattan Bank, 1977) indicated that the average total tax rate for the oil industry, which includes foreign taxes, is in excess of 50 percent. A nominal domestic tax rate of 28 percent was estimated, although no verification of that figure was available. Recently, a new study by the Congressional Research Service of the Library of Congress cites an expressed intangibles of 29 percent (Oil and Gas Journal, October 17, 1977, p. 32). The study concluded that the “ effective rate for the industry, without the advantage of percentage depletion, was 17.2 percent.

To consider an envelope covering the range of the above values around the industry average tax rate, an upper value a few percentage points over the 29 percent value, and a lower value below the 17 percent rate have been selected. The selected values to cover the range were 35 percent and 10 percent. The after-tax rate of return which will result from a particular income stream varies monotonically between the two tax rate parameters. The total rates of return (used in the computation of the present worth factors) which correspond to after-tax returns are given by:

$$\frac{\text{After-tax rate}}{(1 - \text{Effective tax rate})} = \text{Total rate of return}$$

Total Rates of Return

After-Tax Return	Low Tax Case	High Tax Case
5%	5.56%	7.69%
10%	11.11%	15.38%
15%	16.67%	23.08%
20%	22.22%	30.77%

For pipelines, the rates of return are taken (as an approximation) to be the interim return to bondholders. Values of 9 percent and 10 percent are assumed as interest rates. A value of 7 percent is given for sensitivity comparison.

Pipeline return rates are considered pre-tax, since the interest rates form a contractual rate of return. The present worth factor for a pipeline with throughput schedules of different annual volumes is calculated identically to that of an oil field or oil well. Gas lines (or fields) with constant annual output have a present worth factor given by:

$$\frac{(1+i)^n - 1}{ni\,(1+i)^n}$$

Where n is the number of years and i is the annual rate of return.

A present worth factor for delayed production, i.e., relative, to a date t years in advance of production startup, can be expressed in terms of the factor calculated at start of production by reduction by $(1 + i)^t$. Mathematically:

$$PW_{-t} = (1 + i)^{-t} PW_o$$

This expression is used in combining the volume and time-weighted revenue streams starting at different points in time. Some present worth factors for the scenarios developed in this study are given in Tables 16, 17, and 18.

The variation in the present worth factors for the four detailed scenarios arises strictly from variations in the drilling scheduling. The standard deviation given in Table 16 indicates a range of 14 to 18 percent for the low tax option in the 10 to 15 percent return bracket. For the higher tax option, the variation is 18 to 22 percent.

Example: $\pm \frac{.0333}{.3904} = \pm 9\%$, range is 18%.

6.2.2 Petroleum Development Costs

Two major components of developing two Beaufort oil and gas fields projected in the scenarios are the platforms, wells drilled, connecting pipelines to a transportation system, processing equipment, and base camp. Exploratory costs are not considered in the development cost analysis, since they are borne by all of the operations of an oil company and are not considered an expense related to a particular or nearby operating field.

Typical bid costs of one to $10 million per tract are included in the investment for developed tracts. Costs of undeveloped tracts, either explored or not, are assumed to be an exploration expense, not further considered.

The range of unit cost values considered (except for pipelines, which are developed separately) is given in Table 19. Comparison of the values with those given in Appendix B reveals that a much lower estimate of individual well costs is given. While exploratory well costs in frontier areas continue to rise astronomically -- thirteen to $17 million

TABLE 16

REPRESENTATIVE PRESENT WORTH FACTORS FOR OIL PRODUCTION[1]

Output Profile Source	After 10% Tax				After 35% Tax			
	5%	10%	15%	20%	5%	10%	15%	20%
Camden-Canning Scenario	.6090	.4624	.3411	.2617	.5112	.3645	.2520	.1849
Prudhoe Offshore 1.9 Bbbl Scenario	.7061	.5213	.3989	.3144	.6253	.4231	.3037	.2300
Prudhoe Offshore 0.8 Bbbl Scenario	.6547	.4569	.3357	.2570	.5662	.3590	.2474	.1816
Cape Halkett Scenario	.6995	.5130	.3910	.3075	.6177	.4151	.2971	.2232
Individual Well 14 yr.	.7781	.6261	.5175	.4369	.7132	.5396	.4264	.3480
Individual Well 18 yr.	.7287	.5578	.4434	.3630	.6541	.4662	.3528	.2789
Field Average, Appendix B	.73	.56	.45	.37	.66	.47	.36	.29
Average of Four Scenarios	.6673 ± .0451	.4884 ± .0334	.3667 ± .0329	.2852 ± .0300	.5801 ± .0529	.3904 ± .0333	.2751 ± .0295	.2049 ± .0252

Source: Dames & Moore

(1) Refer to Tables 35, 39, 43 and 47 for oil production schedules of detailed scenarios.

TABLE 17

REPRESENTATIVE PRESENT WORTH FACTORS FOR GAS PRODUCTION

Years	After 10% Tax						After 35% Tax					
	2.5%	5%	7.5%	10%	15%	20%	2.5%	5%	7.5%	10%	15%	20%
20	.7594	.5948	.4790	.3953	.2863	.2209	.6889	.5024	.3845	.3064	.2133	.1617
21	.7500	.5818	.4650	.3817	.2745	.2111	.6776	.4885	.3710	.2942	.2037	.1542
22	.7408	.5691	.4517	.3688	.2635	.2021	.6666	.4752	.3583	.2828	.1949	.1473
23	.7317	.5569	.4390	.3566	.2533	.1937	.6559	.4624	.3462	,2721	.1868	.1410
24	.7228	.5451	.4268	.3451	.2438	.1860	.6454	.4502	.3348	.2621	.1793	.1352
25	.7141	.5337	.4151	.3342	.2349	.1788	.6352	.4385	.3241	.2527	.1724	.1298
26	.7055	.5226	.4039	.3238	.2266	.1721	.6252	.4272	.3138	.2439	.1659	.1249
28	.6887	.5014	.3830	.3046	.2114	.1601	.6058	.4060	.2950	.2279	.1543	.1160
30	.6725	.4815	.3638	.2873	.1980	.1496	.5873	.3864	.2780	.2137	.1442	.1083

Source: Dames & Moore

TABLE 18

REPRESENTATIVE PRESENT WORTH FACTOR FOR PIPELINE

Output	Time	7%	9%	10%
Gas	20 years	.5297	.4564	.4257
	21 years	.5160	.4425	.4118
	22 years	.5028	.4292	.3987
	23 years	.4901	.4165	.3862
	24 years	.4779	.4044	.3744
	25 years	.4661	.3929	.3631
	26 years	.4548	.3819	.3523
	28 years	.4335	.3613	.3324
	30 years	.4136	.3425	.3142
Oil	Assumed Alyeska throughput 1977-2006	.6909	.4335	.4047
	Projected Alyeska 14.9 Bbbl throughput 1977-2010	.4308	.3555	.3252
	Projected Alyeska 13.8 Bbbl throughput 1977-2010	.4369	.3627	.3326

Source: Dames & Moore

TABLE 19

UNIT COSTS FOR PETROLEUM FIELD DEVELOPMENT
(1977 Dollars Assumed)

Unit	Millions of Dollars Each	Millions of Dollars Installed
Tracts (not size dependent)	1 - 10	
Production Platform		
Gravity		
15 meters (50 ft) depth	35 - 65	
6 meters (20 ft) depth	15 - 40	
Artificial Islands		
3 - 6 meters (10 - 2 ft) depth	10 - 35	
Production and Development Wells	1 - 1.7	
Gas Processing Equipment per 100 MMcfd		50 - 70
Oil Processing Equipment per Mb/d		1.3 - 2.1
Base Camp		80 - 200

Source: Dames & Moore

dollar holes being reported as typical -- the oil industry in Prudhoe Bay has demonstrated the capability to achieve good cost efficiency in production and development wells. Costs for field processing equipment have been raised, reflecting some costs allocated to the installed costs of platforms and pipelines. Platform costs vary widely, and the most likely values are to be found at the upper end of the range. The low end of the range may be achievable with use of dredged local material from the sea bottom as fill. The spread of base camp costs depends strongly upon gravel material costs for working and transportation areas. The upper figure cited could be greatly increased by a need to transport gravel beyond nominal haul distances (13 kilometers or less).

The unit investment costs are calculated by constructing at least six estimates for the detailed scenarios, and one or two for the remaining skeletal scenarios. The total cost is then divided by the number of resource units (barrels and thousands of cubic feet) to obtain the unit cost. More refined oil field analysis would distinguish between the costs of primary and secondary projects. The resource size levels for the scenarios are all referenced to a single recovery factor for all the scenarios, and the average unit investment provides an adequate basis for the approximate economic considerations of this study. The escalation of 5 percent -- i.e., the difference between the prime money rate and the inflation factor for construction, in excess of general inflation -- was assumed to be 5 percent. This number would be less under an assumption that money was plentiful and construction labor was in short supply. Conversely, higher values of the rate would place more premium on capital. The same factor applies for the discounting of downstream drilling.

6.2.3 Pipeline Systems

The costs of the Alyeska pipeline at the present capacity levels of about 1.2 million barrels daily has been quoted at around $9.1 billion -- $8 billion for the pipeline, and $1.1 billion for the

Valdez terminal (Hale, 1977). This figure includes a reserve of around $1 bil lion for eventual removal of the line. Other citations of the cost go as high as $10 billion. The cost figures for the line are being contested by the State of Alaska, the operators, the Interstate Commerce Commission (ICC), and consumer groups.

The cost of the line at ultimate capacity of 2 million barrels per day is estimated for the purposes of this study at between $9.2 billion and $10.5 billion. The lower figure projects a possibility that the cost basis for the line may be reduced by the courts by reducing the removal contingency allowance. The higher figure projects that current contingency is allowed.

The tariffs to be charged are also being contested (Oil and Gas Journal, July 4, 1977). The rates filed by the carriers range from $6.04 to $6.44 per barrel. Other rates proposed range from $3.59 to $4.42 (State of Alaska), $4.19 to $4.58 (Dept. of Justice), $4.68 to $5.10 (ICC interim rates).

The composite rate filed by the carriers is being permitted until resolution of the litigation, and amounts to an average of $6.20. For this study, rates of $5.50, $6.00, and $6.50 are used as a low, medium, and high tariff base for the Alyeska system. The excess between the $6.20 composite tariff and the high value is attributed to uncertainty in average tanker rates over the next 5 years. A single value has been ascribed to the ocean transport leg ($0.90 per barrel), but any variation in tanker costs would have an effect on wellhead value of the oil identical to variation in the pipeline tariff.

The system cost for a second oil pipeline along the Alyeska right-of-way is estimated at 65 percent of the present pipeline costs, i.e., $4.9 billion to $5.1 billion for 1 million barrels daily throughput (48-inch line), and six to $6.8 billion for 2 million barrels daily, in 1977. This figure is based upon a mental extrapolation of some early analysis given in discussion with an Alyeska engineer.

Current quotations of the cost of the Alcan gas line range from $10.5 billion to $13 billion. (1977 dollars) (Oil & Gas Journal, 9 May 1977; Oil & Gas Journal, 12 December 1977) for the pipeline at 48 and/or 54-inch diameter and sufficient compressor installation to move 2.6 Bcfd. The expense of increasing compressor installation to 3.4 Bcfd was estimated at $800 million. For this study, the Alcan system is assumed to cost $10.5 billion, with eventual costs of either twelve or $14 billion at full capacity.

These major pipeline projects provide the estimating basis for Arctic pipelines. The Alyeska line at $9.2 billion averages over $11 million per mile for 2 million barrels per day. At 1 million barrels per day, it would average $10 million per mile. The Alcan project in Alaska will average from $4.9 million per mile to about $6.5 million per mile.

Offshore pipelines with ice exposure could be either more or less expensive than onshore lines, depending upon the presence of permafrost. If the pipelines near shore have to be placed in insulated trenches, the cost will be higher than onshore. However, if the permafrost level under the sea bottom is sufficiently deep to permit conventional burial, then offshore pipelines could be significantly less expensive than in onshore permafrost areas.

It is projected here, as discussed in Section 2.1.3.4, that the permafrost problem will be encountered only at the landfall. Thus offshore line costs estimated in the study are reduced from the unit investment costs indicated in Appendix B. The reduced investment costs calculated here, in comparison with those in Appendix B, result from the more optimistic viewpoint of offshore pipelines, and the demonstrated production well costs.

A table of investment costs in Arctic pipelines is given below, in millions of dollars per mile.

	Oil Lines			Gas Lines			One Oil, One Gas Line	
	18-24 inches Dia.	24-36 inches Dia.	42-54 inches Dia.	18-24 inches Dia.	24-36 inches Dia.	42-54 inches Dia.	18-24 inches Dia.	24-36 inches Dia.
Onshore								
Low	6.5	8	9	4	5	6	8.5	10.5
High	7	9	11	4.5	6	7	9	12
Offshore								
Low	2.5	3	-	2	2.5	-	4	5
High	5	6	-	4	5	-	8	10

The remaining oil transportation pipeline system previously discussed was a possible new line from the western areas across the Seward peninsula to Nome. Such a system would contain between 450 and 500 miles of line. The investment costs indicated above, nearly 80 percent in permafrost, would be $5 to $5.2 billion, with an additional one billion for a terminal at Nome, for a major line. For a smaller line, say 30-inch, the projected estimate would be $4.2 billion, plus $750 million for a terminal.

6.2.4 Operating and Other Unit Costs

The costs considered to this point have been primarily related to investment and capital recovery. Operating costs and transportation are added directly to the capital costs to obtain the market price necessary to recover the capital. These include field operating costs, transport costs, and any other per-barrel charges incurred in petroleum production, whether they represent "well head" or downstream surcharges. Under U.S. petroleum policy, the price at the well head may be held to some fixed allowance, and it may be important to specify whether a charge is attributed to the producer or the transporter (or refiner, distributor, or consumer). Such distinctions are not considered in the simplified analysis here. All the non-capital costs could be lumped together as a "black-box" increment between the market price and the capital recovery. However, the impact of the increased transport system utilization afforded by the production projected in the scenarios is one of the limited objectives of the economic analysis. The capital recovery in the transport system is estimated to consider the impact of the scenarios assumptions on future tariffs.

The processing costs to condition Prudhoe Bay gas for pipeline transport are not yet specified, neither with respect to magnitude nor location of the costs -- by the producer, transporter, or third party. The third party, in this case, could be a petrochemical interest receiving LP-gas stripped in the conditioning. Although the analysis here has assumed that petrochemical decisions would have very little effect on the return on investment to the gas producers, it should not be considered as a negative judgement on the merits of petrochemical operations from gas liquids. To the extent that such a project can demonstrate profitability under near-term market conditions, then every "little bit" helps. The "little bit" in this instance refers to a small increment of price premium on 3 to 5 percent of the gas volume.

Operating costs, especially in the petroleum fields and treatment plants for gas and oil, reflect economies of scale which vary the unit costs as the volume of throughput varies. They also depend on the energy costs (which are proportional to the market price of the product). The rise in operating cost per unit throughput near the end of the productive life of the field is a major determinant of the abandonment date of the field. These variations are neglected in the economic analysis for this study, for two reasons. They are second-order relative to the variations in capital recovery costs. Furthermore, the greater variations in operating costs tend to come in the declining period of the field. The contribution of that segment of the output is minimal with respect to the present worth of the total output, because of the time discount and the small portion of total output achieved in the "tail" segment of the production.

The operating cost for Beaufort Sea oil production is estimated at $0.90 to $1.00 per barrel average (in constant current dollars). This is based upon extrapolation of projection for the Prudhoe Bay field with a significant amount of water injection. A similar value was estimated in the interim study in 1975 dollars. Thus the current estimate reflects a slightly lower estimate -- i.e., a more optimistic view of future Arctic operations.

The tanker tranport charges between Southern Alaska and Southern California have been estimated in the analysis at $1.00 per barrel (constant 1977 dollars) . This is at the top of the range of published estimates, and may be higher than charges currently incurred for North Slope crude. Published estimates range from $3.00 to $6.50 per long ton ($0.40 to $1.00 per barrel) for U.S. flag carriers (Arthur D. Little, Inc., 1976); $0.80 to $1.00 per barrel (Oil and Gas Journal, June 7, 1976) . However, the eventuality of tanker rate recovery is not debated in shipping and petroleum journals -- only whether the early or mid 1980’s is the timing. Thus the 1990’s average has been projected at the upper value. The assumed transport charge of $1.00 per barrel covers the unloading costs contingency fund, and so forth, included in the landed cost at point of entry to the Southern California market.

The Alyeska tariff composite at present is about $6.20. The output schedule upon which it is based is assumed to be Sadlerochit production only totalling 9.6 billion barrels over 25 years rather than the schedule used in this study (totalling 10.5 billion). With maximum throughput limited to 1.2 million barrels per day, the present worth factor would be about 0.36 or <u>less</u>. Capital recovery would range from $2.61 to about $2.87. The difference between this and the composite tariff would be $3.58 to $3.33. On this basis, operating costs of $3.30 to $3.60 per barrel are estimated for the Alyeska line.

Correlating these with the parametric tariff values used in this study gives:

Tariff: $6.50;	Capital cost: $2.90;	Operating cost: $3.60
$6.00	$2.50	$3.50
$5.50	$2.20	$3.30

The lower capital cost would correspond, for example, to an assumed Alyeska system expanded to 2 million barrels per day, with allowed investment costs of $10 billion, 9 percent interest, and 10.5 billion barrels throughput. The $2.50 capital cost could correspond to $10.5 billion investment cost, 10 percent interest cost, and 10.4 billion barrels throughput. The $2.90 capital cost could result from further delay in the present system, with allowed costs of $10 billion at 10 percent interest costs and 9.6 billion barrels (or alternatively, reduction of the total throughput if the present system does not prove as responsive to water flood as presently projected).

The field operating costs for natural gas have been estimated previously at $0.08 per Mcf (Appendix B). Because of the wide range of operating cost estimates available for the proposed Alcan line, this value will be retained here. However, it cannot include major conditioning of the gas beyond the first stage of field condensate removal; nor does it permit more than nominal sour gas or carbon dioxide removal. Depending upon how gas treatment costs are eventually divided between the Prudhoe Bay producers and the gas transmission system, the $0.08 per Mcf value may lead to a misleading well head price.

Processing costs for the Alcan line quoted in recent newspaper reports range from:

-$0.30/Mcf plus $1.03 -$1.05 tariff,
by the Carter Administration (Baltimore Sun, 12 January 1978)

-$0. 90/Mcf plus 1.20 tariff,
by McMillian, head the Alcan consortium (Baltimore Sun, 12 January 1978)

-$0 .50/Mcf (Anchorage Times, 26 January 1978).

For 26-tcf reserves (26 billion Mcf), and a 26-year life, the capital recovery cost for a $10.5 billion system would be $1.05 and $1.14 for 9 and 10 percent interest costs. At best, a tariff of $1.20 would allow for transmission operating costs of $0.15 per Mcf, excluding consumption of the gas for transmission power. Energy consumption in gas pipelines typically runs at one percent of BTU content per 500 or 600 miles.

Since the final design of the plant, and as well, the allocation of processing costs, will depend upon decisions not yet made (and independent of future Beaufort Sea production), it is prudent to place a range of uncertainty over the operating costs. The range of processing/transmission operating costs assumed for this study is:

low	-	$0.50/Mcf
medium	-	$0.75/Mcf
high	-	$1.00/Mcf

Some of the major decisions yet to be made include:

- U.S. well head allowances for gas prices.
- Canadian preference for a low-pressure system to accommodate Canadian-made pipe.
- Alaskan decisions to support petrochemical operations.

The resultant tariff for an Alcan line, with 26 year 26 tcf throughput is estimated at:

	Cost per Mcf		
	Low	Medium	High
Investment:	$0.40	$0.46	$0.54
Capital recovery: 9%	$1.05	$1.20	$1.41
10%	$1.14	$-1.31	$1.53
Operating Costs:	$ .50	$ .75	$1.00
Tariff:	$1.55-1.64	$1.95-2.06	$2.41-2.53

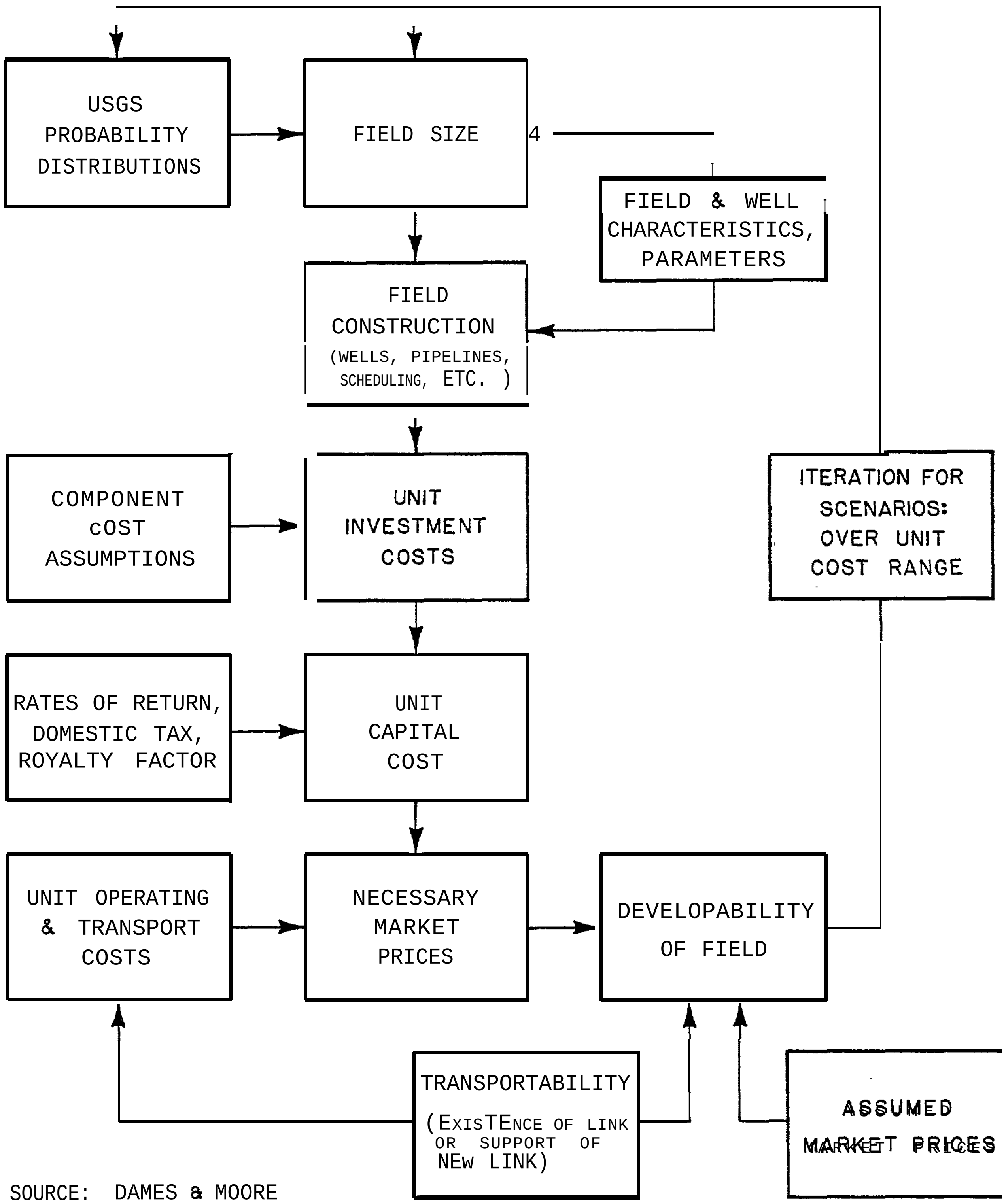
With respect to gas well head price, it should be remembered that some of this parametric tariff could be shifted into that wellhead value.

6.3 ECONOMIC SCREENING OF SKELETAL SCENARIOS

The logic sequence of constructing a necessary market price for the skeletal scenarios is depicted in Figure 21. For at least two scenarios in each of the four regions, six different sets of investment costs were constructed, using various combinations of component cost values. A median value of the set was selected as the most likely cost of the field. The remaining scenarios in each region were then costed by incremental-differences from these medians.

The investment cost totals, separated for oil and gas operations, were then divided by the resource units to obtain the unit investment costs. These are displayed in Table 20-A for all 24 skeletal scenarios. The values of investment for gas operations are dependent upon inclusion in the oil field operations. Gas operations were charged a proportional facility cost (base camp and platform construction), which turns out always less than the minimum fixed cost of a single camp or platform.

The present worth factors used in the scenario screening are specific only to a particular scenario. However, for screening, the factor developed for the Camden-Canning and Cape Halkett regions were used for all of the cases in those respective regions. For the Smith Bay-Dease Inlet cases, the average factor of all scenarios was used. In



SOURCE: DAMES & MOORE

FIGURE 21 - LOGIC FLOW SHEET FOR THE ECONOMIC ANALYSIS

TABLE 20-A

SKELETAL SCENARIOS

MEDIAN INVESTMENT COST

(1977 Dollars, Unit Average)

Scenario	Oil (Bbbl)	Gas (Tcf)	Oil Investment per barrel	Gas Investment per Mcf	Total millions
Camden-Canning					
	0.60	1020	2.06	0.37	1,680
	0.60	1.20	2.72	0.39	2,100
	1.10	2.20	1.55	0.29	2,340
	1.10	2.20	1.85	0.32	2,740
	1.30	3.25	1.43	0.23	2,610
	1.30	3.25	1.70	0.26	3,060
Prudhoe Offshore					
	0.60	1.20	1.39	0.39	1,300
	0.80	1.60	1.50	0.29	1,660
	1.40	2.80	1.25	0.22	2,370
	1.40	2.80	1.38	0.24	2,600
	1.90	4.75	1.10	0.16	2,850
	1.90	4.75	1.29	0.17	3,250
Cape Halkett					
	0.30	0..20	3.70	2.20	1,550
	0.30	0.20	4.17	2.20	1,690
	0.80	0.60	2.00	0.76	2,060
	0.80	0.60	2.23	0.81	2,270
	1.20	1.20	1.36	0.39	2,100
	1.20	1.20	1.66	0.42	2,490
Smith-Dease					
	0.15	0.10	7.67	7.80	1,930
	0.15	0.10	10.10	7.80	2,300
	0.40	0.40	3.52	2.08	2,240
	0.40	0.40	4.52	2.08	2,640
	0.60	0.90	2.45	0.97	2,340
	0.60	0.90	3.38	0.97	2,900

Source: Dames & Moore

the Prudhoe Offshore cases, separate present worth factors were available for the high, medium, and low resource levels in that area.

The resultant market price constructions are displayed in Tables 20-B and 20-C for the two tax rate options. The next higher construction value over $20 per barrel was dropped. The market range of practical interest is the $13 to $14.50 per barrel bracket. The market price displayed in the tables reflects the medium tariff in the Alyeska system -- $6.00 per barrel. Parametrically, the market price is bracketed by ± $0.50 for the high and low tariff assumptions.

The results of the oil price constructions reflect the high cost of getting the oil into the Alyeska system. Similar conclusions were indicated in the interim study (Appendix B), although current estimates are more optimistic in economic feasibility. A market price of $13.50, with moderate transport costs, could return over 10 percent to producers for finds offshore Prudhoe, and some favorable situations could return over 15 percent. Those same situations could return over 20 percent to a producer with a low effective income tax. In other areas, however, even a market price of $14 per barrel would return 10 percent only in the most favorable situations. The designations "A" and "S" refer to the favorability of the reservoir assumptions -- "associated" and "separated." The "A" scenarios reflect individual well output averages up to 7 million barrels; for the "S" scenarios, the individual well average output is typically about 3 million barrels.

The necessary gas market price for producers paying tax at the 35 percent option is shown in Table 20-D. Again, the medium transport cost estimate is used. In a recent review of the Alcan proposal, government estimates for Prudhoe Bay gas projected market prices of $2.49 to $2.79 per Mcf, with worst case prices of $3.02 to $3.32. Worst case presumably referred to potential cost overruns in Alcan construction (Baltimore Sun, 12 January 1978). The projections given here, in like dollars,

TABLE 20-B

OIL MARKET PRICE CONSTRUCTION

FOR SKELETAL SCENARIOS

(35 PERCENT EFFECTIVE TAX RATE)

Scenarios	Resource (Bbbl)		Market Price (1977 Dollars) [1] Return: 5%	10%	15%	20%
Camden-Canning						
	0.6	A(2)	12.84	14.78	17.81	21.37
	0.6	A	14.38	16.95	20.95	--
	1.1	A	11.64	13.10	15.38	18.06
	1.1	S	12.34	14.09	16.81	20.01
	1.3	A	11.36	12.71	14.81	17.28
	1.3	S	11.99	13.60	16.10	19.03
Prudhoe Offshore						
	0.6	A	10.95	12.65	14.74	17.19
	0.8	S	11.18	13.01	15.78	17.91
	1.4	A	10.59	11.84	13.45	15.32
	1.4	S	10.85	12.24	14.02	16.08
	1.9	A	10.11	11.12	12.35	13.74
	1.9	S	10.48	11.66	13.10	14.73
Cape Halkett						
	0.3	A	15.19	18.70	22.94	--
	0.3	A	16.10	20.05	--	--
	0.8	A	11.89	13.78	16.08	18.75
	0.8	S	12.33	14.45	17.01	19.99
	1.2	A	10.64	11.93	13.49	15.31
	1.2	S	11.22	12.80	14.70	16.92
Smith-Dease						
	0.15	S	23.87	--	--	--
	0.15	S	28.89	--	--	--
	0.4	S	15.28	18.82	23.35	--
	0.4	S	17.35	21.89	--	--
	0.6	S	13.07	15.53	18.69	22.35
	0.6	S	14.99	18.39	22.74	--

(1) Operating Costs $1.00
Transport Cost, Southern California $7.00 (medium option, otherwise ± $0.50)

(2) "A" scenario parameters involve average well outputs up to 7 MMbbls.
"S" scenario parameters involve average well outputs down to 3 MMbbl.

Source: Dames & Moore

TABLE 20-C

OILMARKET PRICE CONSTRUCTION

FOR SKELETAL SCENARIOS

(10 PERCENT EFFECTIVE TAX RATE)

Scenario	Resource (Bbbl)	Market Price (1977 Dollars)[1]			
	Return:	5%	10%	15%	20%
Camden-Canning					
	0.60 A[2]	12.06	13.35	15.25	17.45
	0.60 A	13.36	15.06	17.57	20.47
	1.10 A	1-1.05	12.02	13.45	15.11
	1.10 s	11.65	12.80	14.51	16.48
	1.30 A	10.82	11.71	13.03	14.56
	1.30 s	11.35	12.41	13.98	15.80
Prudhoe Offshore					
	0.60 A	10.55	11.65	12.97	14.49
	0.80 S	10.75	11.94	13.36	15.00
	1.40 A	10.25	11.07	12.09	13.26
	1.40 s	10.48	11.39	12.52	13.81
	1.90 A	9.87	10.53	11.31	12.20
	1.90 s	10.19	10.97	11.88	12.92
Cape Halkett					
	0.30 A	14.35	16.65	19.36	22.44
	0.30 A	15.15	17.75	20.80	24.27
	0.80 A	11.43	12.68	14.14	15.80
	0.80 S	11.83	13.22	14.84	16.70
	1.20 A	10.33	11.18	12.17	13.31
	1.20 s	10.85	11.88	13.09	14.48
Smith-Dease					
	0.15 s	21.79	--	--	--
	0.15 s	26.16	--	--	--
	0.40 s	14.33	16.65	19.52	22.81
	0.40 s	16.13	19.11	22.79	--
	0.60 S	12.41	14.02	16.02	18.31
	0.60 S	14.08	16.30	19.06	22.22

(1) Operating Cost $1.00
Transport cost, Southern California landed $7.00 (medium option, otherwise ± $0.50)

(2) "A" scenario parameters involve average well outputs up to 7 MMbbls.
"S" scenario parameters involve average well outputs down to 3 MMbbl.

Source: Dames & Moore

TABLE 20-D

GAS MARKET PRICE CONSTRUCTION

FOR SKELETAL SCENARIOS

(35 PERCENT EFFECTIVE TAX RATE)

Scenario	Resource (tcf)		Market Price (1977 Dollars)[1]				
		Return:	25%	5%	7.5%	10%	15%
Camden-Canning							
	1.20 A[2]	20 yr.	2.72	2.96	3.23	3.53	4.16
	1.20 A		2.76	3.01	3.30	3.61	4.27
	2.20 A		2.65	2.94	3.26	3.61	4.34
	2.20 S	28 yr.	2.71	3.03	3.38	3.76	4.57
	3.25 A		2.54	2.76	3.02	3.29	3.87
	3.25 S		2.60	2.85	3.14	3.45	4.10
Prudhoe Offshore							
	1.20 A	20 yr.	2.72	3.01	3.30	3.61	4.27
	1.60 S		2.59	2.77	2.99	3.22	3.71
	2.80 A		2.52	2.73	2.97	3.24	3.79
	2.80 S	28 yr.	2.56	2.79	3.06	3.34	3.95
	4.75 A		2.40	2.55	2.73	2.92	3.32
	4.75 S		2.42	2.58	2.77	2.98	3.40
Cape Halkett							
	0.20 A		5.91	7.33	8.95	10.70	--
	0.20 A		5.91	7.33	8.95	10.70	--
	0.60 A	20 yr.	3.40	3.90	4.45	5.06	6.33
	0.60 S		3.49	4.01	4.61	5.25	6.64
	1.20 A		2.76	3.01	3.30	3.61	4.27
	1.20 S		2.81	3.08	3.39	3.72	4.44
Smith-Dease							
	0.10 S		15.67	--	--	--	--
	0.10 S		15.67	--	--	--	--
	0.40 S	20 yr.	5.70	7.05	8.57	10.23	--
	0.40 S		5.70	7.05	8.57	10.23	--
	0.90 S		3.77	4.40	5.11	5.88	7.54
	0.90 S		3.77	4.40	5.11	5.88	7.54

(1) ALCAN ROUTE, operating and transport costs \$2.08, medium option. (high option + \$0.47, low option -\$0.47).

(2) "A" scenario parameters involve average well outputs up to 7 MMbbls. "S" scenario parameters involve average well outputs down to 3 MMbbl.

Source: Dames & Moore

indicate that the government estimates could be realized in the offshore Prudhoe fields, with returns of 2 percent to 5 percent, and in the eastern Beaufort field at about 2 to 3 percent. In order to achieve more equitable returns, a price increment to reflect the transport cost from the field to the Alcan system must be added. Also, the price constructions are dependent upon the gas production being ancillary to oil production.

Very few scenarios in the western Beaufort areas can fit within a $3.50 per Mcf price at 5 percent return. A find of about one tcf in the Cape Halkett area could realize about 8 percent return, but no other western scenarios could return 5 percent.

The estimation of minimum developable field sizes follows directly from the median investment cost schedules. First, the fixed costs for a pipeline system, base camp, and nominal processing facility are taken from the investment cost schedule. The minimum field size is then estimated by the pricing formula:

$$\text{Unit Capital recovery} = \frac{\text{Investment cost}}{N \times R \times PW}$$

where N is the number of units,

R is the royalty factor (= the complement of the royalty rate)

PW is the present worth factor.

The present worth factor for zero return -- break even -- is unity. Once the minimum field size is determined, then the costs to cover platforms and wells for the field are added to the investment cost, and the estimate is recalculated. The results after iteration are displayed in Tables 20-E and 20-F for market prices of $13 and $14. The money available for capital recovery with a $13 market price is $4.50, $5.00, or $5.50, depending on whether the pipeline tariff is respectively $6.50, $6.00, or $5.50.

TABLE 20-E

MINIMUM FIELD SIZES

FOR SKELETAL SCENARIO REGIONS

(MILLIONS OF BARRELS)

($13 .00 SOUTHERN CALIFORNIA MARKET)

Scenario		Break-Even A(1)	Break-Even S(1)	5% Return, 35% Tax A(1)	5% Return, 35% Tax S(1)
Camden-Canning					
Transport cost:	high	360	385	710	750
	med.	330	345	640	675
	low	300	315	580	610
Prudhoe Offshore					
Transport cost:	high	260	285	465	505
	med.	235	260	415	455
	low	215	235	380	415
Cape Halkett					
Transport cost:	high	415	440	670	710
	med.	375	395	605	640
	low	340	360	550	580
Smith-Dease					
Transport cost:	high	480	515	830	890
	med.	435	465	745	800
	low	395	425	680	725

(1) "A" scenario parameters involve average well output up to 7 MMbbls.
"S" scenario parameters involve average well output down to 3 MMbbls.

Source: Dames & Moore

TABLE 20-F

MINIMUM FIELD SIZES

($14 .00 SOUTHERN CALIFORNIA MARKET)

(MILLIONS OF BARRELS)

Scenario		Break-Even		5% Return, 35% Tax	
		A(1)	S(1)	A(1)	S(1)
Camden-Canning					
Transport cost:	high	300	315	580	610
	med.	275	290	535	560
	1 Ow	255	265	495	520
Prudhoe Offshore					
Transport cost:	high	215	235	380	415
	med.	200	215	350	380
	1 Ow	185	200	320	350
Cape Halkett					
Transport cost:	high	340	360	550	580
	med.	310	330	505	535
	1 Ow	290	305	465	490
Smith-Dease					
Transport cost:	high	395	425	680	725
	med.	360	390	620	665
	1 Ow	335	360	575	615

(1) "A" scenario parameters involve average well outputs up to 7 MMbbls.
"S" scenario parameters involve average well outputs down to 3 MMbbl.

Source: Dames & Moore

The base investment schedule for the fields were (in millions of dollars):

	"A"	"S"
Prudhoe Offshore	980	1070
Camden-Canning	1360	1430
Cape Halkett	1550	1640
Smith-Dease	1880	1930

6.4 ECONOMIC VARIATION IN THE DETAILED SCENARIOS

Five scenarios of the 24 skeletal scenarios were selected for detailing of their output schedules, employment, and economic structure. Implicitly, there are an additional four skeletal scenarios, one in each region of insignificant or zero resource discovery in reservoirs. The five scenarios selected are:

1. Camden-Canning — 1.3 billion barrels of oil, 3.25 tcf of gas, less favorable production parameters (scenario is described in Section 9.2)

2. Prudhoe Offshore — 1.9 billion barrels of oil, 4.25 tcf of gas, favorable production parameters (scenario is described in Section 9.3)

3. Prudhoe Offshore — 0.8 billion barrels of oil, 1.6 tcf of gas, less favorable production parameters (scenario is described in Section 9.4)

4. Cape Halkett — 0.8 billion barrels of oil, no gas production, favorable production parameters (scenario is described in Section 9.5)

5. Smith-Dease | No production (scenario is described in Section 9.6)

These were included in the construction of multiple investment cost schedules. The resultant spread of unit investment costs is listed in Table 21-A. The percent range averaged across these cases was ±30 percent for oil investment, ±35 percent for gas investment.

The effect of these variations was analyzed by constructing market prices for them, with low, medium, and high transport or operating costs , These market requirements are given in Table 21-B. It can be seen that high cost projections can make the Cape Halkett scenario marginal, returning only 5 percent in the $13 to $14 market. On the other hand, low cost conditions in "most favorable" offshore Prudhoe scenario can reach 25 percent for $13/bbl oil, and 20 percent for $3.00/Mcf gas. This situation represents the projection limit for the Beaufort, and has to be considered less than 500 to 1 longshot condition: resource discovery probability of 1 percent (100 to 1), plus favorable reservoir characteristics (2 to l?), plus low cost construction, which can be affected by weather (2 to 1, 3 to 1?) as well as engineering conditions, bottom soils, gravel, etc.

It is interesting to note that in recent newspaper advertisements placed by the petroleum industry in Alaskan newspapers, commenting on Alaskan tax policies, a note was made that the industry hopes to achieve a return of 12 percent on Prudhoe Bay field investments. That figure may include exploratory costs (not considered here), and the industry investment in the pipeline. Furthermore, major investments are yet to be made in the Prudhoe Bay field. The unit investment for the Prudhoe Bay field, on the basis considered here would be projected at $13 billion, for about 10.5 to 11.3 units of oil and 26 tcf gas, about $0.90 per barrel of oil and $0.10 per Mcf of gas (Oil & Gas Journal, 12 December 1977).

TABLE 21-A

VARIATION IN INVESTMENT COSTS

Scenario	Oil ($ per bbl)			Gas ($ per Mcf)		
	Low	Med	High	Low	Med	High
Camden-Canning 1.3 Bbbl, 3.25 tcf	1.40 -21 %	1.70	2.20 +29%	.20 -30%	.26	.35 +35%
Prudhoe Offshore 1.9 Bbbl, 4.75 tcf	.70 -57%	1.10	1.50 +36%	.11 -45%	.16	.23 +44%
Prudhoe Offshore 0.8 Bbbl, 1.6 tcf	1.20 -25%	1.50	1.90 27%	.24 -2-1%	.29	.38 31%
Cape Halkett 0.8 Bbbl	1.70 --18%	2.00	2.50 25%	--	--	--
Average	"30%	= ± 30%	+29%	-32%	= ± 35%	+37%

Source: Dames & Moore

TABLE 21-B

MARKET PRICE CONSTRUCTIONS FOR DETAILED SCENARIOS

(35% TAX OPTION)

	Return	Oil ($ per barrel) Low(1)	Med(1)	High(1)		Return	Gas ($ Per Mcf) Low(1)	Med(1)	High(1)
Prudhoe Offshore									
1.9 Bbbl, 4.75 tcf (26 yr)									
Low, $.70/bbl	15%	10.27	10.77	11.27	.11/Mcf	10	2.22	2.62	3.09
	20%	11.15	11.65	12.15		15	2.48	2.88	3.35
	25%	12.23	12.73	13.23		20	2.74	3.14	3.61
Med., 1.10/bbl	10%	10.62	11.12	11.62	.16/Mcf	7.5	2.29	2.69	3.16
	15%	11.85	12.35	12.85		10	2.47	2.87	3.34
	20%	13.24	13.74	14.24		15	2.84	3.24	3.71
High, 1.50/bbl	10%	11.75	12.25	12.75	.23/Mcf	5	2.33	2.73	3.20
	15%	13.43	13.93	14.43		7.5	2.56	2.96	3.43
	20%	15.33	15.83	16.33		10	2.81	3.21	3.68
Prudhoe Offshore									
0.8 Bbbl, 1.6 tcf (22 yr)									
Low, 1.20/bbl	5%	10.04	10.54	11.04	.24/Mcf	7.5	2.48	2.88	3.35
	10%	11.51	12.01	12.51		10	2.70	3.10	3.57
	15%	13.32	13.82	14.32		15	3.16	3.56	4.03
Med., 1.50/bbl	5%	10.68	11.18	11.68	.29/Mcf	5	2.41	2.81	3.28
	10%	12.51	13.01	13.51		7.5	2.65	3.05	3.52
	15%	14.78	15.28	15.78		10	2.91	3.31	3.78
High, 1.90/bbl	5%	11.53	12.03	12.53	.38/Mcf	2.5	2.36	2.76	3.23
	10%	13.85	14.35	14.85		5	2.64	3.04	3.51
	15%	16.72	17.22	17.72		7.5	2.95	3.35	3.82
Camden-Canning									
1.3 Bbbl, 3.25 tcf (25 yr)									
Low, 1.40/bbl	10%	12.11	12.61	13.11	.20/Mcf	7.5	2.42	2.82	3.29
	15%	14.17	14.67	15.17		10	2.63	3.03	3.50
	20%	16.59	17.09	17.59		15	3.07	3.47	3.94
Med., 1.70/bbl	5%	11.49	11.99	12.49	.26/Mcf	5	2.39	2.79	3.26
	10%	13.10	13.60	14.10		7.5	2.64	3.04	3.51
	15%	15.60	16.10	16.60		10	2.91	3.31	3.78
High, 2.20/bbl	5%	12.66	13.16	13.66	.35/Mcf	2.5	2.34	2.74	3.21
	10%	14.74	15.24	15.74		5	2.64	3.04	3.51
	15%	17.98	18.48	18.98		7.5	2.98	3.38	3.85
Cape Halkett									
0.8 Bbbl									
Low, 1.70/bbl	5%	10.80	11.30	11.80					
	10%	12.41	12.91	13.41					
	15%	14.37	14.87	15.37					
Med., 2.00/bbl	5%	11.39	11.89	12.39					
	10%	13.28	13.78	14.28					
High, 2.50/bbl	5%	12.36	12.86	13.36					
	10%	14.73	15.23	15.73					

(1) Non Capital Costs: Oil - Low $7.50, Med. $8.00, High $8.50; Gas - Low $1.68, Med. $2.08, High $2.55

Source: Dames & Moore

The relatively high potential for favorable investment in the offshore Prudhoe fields is clearly created by being on the doorstep of (assumed) existing transport systems.

The structure of investment schedule has not been detailed as in Appendix B. For comparative purposes, the major portions of the Camden-Canning scenario are listed at the low and high values (after exclusion of some outliers):

	Low Cost ($ Millions)		High Cost ($ Millions),	
	Oil	Gas	Oil	Gas
Tracts (34)	196	25	280	124
Platforms (13)	150	20	290	110
Wells (520)	520	12	800	22
Pipelines (54 onshore, 34 offshore, variable)	354	293	650	494
Facilities	600	300	840	390
	$1,820	$650	$2,860	$1,140

Since the variations are arbitrary over the range of component costs, the median was felt to be more representative of the most likely values. To achieve statistical weight for averaging, it is necessary to weigh the distributions in component values as well.

6.5 TRANSPORT SYSTEM ALTERNATIVES

6.5.1 Impact of the Scenario Outputs on Pipeline Tariffs

The petroleum and gas production projected in the scenarios will improve the utilization factor for pipeline systems from the North Slope. At the time that the delivery capacity is contracted for, it will be necessary to reconstruct the pipeline tariffs. To estimate the impact of this additional utilization on the tariffs, various assumptions have been made on the profile of usage, the valuation of the systems, and the investment costs (if any) for the new increment. of usage.

Under the approximation for tariff construction considered here, no provision is made for rate equalizations between past users of a system and future users after the contracted throughput has been increased. The approximation is reasonable only under past tariff construction. If the tariffs advocated by the ICC in the Alyeska pipeline should prevail, the approximation will overstate the tariffs, and the increments in them. However, the overstatement could be proportional throughput, so that if the tariffs are reduced 10 percent, incremental changes will be reduced accordingly.

Capital recovery charges considered presently applicable to the Alyeska line ranged from $2.20 to $2.90 per barrel, with a throughput of 9.6 billion barrels. First, one must consider the impact of increasing throughput to 10.5 billion barrels with 2 million barrels per day capacity.

The investment cost is assumed to have the values

low -$8.8 billion - provisions for dismantlement shifted to operating charges.

medium -$9.2 billion - higher range of above assumption.

high -$10.5 billion - investment allowed.

With present worth factors of 0.4335 at 9 percent, or 0.4047 at 10 percent interest cost, the capital recovery requirements would be:

Assumed Alyeska Capital Recovery 1977-2010 (Dollars per Barrel)

Low	Medium	High	
1.93	2.03	2.31	9 percent interest cost
2.08	2.17	2.47	10 percent interest cost

There are several ways to value the pipeline at that time. Using the medium investment, the value remaining in 1988 would be estimated at:

$5.9 billion - straight yearly depreciation
5.4 billion - regular amortization by throughput
4.6 billion - unit amortization (proportional to throughput)

This value can be used as a value base range for 1988. The throughput beyond 1988 is either 7.8 or 8.9 billion barrels, depending on whether the larger or smaller offshore Prudhoe scenario is selected:

Prudhoe Bay	4.5 Bbbl
Prudhoe Offshore	1.9 or 0.8 Bbbl
Camden-Canning	1.3 Bbbl
Cape Halkett	0.8 Bbbl
Other	0.4 Bbbl
	8.9 or 7.8 Bbbl

For the 8.9 Bbbl reserves, the present worth factor at 10 percent interest is 0.5223, computed from 1988. For 7.8 Bbbl reserves, the factor is 0.5064. The respective factors for 9 percent are 0.5531 and 0.5376.

The capital recovery for these conditions is:

Projected Alyeska Capital Recovery, 1977-2014 (Dollars per Barrel)

	Low	Medium	High	
8.9 Bbbl	0.93	1.13	1.23	9 percent interest cost
	0.99	1.16	1.27	10 percent interest cost

	Low	Medium	High	
7.8 Bbbl	1s10	1.25	1.34	9 percent interest cost
	1.16	1.37	1.49	10 percent interest cost

The tariff impacts, or capital cost differences, are:

Projected Alyeska Tariff Impacts (Reductions)
(1977 $)

Low	Medium	High	
.83-1 .00	.78-.90	.97-1 .04	9 percent interest cost
.92-1 .09	.80-1 .01	.98-1 .20	10 percent interest cost

No impact on operating costs were considered.

What would be the impacts of the four detailed scenarios individually? The present worth factor of the assumed 4.5 billion barrels remaining in the Prudhoe Bay field is 0.5541 (10 percent) from a 1988 contract date.

For the individual scenarios, the discounted values (10 percent interest) of units to be delivered is estimated as follows, which includes the Prudhoe Bay oil:

Camden-Canning	(1.7 Bbbl, .48)	3.31 billion units
Prudhoe Offshore	(1.9 Bbbl , .54)	3.52 billion units
	(0.8 Bbbl, .47)	2.87 billion units
Cape Halkett	(0.8 Bbbl, .53)	2.92 billion units

The capital recovery charges would be:

	Low ($/bbl)	Medium ($/bbl)	High ($/bbl)
Camden-Canning	1.39	1.63	1.78
Larger Prudhoe Offshore (1.9 Bbbl)	1.31	1.53	1.68
Smaller Prudhoe Offshore (0.8 Bbbl)	1.60	1.88	2.06
Cape Halkett	1.58	1.85	2.02

The tariff impacts would be:

	Low ($/bbl)	Medium ($/bbl)	High ($/bbl)
Camden-Canning	.69	.54	.69
Prudhoe Offshore (1.9 Bbbl)	.77	.64	.79
Prudhoe Offshore (0.8 Bbbl)	.48	.29	.41
Cape Halkett	.50	.32	.45

Note that the columns low, medium, and high correspond to system cost.

The tariff impact for the Alcan line can be considered similarly. The 1990 values for the line, after a 1983 start, are estimated at:

	Low ($-Billions)	Medi urn ($-Billions)	High ($-Billions)
Depreciation	7.9	9	10.5
Amortization	8.9	11	13.0

Amortization gives the higher values, contrary to typical oil field lines, and is used as the value base.

The reserves to be delivered after 1990 are either 27.5 tcf or 24.4 tcf, depending on whether the larger or smaller Prudhoe Offshore scenario is selected:

Prudhoe Bay	19.5 tcf
Prudhoe Offshore	4.75 or 1.6 tcf
Camden-Canning	3.25 tcf

In Section 6.2, capital recovery of the Alcan line was estimated at $1.14, $1.31, and $1.51 per Mcf, for the three values of line cost, all at 10 percent interest and 26 years of operation. A value of 800 million was cited as an early estimate of the cost to pressure the line to full flow capacity. The capital recovery impacts for the new system are:

	Low	Medi urn	High
System cost:	$10.6 billion	$11.9 billion	$13.8 billion
Capital recovery 27.5 tcf:	$ 0.88 per Mcf	$0.98 per Mcf	$ 1.4 per Mcf
(1 0 percent, 19 years)			
24.4 tcf:	$ 0.99 perMcf	$ 1.11 perMcf	$ 1.28 per Mcf
Projected original charge			
(26 year, 10 percent):	$ 1.14 per Mcf	$ 1.31 perMcf	$ 1.53 perMcf
Tariff impact,			
High throughput:	$ 0.26 per Mcf	$ 0.33 perMcf	$ 0.39 per Mcf
Low throughput:	$ 0.15 perMcf	$ 0.20 perMcf	$ 0.25 perMcf

This situation can be reconsidered for less favorable conditions. Suppose that the Alcan delivery slips to 28 years, and that the pressurization runs as high as $1.5 billion. The calculation produces:

	Low	Medium	High
System cost:	$11.3 billion	$12.6 billion	$14.5 billion
Capital recovery 27.5 tcf: (10 percent, 21 years)	$ 1.00 per Mcf	$ 1.11 per Mcf	$ 1.28 per Mcf
24.4 tcf:	$ 1.12 per Mcf	$ 1.25 per Mcf	$ 1.44 per Mcf
Projected original charge (10 percent, 28 years):	$ 1.21 per Mcf	$1.39 per Mcf	$1.62 per Mcf
Saving, per Mcf - 27.5 tcf:	$ 0.21 per Mcf	$ 0.28 per Mcf	$ 0.34 perMcf
- 24.4 tcf:	$0.09 per Mcf	$0.14 per Mcf	$0.18 per Mcf

6.5.2 Pipeline System Reserve Requirements

A second Alyeska pipeline route has been cited as costing (possibly) $5 billion for 1 million barrels per day, or about $6.5 billion for 2 million barrels per day. An estimate of the reserves needed to support such a system is desired. The assumptions implicit in such an estimate are:

1) Operating costs per barrel are similar.

2) Similar tariffs must be accepted; or a tariff premium will be permitted.

3) Present worth profiles will be similar to those of the Alyeska system.

With respect to:

3) A present worth factor of .47 ± .04 can be extrapolated for a 1 MMb/d line, .39 ± .03 for a 2 MMb/d line from the schedules, 20 years at 10 percent.

2) Tariffs permitted are $7.00, $6.50, $6.00 (fifty cent premium).

1) Operating costs of $3.50 will be incurred. Therefore, capital recovery money available is $3.50, $3.00, $2.50 per barrel.

Application of the capital recovery formula, without royalty, gives

$5 Billion line - $7.00 tariff - 2.8 Bbbl
(1 MMb/d) 6.50 tariff - 3.5 Bbbl
6.00 tariff -4.6 Bbbl

as a distribution of reserve size, which could justify the new line. The capacity of throughput in 20years would be 7.3 Bbbl. Additionally,

$6.5 Billion line - $7.00 tariff - 4.4 Bbbl
(2 MMb/d) 6.50 tariff - 5.6 Bbbl
6.00 tariff - 7.2 Bbbl

Increased line investment costs would be reflected proportionately in necessary reserve estimates.

For gas, throughput is generally assumed to be constant. With capital recovery costs of $1.30, $1.55, and $1.80 permitted (the medium, high, and premium values for the Alcan system), and 20 year reserves considered:

$8 billion system - $1.80 capital charge - 10.4 tcf; 1.4 Bcfd
1.55 capital charge - 12.1 tcf; 1.7 Bcfd*
1.30 capital charge - 14.5 tcf; 2.0 Bcfd**

$10 billion system - $1.80 capital charge - 13.1 tcf; 1.8 Bcfd
1.55 capital charge - 15.2 tcf; 2.1 Bcfd
1.30 capital charge - 18.1 tcf; 2.5 Bcfd*

$12 billion system - $1.80 capital charge - 15.7 tcf; 2.2 Bcfd**
1.55 capital charge - 18.2 tcf; 2.5 Bcfd
1.30 capital charge - 21.7 tcf; 3.0 Bcfd

The daily capacity may not be compatible with the overall system cost, and this is the measure of merit for the gas system reserve justification. Those cases marked (*) are marginal to doubtful, and (**) are not reasonable. Thus, if one is willing to pay the premium, smaller and smaller resource deposits can be considered.

6.5.3 Transport of Western Area Petroleum

The criteria for estimating resource necessary to support an oil pipeline system, discussed in the previous section, can be applied to the western areas of the North Slope and Alaskan Beaufort. For an NPR-A pipeline system to Nome, the two levels estimated were:

$4.95 billion system	- 2.8 Bbbl, low
(500 Mb/d)	- 3.5 Bbbl, medium *
	- 4.5 Bbbl, high **
$6.1 billion system	- 3.4 Bbbl, low
(1 MMb/d)	- 4.3 Bbbl, medium
	- 5.6 Bbbl, high

The notations (*) and (**) again refer to a marginal to unreasonable relationship between resource size, system capacity, or cost. The low, etc. values correspond to premium, high, and medium capital recovery charges of $3.50, $3.00 and $2.50 per barrel.

The western offshore areas of the Alaskan Beaufort are projected at totalling 1.8 billion barrels (include Cape Halkett) of resource -- at the 100 to 1 probability level -- but most likely will total 500 million barrels (1.4 to 1 odds). If one billion barrels are discovered in

NPR-A, and are joined with the 100 to 1 1.8 billion barrels offshore, the western line to Nome could become feasible. Such oil could return about 8 percent in a $14.00 market, based upon connecting lines not longer than 97 kilometers (60 miles).

The more likely situation, assuming a find of one billion barrels in NPR-A, is a downstream tie-in to the Alyeska line after the 1993 projected peak from the eastern scenarios. If such projections do not materialize, the connection could be made anytime after the Prudhoe Bay throughput enters decline. This would not necessarily be earlier. If the Alyeska capacity remains at 1.2 million barrels per day, production capacity may remain near that level into the 1990's under water injection methods.

A system of capacity of 250,000 barrels per day to serve 1.5 billion barrels would cost about $1 billion for up to 240 kilometers (150 miles). Necessary capital recovery charge would range from $1.52 to $1.31 per barrel. Assuming a $0.50 to $1.00 tariff reduction in the Alyeska line, such oil could return about 8 percent in a $13.50 oil market:

Capital recovery	$2.60 (1 .50 at 5%)	$4.40 (1.70 at 10%)
Operation	1.00	1.00
Connecting line	2.50	2.50
Alyeska	5.50	5.50
Tanker	1.00	1.00
	$12.60 - for 5%	$14.40 - for 10%

6.6 SENSITIVITY ANALYSIS

The range of parameters involved in an economic model of petroleum development have been reviewed by direct construction of a number of situations to cover that range. A classical method of sensitivity analysis is to compute the effects of linearized differentials of single variables in the model upon all others.

The cost model for the field is of the form, for a single commodity (either oil or gas),

$$\Sigma_i \; a_i A_i = NRPZ$$

where

- a_i is the number of components of type i
- A_i is the average price (after escalation or discounting) of component type
- N is the number of resource units available (barrels or thousands of cubic feet)
- R is the royalty factor (= 1 - the royalty rate) = 5/6
- P is the present worth factor
- Z is the unit money available for capital recovery = market price less operating and transport costs

Differentiation of this model gives

$$\Sigma_i (\Delta a_i) A_i + \Sigma a_i (\Delta A_i) = RPZ(\Delta N) + NPZ(\Delta R)$$
$$NRZ(\Delta P) + NRP(\Delta Z)$$

The differential analysis is limited to small changes, and is most frequently used for looking at individual differences. For example, in a $2.2 billion dollar system that requires a capital recovery of $4.80, one might ask what would be the effect of saving $200,000 per mile in a 90-mile line.

The cost relation states:

$$2.2 \text{ billion} = NRP\ (\$4.80)$$

and the differential relation is limited to

$$A_k\ (\Delta A_k) = NRP\ (AZ)$$

One substitutes: $NRP = 0.46$ billion

$'_k = 90$ miles

$(\Delta A_k) = (\$-200{,}000$ per mile$)$

and obtains $AZ = -4¢$

Changes in the capital recovery translate directly (linearly) into changes in necessary market price, operating costs, and transport costs. The converse applies as well -- market changes or transport tariff reductions reflect directly in capital recovery, penny for penny:

$$\Delta(\text{market}) = \Delta(\text{operations}) + \Delta(\text{transport}) + \Delta(\text{capital recovery})$$

The relative influence of the remaining factors in the economic model is dependent upon percentage changes. Let the investment cost be represented by C:

$$\Sigma\ a_i A_i = C = NRPZ$$

The logarithmic differentials state:

$$\frac{\Delta C}{C} = \frac{\Delta N}{N} + \frac{\Delta R}{R} + \frac{\Delta P}{P} + \frac{\Delta Z}{Z}$$

and these are just percentage changes. Thus a ±35 percent variation in gas system investment costs becomes a ±35 percent variation in necessary capital recovery. If the system is designed for a (median) capital recovery of (say) \$0.90 per Mcf, then this translates to ± 35 percent of \$0.90 in the necessary market price for gas - i.e., $\pm$\$0.32 per Mcf.

The present worth factor encompasses several complex relationships that cannot be expressed analytically. The contributing factors in it are the total number of resource units, the scheduling of the resource output by time, the desired rate of return, and the effective tax rate. One must rely upon tabulated values of this function to obtain differential values. The range of percentage change available due to scheduling and total output has been shown to lie between 14 and 26 percent for practical petroleum field situations.

Estimates of the effect of changes in rate of return and tax rates can be extracted from the present worth tables given in this report (Tables 16, 17, and 18). The present worth factor is tabulated by desired return:

$P = P(i)$ when i is the factor used in the calculation

and

$i = \frac{r}{1-t}$ when r is desired rate of return and t is the effective tax rate

The effect of increasing rate of return, or tax rate on true present worth can be estimated from chain differentiation!

$$\frac{\Delta P}{\Delta r} = \frac{\Delta P}{\Delta i} \cdot \frac{\Delta i}{\Delta r} = \frac{\Delta P}{\Delta i} \left(\frac{1}{1-t}\right)$$

$$\frac{\Delta P}{\Delta t} = \frac{\Delta P}{\Delta i} \cdot \frac{\Delta i}{\Delta t} = \frac{\Delta P}{\Delta i} \cdot \frac{r}{(1-t)^2}$$

$$\frac{\Delta r}{\Delta t} = i = \frac{-r}{(1-t)}$$

From the average present worth factor of the scenarios, a table of the exchange factors can be constructed (P for petroleum only, not gas).

Exchange Factors for Petroleum

Rate of return	5 - 7.5%	7.5 - 12.5%	12.5 - 17.5%	17.5 - 22.5%
$\frac{\Delta P}{\Delta i}$	-.0793	-.0387	-.0205	-.0130
$\frac{\Delta p}{\Delta r}$ (at 35% tax)	-.1220	-.0565	-.0315	-.0200
$\frac{\Delta P}{\Delta r}$ (at 10% tax)	-.0881	-.0430	-.0228	-.0144
$\frac{\Delta P}{\Delta t}$ (at 35% tax)	-.0113	-.0092	-.0073	-.0062
$\frac{\Delta P}{\Delta k}$ (at 10% tax)	-.0059	-.0048	-.0038	-.0032
$\frac{\Delta r}{\Delta t}$ (at 35% tax)	-.077	-.154	-.231	-.31
$\frac{\Delta r}{\Delta t}$ (at 10% tax)	-.056	-.111	-.167	-.222

Thus the question of what absorbing a $0.40 per barrel transport increase would do to a producer whose capital recovery of $4.80 per barrel returned 9 percent after paying 35 percent taxes would be treated as follows:

The average present worth factor for the stated condition would be about 0.39. Since the loss in capital recovery is absorbed in the present worth factor,

$$\frac{\Delta p}{p} = -\frac{\Delta Z}{Z}, \quad \text{or } \Delta P = (.39)(*) = +.033$$

From the above values, $\frac{\Delta P}{\Delta r} = -.0565$,

and $\Delta r = \frac{-.033}{.0565} = -0.58$, The 9 percent return would be reduced to 8.4 percent..

For reference, some exchange factors for gas present worth factors are:

Exchange Factors for Gas Production
(25 year constant producing life)

	2.5 - 5%	5% - 7.5%	7.5% - 12.5%
$\frac{\Delta P}{\Delta i}$	-.0657	-.0377	-.0191
$\frac{\Delta P}{\Delta r}$ (at 35% tax)	-.1011	-.0580	-.0294
$\frac{\Delta P}{\Delta r}$ (at 10% tax)	-.0730	-.0419	-.0212
$\frac{\Delta P}{\Delta t}$ (at 35% tax)	-.0055	-.0058	-.0045
$\frac{\Delta P}{\Delta t}$ (at 10% tax)	-.0028	-.0030	-.0024

CHAPTER 7.0

MANPOWER REQUIREMENTS

7.1 RELEVANT EXPERIENCE

Labor force requirements for the exploration and development scenarios described in Chapter 9.0 are extrapolated primarily from available information about labor force requirements for the various aspects of exploration and development at Prudhoe Bay in the Alaskan Arctic, including construction of the northernmost sections of the Alyeska crude oil pipeline. Also, information about exploration activities in NPR-A has been used, as has information about exploration in the Canadian Arctic. Trade literature of the oil, gas, and pipelining industries and the Alaskan construction industry has been consulted extensively, and discussions have been held with representatives of the petroleum and construction industries in Alaska.

However, it must be recognized that exploration and development of oil and gas resources in the Beaufort Sea-will be a unique undertaking in important respects. For example, Beaufort Sea operations will occur offshore as well as in the Arctic. Prudhoe Bay development was an Arctic but not an offshore experience. Offshore experience elsewhere in Alaska, in other parts of the United States, and in the North Sea are not directly relevant to the Beaufort Sea because they occurred in different types of environments. While there has been extensive exploration in the Canadian Arctic, there has been no gas or oil field development there.

7.1.1 Prudhoe Bay

Development of the Prudhoe Bay field has many similarities with the effort which will be made to recover oil and gas from offshore fields in the Beaufort Sea. Certainly the remoteness, climate, and environmental sensitivity of the Arctic region are critical determinants of the schedule, cost, and labor requirements of exploring for and developing Beaufort Sea petroleum resources. Much of the labor intensive construction work involved with development of offshore Beaufort Sea fields will occur onshore in a social and technological enclave similar to that built at Prudhoe Bay.

The Prudhoe Bay experience provides a benchmark for estimating labor force requirements for offshore Arctic exploration and development. For example, the modular approach to construction of Arctic field facilities, in which buildings and equipment are pre-fabricated outside Alaska and shipped to the field for installation, is sound and will be used in future Arctic work. The Prudhoe Bay experience has also demonstrated the staggering penalties in manpower productivity that are imposed by the remoteness, climate, and wintertime darkness of the Arctic environment. There is an annual average individual productivity loss of some 250 percent in contrast to similar work performed in an average setting in the lower 48 states (Chandler, 1977). This lost labor productivity factor does not include the large labor requirements for support of an Arctic field work force.

A major difficulty in drawing on the manpower requirements actually experienced in Prudhoe Bay and related North Slope development activity is the lack of readily available information about what those manpower requirements were. Neither the industry nor the state has developed a comprehensive statistical statement of the manpower requirements for construction and operation of the major components of the field. Each field operator -- Sohio/BP in the western half and Atlantic Richfield/Exxon Company, U.S.A. in the eastern half --developed its own side of the field according to its own designs, schedules, and techniques, and each kept records according to its own needs. Also, a large number of contractors and sub-contractors were involved with drilling, oil field service, and construction activity. Contracts often involved aspects of work on several different facilities, such as site preparation for various buildings and drill pads, electrical work or insulation for different buildings, etc. As a result, manpower requirements for each major separate component of the field (drill pads, roads, central compressor plant, the six gathering centers, the operation centers, etc.) are not available from a single source.

Another difficulty is that the Prudhoe project was the first of its kind, and much money and manpower were expended in the process of learning how to build in the Arctic. For example, much of the early work on gathering centers (pump stations) on both sides of the field had to be either re-done or abandoned at significant cost and labor expenditure. Although development of the Prudhoe Bay field involved far less general waste and inefficient manpower utilization than construction of the Alyeska pipeline, reengineering of components and field work orders were frequent.

Furthermore, the Beaufort Sea field sizes postulated in this study are much smaller than the Prudhoe Bay field which, at 9.6 billion barrels, is one of the largest in the world. By comparison, the largest discovery forecast by this study is 1.9 billion barrels, or about 20 percent of the bonanza Prudhoe Bay field. Other field sizes projected by this report are 800 million barrels and 500 million barrels, or approximately 8 percent and 5 percent, respectively, of Prudhoe Bay. Thus, the labor force requirements to develop Beaufort Sea fields will differ vastly from those necessary to develop the Prudhoe Bay field, and extrapolation from the Prudhoe experience must take this disparity into account.

It must also be kept in mind that development of fields in the central Beaufort Sea area off Prudhoe Bay would benefit from the existing Prudhoe Bay infrastructure, such as crew camps, roads, airfields, communications facilities, oil field service company warehouses and shops, etc. The Prudhoe Bay development had to supply all its own support facilities from scratch.

7.1.2 Cook Inlet

It is widely known that employment associated with development of Cook Inlet petroleum fields reached a peak of some 2,300 in 1969. Crude oil reserves in Cook Inlet are in the neighborhood of 500 million barrels. By comparison, this study projects a peak labor force of only 2,750 for development of the largest field (1.9 billion barrels) in the Beaufort Sea. However, this comparison is misleading. Table 22 shows employment related to development of Cook Inlet fields between 1961 and 1972. Onshore development of several oil and gas fields in the Kenai region was completed by 1964, when, employment reached a peak of 306 (Mathematical Sciences Northwest, Inc. and Human Resources Planning Institute, 1976).

During the period from 1961 to 1964, a 137-kilometer (85-mile) gas pipeline to Anchorage was built that included a crossing at Turnagain Arm, several miles of pipe that connected the oil fields to tidewater, a marine terminal and tank storage capacity at Nikiski, and a 20,000 bbl/day refinery. Offshore development did not start until 1964, and was completed by 1969. During this period there was considerable offshore exploration activity. By 1966, there were 6 offshore platforms in place, and by 1968, there were 11 platforms in place. Moreover, some 225 kilometers (140 miles) of small -diameter submarine pipeline and 68 kilometers (42 miles) of 20-inch diameter onshore pipeline were laid. This activity resulted in employment in the Cook Inlet-Kenai area of less than 850 (Mathematical Sciences Northwest, Inc. and Human Resources Planning Institute, 1976).

The large employment which was experienced in 1967, 1968, and 1969 was attributable to the construction of 3 major petrochemical plants and a 20,000 bbl/day refinery [an ammonia plant, a urea plant, a natural gas liquefaction plant, and the Alaskan Oil and Refining Co. (now Tesoro Alaskan Petroleum Co.) refinery]. Construction of these facilities was undoubtedly more labor-intensive on site than would be the case with similar facilities on the North Slope because of the extensive use of modular construction techniques in the Arctic.

TABLE 22

KENAI-COOK INLET EMPLOYMENT ASSOCIATED WITH
PETROLEUM DEVELOPMENT 1969-72

Year	Petroleum	Construction	Total
1961	154	57	211
1962	169	94	263
1963	158	101	259
1964	179	127	306
1965	212	259	471
1966	415	432	847
1967	916	821	1,737
1968	1,098	1,209	2,307
1969	966	739	1,705
1970	652	354	1,006
1971	524	398	922
1972	529	432	961

Source: Mathematical Sciences Northwest, Inc. and Human Resources Planning Institute, 1976.

Commercial production of the petroleum resources in the Kenai and Cook Inlet area involved the development of 6 separate oil fields and 15 separate gas fields. By contrast, three of the four scenarios in this study involve the development of only one field; the fourth scenario (Camden-Canning) postulates two adjacent fields in order to assess such a contingency in the analysis. A single field involves significantly less construction effort than a multi-field situation, because fewer production platforms and fewer miles of submarine pipeline are required. Development of the Cape Halkett field, for example, requires only 4 production platforms, of these three are of the gravity type, which require little construction labor to place. A further assumption that tends to minimize labor force levels is that the fields would be unitized and all facilities shared by leaseholders according to a unitization agreement.

7.2 FACTORS AFFECTING ACTUAL LABOR UTILIZATION

In addition to the difficulties of extrapolating manpower requirements for Beaufort Sea operations from previous experience, there are general difficulties forecasting manpower requirements for hypothetical exploration and development programs. Many factors will influence actual labor utilization. The labor requirements projected for each scenario in Chapter 9.0 could vary by as much as 30 percent, depending on the factors discussed below.

The most important factor is the engineering technology that is developed by industry for drilling and producing in offshore Arctic waters. It is simply too early to determine with precision the techniques that will be employed, and the related manpower requirements. Industry will attempt to limit field construction requirements as much as possible in developing new technology. For example, prefabricated barges may be developed that can be floated into place easily, bolted together and sunk. If feasible, these barges could eliminate virtually all platform construction. The availability of gravel will be an important factor.

The farther the borrow source is from the road, airport, or other facility to be built, the more men (and/or time) will be required.

Another variable that will influence actual labor force size is the time available for construction of the production facilities. To a large degree, manpower can be substituted for time. If a 3-year development schedule were used instead of the projected 4-year schedule, employment could be increased by 25 percent or more.

Manpower requirements will also be influenced by the environmental stipulations contained in the State and Federal lease sale agreements. Government regulations could specify certain techniques and operations, such as the removal of gravel islands upon completion of drilling, which would increase manpower needs. Regulations could also require the location of onshore facilities farther than the nearest landfall point, which would increase the lengths of pipelines and roads, thereby increasing manpower requirements.

Union contracts covering Beaufort Sea operations may also affect employment levels. Such things as crew size requirements and work period limitations could be affected. These could also be delayed due to labor disputes.

7.3 METHODOLOGY

Work force projections made for the Beaufort Sea exploration and development scenarios in this report are presented in a form directly useable by the econometric model to be developed by the Institute of Social and Economic Research (ISER) at the University of Alaska. This model requires labor force data expressed as annual average employment. It also requires that annual average employment be classified as either "petroleum" or "construction", according to the Standard Industrial Classification system used by the Alaska Department of Labor.

Only field labor requirements have been estimated. Transportation services provided by trucking companies (except oil field hauling services) and air charter companies will be forecast by the ISER model, since these services are based in Fairbanks and Anchorage, and pilots and truck drivers do not typically maintain residence on the North Slope. Administrative, professional, and clerical employment in Fairbanks and Anchorage that is associated with Arctic petroleum and construction operations will also be forecast by the ISER model.

To forecast field employment in the petroleum and construction sectors, the scenarios are divided into exploration, development (construction for production), and operation phases. Within each phase, major activities and their schedules have been determined, and manpower requirements estimated for each activity. Manpower forecasts are expressed in man-months, which are derived from an estimate of the average monthly work force (including the dilation factor discussed below) required to complete a project in a certain number of months. The number of man-months for all activities can then be expressed as an annual monthly average. For example, a particular task could require an average monthly labor force of 50 men 5 months to complete, consuming 250 man-months. This is the equivalent of an annual monthly employment of 21 (250/12 = 20.8).

Figures 22 through 24 explain the typical employment cycles that are postulated in estimating annual labor force peaks and labor force levels on January 1 of each year (the date on which population estimates are made for the purpose of allocating to eligible municipal governments tax revenues collected through the state's ad valorem oil and gas transportation property tax) and on June 1 of each year (the date on which population estimates are made for the purpose of allocating state per capita revenue sharing funds). Seasonal employment levels are derived from the likely pattern of construction and drilling activity, based on ice and weather conditions. In each of the four years of field development peak employment is substantially greater than average annual

Figure 22

Typical Annual Employment Cycle - Exploration Phase

Figure 23

Typical Employment Cycle -- Development Phase employment. This is shown in Figure 23 which presents the general projected manpower demand curve for the development phase. In each of the four years, peak employment might usually range between 1.3 and 1. times the average annual employment. We have used an average value of 1.5 for each year; that is, we assume that annual peak construction during each of the four years of the development phase will be half again as large as the annual average employment for the same year. During the operational phase, employment fluctuations should cease, so annualmonthly average employment will approximate actual monthly employment, and annual peak employment will be the same as annual average.

It must be noted that total development employment is a higher number than the sum of crew sizes working at any one time. This is because a portion of the total employment is always expected to be on rest break, away from the construction site. For example, Prudhoe Bay geophysical and drilling crews are allowed by union agreement or company policy to work two weeks and take one week off; construction crews are allowed by union agreement to work nine weeks and take one week off; operations and administrative personnel typically work one week on and one week off. Thus, employment is a multiple of crew size.

For the purposes of this study, construction employment is estimated at 1.1 times crew size (one week off ÷ nine weeks on = .11); drilling and other petroleum employment at 1.5 (one week off ÷ two weeks on = .5) times crew size; and operation employment at 2.0 (one week off ÷ one week on = 1) times crew size. These factors are referred to as labor force dilation factors. Dilation factors are omitted for construction work that lasts 3 months or less.

7.4 ASSUMPTIONS

Tables through 25 list the major employment assumptions that have been made for each scenario phase (exploration, development, operation). Some of these are discussed below.

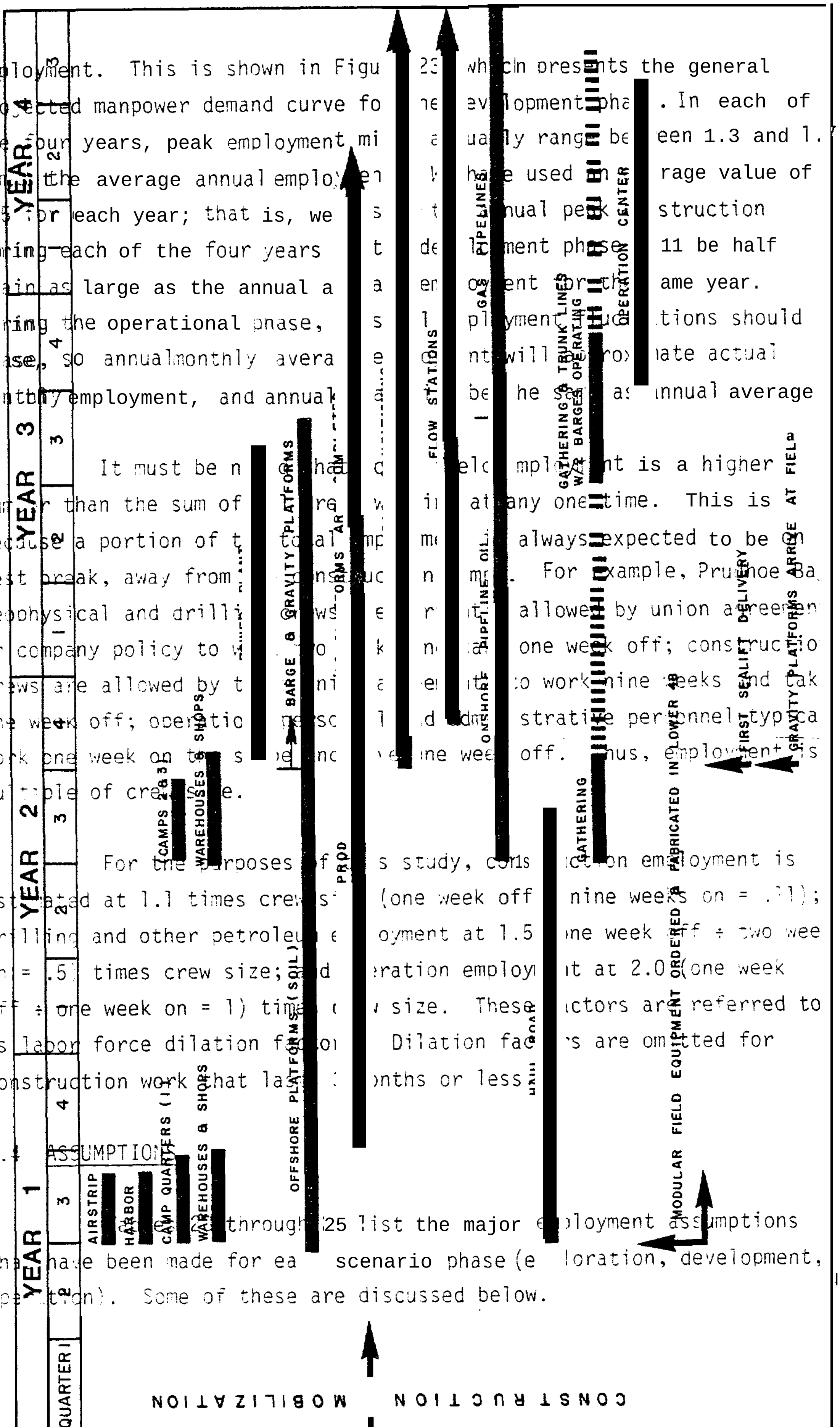


FIGURE 24 - TYPICAL FIELD DEVELOPMENT SCHEDULE

SOURCE: DAMES & MOORE

TABLE 23

GENERAL ASSUMPTIONS FOR ESTIMATES OF MANPOWER REQUIREMENTS--EXPLORATION PHASE

Geophysical Work

1) For eastern lease (State-Federal) sale (Camden-Canning and Prudhoe Offshore):

Assume 3 years remaining work after sale

each year following effort is made

2 ice crews
2 boat crews

ice crews work from December through April (5 months)

- boat crews work from July through September (3 months)

- 40 men per ice crew plus 1 shore expediter per crew

- 30 men per boat crew plus 1 shore expediter per crew

Therefore:

41 x 2 (crews) x 1.3 (dilation factor) x 5 (months) = 530 man-months/year for 3 years

31 x 2 (crews) (omit dilation factor) x 3 = 186 man-months/year for 3 years

2) For western (Federal OCS) sale

Assume 1/2 effort above for 3 years

TABLE 23, continued

Platform Construction, Maintenance and Support

Construction

Platform Type	Labor Requirements
soil	150 men x 3 months = 450 man-months
barge	40 men x 2 months = 80 man-months
ice	60 men x 2 months = 120 man-months

Maintenance

6 men per platform during 3-month drilling period (includes dilation factor)

6 x 3 = 18 man-months/platform

Support

1/10 x construction labor requirements

Platform Type	Labor Requirements
soil	15 men x 3 months = 45 man-months
barge	4 men x 2 months = 8 man-months
ice	12 men x 2 months = 12 man-months

TABLE 23, continued

<u>Drilling and Shore Support for Drilling Operation</u>

<u>Drilling</u>

60 men/well x 3 months/well = 180 man-months/wel

<u>Shore Support</u>

5 men/wel x 3 months/well = 15 man-months/well

Source: Dames & Moore

TABLE 24

GENERAL ASSUMPTIONS FOR ESTIMATES OF MANPOWER REQUIREMENTS--DEVELOPMENT PHASE

Petroleum Employment

- 60 men per rig
- each rig works 365 days/year and drills 8 wells/year
- 1 rig/platform

Therefore, 60 men x 12 months = 720 man months/rig/year or 720 man months/platform/year

- Maintenance = 6 men/rig/year

Therefore, 6 men x 12 months = 72 man-months/rig/year or 72 man-months/platform/year

Construction Employment

Platform Type	Labor Requirements
Soil (Gravel)	150 men x 6 months = 900 man-months
Barge or Gravity	80 men x 4 months = 320 man-months

TABLE 24, Cont.

Oil Field Facilities Construction

Facility	Year Built	Time and Labor Requirements	Facility Needs and Manpower Requirements				
			Camden[1]	Canning[1]	Prudhoe Offshore (0.8 Bbbl)	Prudhoe Offshore (1.9 Bbbl)	Cape Hal kett
1) Roads	1						
Miles:			64	15	15	15	51
Man-Months:		.5 mile/day x 70 men + 20-day mobilization	345	117	117	117	285
2) Airstrip	1						
Man-Months:		60 men x 1.5 months + 15-day mobilization	120	N/A	N/A	N/A	120
3) Harbor & Storage Areas	1/2 Year 1 1/2 Year 2						
Man-Months:		50 men x 2 months	100	N/A	N/A	N/A	100
4) Crew Camps	1 camp Year 1 remainder Year 2						
800-Man Camps Required:			2	1	N/A	N/A	3
Man-Months:		110 men x 2.5 months or 275 man-months per camp	550	275	0	0	825
5) Power Plant and Distribution System	1/4 Year 2 3/4 Year 3						
Man-Months:		150 men x 8 months for Prudhoe-Large; others in proporation to field size	504	312	504	1,200	504
6) Flow Stations	1/2 Year 3 1/2 Year 4						
Man-Months:		300 men x 24 months for capacity of 300,000 bbl/day labor allocation is proportional to flow/day	5,040	3,120	7,200	14,400	7,200

TABLE 24, Cent.

Facility	'tear Built	Time and Labor Requirements	Camden	Canning	Prudhoe Offshore (0.8 Bbbl)	Prudhoe Offshore (1.9 Bbbl)	Cape Halkett
			Facility Needs and Manpower Requirements				
7) Pipelines	1/2 Year 2 1/2 Year 3						
a) Gathering							
Miles:			102	57	105	108	42
Man-Months:		.75 mile/day x 200 men + 15-day mobilization	1,000	600	1,033	1,060	473
b) Truck Line to Shore							
Miles:							51
Man-Months:		.25 mile/day x 200 men + 5-day mobilization	N/A	N/A	N/A	N/A	1,393
c) Main Onshore							
1) Oil	l/2 Year 2 1/2 Year 3 for Camden, Canning and Halkett; Year 3 for Prudhoe						
Miles:			54	N/A	9.5	9.5	41
Man-Months:		.5 mile/day x 900 men + 30-day mobilization for 54- and 41-mile spreads	4,140	N/A	570	570	3,360
2) Gas	1/2 Year 3 1/2 Year 4 for Camden, Canning and Halkett; Year 4 for Prudhoe						
Miles:			54	N/A	9.5	9.5	41
Man-Months:		.5 mile/day x 450 men + 30-day mobilization for 54- and 41-mile spreads	2,070	N/A	285	285	
8) Warehouses and Shops							
Man-Months:		80 men x 4 months	320	320	320	320	320

TABLE 24, Cont.

Facility	Year Built	Time and Labor Requirements	Facility Needs and Manpower Requirements: Camden	Canning	Prudhoe Offshore (0.8 Bbbl)	Prudhoe Offshore (1.9 Bbbl)	Cape Halkett
9) Operations Center	1/2 Year 3 1/2 Year 4						
Man-Months:		200 men x 12 months for Prudhoe-Large; other fields in proportion to their size	.008	624	.008	2.400	,008
0 Gas Conditioning	1/2 Year 3 1/2 Year 4						
Man-Months:		325 men x 30 months for Prudhoe-Large; other fields in proportion to their size	4,095	2,535	4,095	9,750	4,095
Pump Stations							
a) Oil	1/2 Year 2 1/2 Year 3						
Man-Months:		125 men x 8 months	,000	300(2)	N/A	N/A	1,000 (reciprocating engine fueled by crude oil)
b. Gas	/2 Year 3 /2 Year 4						
Man-Months:		125 men x 8 months	.000	300(2	N/A	N/A	1,000 (gas compression for reinjection)
12) Camp Support		approximately .1 x construction work force	(Derived for each year from annual average columns on worksheets (See Appendix C)				
13) Miscellaneous		approximately .05 x construction sector subtotal, including camp support	(Derived for each year from worksheets) (See Appendix C)				

(1)Camden-Canning scenario postulates two adjacent fields, therefore, estimates are provided for each field.

(2)Needed to expand capacity

TABLE 25

GENERAL ASSUMPTIONS FOR ESTIMATES OF MANPOWER REQUIREMENTS--OPERATIONS PHASE

1) Remedial work begins after 6 years of production from first wells on line; stops 2 years before field stops production.

40 wells x 12 months = 480 man-months to accomplish about 40 wells/year

Therefore 80 wells/year - 960 man-months/year

Assume we s must be worked over 2 times in their productive lives.

2) Operations Personnel

a) Assume platform operational crew of 10 men/platform (including camp support)

10 x dilation factor of 2 = 20 men/platform;
20X 12 - 240 man-months/platform

b) Assume base operations personnel for Prudhoe-Large - 350 men

35o x 2 dilation factor = 700 workers x 12 months = 8400 man-months

Includes operations center personnel; power plant, sewage treatment, and kitchen personnel; snow removal and equipment maintenance, and facilities maintenance, and general facilities maintenance.

Other fields are estimated to be in proportion to their size, relative to Prudhoe Offshore (1.9 Bbl).

3) Construction

Assume miscellaneous construction to employ 5 men/month or 60 man-months/year.

Source: Dames & Moore

7.4.1 Petroleum Employment

Estimates of petroleum employment are easier to make than construction employment because much of petroleum employment is made up of drilling crews that are identifiable units of a standard size and whose pace of work is established by the depth and function (exploratory, confirmation, or production) of the wells being drilled. There are typically 40 to 50 workers on an exploration drill rig, including the drilling crew (approximately 11 workers per shift, or 22 total), geologists, client representatives, water haulers, maintenance people, camp support, and oil field service company personnel (mud engineers, well testers, and well loggers) who are on a separate contract (Taylor, 1977; see also U.S. Department of the Navy, 1977). For purposes of this study, a crew size of 40 workers per well (exploration and development) is assumed.

Since each exploration drilling rig is a separate camp, support personnel (approximately 10 per 40-man camp) are included with the rig crew. During the exploration and production phases, it is assumed that 6 service personnel serve each well. Therefore, total employment for each exploration and confirmation well is 60 (46 x 1.3) (Taylor, 1977). Development drilling will take place from platforms that will accommodate up to 48 wells. Each platform will have one drilling rig and crew.

In addition to the manpower requirements of 60 men for each exploration drill rig, it is assumed that the oil companies, drilling contractors, and/or service companies will have an expediter, radio operator, and administrative staff in the Deadhorse area during drilling. An estimate of 5 such positions per well is made, including the labor force dilation factor of 1.3. This employment is defined as “field support” and is different from the “camp support”.

Approximately twice during their producing life, oil wells need to be reworked so casings can be reperforated, sand can be removed, bottom zones sealed, etc. This is referred to as work-over, or remedial work. It can be accomplished in about 18 days, with a crew of about 30 men (employment 40).

Another component of petroleum employment is that associated with geophysical exploration. It is assumed that as much geophysical work as possible will be conducted from boats during periods of open water in the summer. Typically, a crew of 30 works on a geophysical exploration boat, supported by an expediter onshore. Geophysical work from the ice during the winter and spring is conducted by a conventional mobile crew of approximately 40, also supported by an expediter onshore.

7.4.2 Construction Employment

Manpower requirements for construction activity are more difficult to estimate than for petroleum activity because of the greater number of factors that influence the size of this labor force, such as the magnitude of the project, scheduling, engineering, design, etc. Estimates of construction employment are made on the basis of comparable construction work performed at Prudhoe Bay or in the Canadian Arctic.

Construction of an onshore drilling pad of gravel in the Arctic or Subarctic environment typically requires about 40 men (U.S. Department of the Navy, 1977). However, it is not altogether certain what the construction labor force requirements will be for offshore ice or gravel platforms. A relatively small offshore exploration drilling platform of reinforced ice was constructed in the Beaufort Sea by Union Oil Company of California with a work force of about 90 (needed for both island construction and drilling the well) (Oil & Gas Journal, July 11, 1977; Duthweiler, 1978). Construction of large artificial islands from bottom sediments and onshore gravel has been accomplished in the Canadian Arctic. Some 200 workmen were involved in the larger of these construction projects (Riley, 1976). Tables 23 and 24 include the manpower assumptions made for each platform type.

For pipeline construction, it is assumed that medium-diameter (30-inch) crude oil pipe can be installed above ground (onshore) in the Arctic at a rate of about 0.8 kilometer (0.5 mile) per day during the summer months by a crew of some 900 men (including direct and indirect labor but excluding camp support), working a basic spread of about 136 kilometers (80 miles) that involves work pad construction. Rivers are crossed during the winter months (Green Construction Company, 1976). It is assumed that gas pipe can be buried on the North Slope at the same rate with a work force of 450. A mobilization factor of 30 days is included for spreads over 17 kilometers (10 miles).

Pipe has never been layed offshore in the Arctic so estimates of related manpower requirements are much less certain. It is assumed that offshore small-diameter pipe can be buried in the Beaufort Sea from a modified conventional lay barge at a rate of approximately 1.2 kilometers (0.75 mile) per day with a crew of about 200 men. A 10-inch-diameter pipeline was recently laid across Turnagain Arm in Cook Inlet at a rate of 1 kilometer (0.625 mile) per day; water depth and tidal currents were much greater than those that would be encountered in the Beaufort Sea (Michels, 1977).

Construction of a heavy-duty gravel road on the North Slope could proceed at a rate of about 0.8 kilometer (0.5 mile) per day with a crew of 40 men. Actual rate of production could depend on the proximity of a gravel source. Construction of an airstrip could be accomplished by a crew of about 60 men in approximately 1-1/2 months; a harbor by 50 men in 2 months.

Estimates of manpower requirements for construction of oil and gas processing facilities, a central power station, crew camps, and other field components have been derived from available information about construction of comparable facilities on the North Slope. It is assumed that a direct linear relationship exists between the manpower requirements and the size of the field for all of the fields in the scenarios. Therefore, estimates are made of the manpower required to construct facilities for the largest of the fields (Prudhoe Bay, 1.9 Bbbl) and then reduced proportionately for the smaller field scenarios.

Most estimates of manpower requirements make allowance for a mobilization period. Occasionally, however, it was necessary to make an explicit allocation for pre-construction mobilization labor requirements.

Camp support requirements are estimated on a basis of 1 man per 10 field workers, which is an average figure derived from the Prudhoe Bay and Alyeska experiences. This category of labor includes cooks, kitchen helpers, bull cooks, sewer treatment plant maintenance personnel, water haulers, generator operators, and snow removal and other maintenance crews.

CHAPTER 8.0

TECHNOLOGY

This chapter details the technical and technology framework of the petroleum development scenarios. The text draws extensively from the technology review contained in Chapter 3.0. Equipment, materials, and facilities requirements are given for each scenario along with specifications for individual field components such as wells. When appropriate, technical assumptions made to identify the scenario technology components are explained.

Throughout this narrative two important facts concerning Arctic petroleum development should be kept in mind. First, there are no examples of offshore Arctic oil or gas field production to draw upon in formulating the scenario technical parameters. To date, petroleum development in Arctic offshore areas has not progressed beyond the exploration stage. The second factor to consider is the applicability of the Prudhoe Bay experience to Beaufort Sea petroleum development. Prudhoe Bay is a supergiant oil and gas field unlikely to be replicated in the North American continent. The oil and gas fields most likely to be encountered in the Beaufort Sea will, at most, contain about 20 percent of the reserves of the Prudhoe field. The facilities requirements, though in many respects similar to those Prudhoe Bay, will be significantly smaller. Nevertheless, Prudhoe Bay does, to some extent, serve as a technical or technology model for Beaufort Sea scenarios, especially those that predict oil and gas discoveries in the same reservoir rock (the Permo-Triassic Sadlerochit Group). Continuing exploration on State leases in a coastal strip between the Canning and Colville Rivers, including two offshore wells, and the exploration program in NPR-A, provide a data base on equipment, materials, facilities, and logistics requirements that, to various degrees, are relevant to predicting offshore exploration requirements.

8.1 EXPLORATION PLATFORMS

Exploratory drilling in the Alaskan Beaufort Sea will either be subject to federal OCS lease sale regulations requiring proof of reserves within five years, or State lease regulations that specify 10 years. The joint State-Federal Beaufort Sea lease sale regulations are still under review. A 10 year exploration period was used in this scenario study. However, as indicated previously (Section 5.2.3.1), this should not be construed as knowledge that State rules will prevail. With respect to scenario construction, it can also be assumed that the scenario area could be covered with successive five year sales.

To predict the types of platforms to be adopted for Beaufort Sea exploration, all the factors discussed in Section 3.3, Platform Selection Criteria, were reviewed with respect to the environmental conditions (oceanography, gravel resources, etc.) at each scenario location. In addition, the opinions of representatives from various government agencies and petroleum operators were sought. The numbers and types of platforms required for each of the detailed petroleum development scenarios are specified in Table 26.

Given the location of the anticipated lease sale(s) and various discovery sites, most of the exploratory drilling will take place within the landfast ice zone and in water depths of less than 20 meters (66 feet). For the Camden-Canning and Prudhoe Bay scenarios a mix of artificial soil islands, barges, and artificial ice islands has been adopted in a ratio of about 3:2:1, respectively. Among several factors, artificial soil islands will probably comprise the majority of exploration platforms because of the availability of both onshore and offshore gravel and sand within short haul distances. Barges will also be utilized, providing the mobility that artificial soil islands lack. Since more than one well can be drilled by a single barge, Table 26 reflects the numbers of exploratory wells to be drilled, not necessarily the numbers of barges in operation. Ice islands will be of more limited application, especially

TABLE 26

SCENARIO PLATFORM TYPES AND NUMBERS

Platform Type	EXPLORATION Artificial Soil Islands	Ice Islands	Ballasted Barges[1]	Gravity Structures	PRODUCTION Artificial Soil Islands	Ice Island	Ballasted Barges	Gravity Structures
Camden-Canning	9	3	6		9		3	1
Prudhoe (0.8 Bbbl)	6	2	4		5		2	1
Prudhoe (1.9 Bbbl)	7	3	4		4		1	1
Cape Halkett	-	6	2		1			3
Smith-Dease[2]	-	8	4					

(1) Since ballasted barges are mobile exploration platforms, these numbers reflect the number of exploration wells drilled by barges rather than number of barges involved in exploration.

(2) Smith-Dease fields are deemed uneconomic and do not go into production.

Source: Dames & Moore

where deep exploration targets are anticipated as in the Camden Basin. Artificial soil islands, despite their significantly higher cost, can be constructed in either winter (in the shallower areas) or summer, and can provide a year-round platform for drilling. Drillships and other floating platforms such as semi-submersibles are not anticipated to play a significant role in the first Alaskan Beaufort Sea operations for a variety of reasons, including:

- Operational limitations due to shallow water (see Table 5).

- High standby costs when they remain inoperative (frozen in) during the long period of winter ice make the economics of such platforms unfavorable.

- Short drilling season (2-1/2 to 3 months), which is especially a limitation if deep targets are anticipated or well testing is required.

Mobile gravity structures specially designed for Arctic operations such as the monopod or cone are unlikely to be adopted for Alaskan Beaufort Sea operations, at least with respect to the State-Federal lease sale scheduled for late 1979. The principal reasons are long developmental lead time and high capital costs. In addition, such platforms are more suited to deeper waters affected by pack ice movement.

Other factors being equal, in the western Alaskan Beaufort (i.e., west of the Colville River), the availability of gravel will be a major determinant in the selection of artificial soil islands; the limited available data indicates that both onshore and offshore sand and gravel become scarce west of the Colville River. As a result, more ice islands and fewer artificial soil islands are assumed as exploratory platforms in the western scenarios (Cape Halkett and Smith-Dease areas) than in the eastern (Prudhoe Offshore, Camden-Canning). The actual use of soil platform structures will depend upon the dredging potential in the offshore Beaufort waters, Canadian artificial soil island construction in the southern Beaufort Sea, where suitable fill is scarce west of 134°W longitude, has involved barge haul of sand as much as 32 kilometers (20 miles) from the Tuft Point offshore borrow site. The economics of barge-haul will, therefore, influence the adoption of artificial soil islands, and make them increasingly expensive the farther west one goes in the Alaskan Beaufort. The shallower exploration targets anticipated in the western Beaufort along the axis of the Barrow Arch are also favorable to the utilization of artificial ice islands. Consequently, the majority of exploratory wells in the western Beaufort are assumed to be drilled from ice islands with barges -- either conventional barges protected by soil berms (which require less fill than artificial soil islands) using dryland rigs, or specially designed self-contained drilling systems -- performing a secondary role. An important factor to be considered with respect to exploration in the western Alaskan Beaufort is scheduling. A lease sale or sales in this area will take place after the planned State-Federal sale in the central-eastern Alaskan Beaufort. Thus, technological developments and the possible availability of surplus drill rigs, barges, etc. from that area will influence the offshore drilling system to be adopted in the remainder of the State and Federal OCS.

Based upon the Canadian experience, construction of exploratory soil islands in summer, with a working surface of 7,500 square meters (80,730 square feet), or 0.7 hectares (1.9 acres)[1], will require about two to four months depending upon weather, ice, water depth, and construction techniques. Winter constructed shallow water islands (less than 3 meters or 10 feet) will probably take about one to 1-1/2 months. Depending upon water depth, an ice island will take about two months (dictated by rate of ice growth) to build (with a minimal construction spread). A maximum construction time of two months can be envisaged for emplacement of a barge with its protective berm.

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(1) Average size of the Canadian islands.

Drilling can commence from artificial islands and ballasted barges as soon as the working surface is stabilized and can continue while slope construction is still in progress.

8.2 PRODUCTION PLATFORMS

Production platforms have been assumed to be a combination of artificial soil islands, ballasted barges, and gravity structures (Table 26). With the exception of the Cape Halkett scenario, artificial soil islands comprise the predominant platform type and are assumed to be either expanded and reinforced exploration islands or newly constructed islands of the caisson or sheet pile reinforced designs. This assumption is based on the presence of sufficient onshore and offshore sand and gravel in the central-eastern section of the Beaufort Sea and the fact that artificial soil islands are a currently developed technology, using conventional equipment.

Production islands will probably encompass at least twice the working area of an exploration island (about 1.5 hectares or 3.7 acres), depending upon the amount of oil treatment conducted on the platform. Economy and environmental concerns may encourage as small an island as possible. Installation of oil field equipment at production islands will probably involve sea-lifting modular units from the Lower 48. Ballasted barges with long-term ice and wave protection probably will also be adopted. They can be fabricated in the Lower 48 with production systems on board and travel to the site. Essentially, production barges can be viewed as a hybrid gravity structure with a shallow draft best suited to the shallow waters of the OCS in areas of minimal ice movement.

Gravity structures (cone, monotone, or monopod) are only postulated as playing a minor role in the State-Federal lease sale area since in the shallower waters, where significant ice movement does not occur, artificial soil islands are probably more economic. For the Cape Halkett scenario, however, it is postulated that three of the four production platforms will be gravity structures due to the lack of nearby borrow materials and to their development and successful employment in the earlier State-Federal lease sale.

With respect to the location of the oil treatment facilities (oil -gas separation, dehydration, etc.), they are assumed onshore in the Canning-Camden scenario, either onshore or on platforms in the Prudhoe scenarios, and on platforms at Cape Halkett. The logic follows from the location of the fields and their descriptive parameters. The offshore Prudhoe fields are compact, and involve short transport corridors of 14.4 to 19.2 kilometers (9 to 12 miles) to shore. It makes little difference whether the facilities are assumed offshore or at the landfall (which would be at or near the existing Prudhoe Bay field).

When treatment facilities are located on the platform, they 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 power on the platform can be gas turbines or diesel generators. Some of the latter will operate on raw crude oil if diesel supply is not available.

For Cape Halkett, the most advantageous route for oil transport is directly across the Beaufort, especially for offshore platforms. Such a route is much cheaper than a route that goes to the closest landfall and thence by a circuitous land route around Harrison Bay. It is also more efficient. The alternative circuitous land route, which involves detours around sensitive wildlife areas, could be used with onshore processing facilities. A booster station along the line might be required which may price the scenario out of economic competition.

The Camden-Canning scenario is based upon dispersed field characteristics. A centralized onshore plant is more reasonable, and provides the option of channeling production on the existing State leases through this point.

8.3 WELLS

As indicated in Section 5.2.4.1 and Appendix B, reservoir depths will vary significantly in the Beaufort Sea lease sale areas. In general, the depths of the primary reservoirs are expected to decrease from east to west, from about 4,270 meters (14,000 feet) in the Camden-Canning area to about 1,830 to 2,440 meters (6,000 to 8,000 feet) in the western Alaskan Beaufort. For a given reservoir, a general statement can be made that targets may be progressively deeper with distance offshore due to the general regional dip and down-to-the-basin faulting that occur on the northern flank of the Barrow Arch (Grantz, Holmes and Kososki, 1975). The precise depth of either an exploration or production well will, of course, depend upon the target depth and the length will depend upon the angle of deviation if the well is directionally drilled. Therefore, specifications on "typical" exploration or production wells for each scenario are not really meaningful beyond the general range cited in Table 27. Well depths will not only vary with each scenario location but also within each field due to geologic structure and stratigraphy.

Exploration wells in the Prudhoe Bay area, for example, may vary from 1,980 meters (6,500 feet) for shallow Cretaceus (e.g., Kuparuk River sand) targets to about 2,740 meters (9,000 feet) for Sadlerochit targets and to approximately 2,895 meters (9,500 feet) for the underlying Lisburne carbonates. (Relief at the top of the Sadlerochit is on the order of 300 meters or 1,000 feet.)

North of the Prudhoe Bay field offshore, however, the depth of the Sadlerochit increases more than 610 meters (2,000 feet) in 8 kilometers

TABLE 27

PROJECTED DEPTHS OF PRINCIPAL RESERVOIRS FOR SELECTED SCENARIOS

Scenario	Age	Reservoir Name	Lithology	Depth (meters)
Camden-Canning	Late Cretaceous and Tertiary	---	Sandstones	3,600 to 4,270
Prudhoe Bay Offshore	Permo-Triassic	Sadlerochit Group	Sandstones	3,350 to 3,660
Cape Halkett	Permo-Triassic	Sadlerochit Group	Sandstones	2,740 to 2,900
Smith Bay - Dease Inlet	Permo-Triassic Triassic	Sadlerochit Group(?) ---	Sandstones Sandstones	2,130 to 2,440 760 to 1,525

Notes:

1. See Appendix A for detailed description of North Slope and Beaufort Sea petroleum geology.
2. As indicated in Appendix A, a significant portion of the petroleum reserves at each scenario location may be found in other reservoirs; only the primary reservoirs are indicated here.

Source: Dames & Moore

(5 miles) due to faulting on the northern flank of the Barrow Arch. Northwestward along the axis of the Barrow Arch the same Prudhoe Bay reservoir rocks become shallower. Offshore and to the northwest in NPR-A, the Sadlerochit is truncated or pinches out.

8.3.1 Exploration Wells

The specifications, or generalized casing program, for an "average" exploration well drilled vertically in the Prudhoe Bay area serve as a reasonable model for offshore Beaufort exploration. The casing program is as follows (Votava, Drilling Supervisor, British Petroleum, personal communication, 1978):

O to 27 meters (O to 90 feet) 20" by 30" Thermal Conductor
O to823 meters (O to 270 feet) 13-3/8" 72# N-80
O to 2,743 meters (O to 9,000 feet) 9-5/8" 47# N-80
2,590 to 3,200 meters (8,500 to 10,500 feet) 7" 29# N-80
3,048 to 3,658 meters (10,000 to 12,000 feet) 4-1/2" 12.75# N-80

The target depths indicated in Table 27 should be compared with the above specifications. Modifications to this program will be caused by target depth, geological, and permafrost conditions. The reader is referred to a detailed description of a drilling program for shallow, medium and deep exploratory wells in the Final Environmental Impact Statement, Continuing Exploration of Naval Petroleum Reserve No. 4 (U.S. Department of the Navy, 1977, Appendix A-2).

A medium depth North Slope exploratory well will take about 80 to 90 days to complete; this includes installation of equipment, drilling, evaulation, testing, and rig dismantling. Since the scenarios postulate the use of dryland rigs on offshore platforms, this completion schedule is applicable. Union Oil's East Harrison Bay - 1 well drilled from an ice island in the winter of 1976-77, for example, took 80 days to drill (Duthweiler, personal communication, 1978). The deeper targets anticipated in the Camden-Canning area will' take somewhat longer to drill and the shallower targets of the western Beaufort somewhat less time to complete.

8.3.2 Production Wells

In addition to the depth of the reservoir, the main factors affecting the specifications of production wells will be the angle of deviation and thickness of producing horizon(s). The majority of offshore production wells in the scenarios are assumed to be directionally drilled. At Prudhoe Bay production wells are located on gravel pads with 8 wells per pad on 33.5 meter (110 feet) centers (Votava, personal communication, 1978). The average well directional depths (i.e., actual length) at Prudhoe are in the following ranges:

18%	2,743 to 3,048 meters (9,000 to 10,000 feet)
47%	3,048 to 3,353 meters (10,000 to 11,000 feet)
27%	3,353 to 3,658 meters (11,000 to 12,000 feet)
8%	Over 3,658 meters (12,000 feet)

A generalized casing program for Prudhoe Bay production wells is as follows:

0 to 27 meters (0 to 90 feet) 20" x 30" Thermal Conductor
0 to 823 meters (0 to 2,700 feet) 13-3/8" 72# N-80
0 to 2,743 meters (0 to 9,000 feet) 9-5/8" 47# N-80
2,591 to 3,505 meters (8,500 to 11,500 feet) 7" 29# N-80

For wells of different depths, the only important difference will be the length of the 7-inch production string and its perforation intervals.

On offshore platforms, in contrast to Prudhoe Bay, up to 50 production wells will be drilled from a single location (i.e., platform), In the case of gravity structures, such as a monopod, all the wells would be located within a single column. The relationship between well depth, spacing, and deviation is explained in Section 5.2.4.1.

At Prudhoe Bay, deviation angles of up to 60 degrees have been employed although the average is approximately 35 degrees.

A directional drilled well at an average of 50 degrees from the vertical would have an average length of 4,100 meters (13,500 feet) to reach a target at a depth of 3,050 meters (10,000 feet). Permafrost will be an important design consideration especially wellbore loading caused by differential freeze-thaw (Goodman, 1977b). To maintain the integrity of the well hole, a thermocasing string is assumed and used in the top 60 to 150 meters (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 production well is shown schematically in Figure 25 and includes five strings:

1. Structural casing about 30 inches in diameter set at 30 meters (100 feet) to provide stability in unconsolidated sediments;

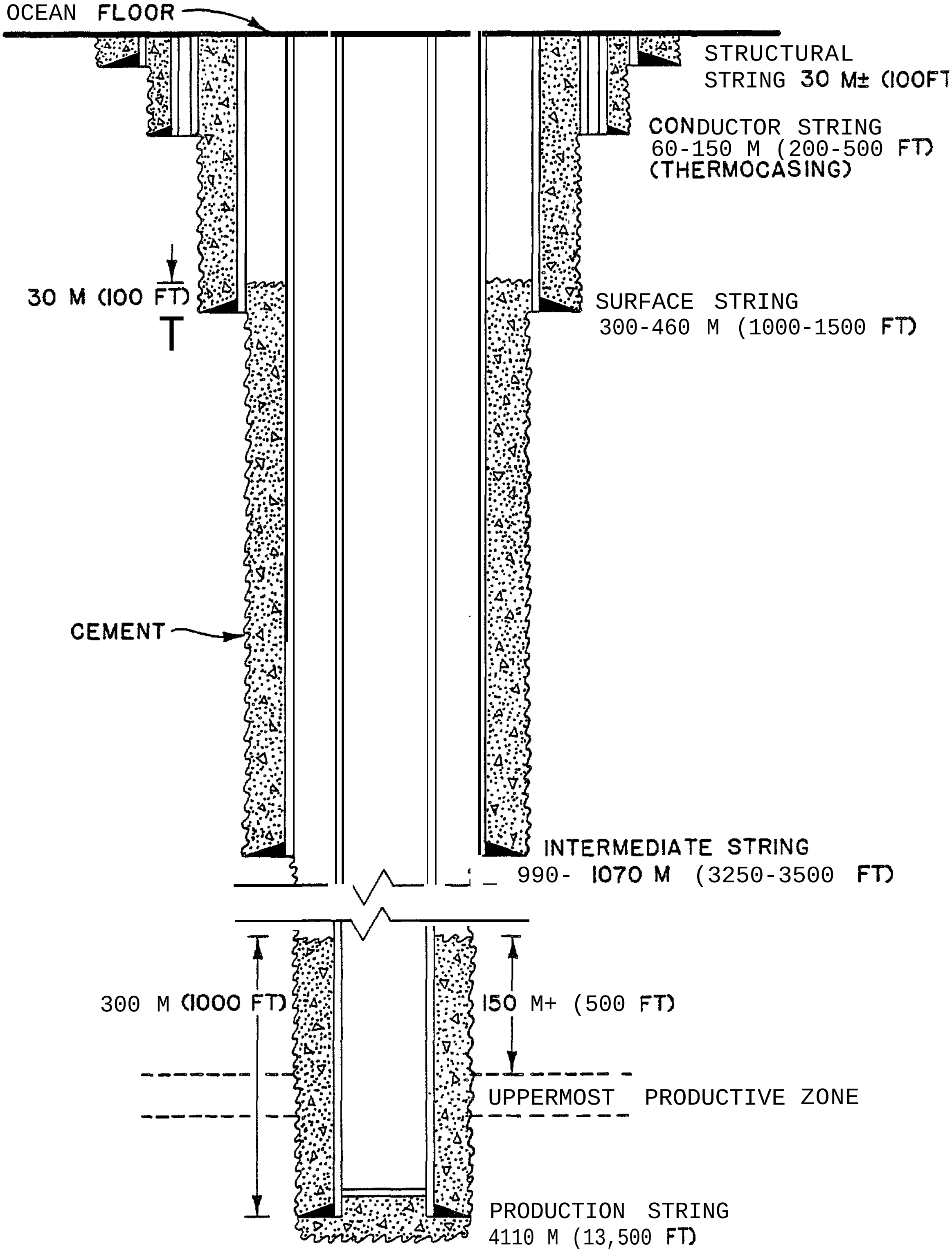
2. Thermocasing set at 60 to 150 meters (200 to 500 feet) comprising" an outer casing, which serves as the conductor string (20-inch), and an inner casing, which serves as a sleeve, with a plastic insulation between;

3. 13-3/8-inch surface casing set at 460 meters (1,500 feet);

4. 9-5/8-inch intermediate casing set at 1,070 meters (3,500 feet); and

5. 7-inch production casing set below 1,070 meters (3,500 feet).

As mentioned above, for wells with depths dissimilar to this example, the length of the production casing will generally be the variable.



NOT TO SCALE

SOURCE: DAMES & MOORE

FIGURE 25 - SCHEMATIC SKETCH
EXAMPLE OF 4,110 M (13,500 FT) WELL CASING PROGRAM

Production well completion at Prudhoe Bay averages 40 days (Votava, personal communication, 1978). This time includes installation of the drilling rig, drilling, evaluation, and rig dismantling. Once installed on the pad, rig moves to subsequent wells involve only a few meters travel and minimal down time. These facts are equally applicable to offshore production well drilling, although many more wells will be drilled from a single location.

8.3.3 Well 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.

8.4 EQUIPMENT AND MATERIALS

This section identifies the material and equipment requirements for exploration and production wells and other petroleum facilities. These requirements are mainly given on a unit basis and should be compared with the scenario facility assumptions tabulated in Chapter 9.0.

8.4.1 Well Materials and Supplies

8.4.1.1 Mud

The drilling mud requirements for Prudhoe Bay exploration and production wells are reported to be 2,000 bbl per well of Gel (Bentonite) - XC Polymer freshwater type mud (Votava, personal communication, 1978). The availability of fresh water will, in part, determine what types of mud are used for offshore drilling. Freshwater mud was used to drill Union Oil's offshore well East Harrison Bay - 1; the water was obtained from a lake on Anakalik Island and trucked ?6 kilometers (10 miles) over the ice to the well site (Duthweiler, personal communication, 1978).

8.4.1.2 Drill Cuttings

Based upon the schematic well design in Figure 25, the minimum volume of cuttings that would be produced is 206 cubic meters (207 cubic yards). Since the well bore is never uniform because of cavitation and bulking of the fragmented material, the actual volume of cuttings is greater than the dimensions of the idealized well in Figure 25. Typical ranges of drill cutting volumes are from 229 to 287 cubic meters (300 to 375 cubic yards) for a 3,048-meter (10,000-foot) well, from 276 to 344 cubic meters (350 to 450 cubic yards) for a 3,658-meter (12,000- foot) well and 306 to 401 meters (400 to 525 cubic yards for a 4,267-meter (14,000-foot) well (U.S. Department of the Interior, 1976a).

8.4.1.3 Cement (Grout)

Based upon the schematic well design shown in Figure 25, the volume of cement required per well is about 106 cubic meters (142 cubic yards) or 152 tons.

8.4.1.4 Water

Water will be required for drilling the well, equipment operation and human consumption. Potable water required by the drilling camp for domestic purposes on the North Slope is about 303 liters (80 gallons) per capita per day (Votava, personal communication, 1978; Duthweiler, personal communication, 1978). Average water consumption for both rig and domestic uses is reported to be 350 bbls (55,640 liters or 14,700 gallons) per day with a peak consumption of 1,000 bbls (158,970 liters or 42,000 gallons). Alyeska pipeline camp per capita freshwater consumption of 265 liters (70 gallons) per day agrees with the above figures for exploration camp domestic consumption (Eggener, personal communication, 1977).

Average water consumption for exploration wells in NPR-A is given as 75 bbls (11,923 liters or 3,150 gallons) per day for domestic purposes (this water is kept separate from drill rig water storage and filtered prior to use). About 600 bbls (95,382 liters or 25,200 gallons) of water per day is needed for rig operation, which includes the mixing of drilling mud and cement, and washing down the rig floor (U.S. Department of the Navy, 1977).

Similar daily water requirements for production wells can be anticipated although total consumption will generally be significantly less than an exploratory well since a production well can be completed in about half the time (about 40 days vs. 80 days).

About one million barrels (159 million liters or 42 million gallons) of sea water were required to construct Union Oil's Harrison Bay ice island. Fresh water supplemented salt water in the ice thickening process. Ice growth rates (and strength) are better using fresh water because there is no brine drainage problem. Such water consumption for Beaufort Sea drilling can only be anticipated where an adequate water source is located nearby. Fresh water for the Harrison Bay ice island well was obtained from an artesian-fed lake on Anakulik Island (located in the Colville River delta) 16 kilometers (10 miles) from the site. No drawdown of the Anakulik Lake was observed on completion of the well.

8.4.1.5 Fuel

In winter, fuel consumption averages 14,004 liters (3,700 gallons) per rig per day of Arctic diesel fuel and 6,434 liters (1,900 gallons) in summer at Prudhoe Bay (Votava, personal communication, 1978). Gasoline consumption averages about 302 liters (80 gallons). Fuel consumption for Union Oil's E. Harrison Bay - 1 well drilled from an ice island is similar to the Prudhoe Bay figures -- about 1,514 liters per day of Arctic diesel fuel and 750 gallons per day of gasoline. The above figures are applicable to both exploration and production wells although the totals will be different since production wells can be drilled in about half the time.

The Arctic diesel fuel for Union Oil's well was flown into the site from Fairbanks by Hercules aircraft with one load (about 22,710 liters or 6,000 gallons) providing enough fuel for a day and half of drilling.

No estimates are available for the additional fuel requirements of the construction equipment (dredges, barges, cranes, etc.} needed to build artificial soil islands. The fuel requirements of construction equipment needed to construct shallow-water soil islands in winter are probably not significantly greater than that required for onshore pre-drilling site preparation (construction of gravel pad, airstrip, etc.) since a similar construction spread is required. The major variable will be the haul distance for gravel.

Since a minimal construction spread is required to build an ice island (in fact probably less than is required for site preparation for an onshore well), fuel requirements, in addition to those of well drilling, are probably insignificant.

8.4.1.6 Waste Disposal

Waste materials produced in the drilling of exploration and production wells and related support activities include drill cuttings, drill mud, domestic wastewater, and solid waste.

Drill cuttings are separated from the mud during drilling and, in offshore operations, discharged onto the sea floor. Onshore the cuttings are dumped into a reserve pit adjacent to the drill pad.

Drill mud is recycled during drilling although occasional dumping is required to change the mud characteristics or chemistry for changing conditions as the well gets deeper. Mud remaining upon completion of the well may be recycled to drill other wells.

Disposal of mud in the ocean must be in compliance with OCS operating orders. In State waters, mud must be disposed onshore at approved sanitary landfill sites. Mud from Union Oil's Harrison Bay well, for example, was disposed on land at a State-approved sanitary landfill on Anakulik Island.

Mud is discharged into a mud pit adjacent to the well pad in onshore drilling and the pit is filled in with sand or gravel upon completion of the well.

In addition to the cutting and mud volumes indicated above, there will be solid waste of about 4.5 kg per capita per day (10 pounds per capita per day) generated at temporary construction and drill site camps. Water usage and thus domestic wastewater discharge can be expected to be about 378 liters per capita per day (100 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 disposal by incineration. Non-combustibles will be taken to an approved sanitary landfill. For a more complete discussion on wastewater treatment at temporary construction camps, the reader is referred to a paper by Eggener and Tomlinson (1977).

8.4.2. Gravel Requirements -All Facilities

Gravel and sand are important construction materials in the Arctic. They provide a stable and trafficable working surface and provide insulation and protection to the underlying permafrost. Beaufort Sea petroleum development will impose additional demands on the sand and gravel resources of the North Slope and Beaufort Sea. These demands will be greater than for onshore petroleum development because of the requirements for such facilities as artificial islands and causeways, harbors, and staging areas.

The quantities of gravel or sand are given on a unit basis for offshore exploration and production islands, causeways, air strips, and other petroleum related facilities in Table 28. As indicated in Section 7.7, exploration activities, since they are of a temporary nature, will to some degree use ice or snow strips, ice, and snow roads and existing facilities to minimize the requirements for gravel and sand. Estimates of gravel requirements for the four development scenarios are presented in Tables 29 through 32.

8.4.3 Artificial Soil Island Construction Spread

The current construction spread under contract to Imperial Oil in the southern Canadian Beaufort Sea, where an average of 2 to 3 islands a year have been constructed since 1972, serves as a reasonable model for the Canning-Camden and Prudhoe Bay scenarios, which predict extensive use of artificial soil islands for exploration and production. Imperial Oil's construction spread includes:

TABLE 28

SUMMARY OF GRAVEL REQUIREMENTS FOR BEAUFORT SEA PETROLEUM DEVELOPMENT

Facility	Dimensions	Gravel Requirements	Comments
Exploratory Islands			
a. Winter constructed, shallow water island	121 meters x 99 meters (400 feet x 325 feet), 1.2 hectares (2.98 acres); freeboard 1.5 meters (5 feet); water depth 1.2 meters (4 feet).	36,700 cubic meters (48,000 cubic yards)	E.g. BP's Sag Delta Island. Winter islands can also be constructed of silt.
b. Sandbag retained island	Circular. 98 meters (320 feet) diameter, working surface; 0.75 hectares (1.86 acres) freeboard 5 meters (15 feet), water depth 10 meters (30 feet).	278,650 cubic meters (364,438 cubic yards)	
c. Sacrificial beach island	Circular, 206 meters (675 feet) diameter, 98 meters (320 feet) diameter working surface; 0.75 hectares (1.86 acres) working surface, 33 hectares (81.5 acres) total surface area; freeboard 5 meters (15 feet); water depth 8.5 meters (28 feet).	1,200,000 cubic meters (1,600,000 cubic yards)	Only economic if on-site fill is available with no barge-haul involved.
Production Island (caisson-retained or sheet piling)	Circular, 190 meters (623 feet) diameter, 2.8 hectares (7 acres); freeboard 5 meters (15 feet); water depth 7.6 meters (25 feet)	477,030 cubic meters (621,133 cubic yards)	Use of caissons or sheet piling may effect significant savings in gravel requirements
Pipeline Work Pad	1.5 meters (5 feet) thick; 20 meters (65 feet) wide.	30,177 cubic meters/km (63,555 cubic yards/mile)	Typical Alyeska dimensions for aboveground pipe; scenario work pads may be somewhat narrower.
Pipeline Access Road	1.5 meters (5 feet) thick; 8.5 meters (22 feet) wide.	10,214 cubic meters/km (21,511 cubic yards/mile)	
Pipeline Haul Road	1.5 meters (5 feet) thick; 9 meters (30 feet) wide.	13,928 cubic meters/km (29,333 cubic yards/mile)	
Airstrip (all weather)	1,523 meters x 40 meters (5,000 feet x 150 feet); 1.2 to 1.8 meters (4 to 6 feet) thick.	84,955 to 126,159 cubic meters (110,000 to 165,000 cubic yards)	
Camp and Drill Pad (onshore exploratory well)	128 meters x 98 meters (420 feet x 320 feet), 1.27 hectares (3.1 acres).	26,760 to 38,230 cubic meters (35,000 to 50,000 cubic yards)	
Causeway	30 meters (100 feet) wide, average water depth of 1.5 meters (5 feet) and freeboard of 4.5 meters (15 feet).	185,706 cubic meters/km (391,000 cubic yards/mile)	Hypothetical example based on approximate dimensions of Prudhoe Bay (west bay) causeway
Staging Area/Production Center		573,450 to 746,000 cubic meters (750,000 to 1,000,000 cubic yards)	Estimate for an onshore staging area/production center at landfall of offshore pipelines and start of Prudhoe Bay pipeline connection. Facilities would include causeway/dock, storage yard, gas and oil treatment plants, airstrip, base camp, roads, storage yards and permanent camp.

Source: Dames & Moore

TABLE 29

CAMDEN-CANNING SCENARIO (1.3 Bbbl RESERVES)[1] - SUMMARY OF GRAVEL REQUIREMENTS

FACILITY	SPECIFICATIONS	GRAVEL REQUIREMENTS[2] CUBIC METERS (CUBIC YARDS)	COMMENTS
Exploratory Islands	9 Soil Islands 6 Barges (with berms)	3,440,700 (4,500,000) 91,752 (120,000)	Assumes average of 382,000 cubic meters. (500,000 cubic yards) per island; production islands include mix of sandbag-retained, sacrificial beach and shallow water pad designs.
Production Islands	9 Soil Islands	3,440,700 (4,500,000)	Assumes average of 382,000 cubic meters (500,000 cubic yards) per island; production islands larger than exploratory islands but caisson or sheet pile design will effect gravel savings.
Pipeline Work Pad	87 kilometers (54 miles)	2,625,399 (3,431,970)	
Pipeline Haul Road	87 kilometers (54 miles)	1,211,736 (1,583,982)	
Airstrip	1 - 1,829 meter [6.000 feet)	122,336 (160,000)	
Causeways	2 - (each 2.4 kilometers or 1.5 miles long)	891,388 (1,173,000)	At landfall of each field.
Staging Area/ Production Center	2 flow stations 1 pump station 1 compressor plant storage areas 1 camp/operations center	1,529,200 (2,000,000)	
Total		13,353,211 (17,360,952)	

(1) Scenario comprises two adjacent fields which share staging area, base camp, harbor, storage facilities and airstrip but each have separate flow stations at pipeline landfalls.

(2) Gravel requirements for staging area/production center facilities including storage areas, camp/operations center, flow stations, pump stations and compressor plants have been estimated by scaling down Prudhoe Bay facilities. Other estimates are based on Alyeska and Canadian Beaufort Sea experience (also see Table 28).

Source: Dames & Moore

TABLE 30

PRUDHOE BAY OFFSHORE SCENARIO (1.9 Bbbl RESERVES) - SUMMARY OF GRAVEL REQUIREMENTS

FACILITY	SPECIFICATIONS	GRAVEL REQUIREMENTS[1] CUBIC METERS	(CUBIC YARDS)	COMMENTS
Exploration Islands	7 Soil Islands 4 Barges (with berms)	2,676,100 61,168	(3,500,000) (80,000)	Assume average of 382,000 cubic meters (500,000 cubic yards) per island; islands include mix of sandbag-retained, sacrificial beach and shallow water pad designs.
Production Islands	4 Soil Islands	1,528,000	(2,000,000)	Assume average of 382,000 cubic meters (500,000 cubic yards) per island; islands larger than exploratory islands but caisson or sheet pile design will effect gravel savings.
Pipeline Work Pad	15 kilometers (9.5 miles)	452,655	(603,772)	
Pipeline Haul Road				Existing Prudhoe roads utilized, minor construction of additional access roads.
Airstrip				Existing Prudhoe Bay and Deadhorse airstrips utilized.
Causeways				Existing Prudhoe Bay causeway/dock utilized with minor expansion of facilities.
Staging Area/ Production Center	2 flow stations 1 pump station 1 compressor station operations center storage areas	382,300	(500,000)	New processing facilities constructed (flow stations, etc.) but existing Prudhoe Bay camps and Deadhorse services utilized.
Total		5,100,223	(6,683,772)	

(1) Gravel requirements for staging area/production center facilities including flow stations, pump stations, compressor plants, operations centers, and storage areas have been estimated by scaling down Prudhoe Bay facilities. Other estimates are based on Alyeska and Canadian Beaufort Sea experience (also see Table 2B).

Source: Dames & Moore

TABLE 31

PRUDHOE BAY OFFSHORE SCENARIO (0.8 Bbbl RESERVES) - SUMMARY OF GRAVEL REQUIREMENTS

FACILITY	SPECIFICATIONS	GRAVEL REQUIREMENTS(1) CUBIC METERS	(CUBIC YARDS)	COMMENTS
Exploration Islands	6 Soil Islands 4 Barges (with berms)	2,293,800 61,168	(3,000,000) (80,000)	Assume average of 382,000 cubic meters (500,000 cubic yards) per island; islands include mix of sandbag-retained, sacrificial beach and shal low water pad designs.
Production 1s1 ands	5 Soil Islands	1,911,500	(2,500,000)	Assume average of 3B2 ,000 cubic meters (500,000 cubic yards) per island; islands larger than exploratory islands but caisson or sheet pile design will effect gravel savings.
Pipeline Work Pad	15 kilometers (9.5 miles)	452,655	(603,772)	
Pipeline Haul Road				Existing Prudhoe roads utilized, minor construction of additional access roads.
Airstrip				Existing Prudhoe Bay and Deadhorse airstrips utilized.
Causeways				Exist i ng Prudhoe Bay causeway/dock ut i 1 i zed with minor expansion of facilities.
Staging Area/ Product ion Center	2 flow stations 1 pump station 1 compressor station operations center storage areas	267,630	(350,000)	New processing facilities constructed (flow stations, etc.) but existing Prudhoe Bay camps and Deadhorse services utilized.
Total		4,986,733	(6,533,772)	

(1) Gravel requirements for staging area/production center facilities including flow stations, pump stations, compressor plants, operations centers, and storage areas have been estimated by sealing down Prudhoe Bay facilities. Other estimates are based on Al yeska and Canadian Beau fort Sea experience (also see Table 28).

Source: Dames & Moore

TABLE 32

CAPE HALKETT SCENARIO (0.8 Bbbl RESERVES) - SUMMARY OF GRAVEL REQUIREMENTS

FACILITY	SPECIFICATIONS	GRAVEL REQUIREMENTS[1] CUBIC METERS	(CUBIC YARDS)	COMMENTS
Exploration Islands	2 Barges (with berms)	30,584	(40,000)	
Production Islands	1 Soil Island	382,000	(500,000)	Caisson or sheet pile design effecting gravel savings.
Pipeline Work Pad	66 kilometers (41 miles)	1,991,682	(2,605,755)	
Pipeline Haul Road	66 kilometers (41 miles)	919,248	(1 ,202,653)	
Airstrip	1 - 1,829 meter (6 ,000 feet)	122,336	(160,000)	
Causeways	2 - (each 2.4 kilometers or 1.5 miles long)	891,388	(1 ,173,000)	One located at landfall of pipeline in east Harrison Bay and one located at staging area at Cape Hal kett.
Staging Area	Camp Storage area	191,150	(250,000)	Oil/gas processing facilities, pump station and compressor station are located on platforms.
Total		4,528,388	(5,931,408)	

(1) Gravel requirements have been estimated by sealing down Prudhoe facilities or based on Alyeska and Canadian Beaufort Sea experience (also see Table 28).

Source: Dames & Moore

- 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-h.p. 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
- Several other barges, launches, and auxiliary equipment

Not all the soil islands will be constructed in summer; in shallower waters (less than 3 meters or 10 feet approximately) some islands will be constructed through backfilling executions in the landfast ice with over-ice gravel hauling by trucks from onshore borrow sources. The construction spread required to build BP's Sag Delta Island can serve as a reasonable model for similar islands, although more gravel trucks would appear to be required. This included (Votava, personal communication, 1978):

- One Crane
- Two Cats
- One Grader
- Six Loaders
- One Gravel Truck

8.4.4 Artificial Ice Island Construction Spread

In some respects the equipment required to build an ice island is less than that required for site preparation for an onshore exploratory well since no gravel hauling and handling is required. The on'ly additional equipment would be small pumps for flooding/ice thickening and an ice cutter, (e.g., "Ditch Witch").

8.5 PIPELINE SPECIFICATIONS

The diameter of the trunk pipelines between the scenario locations and the Alyeska pipeline system can be specified from estimating the average flow velocity. The pressure in a pipeline declines downstream due to friction at the pipe wall. Thus the flow, or throughput of oil, "is dependent both on the pumping pressure and the distance -- or pressure drop -- between pumping stations. The Alyeska line itself furnishes a well-publicized example of this principle. The line at maximum flow conditions will pass 2 million barrels per day, with 12 pumping stations, or an average interval of 107 kilometers (67 miles). Present capacity is rated at 1.2 million barrels per day with 8 stations, an average interval of 160 kilometers (100 miles). However, when one station was being repaired following a start up accident, it was bypassed by the flow, leaving one section of the line excessively long. The throughput of the line was restricted to 600 to 800 Mb/d by this section of maximal pressure drop.

The maximum pressure in the line is experienced at the pumping station discharge. As the pressure declines downstream, less strength is needed in the line. It is customary to reduce the wall thickness downstream of each station to save steel, since the downstream stress limits cannot be exceeded without also exceeding those at the pump station discharge point. The Alyeska line utilizes thicknesses of around 14 to 11 millimeters. Similar principles apply to gas lines, although they are governed by relations for compressible fluid flow, which differ markedly from the hydraulic behavior of oil lines.

The resultant pipeline diameters are given in Tables 33, 34, 35, and 36 for the four scenario areas. The necessary diameters for the western area (Smith Bay-Dease Inlet) are given for a cost reference, even though production is not assumed in that area for a detailed scenario. The velocity estimate is nominal -- no allowance for exact inner pipe diameter has been made, since there is adequate leeway in pumping pressure

TABLE 33

OIL PIPELINE SPECIFICATIONS

CAMDEN-CANNING SCENARIOS

Field[1] Resources Bbbl	Nominal[2] Capacity Mb/d	Onshore Line Diam.-inches (54 miles-87 km)	Offshore[3] Single line Diameter - inches	No. of 12-in lines[4]
[illegible].3[5]	(450	34" (30" or 36")	24" + 20"	8
	(400	32" (30")	22" + 18"	7
1.1	(370	30"	22" + 18"	6
	(330	30"	20" + 16"	6
[illegible]	(300	28"	18" + 16"	5
	(270	26"	18" + 14"	5

(1)Plus 400 MMbbl additiona onshore

(2)Nom nal flow speed 5 ft/sec 5.5 kph

(3)Two f elds require 2 trunk lines

(4)Nomina flow speed 5 ft/sec (5.5

5)Scenario selected for detailed ana ysis

Source: & Moore

TABLE 34

OIL PIPELINE SPECIFICATIONS

PRUDHOE OFFSHORE SCENARIOS

Field Resources Bbbl	Nominal[1] Capacity Mb/d	Onshore or Offshore Diameter-inches (12 miles-19 km)	Offshore[2] No. of 12-in lines
1.9[3]	(650	32" (30" or 36")	11
	(500	28"	9
1.4	(480	28"	8
	(360	22"	6
.8[4]	(200	18"	4
	(150	16"	3
.6	(150	16"	3
	(110	14"	2

(1) Nominal flow speed 8 ft/sec (8.7 kph)

(2) Nominal flow speed 5 ft/sec (5.5 kph)

(3) Scenario selected for detailed analysis

(4) Scenario selected for detailed analysis

Source: Dames & Moore

TABLE 35

OIL PIPELINE SPECIFICATIONS

CAPE HALKETT AREA SCENARIOS

Field Resources Bbbl	Nominal (1) Capacity Mb/d	Onshore-Offshore (2) Line Diameter (92 miles-148 km)
1.2	350	34" (30" or 36")
	310	32" (30")
.8 (3)	260	28"
	230	28"
.3	120	20"
	90	18"

(1) na flow speed 4 ft/sec (4.4 kph)

(2) Mu tiple offshore lines not considered

(3) Scenar o selected for detai ed analysis

Source: Dames & Moore

TABLE 36

OIL PIPELINE SPECIFICATIONS

SMITH BAY-DEASE INLET SCENARIO

Field Resources Bbbl	Nominal[1] Capacity Mb/d	Onshore Line Diameter-inches
0.6	(200	22"
	(150	20"
0.4[2]	(130	18"
	(100	16"
0.15	(50	12"
	(30	10"

[1] Nominal flow speed 5 ft/sec (5.5 kph) with booster station

[2] Scenario selected for design analysis

Source: Dames & Moore

available and permitted. The throughput in the Camden-Canning area has included capacity for the 400 MMbbl allowance of additional reserves on State lands in that sector. Specifications on pipelines for each of the detailed scenarios are given in Chapter 9.0; Tables 33 through 36 provided specifications for all resource levels identified in the skeletal scenarios.

The diameter specification for gas pipelines was estimated from the Panhandle formula and the supercompressiblity of natural gas. It is probable that deviations from the supercompressibility of natural gas may be experienced in the raw product gas, depending on the necessary processing in the regional treatment plant. However, the estimation gives an indication of the relative differences between transport options -- system pressure, pressure drop, and cooled or uncooled field product gas. The specifications shown in Table 37 represent a medium system pressure -- alternatives are a high system pressure at 3000 to 4000 psi, or a low system pressure at 600 to 800 psi. The'high pressure system would use line diameters of 12 inches or less. A low pressure system from the Camden-Canning area would require up to a 30-inch line. The choice will be influenced partly by the eventual specifications for the Alcan line, and by whether LP gas and field condensate extraction for petrochemical production is eventually realized prior to the development of the Beaufort fields.

The primary pumping station and treatment center for the Camden-Canning area is assumed to be onshore. For the central Prudhoe offshore area, it could be either at the beach, or on a platform offshore. For the Cape Halkett scenario, it is assumed to be offshore in the field, and the major portion of the pipeline corridor is across the Beaufort Sea. The alternative route, either to Cape Halkett and overland to a downstream pump station, or any other land route to the Alyeska system, will likely require a booster station since the distance exceeds 160 kilometers (100 miles).

TABLE 37

GAS PIPELINE SPECIFICATIONS

Line Diameter, Inches(1)

Average Capacity	CAMDEN-CANNING 87 Kilometers (54 Miles) 1800 psi 70°C	1800 psi 0°C	1600 psi 70°C	1600 psi 0°C	1400 psi 70°C	1400 psi 0°C	PRUDHOE OFFSHORE 19 Kilometers (12 Miles) 180° psi 70°C	180° psi 0°C	160° psi 70°C	160° psi 0°<	140° psi 70°C	140° psi 0°C
500 MMcfd	24"	20"	26"	22"	26"	22"	18"	16"	18"	16"	20"	18"
300 MMcfd	20"	18"	20"	18"	22"	18"	4"	14"	16"	14"	16"	4"
100 MMcfd	14"	12"	14"	12"	14"	12"	10"	8" or 10	0"	10"	2"	10"

(1) Line Pressure Drop: 200 psi, Camden-Canning
100 psi, Prudhoe Offshore

Source Dames & Moore

The pipeline distances given are the most direct offshore and onshore links from the hypothetical oil fields to the existing Prudhoe Bay facilities (Alyeska terminal). Two options are indicated for transporting oil to shore. Multiple pipelines could transport the oil to shore in several separate corridors from individual platforms. Alternatively, 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 Alyeska terminal.

The Cape Halkett scenario presents a case where the most direct routing to the Prudhoe Bay interconnection involves a significant offshore segment across Harrison Bay. A pipeline routing involving an offshore pipeline from the field to the closest landfall (Cape Halkett) and an overland segment to Prudhoe Bay is significantly longer (148 kilometers or 92 miles vs. 229 kilometers or 142 miles) than the most direct route. The geography of the Camden-Canning and Prudhoe scenarios does not present this problem although there are other locations in the Beaufort Sea where (assuming the need for a Prudhoe Bay interconnection) long offshore routings would comprise the most direct route. In the case of the Cape Halkett scenario, the research team felt that taking the most direct route across Harrison Bay was a reasonable economic and technological assumption. The route is located in the landfast ice zone in water depths of less than 9 meters (30 feet). Provided the route avoids some potential scour areas on shoals in outer Harrison Bay, no insurmountable or costly engineering problems should occur. Furthermore, Cape Halkett petroleum development will take place after that in the State-Federal lease sale area and will benefit from technological developments in pipelining that will have occurred in the first sale area.

An alternative to conventional trunk pipelines is a series of small diameter (12 to 14 inches) pipelines that can be transported and laid from spools on a barge. This alternative is also shown in Tables 33 through 36. 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 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 it is doubtful that refrigerating radiators, such as those used on the Alyeska project, can survive the occasional exposures of moving ice. Short causeways at the pipeline landfall are favored by some petroleum operators to avoid potential problems from ice-rich subsea permafrost near the shore, areas of rapid shoreline erosion and ice push. Ice-rich subsea permafrost is not anticipated to be a problem beyond a water depth of about 2meters (6 feet). The pipelines would be either elevated above the causeway on piles or located within the causeway. Some causeways may be linked to offshore production islands or platforms. It is recognized, however, that causeways are a sensitive environmental issue and their extensive use cannot be predicted at the present time.

Offshore pipelines will also have to be buried to sufficient depths to afford protection from ice scour. Maximum ice scour in the landfast ice zone is on the order of 2 meters (6 feet).

Because of the short open water season, rapid burial techniques will have to be developed to improve the economics of summer pipelaying.

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 3.5.1.

8.5.1 Alternative Crude Oil Properties

Although not incorporated in the economic analysis, it is important to note some economic and transportation problems related to alternative crude oil properties. Beaufort crude has been characterized as similar to North Slope crude, especially with respect to gravity and sulfur content. A recent find east of Prudhoe Bay contained oil of 22 degrees (API) gravity, compared to the 26 degree of the Sadlerochit reservoir oil. The changes in the scenario outcomes which might depend upon the oil properties are discussed qualitatively. However, no effort will be made to incorporate variations in the oil properties into the scenario analysis, since they can be related to cost and resource size variations by referring to the discussion in Section 6.5.

Variations in oil ingredients that have to be removed from the crude before pipeline delivery, such as water, hydrogen sulfide, and impurities, would be reflected in the scenario picture only as incremental changes in the processing cost of the crude.

The question of differences in the characteristics of the oil that lead to different market values -- i.e., gravity, paraffin, sulfur, etc. is usually predetermined by the tariff agreements for the pipeline. Although a pipeline system tries to function as a common carrier -- providing reasonable access and equitable 'rates to various users -- the Alyeska line is not equipped on the North Slope to provide grade sorting of the oil. That would require batch storage tanks at the head of the system, and appropriate valving controls at the Valdez terminal. Thus, the oil accepted tends to be blended. The tariffs can provide for exclusion of grades of oil which would lower the average price received by the other producers. High sulfur content is a particular problem in this respect. If the sulfur content of a Beaufort reservoir exceeded the tariff limits for the Alyeska system, the reservoir might not be producible within the schedule projected for the scenarios. On the other hand, the premium value of low sulfur oil might not be recoverable, since it would be lost by blending. If a large reservoir of low-sulfur crude were found, agreements might be worked out under which the producer of the crude paid the batching costs for the system (provided that the increased revenue from the low-sulfur premium justified such a project). Low-sulfur reservoirs represent a premium condition, and are unfortunately unlikely for the Beaufort Sea scenario areas projected for production.

Gravity differences, however, should be expected over a reasonable range of densities. Gravity decrease in the scenario crudes could require a size larger (i.e., 2 inches) pipeline than those specified for the scenarios. Gravity differences can lead to differences in the ultimate recovery factors realized in reservoirs of otherwise similar properties. Resource size differences, regardless of underlying reasons, all fit within the probabilistic framework of the scenario projections. This includes reservoirs which are non-producible for reasons of density as well as size.

8.6 SUPPORT FACILITIES

8.6.1 General Locational and Logistical Considerations - Exploration Phase

During the exploration phase of Beaufort Sea petroleum operations, very limited, if any, new construction of onshore camps, airstrips, staging areas, communication sites, or other facilities would be required. Permits for new construction outside the vicinity of the Deadhorse industrial area would probably be difficult to obtain from State and federal agencies. In any case, it is doubtful that exploration would require shore-based support from facilities other than those available at Prudhoe Bay with the possible exception of Lonely, which is currently serving as the staging area for exploration in the northeastern sector of NPR-A. Lonely could continue to be a staging area for exploration activities west of Harrison Bay. The facilities of existing or abandoned DEW line stations, principally airstrips, may be used for offshore exploration if fortuitously located with respect to the well site. The existing North Slope petroleum infrastructure is described in Section 2.4.2.

During exploration, each offshore platform would accommodate both a drill rig and a crew camp. Most North Slope drilling rigs come supplied with a camp. During the winter, these camps could be supplied from Anchorage or Fairbanks by cargo aircraft that could land on ice airstrips built near the drilling pads or at the Deadhorse airstrip. Deadhorse would probably be used as much as possible for a staging, supply, and communications center. Unlike onshore exploration, Beaufort Sea exploration will be a year-round activity with construction of soil islands taking place in summer or winter; in the case of summer constructed islands, drill rigs will be transported to the site by barge prior to freeze-up and drilling can continue throughout the fall and winter. In the case of ice islands and winter-constructed soil islands, the option of either rig mobilization by air or land (and over-ice) is available. Union Oil's East Harrison Bay-1 well was flown to the drill site from an exploration site in the Brooks Range foothills, for example, while Exxon's Pt. Thompson No. 1 well was drilled by a rig mobilized overland from Prudhoe Bay (an air-transportable drill rig takes approximately 90 Hercules plane loads to ship to a well site). The mode of rig mobilization will, therefore, vary according to the availability of suitable drill rigs, their location, whether or not the rig is air-transportable, and the type of platform from which the exploratory well will be drilled (ice island, summer-constructed soil island, etc.). Although there is a pool of Arctic rigs at Prudhoe Bay, some of which are available for exploration, additional Arctic rigs will be required for exploration of State-Federal lease tracts especially since many of those at Prudhoe are near the end of their life span. .

Much of the supplies, such as mud, cement, and casing, would be obtained from oil field suppliers at Deadhorse. These may not necessarily be trucked to the well site since trucking costs on the North Slope are comparable to transportation by air. Servicing Union Oil's East Harrison Bay well required a total of 338 Hercules flights while only 30 loads of supplies were shipped by truck from Prudhoe Bay over the ice. Arctic diesel fuel was flown in from Fairbanks since a supply from Atlantic Richfield's topping plant at Prudhoe Bay could not be guaranteed (the output of the plant is devoted to oil field activities).

Exploratory islands will be supplied by barge during the summer and by air or ground transportation during the winter. Because of access difficulties during freeze-up and breakup, islands will have to be stockpiled with supplies if drilling is to continue during these periods. The Canadians have developed storage modules to maximize space usage on their exploratory islands in the Beaufort Sea. Air cushion transporters, which have been tested in the Canadian Arctic, may alleviate the supply problem during these periods. Artificial ice thickening techniques have also been employed on ice roads by the Canadians to provide earlier access to offshore well sites. The natural ice is not thick enough (about 90 centimeters or 30 inches) to support heavy trucks until about January 1 in the Alaskan Beaufort and until mid-January for Hercules aircraft (about 130 centimeters or 54 inches). A significant increase in the North Slope/Beaufort Sea exploration following the State-Federal lease sale will undoubtedly produce expansion of the Deadhorse oil field supplies and services.

8.6.2 General Locational and Logistical Considerations - Production Phase

Permanent onshore facilities, such as airfields, harbors, and base camps, would be built only after economically recoverable oil was found. Onshore field development activity would tend to be located as near as possible to the closest point of landfall for the offshore field. The onshore facilities required for the operation of an offshore oil and gas field (assuming that oil and gas treatment is conducted onshore at the pipeline landfall) include oil/gas/water separating plant (flow stations) , gas compression plant., base camp, airstrip, dock/harbor, pump station, storage area, and access roads. A number of environmental and engineering criteria would have to be met and would influence the actual site of onshore construction, such as avoidance of environmentally sensitive areas, availability of fresh water, proximity to gravel, soil stability, barge access, etc.

The location of onshore facilities would only coincidentally be at an existing DEW line site, as there would be no infrastructure of sufficient value at such a site to attract facilities to its vicinity. The cost of deviating one or two kilometers from an acceptable site would far exceed the cost of any usable infrastructure a DEW line site might possess.

No use of facilities at existing North Slope communities is anticipated. Even the two largest communities, Barrow and Kaktovik, do not have an infrastructure of sufficient economic value to justify relocation of support facilities from points nearest the offshore production wells. In addition, there are strong social reasons why oil companies would want to avoid development near an established North Slope community. The close juxtaposition of an oil field camp and an Eskimo community would jeopardize the social stability and cultural integrity of the 1 atter. It could precipitate far-reaching cultural changes for which the oil companies would not want to be responsible, and which the local leadership would abhor. In addition, jurisdiction conflicts would undoubtedly emerge between the town and oil companies over such things as possession of liquor. For their part, the oil companies would want to maintain the greatest possible control over the field camp.

A detailed analysis would be required for sitespecific planning of support facilities. The general criteria that would be used to select the location of a production base camp/staging area are briefly described below. These factors would essentially “fine tune” the location of the staging area since for each scenario there is a certain length of coastline in which a staging area could be located opposite the offshore field. While the closest landfall would be the most favored site, the position of the hypothetical fields relative to the shoreline (long axis parallel or sub-parallel to the coastal trend), which is dictated by geologic structure, means that there is some flexibility in the selection of onshore stage areas/production facilities. For the selected (detailed) scenarios, the approximate length of coastline in which a staging area may be located opposite the offshore field(s) is:

Camden-Canning	40 kilometers (25 miles)
Prudhoe (0.8 Bbbl)	19 kilometers (12 miles)
Prudhoe (1.9 Bbbl)	32 kilometers (20 miles)
Cape Halkett	11 kilometers (7 miles)

8.6.2.1 Proximity to Offshore Production Field

The most important requirement for base camp location is its proximity to the area of offshore development. Close proximity minimizes the running time of supply ships, over-ice vehicles and helicopters. This is especially important during periods of inclement weather or emergency. Close proximity also minimizes the length and therefore the investment requirements for offshore pipelines which have landfalls at the service base. In the scenario analysis the postulated base camp or staging area locations, with the exception of the Cape Halkett scenario, are also the location of the oil and gas treatment facilities (oil and gas separation, dehydration, gas compression). Economic and environmental factors will encourage centralization of facilities and minimization of duplication. The assumption has been made that oil/gas processing will be done onshore in the case of the Camden-Canning scenario and possibly in the Prudhoe scenarios. If oil/gas processing is done on the platforms, then the base camp/staging area does not need to be at the pipeline landfall.

8.6.2.2 <u>Deep Water</u>

Since the Beaufort Sea is shallow (the 20-meter isobath lies 16 to 80 kilometers or 10 to 50 miles offshore), depth of water close to shore is an important locational criteria for a port site. In general, the presence of shallow waters on the Beaufort Sea coast necessitates lightening of freight from deep draft vessels to shore in barges that draw less than 2.5 meters (8 feet) of water. Other factors that are important in port site location include submarine topography, the type of bottom sediments, coastal erosion, and near-shore sediment transport.

In addition to the requirement to offload oil field equipment and supplies brought in on an annual sea lift, a port facility would also provide winter anchor for vessels constructing or servicing offshore production islands. Most of these are shallow draft vessels.

Few port sites capable of accommodating ocean going vessels are available on the Alaskan Beaufort coast. Ocean going tugs and barges that have been involved in the annual sea lifts to Prudhoe Bay draw 5.5 to 6 meters (18 to 20 feet) of water. Even with causeways several kilometers long, such barges cannot be offloaded without lightering and shallow-draft tugs. Sites that have been identified as potential medium- to deep-draft ports on the Alaskan Beaufort coast include Pingok Island, Cross Island, Pole Island, Flaxman Island, and Kangigurik (Arctic Institute of North America, 1973). To a lesser or greater extent these sites are at exposed locations where large ice floes and summer storms impact.

Lightening and long causeways can be anticipated as necessary to Beaufort Sea petroleum development transportation since there are no suitable port sites on the mainland adjacent to the scenario field locations.

8.6.2.3 Shelter

A sheltered harbor in the general proximity of the development area is a major factor in locating the supply base. Barges require protection from fall storms and movement of sea ice. This requires the construction of a jetty or causeway, or the location of the port in a protected, natural harbor, or inside a lagoon protected by offshore islands. Port sites have to be in the landfast ice zone. As indicated in Section 8.6.2.2, potential port sites with suitable hydrographic conditions appear to lack shelter. The barrier islands do afford a significant amount of protection from pack ice and storm waves to inshore waters. However, these waters are generally too shallow to provide good port sites. Marine traffic in the Beaufort Sea will stay to the seaward of the barrier islands unless ice conditions force them shoreward where speeds have to be reduced because of shoals.

8.6.2.4 Environmental Sensitivity

In selecting base camp/staging area sites, the location and timing of marine mammal and fish migrations must be considered. Onshore habitats, such as the dens of polar bears, the calving areas of caribou, and the nesting and molting sites of waterfowl, have to be evaluated in the planning of ports and pipelines, and the timing of onshore construction. These marine and terrestrial wildlife resources are important to the subsistence economies of the villages and the overall welfare of Arctic ecosystems. Regulatory protection can be expected.

Marine traffic routes and the timing of such traffic may create significant impacts to marine mammal populations. Studies on the impact of the Canadian artificial soil island program in the southern Beaufort indicate that this is probably the most important impact.

8.6.2.5 Gravel

The availability of gravel is an economic, environmental and locational consideration. If it is necessary to build where sand and gravel are in short supply, alternative construction methods or substitute materials are sometimes used. Environmental concerns regarding sand and gravel extraction include:

- Siltation of fish spawing streams.
- Siltation in offshore fish habitats.
- Acceleration of erosion on" beaches, river and coastal bluffs, barrier islands, and tundra surface.

As a locational factor, however, the availability of gravel and sand will not be very important with respect to onshore facilities although geotechnically gravel deposits tend to be thaw-stable materials and present fewer foundation problems. Rather, the importance of gravel availability affects construction economics since haul distance is a significant cost factor. Offshore petroleum development will probably require significantly more gravel for a given field size than an equivalent onshore Arctic field.

8.6.2.6 Water

Water resource availability is a major concern in Arctic petroleum development since water is required in large quantities during every phase of petroleum development. The water supply problem on the North Slope is compounded by environmental problems of its withdrawal in some areas. These include:

- Winter extraction from portions of rivers where fish winter.

- Winter extraction from deeper lakes where fish winter.

Like gravel availability, water availability will probably be only a minor influence in facilities siting although the distance, and hence haulage or transmission costs, will be an economic factor in petroleum development.

8.6.2.7 Archaeological and Historical Sites

The discovery of important historic and archaeologic sites can modify the location of pipelines, base camps, etc. (The major river valleys of the North Slope, in particular, are historically and archaeologically important.) Archaeological surveys are generally conducted as part of siting studies and add to existing knowledge.

8.6.2.8 Use of Existing Infrastructure

As discussed in Sections 8.6.1 and 8.6.2, the use of the existing infrastructure of the North Slope will not be an important locational factor for production facilities. The Prudhoe Bay Offshore scenarios do predict use of some of the infrastructure and services available at the existing field but not the processing facilities.

8.6.3 Support Facilities Requirements

8.6.3.1 Exploration

The support facility requirements for Beaufort Sea exploration, as discussed in Section 8.6.1, are not anticipated to be significant relative to the existing North Slope petroleum infrastructure. Prudhoe Bay will most likely serve as a staging area for the central and eastern Alaskan Beaufort; in the western Beaufort, depending upon the area of exploration interest, Lonely would be the staging area. The facility requirements for offshore exploration are somewhat greater than onshore since construction of artificial islands is involved and men and materials have to be ferried to the well site.

If additional temporary staging areas were required, the following facilities would be involved:

- Camp
- Airstrip (capable of taking Hercules aircraft)
- Storage for fuel, mud, cement, casing
- Beach suitable for lightering
- Sewage treatment plant
- Sanitary landfill

In assessing the facilities requirements for Alaskan Beaufort Sea operations through the Canadian experience in the southern Beaufort Sea, the following contrasts should be noted.

- The North Slope lacks a major north-south river such as the Mackenzie River suitable for summer transportation of heavy equipment and supplies; some of the equipment and materials for Alaskan Beaufort operations may be shipped via the Hay River (N.W.T.)-Mackenzie River route.

- Greater reliance is placed on air transportation in the Alaskan Arctic than in the Mackenzie delta area.

8.6.3.2 Production

The support facility requirements for each of the selected petroleum development scenarios are given in Chapter 9.0. This section briefly outlines the general support facility requirements for offshore oil and gas production. Essentially the staging area would conduct one or more of the following functions:

1. Support base for servicing offshore platforms;

2. Pipeline landfall (s)-terminus of offshore pipelines and start of onshore trunk pipeline to Prudhoe Bay; and

3. Oil/gas processing center (oil/gas separation, dehydration), pump station, gas compression station.

In the selected scenarios the following staging area assumptions are made:

1. Camden-Canning -- a single staging area will serve functions numbers 1, 2 and 3 (above) since oil and gas processing will be done onshore.

2. Prudhoe Bay Offshore (1.9 Bbbl and 0.8 Bbbl) -- processing will be conducted either on the platforms or onshore; some of the existing infrastructure (e.g. camps, oil field services) may be shared, but not the production/processing facilities, since these are commited to the existing Prudhoe Bay unit.

3. Cape Halkett -- oil and gas processing will be done on platforms which will have pumping and gas compression facilities. One platform may actually be a platform complex with individual platforms performing single functions and separated for safety. An adequate onshore staging area would only perform function No. 1 (above); i.e. to service the offshore platforms. No significant facilities would be located at the pipeline landfall except a shore causeway to elevate the pipeline.

8.6.4 Description of a Hypothetical Staging Area

The typical facilities at a multi-purpose staging area, such as that identified in the Camden-Canning scenario are described in the following paragraph.

The harbor facilities would include a "T" shaped loading dock, perhaps constructed of sunken barges as at Prudhoe Bay, connected to the shore by a 30-meter wide (100-foot) causeway. Mooring space would have to be sufficient for the artificial island and platform construction and maintenance fleet, service vessels, shallow draft tugs, and lightening barges that would winter here. A minimum water depth of about 2.4 meters (8 feet) would have to be provided at the dock to accommodate these vessels; depending on bathymetric conditions, this may necessitate a causeway 1 to 2 kilometers (0.6 to 1.2 miles) or more long. A dredge channel may be required; the dredge material could be used for construction of the causeway or artificial islands. The causeway may carry the offshore pipelines either buried or elevated.

A ramp would be provided at the end of the causeway to permit access on and off the ice for trucks and tractors.

A marshalling area would be developed near the dock for storage of such drilling equipment as casing and drill pipe, cement, drilling mud, water and fuel, tractors, skids and other inactive materials. Base operation buildings would be constructed on gravel pads. The total area of storage is estimated to be 0.8 to 1.6 hectares (2 to 4 acres).

An all-weather gravel airfield from 1,523 to 1,828 meters (5,000 to 6,000 feet) long capable of handling Hercules and medium-sized jet aircraft.

Oil/gas processing facilities would include an oil/gas separation and dehydration plant (flow station/gathering center), pump station, gas conditioning and compression plant. A small power station would serve the staging area. Other facilities would include a permanent base camp and operations center, sewage treatment plant and water storage. The camp accommodations required for each selected scenario, as indicated by the manpower estimates in Appendix C, are in Table 38.

TABLE 38

CAMP ACCOMMODATION REQUIREMENTS FOR SELECTED SCENARIOS

Scenario	Construction (Temporary Camp)	Operation (Permanent Camp)
Camden-Canning	2,000	650
Prudhoe Offshore (0.8 Bbbl)[1]	1,500	500
Prudhoe Offshore (1.9 Bbbl)[1]	2,500	800
Cape Halkett[2]	1,300	400

(1) Sufficient capacity is assumed to be available at existing Prudhoe Bay camps.

(2) Some of the operation workers will be housed on the platforms.

Source: Dames & Moore

The staging area would be at the beginning of a gravel haul road to Prudhoe Bay as well as the beginning of onshore truck pipelines to Prudhoe Bay.

Overall land requirements for such a staging area are difficult to estimate. However, unlike Prudhoe Bay, the staging area configuration is not constrained or dictated by the oil field area since the field is located offshore. Environmental and economic considerations will tend to encourage maximum utilization of space and minimization of land requirements.

CHAPTER 9.0

DETAILED PETROLEUM DEVELOPMENT SCENARIOS

9.1 SCENARIO SELECTION

Although the variability of the parameters characterizing potential oil field development permits a nearly unlimited selection of possible outcomes, it is evident from the framework of the 24 skeletal scenarios that two parameters outweigh all others with respect to potential impacts on the Alaskan environment and economy: the amount of resource and its location. Consequently, a selection of scenarios which covers the range of locations and of reasonably expected resource deposit sizes should provide a sufficient basis for impact consideration.

At least one scenario is selected from each of the four areas for which resource estimates have been prepared. The scenario selection also covers a range of resource discovery cases as explained in Section 5.2.1. The discovery cases indicate that development of central and eastern areas will be more likely than the western areas.

This means that the probability value on the cumulative resource discovery probability curve at the minimum field size point is higher in the central and eastern areas than in the western area specifically, these are:

	Minimum Field Size	Probability
Eastern Alaskan Beaufort	345 MMbbl	about 95%
Central Alaskan Beaufort	260 MMbbl	better than 95%
Western "Alaskan Beaufort	395 MMbbl	about 40%

The western area (Smith-Dease) has been selected as an exploration-only scenario. However, a higher case of resource discovery has been selected to justify a reasonable level of exploration activity. In the Cape Halkett area, a resource discovery case has been selected based upon allocation of the five percent probability of the total resource occurring in the sub-area as shown in Table 13. In the Prudhoe sector, scenarios related to the modal value and a high value (one percent) have been selected. In the eastern area, a high case has been selected, but it has been split into 'two fields to provide detailing of that contingency. The scenarios selected for detailed study are therefore:

No. 1 Camden-Canning	1.3 Bbbl for two fields; 3.25 tcf
No. 2 Prudhoe Offshore-Large	1.9 Bbbl; 4.75 tcf
No. 3 Prudhoe Offshore-Small	0.8 Bbbl; 1.6 tcf
No. 4 Cape Halkett	0.8 Bbbl; gas not developed
No. 5 Smith-Dease	0.4 Bbbl; exploration only.

This selection of scenarios provides an adequate variation, contrast, and coverage for assessment and review of socioeconomic and environmental impacts. In addition to constructing each of these scenarios with a structural set of cost parameters, producing a range of economic outcomes, small shifts in the location of the large scenario fields were reviewed -- offshore Prudhoe Bay and in the eastern Beaufort to deeper waters. Economic effects of such shifts remain within the envelope of cost parameters considered, even with revision of the assumed mix of platform types. The assumed locations of the scenarios within the study areas is shown on Figure 26. Although an effort has been made to select scenario areas compatible with geologic characteristics known at present about the areas, the locations shown in Figure 26 should not be construed as other than hypothetical.

9.2 SCENARIO 1: CAMDEN-CANNING, 1.3 Bbbl

9.2.1 Location and Environment

9.2.1.1 Tract Assumptions

The Camden-Canning scenario contains two major reservoir areas where surface expressions encompass 10,500 and 6,900 hectares (26,000 and 17,000 acres). The areas are assumed to be elliptical, underlying

Figure 26

Selected Petroleum Development Scenario Locations all or part of the following tracts cataloged in the Joint State-Federal lease sale[1]:

Camden Area - 17 tracts (19,578 hectares) (48,376 acres)

181 (A)	213 (A)	218 (A)	231 (C)
195 (A)	214 (C)	227 (C)	232 (C)
196 (A)	215 (C)	228 (C)	
197 (A)	216 (C)	229 (C)	
198 (A)	217 (A)	230 (C)	

A - Joint State-Federal and Disputed
B - Federal
C - State
D - Disputed
52% State; 48% Joint and Disputed.

Canning Area - 17 tracts (17,464 hectares) (43,153 acres)

176 (C)	190 (c)	194 (c)	211 (c)	225 (C)
177 (c)	191 (c)	208 (C)	212 (c)	
178 (A)	192 (C)	209 (C)	223 (C)	
179 (A)	193 (A)	210 (c)	224 (C)	

82% State; 18% Joint and Disputed.

Alternative tract locations, with the identical field expressions -- area and shape -- involved 37 tracts and a slightly different ratio of Federal and State interests:

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(1) Tract designation according to Alaska Division of Lands, Federal/State, Beaufort Sea Oil and Gas Lease Sale Nomination Map (Preliminary, November 21, 1976).

Camden Alternate Area - 19 tracts (25,432 hectares) (62,842 acres)

*663	196 (A)	167 (B)	216 (C)	229 (C)
*665	197 (A)	181 (A)	217 (A)	230 (C)
191 (A)	198 (A)	214 (C)	218 (A)	231 (C)
195 (A)	199 (A)	215 (C)	228 (C)	

*Federal tracts of 2,304 hectares, not in joint State-Federal area.
24% Federal, 48% joint and disputed, 28% State.

Canning Alternate Area - 18 tracts (21,351 hectares) {52,758 acres)

150 (A)	163 (A)	177 (C)	1'31 (c)	210 (c)
151 (A)	164 (A)	178 (A)	192 (C)	211 (c)
152 (B)	165 (A)	179 (A)	193 (A)	
162 (C)	166 (A)	180 (A)	194 (C)	

9% Federal; 57% joint and disputed; 34% State.

9.2.1.2 Physical Setting

The Camden-Canning oil fields straddle the barrier islands with their long axis approximately parallel to the trend of the islands. Seaward of the barrier islands the 20-meter (66-foot) isobath lies for the most part just outside the three-mile limit. Water depths at the field locations range from about 1 meter (3 feet) at the eastern end of Flaxman Island (inshore) to 4.3 meters (14 feet) about 600 meters (one mile) off Point Thompson to a maximum of about 15.4 meters (50 feet) outside the barrier islands.

The area outside the barrier islands may be affected by late summer storms and by grounding of pack ice ridges in fall and early winter. By late winter landfast ice will cover the field locations.

Greater ice motion can be expected outside the barrier islands than to the landward of them. Offshore and onshore gravel resources can be anticipated in the Canning River delta area, the Shaviovik River, the barrier islands and coastal beaches between the Canning and Shaviovik Rivers.

9.2.1.3 Environmental Considerations

Exploration and development in the Camden-Canning area will require care in selection of staging areas, camps, and pipeline routes both offshore and onshore.

The calving area of the Central Arctic caribou herd extends from Bullen Point west to Oliktok. In addition, caribou make extensive use of beaches, spits, and river deltas from June to August to escape biting insects and parasitic flies. They also wade and swim in rivers and lagoons. Construction camps or above-ground pipelines in this area could cause critical summer ranges to be abandoned as observed by the Alaska Department of Fish and Game at Prudhoe Bay (Cameron and Whitten, 1976; 1977). Coastal oil spills could influence caribou use of the coastal fringe. Burial of pipelines, especially through river deltas, would help to assure caribou passage.

Excessive disturbance at some barrier islands during exploration or construction of facilities can cause abandonment of seal pups and hauling-out areas.

Water contamination from petrochemical pollution would be a threat to marine mammals, birds, fishes and the marine food web in general.

Critical fish overwintering areas have been identified on the deltas of the Kavik and Canning Rivers. Gravel mining or collection of potable water could seriously impact these areas (Wilson et al., 1977).

Dredged islands or onshore facilities with living facilities will undoubtedly attract Arctic foxes, even with good garbage disposal practices. Workers in the Arctic have not been able to resist the impulse to feed wildlife. Animals attracted by feeding are often killed by moving equipment or are shot when they become a nuisance.

Polar bears are known to den between the Sagavanirktok and Canning Rivers, but no traditional sites have been identified. The bears usually range beyond the shorefast ice, but must be considered a serious threat to man whenever they are nearby.

9.2.2 Schedule

The Camden-Canning area is located in the area of the Joint State-Federal lease sale, assumed to take place in the winter of 1979-80. Exploration is assumed to begin immediately in the summer of 1980 from a ballasted barge. The following year, a discovery is made of the Camden field and a confirmation is completed in 1982. By 1983, construction is starting on the Camden field. However, that year, a discovery in the Canning field is made. The decision is made to continue processing and transport of the output, and to include the transport of oil previously discovered on State lands. Construction to accommodate the combined fields begins in 1985. Production of oil and gas commences in 1990. The production schedule is given in Table 39.

The start of production in 1990 is compatible with the petroleum output projected in one of the scenarios for offshore Prudhoe Bay. If the Camden field were considered in isolation, or if the offshore Prudhoe scenario is not realized, or considered, then production in the Camden area could commence as early as 1988.

TABLE 39

PRODUCTION SCHEDULE

CAMDEN-CANNING SCENARIO

Year	Oil (Mb/d) Offshore	Onshore	Total (State)	Gas
1990	63	20	83	360 MMcfd (constant 25 years)
1991	165	20	185	
1992	232	40	272	
1993	289	60	349	
1994	321	70	391	
1995	338	60	398	
1996	336	90	426	
1997	317	80	397	
1998	282	100	382	
1999	242	80	322	
2000	213	90	303	
2001	186	80	266	
2002	157	70	227	
2003	126	50	176	
2004	92	40	132	
2005	166	30	96	
2006	48	20	68	
2007	34	20	54	
2008	22	20	42	
2009	14	10	24	
2010	9	5	14	

Source: Dames & Moore

The activity schedule for the two fields is:

1979-80 - Lease sale.

1980 - One barge platform, one exploratory hole.

1981 - One barge platform, one soil island, two exploratory holes, Camden field discovery.

1982 - Two barge platforms, one ice platform, three exploratory holes, Camden field confirmation.

1983 - Two barge platforms, one soil platform, three exploratory holes, Canning field discovery.

1984 - Two soil platforms, one ice platform, three exploratory holes, Canning and Camden field confirmations.

1985 - Three soil platforms, three exploratory holes, Construction starts, Camden field.

1986 - Two soil platforms, two exploratory holes.

1987 - One ice island, one exploratory hole.

1990 - Production startup. Platform construction and production drilling continue.

1993-98 - Peak production period.

2005 - Two oil platforms shut in.

2010 - Last oil platform shut in.

2015 - Gas production shut in.

9.2.3. Facilities

A map of the assumed facility locations is given in Figure 27. Since the facility locations are predicted in part on hypothetical petroleum reservoirs, the map sites of Figure 27 are to be construed as hypothetical as well.

The two fields are assumed to share an airstrip and harbor. However, separate construction camps, 24 kilometers (15 miles) apart, are assumed. One hundred and three kilometers (sixty-four miles) of road between Deadhorse and Canning camp are assumed, including the harbor connector. Another 24 kilometers (15 miles) of road are required for the Camden camp tie-in. A small boat ramp or removable pontoon pier is assumed at the camp not adjacent to the harbor.

Figure 27

Scenario 1: Camden-Canning, 1.3 Bbbl. Reserves

After construction, a single base camp area near the harbor will be utilized. A flow center of 250 Mb/d and 230 MMcfd, capacity onshore opposite the Camden field will service that field and a portion of State lands production. The flow station for the Canning field, 24 kilometers (15 miles) west, will service that. field and the remaining State lands production. Nominal capacity needed would be 180 Mb/d and 150 MMcfd. In the vicinity of the Canning field flow station, compressor and pumping stations will provide motive force for delivery of the production to the respective Prudhoe Bay stations. A power plant would be included in the Canning onshore plant complex.

The offshore facility and major equipment inventory is given in Table 40. Primary oil and gas separation is accomplished on each platform, which average 40 wells each. Some booster stations are used on the platforms to bring the oil ashore to the flow centers.

Exploratory wells given in Table 40 include -- by allocation -- all wells in the eartern Beaufort. Exploration within the Camden area was assumed complete with 4 wells; in the Canning, with 5.

9.2.4 Manpower Summary

Annualized average employment and annual man-months of work are tabulated in Table 41. The major impact in employment generated by the scenario is in the construction phase of platforms, pipelines, and onshore facilitates. In the 1987-88 period, 1,740 and 1,370 man-years will be needed.

Individual employment impacts can also be judged by peak manpower estimates in direct employment given in Table 42. In the 1980-84 period, peak employment is around 200. With construction, however, peak employment by year is estimated at:

TABLE 40

CAMDEN-CANNING SCENARIO

FACILITIES

Platforms:		Soil/Gravel	Barge	Ice	Gravity
Camden:	Exploration	6	3	1	0
	Production	6	1	0	1
Canning:	Exploration	3	3	2	0
	Production	3	2	0	0

Wells:	Exploratory	Oil	Gas	Development
Camden	10	262	7-8	53-52
Canning	8	171	5-4	22-23

Pipelines:	Oil		Gas	
	km	miles	km	miles
Offshore Connection	85	53	63	39
Offshore Trunk	10	6	10	6
Onshore Trunk	87	54	87	54

Source: Dames & Moore

TABLE 41

MANPOWER SUNMARY SHEET

CAMDEN-CANNING SCENARIO

Phase	Year	PETROLEUM Man-Months	PETROLEUM Annual Monthly Average	CONSTRUCTION Man-Months	CONSTRUCTION Annual Monthly Average	TOTAL Man-Months	TOTAL Annual Monthly Average
Exploration Begins	1	911	76	106	9	1,017	85
	2	1,106	92	619	52	1,725	144
	3	1,301	108	362	30	1,663	138
	4	585	49	725	61	1,310	110
Decision to Develop Camden	5	585	49	2,666	224	3,251	273
	6	585	49	7,794	649	8,379	698
Decision to Develop Canning	7	1,974	165	14,387	1,200	16,361	1,365
	8	3,363	280	9,047	754	12,410	1,034
Camden Production Begins	9	8,280	690	6,968	581	15,248	1,271
	10	9,864	822	3,632	303	13,496	1,125
	11	12,048	1,004	990	83	13,038	1,087
Canning Production Begins	12	12,120	1,010	0	0	12,120	1,010
	13	12,120	1,010	990	83	13,110	1,093
	14	11,712	976	1,346	113	13,058	1,089
	15	10,416	868	0	0	10,416	868
	16	10,416	868	990	83	11,406	951
	17	9,768	814	60	5	9,820	819
	18	9,048	754	60	5	9,108	759
	19	8,328	694	60	5	8,388	699
	20	8,328	694	60	5	8,388	699
	21	7,608	634	60"	5	7,668	639
	22	7,608	634	60	5	7,668	639
	23	7,608	634	60	5	7,668	639
	24	7,608	634	60	5	7,668	639
	25	7,032	586	60	5	7,092	591
	26	7,032	586	60	5	7,092	591
	27	6,072	506	60	5	7,092	511
	28	6,072	506	60	5	7,092	511

Source: Dames & Moore

TABLE" 42

ESTIMATED ANNUAL EMPLOYMENT AND EMPLOYMENT PEAKS

CAMDEN-CANNING SCENARIO

Years from Start of Exploration

	1	2	3	4	5	6	7	8	9	10	11	12	13	14	15	16	17	18	19	20	21	22	23	24	25	26	27	28
Annual Monthly Average	88	144	138	110	273	698	1365	1034	1271	1125	1087	1010	1093	1089	868	951	819	759	699	699	639	639	639	639	591	591	511	511
Employment On Jan 1	0	132	216	207	165	349	1047	1551	1551	1688	*																	
Employment On June 1	44	72	69	55	273	698	1638	1034	1525	1125	*																	
Peak Employment	132	216	207	165	410	1047	2048	1551	1907	1688	*																	
Months of Peak	Sept Dec	Sept Dec	Sept Dec	Sept Dec	Sept	Dec	Sept	Jan	Sept	Jan																		

* As soon as production begins, employment is expected to stabilize at the annual monthly average, year around.

NOTE: See Manpower Summary Sheet (Table 41) for petroleum/construction breakdown and development schedule.

Source: Dames & Moore

Year	Manpower
1985	410
1986	1,047
1987	2,048
1988	1,551
1989	1,907
1990	1,688

After production starts, peak and average manpower are closely correlated. In the 1990-95 period, this is around 1000. By 2000, it has reached 700 and declines slowly until discontinuance of operations.

9.3 SCENARIO 2: PRUDHOE BAY OFFSHORE, 1.9 Bbbl.

9.3.1 Location and Environment

9.3.1.1 Tract Assumptions

This scenario encompasses 15,385 hectares (38,000 acres) of the central Alaskan Beaufort (Figure 26). The tracts assumed involved in the surface expression of the reservoir are[1]:

Prudhoe Bay Offshore - 31 tracts (34,157 hectares) (84,400 acres)

44 (A)	62 (C)	80 (C)	86 (c)	99 (c)	114 (A)
45 (A)	63 (C)	81 (A)	87 (C)	100 (A)	
46 (A)	64 (D)	82 (A)	95 (c)	110 (c)	
47 (A)	65 (A)	83 (A)	96 (A)	111 (A)	
48 (A)	66 (c)	84 (C)	97 (A)	112 (A)	
61 (A)	67 (C)	85 (C)	98 (A)	113 (A)	

A - Joint Federal-State and Disputed

C - State

D - Disputed

36% State; 64% joint and disputed.

(1) 'Tract designation according to Alaska Division of Lands, Federal/State, Beaufort Sea Oil and Gas Lease Sale Nomination Map (Preliminary), November 21, 1977.

As an alternate location, displaced a short distance into deeper water, the following tracts were involved. The shape and extent of the reservoir projection are identical, but the number of tracts involved is less.

Prudhoe Bay Offshore Alternate - 30 tracts (37,511 hectares) (92,688 acres)

427*	47 (A)	64 (D)	82 (A)	87 (C)	100 (A)
428*	48 (A)	65 (A)	83 (A)	96 (A)	111 (A)
429*	49 (A)	66 (C)	84 (C)	97 (A)	112 (A)
45 (A)	50 (A)	67 (C)	85 (C)	98 (A)	113 (A)
46 (A)	63 (A)	68 (c)	86 (C)	99 (c)	114 (A)

*Federal tracts of 2,304 hectares not included in joint State-Federal lease sale.

22% State; 18% Federal, 60% joint and disputed.

Although the Federal tracts are not included in the sale, it is reasonable to assume that they would be offered at a special sale, along with other open tracts, in the 1985-88 period. No adjustments or delays in development need be anticipated, since drilling and platform construction extend well beyond that period.

9.3.1.2 Physical Setting

The oil field lies between the inner barrier islands of Stump, Egg, and Long Island and the outer barrier island, Midway Island (Figure 28). Water depths at the field location vary from about 6 meters (20 feet) near Stump Island, to about 8.5 meters (28 feet) midway between Stump Island and Midway Island, and to a maximum of nearly 18 meters (60 feet) 19 kilometers (12 miles) west-northwest of Midway Island. A number of offshore shoals occur over the western half of the field.

Most of the oil field is located within the landfast ice zone, although in fall and early winter pack ice ridges may ground on the shoals located in the northwest section of the field. Subsea ice-rich permafrost within 20 meters (66 feet) of the sea floor is restricted to Prudhoe Bay and in the lagoon between the mainland and barrier islands.

Significant offshore sand and gravel sources appear to be present within and adjacent to the oil field location; these deposits are located off the Sagavanirktok River delta, and in band parallel to the bathymetric contours north of the barrier islands between Prudhoe Bay and the Colville River.

9.3.1.3 Environmental Considerations

Exploration and development will require care in selection of staging areas, camps and pipeline routes both offshore and onshore.

Critical wildlife concerns in this area include snow geese nesting on Howe Island, black brant nesting on the delta of the Kuparuk River, eider, gull, and tern nesting on offshore islands, caribou calving near the beach, and winter water removal from Sagavanirktok River (Cameron and Whitten, 1977; Hemming and Moorehouse, 1976; Wilson et al., 1977).

The Alaska Department of Fish and Game has concluded that essentially all of the Prudhoe Bay oil field has been abandoned as a caribou calving area since about 1974 (Cameron and Whitten, 1976; 1977; White et al., 1975). Therefore, the oil field area would be the best place to locate exploration and production facilities. Due to the fairly extensive losses from the caribou calving area to date, the Alaska Department of Fish and Game can be expected to be quite restrictive of activities within the remainder of the calving area.

Howe Island at the mouth of the Sagavanirktok River supports the only snow goose colony on the Arctic coast of Alaska. This small colony of about 60 nesting pairs would be threatened by any land uses on Howe Island or if a summer oil spill occurred in the area. Other nesting birds such as glaucous gulls, Arctic terns, and eiders make extensive use of Niakuk, Gull, Cross and Stump Islands.

Collection of potable water and gravel mining near the mouth of the Sagavanirktok River associated with oil field development and construction of the trans-Alaska pipeline have impacted overwintering fish populations (Wilson et al., 1977; U.S. Fish and Wildlife Service, 1976).

9.3.2. Schedule

This scenario is the most favorable situation postulated from the U.S.G.S. reserve estimates and use of Prudhoe Bay reservoir parameters. The leasing is assumed in the winter of 1979-80. Exploration begins in 1981, with discovery in 1982 and confirmation in 1983. Construction begins immediately, and the field is ready to produce by mid-1988.

The productivity of this reservoir results in a lesser drilling interval (from first well to last production well) and rapid buildup of the output. If the Alyeska pipeline has not been expanded to 2 MMb/d, contrary to the scenario assumptions used, it would be expanded for this production. The production schedule is given in Table 43.

The activity schedule is:

1979-80 - Lease sale
1981 - Two barge platforms set, one soil/gravel island, three exploratory holes.
1982 - Two barge platforms set, two exploratory holes, field discovery.
1983 - Two soil platforms set, two exploratory holes, field confirmation, construction buildup.

TABLE 43

PRODUCTION SCHEDULE

PRUDHOE BAY OFFSHORE

(1.9 Bbbl Oil, 4.75 tcf Gas)

Year	Oil (Mb/d)	Gas
1988	84	520 MMcfd constant 1988-2009
1989	300	
1990	465	
1991	602	
1992	647	
1993	635	
1994	565	
1995	461	
1996	360	
1997	273	
1998	210	
1999	161	
2000	123	
2001	93	
2002	58	
2003	38	
2004	22	
2005	10	
2006	3	

Year	Gas
2010	440 MMcfd
2011	350 MMcfd
2012	250 MMcfd
2013	150 MMcfd
2014	50 MMcfd

Source: Dames & Moore

1984 - Two soil island constructed, two exploratory holes, construction begins.

1985 - One artificial island set for exploration, and one ice island, two exploratory holes drilled, two production platforms, one barge based, the other an artificial island, constructed.

1986 - One soil platform set for exploration, one exploratory hole drilled, production drilling begins, two more platforms, both soil, placed for production.

1987 - Two ice islands set, two final exploration wells drilled. Two more platforms, one soil, one prefabricated platform (gravity structure), set for production.

1988 - Limited production starts on one platform.

1991-94 - Peak productive period.

1993 - Production drilling complete.

2006 - Oil production shut in.

2014 - Gas production shut in.

9.3.3. Facilities

The Prudhoe Bay Offshore field is assumed to make use of the Prudhoe Bay infrastructure, although the oil facilities there are not considered to be available. New airstrip, harbor, and construction camp are not assumed.

Two flow centers onshore, each of about 325 Mb/d and 280 Mb/d nominal capacity, are considered. Twin trunk corridors to the shore may be used, although a single trunk line onshore is projected for the 15 kilometer (9 mile) distance to the Alyeska-Alcan terminals. If the flow center space at the shore is not made available, offshore processing can be undertaken. Modular treatment centers would be installed at each platform, possibly as an ancillary platform separated for safety. Flow center power is purchased from surplus or expansion of the Prudhoe Bay field, depending on whether the field output is expanded in the 1979-83 time period. A map of the assumed facility layout is given in Figure 28.

The offshore facility inventory is given in Table 44. With respect to the 14 exploratory walls allocated to the scenario, only 3 or 4 are projected within the field boundaries.

9.3.4. Manpower Summary

The annual employment schedule in man-years and man-months is given in Table 45. Peak effort in the platform and short pipeline laying period is 1,977 man-years in 1986 and 1,686 in 1987. Measured in peak employment, the construction impacts are:

Year	Manpower
1985 -	884
1986 -	2750
1987 -	2529

After production starts, employment remains around 1,100 while drilling continues, then remains around 900 during the main portion of field production. The full schedule of peak employment is given in Table 46.

9.4 SCENARIO 3: PRUDHOE BAY OFFSHORE, 0.8 Bbbl

9.4.1 Location and Environment

9.4.1.1 Tract Assumptions

The location of the field is shown in Figure 26 and Figure 29, and involves the same region as Scenario 2.

This scenario has a surface expression of 10,931 hectares (27,000 acres). The following tracts in the joint State-Federal leasing area were assumed[1]):

(1)Tract designation according to Alaska Division of Lands, Federal/State, Beaufort Sea Oil and Gas Lease Sale Nomination Map (Preliminary), November 21, 1977.

TABLE 44

OFFSHORE FACILITES

PRUDHOE BAY OFFSHORE, 1.9 Bbbl

Platforms:	Barge-Base	Soil/Gravel	Ice	Gravity
Exploratory	4	7	3	0
Production	1	4	0	1

Wells:

Exploratory - 14
Oil - 253
Gas - 15
Development - 22

Pipelines:	Oil		Gas	
	km	miles	km	miles
Interplatform Connectors	68	42	48	30
Offshore Trunk	6	4(1)	6	4(1)
Onshore Trunk	15	9.5	15	9.5

(1) With twin corridors - 16 km (10 miles)

Source: Dames & Moore

TABLE 45

MANPOWER SUMMARY SHEET

PRUDHOE BAY OFFSHORE (1.9 Bbbl) SCENARIO

Phase	Year	PETROLEUM Man-Months	PETROLEUM Annual Monthly Average	CONSTRUCTION Man-Months	CONSTRUCTION Annual Monthly Average	TOTAL Man-Months	TOTAL Annual Monthly Average
	1	716	60	0	0	716	60
	2	1,301	108	725	60	2,026	168
	3	1,106	92	212	18	1,318	110
	4	390	33	1,026	86	1,416	119
	5	390	33	1,026	86	1,416	119
Decision to Develop	6	390	33	1,143	99	1,533	132
	7	195	16	2,880	240	3,075	256
	8	1,974	165	20,018	1,668	21,992	1,833
	9	3,168	264	17,069	1,422	20,237	1,686
Production Begins	10	13,152	1,096	60	5	13,212	1,101
	11	13,152	1,096	60	5	13,212	1,101
	12	13,152	1,096	60	5	13,212	1,101
	13	13,152	1,096	60	5	13,212	1,101
	14	11,712	976	60	5	11,772	981
	15	11,232	936	60	5	11,292	941
	16	9,972	831	60	5	10,032	836
	17	9,792	816	60	5	9,852	821
	18	9,792	816	60	5	9,852	821
	19	9,792	816	60	5	9,852	821
	20	9,792	816	60	5	9,852	821
	21	9,792	816	60	5	9,852	821
	22	9,792	816	60	5	9,852	821
	23	9,792	816	60	5	9,852	821
	24	9,792	816	60	5	9,852	821
	25	9,792	816	60	5	9,852	821
	26	9,792	816	60	5	9,852	821
	27	9,792	816	60	5	9,852	821
	28	8,832	736	60	5	8,892	741
	29	8,832	736	60	5	8,892	741

Source: Dames & Moore

TABLE 46

ESTIMATED ANNUAL EMPLOYMENT AND EMPLOYMENT PEAKS

PRUDHOE BAY OFFSHORE (1.9 Bbbl) SCENARIO

	Years from Start of Exploration																												
	1	2	3	4	5	6	7	8	9	10	11	12	13	14	15	16	17	18	19	20	21	22	23	24	25	26	27	28	29
Annual Monthly Average	60	168	110	119	119	132	256	1853	1696	1101	1101	1101	1101	981	941	836	821	821	821	821	821	821	821	821	821	821	821	741	746
Employment On Jan 1	0	90	252	165	179	179	128	384	2529	*																			
Employment On June 1	30	84	55	60	60	132	256	2200	1686	*																			
Peak Employment	90	252	165	179	179	198	384	2750	2529	*																			
Months of Peak	Sept Dec	Sept Dec	Sept Dec	Sept Dec	Sept Dec	Sept	Dec	Sept	Jan																				

* As soon as production begins, employment is expected to stabilize at the annual monthly average, year around.

NOTE: See Manpower Summary Sheet (Table 45) for petroleum/construction breakdown and development schedule.

Source: Dames & Moore

Prudhoe Bay Offshore - 21 tracts (22,177 hectares) (54,799 acres)

48 (A)	67 (C)	85 (C)	98 (A)	113 (A)
63 (A)	81 (A)	86 (C)	99 (C)	
64 (D)	82 (A)	95 (C)	110 (C)	
65 (A)	83 (A)	96 (A)	111 (A)	
66 (C9	84 (C)	97 (A)	112 (A)	

A - Joint State-Federal and Disputed
C - State
D - Disputed
37% State; 63% joint and disputed.

9.4.1.2 Physical Setting

The discussion of the Physical Setting in Section 9.3.1.2 covers this area.

9.4.1.3 Environmental Considerations

The discussion in Section 9.3.1.3 applies equally to this area.

9.4.2 Schedule

After a lease sale in the winter of 1979-80, exploration begins in 1981. Discovery and confirmation of the field come in succeeding years. However, the field characteristics are not auspicious, and further confirmation is obtained in 1984. Construction begins in 1985, production starts up in 1989.

A schedule of the field output is given in Table 47.

TABLE 47

PRODUCTION SCHEDULE

PRUDHOE BAY OFFSHORE

(0.8 Bbbl Oil, 1.6 tcf Gas)

Year	Oil (Mb/d)	Gas
1989	48	220 MMcfd constant 1989-2007
1990	106	
19!31	138	
1992	170	
1993	177	
1994	184	
1995	193	
1996	193	
1997	187	
1998	178	
1999	158	
2000	130	
2001	103	
2002	78	
2003	55	
2004	41	
2005	30	
2006	21	
2007	15	
2008	9	
2009	6	
2010	1	

Year	Gas
2007	200 MMcfd
2008	190 MMcfd
2009	100 MMcfd
2010	50 MMcfd

Source: Dames & Moore

The activity schedule is:

1979-80 - Lease sale.

1981 - Two barge drill platforms and one soil island are set, three exploration holes are sunk.

1982 - Two barge drill platforms are set, two exploratory holes are sunk, field discovery.

1983 - Two soil islands set, two exploratory wells drilled, field confirmation.

1984 - Two soil islands set, two exploratory wells drilled, one further confirms the field.

1985 - One ice platform set, one exploratory hole drilled, construction started.

1986 - One soil island placed for exploration, one exploratory hole drilled, one barge-base and one gravel/soil island constructed for production.

1987 - One ice island set, and a final exploratory hole drilled, production drilling begins.

1989 - Production begins.

1990-93 - One production platform completed each year, four rigs maintain drilling.

1992-98 - Steady production maintained, 170 to 193 Mb/d.

2010 - Field shut in.

9.4.3 Facilities

The smaller offshore Prudhoe Bay field will resemble the large version in the placement of facilities. Use of the infrastructure at Prudhoe Bay is assumed, without any of the processing facilities. Power may be purchased for an onshore flow center. No new harbor, base camp, or airstrip is assumed.

A flow center at the shore with capacity of 200 Mb/d and 250 MMcfd is the only major unit assumed onshore. A map of the facility placement is given in Figure 29. Alternative treatment centers offshore would use smaller modules of 100 Mb/d and 120 MMcfd capacity. A single trunk line to the shore is assumed.

Offshore facility inventory is listed in Table 48. Only four of the twelve exploratory wells associated with this scenario are within the field.

9.4.4 Manpower Summary

With an extended construction program of limiting production platforms to the capabilities of four drill rigs, this scenario generates less peak employment. The pipeline and equipment installation in 1987 and 1988 create 974 and 856 man-years work in those years. The complete man-year schedule is given in Table 49.

Peak employment of 1,505 and 1,284 occurs in that period. In the toll of drilling and platform construction in 1990-94, average peak employment would be about 600. The full schedule is given in Table 50.

9.5 SCENARIO 4: Cape Halkett 0.8 Bbbl

9.5.1 Location and Environment

9.5.1.1 Tract Assumptions

The Cape Halkett field lies off Cape Halkett, north of Harrison Bay, as shown in Figure 26 and Figure 30. The surface expression of the field encompasses 8,097 hectares (20,000 acres). The following tracts were involved in the assumed location of the field[1]:

---

(1) Tract designation according to U.S. Department of the Interior, Bureau of Land Management, Outer Continental Shelf Official Protraction Diagram, NR5-4, Harrison Bay, April 29, 1975.

TABLE 48

OFFSHORE FACILITIES

PRUDHOE BAY OFFSHORE

(0.8 Bbbl, 1.6 tcf)

Platforms:	Barge	Soil/Gravel	Ice	Gravity
Exploration	4	6	2	0
Production	2	5	0	1

Wells:		
	Exploratory	- 12
	Oil	- 270
	Gas	- 13
	Development & Services	- 47

Pipelines:	Oil		Gas	
	km	miles	km	miles
Connectors	80	50	32	20
Offshore Trunk	6	4	6	4
Onshore Trunk	15	9.5	15	9.5

Source: Dames & Moore

TABLE 49

NANPOWER SUMMARY SHEET

PRUDHOE BAY OFFSHORE (O .8 Bbbl) SCENARIO

Phase	Year	PETROLEUM Man-Months	PETROLEUM Annual Monthly Average	CONSTRUCTION Man-Months	CONSTRUCTION Annual Monthly Average	TOTAL Man-Months	TOTAL Annual Monthly Average
Exploration Begins	1	716	60	0	0	716	60
	2	1,355	113	725	61	2,080	173
	3	1,142	95	212	18	1,354	113
	4	426	36	1,026	86	1,452	121
	5	426	36	1,026	86	1,452	121
Decision to Develop	6	213	18	800	67	1,013	85
	7	213	18	2,960	247	3,173	265
	8	1,797	150	10,250	855	12,047	1,005
	9	3,168	.264	7,102	592	10,270	856
Production Starts	10	6,696	558	3,168	264	9,864	822
	11	6,696	558	990	83	7,686	641
	12	6,768	564	990	83	7,758	647
	13	6,840	570	356	30	7,196	600
	14	6,912	526	990	83	7,902	659
	15	7,944	662	60	5	8,004	667
	16	7,944	662	60	5	8,004	667
	17	7,224	602	60	5	7,284	607
	18	6,504	542	60	5	6,564	547
	19	6,504	542	60	5	6,564	547
	20	5,064	422	60	5	5,124	427
	21	5,064	422	60	5	5,124	427
	22	5,064	422	60	5	5,124	427
	23	5,064	422	60	5	5,124	427
	24	5,064	422	60	5	5,124	427
	25	5,064	422	60	5	5,124	427
	26	5,064	422	60	5	5,124	427
	27	5,064	422	60	5	5,124	427
	29	5,064	422	60	5	5,124	427
	30	4,104	342	60	5	4,164	347
	31	4,104	342	60	5	4,164	347

Source: Dames & Moore

TABLE 50

ESTIMATED ANNUAL EMPLOYMENT AND EMPLOYMENT PEAKS

PRUDHOE BAY OFFSHORE (0.8 Bbbl) SCENARIO

	Years from Start of Exploration																														
	1	2	3	4	5	6	7	8	9	10	11	12	13	14	15	16	17	18	19	20	21	22	23	24	25	26	27	28	29	30	31
Annual Monthly Average	60	169	110	118	118	83	263	1103	856	822	641	647	600	659	667	667	607	547	547	427	427	427	427	427	427	427	427	427	427	347	347
Employment On Jan 1	0	90	254	165	177	177	132	395	1284	*																					
Employment On June 1	30	85	55	59	59	83	263	1204	856	*																					
Peak Employment	9D	254	165	177	177	125	395	1505	1284	*																					
Months of Peak	Sept Oec	Sept Dec	Sept Dec	Sept Oec	Sept Oec	Sept	Dec	Sept	Jan																						

* As soon as production begins, employment is expected to stabilize at the annual monthly average, year around.

NOTE: See Manpower Summary Sheet (Table 49) for petroleum/construction breakdown and development schedule.

Source: Dames & Moore

Figure 30

Scenario 4: Cape Halkett, 0.8 Bbbl Reserves

7	52	96	141
8	53	97	142
51	95	98	

These are all Federal tracts of 2,304 hectares. The tracts contain 25,344 hectares (62,600 acres).

9.5.1.2 Physical Setting

The most seaward part of the Cape Halkett field lies 19 kilometers (12 miles) northeast of Cape Halkett in about 13 meters (44 feet) of water while the portion nearest the shore lies in about 7.6 meters (25 feet) of water.

The field lies for the most part in the landfast ice zone although a distinct shear line that follows the 10 meter (30-foot) bathymetric trend in west Harrison Bay may affect the outermost portion of the field location.

Bottom sediments in west Harrison Bay are probably silt and clay. Shoal areas located immediately north of the field and to the southeast in Harrison Bay (Pacific Shoal) may be composed of sandy or gravelly sediments. Approximately 122,000 cubic meters (160,000 cubic yards) of sand and sandy gravel have been mapped along the beaches within 10 kilometers (6 miles) of Cape Halkett.

9.5.1.3 Environmental Considerations

Except for waterfowl molting and staging areas just inshore from the exploration zone and summer concentrations of beluhka whales during some years in Harrison Bay, there are relatively few potential conflicts with staging areas, camps, or offshore pipelines. However, the use of above-ground pipelines from landfall at Cape Halkett to Prudhoe Bay could seriously influence the distribution and movements of the Central Arctic caribou herd (Child, 1973; Cameron and Whitten, 1976; 1977). Orientation of above-ground pipelines to an alignment immediately adjacent to the beach or increased use of undersea pipelines could significantly reduce adverse impacts on caribou.

Major waterfowl nesting areas and fish overwintering sites on the Colville River delta could be impacted by gravel mining, oil spills, and collection of potable water. Human activity, including movement of equipment and low-level aircraft operation, could result in desertion of nesting sights and seal hauling-out areas, and abandonment of seal pups.

Attraction of foxes and possibly polar bears by improper garbage handling or direct feeding will be a chronic impact requiring nearly constant attention.

Teshekpuk Lake lies a few miles inland from the coast and is a major fish overwintering area. It also supports a traditional subsistence fishery for local residents. This lake should be avoided.

9.5.2 Schedule

This field is assumed to be leased in the 1983-84 period. Exploratory drilling begins in 1985 and results in discovery. After confirmation in 1986, construction starts in 1988, production drilling in 1990. Initial production begins in mid-1992. The production schedule is given in Table 51.

The activity shedule is:

1983-84 - Lease sale.
1985 - One ice platform, one barge platform set, two exploratory holes drilled, field discovered.
1986 - One barge, two ice platforms set, three exploratory holes drilled, construction preparations.
1987 - One ice platform set, and one exploratory hole drilled, construction preparations.

TABLE 51

PRODUCTION SCHEDULE, CAPE HALKETT

(0.8 Bbbl Oil)

Year	Mb/d
1992	54
1993	127
1994	175
1995	227
1996	257
1997	260
1998	241
1999	207
2000	164
2001	128
2002	98
2003	75
2004	57
2005	44
2006	28
2007	19
2008	12
2009	7
2010	2

Source: Dames & Moore

1988 - One ice platform set, one exploratory hole drilled.

1989 - One final ice platform set, last exploratory hole drilled, one production island of soil/gravel finished.

1990 - Production drilling started, second platform of gravity type finished.

1991 - Gravity platform set.

1992 - Production starts.

1993 - Another gravity platform set at deepest section of field.

1995-99 - Peak production period.

2010 - Field shut in.

9.5.3 Facilities

The Cape Halkett field is nearly 150 kilometers (93 miles) from the Alyeska pipeline. For this distance of pipeline construction, the economics are close for a field of this size. The petroleum facilities are assumed to be offshore, with one of the four platforms built into a platform complex. A treatment facility of 300 Mb/d capacity, on a segment of the complex, provides pumping power to the Alyeska terminus. It also separates gas for reinfection. Gas turbine power is used in the field.

At the east Harrison Bay shore, the only installation is a short causeway at the pipeline landfall and above-ground installation (which includes a road along the line). A base camp, harbor, and airstrip are assumed on Cape Halkett.

The offshore facility inventory is given in Table 52. Three of the eight exploratory wells lie in the field boundaries. An alternative pipeline route onshore would measure in excess of 200 kilometers (124 miles). A map depicting facility location is given in Figure 30.

TABLE 52

OFFSHORE FACILITIES

CAPE HALKETT

	Barges	Soil	Ice	Gravity
Platforms:				
Exploratory	2	0	6	0
Production	0	1	0	3

Wells:	Exploratory	8
	Oil	- 143
	Gas	3 (injection)
	Development & Service	- 14

Pipeline:	Connector - 67 km (42 miles)
	Offshore Trunk - 82 km (51 miles)
	Onshore Trunk. - 66 km (41 miles)

Source: Dames & Moore

9.5.4 Manpower Summary

The construction of platforms and pipeline will crest employment of 884 and 606 man-years in the 1990-91 period. The manpower schedule is given in Table 53.

The impact of peak employment reached 1,326 and 909 in that peak period, and 648 in 1989. The employment Table 54 gives the complete schedule. After 1992, employment remains at about 500 through 1966.

9.6 SCENARIO 5: SMITH BAY - DEASE INLET EXPLORATION

9.6.1 Location and Environment

9.6.1.1 Tract Assumptions

No tracts for exploration were selected. The areas considered open to exploration are the Federal offshore tracts out to 20 meters (66 feet) depth in the western Beaufort. Smith Bay and Dease Inlet areas have been assumed as leased for exploration. Submerged lands within Dease Inlet and Smith Bay over which the Navy claimed control as proprietor of NPR-4 are not considered.

9.6.1.2 Physical Setting

The Smith Bay field is located just seaward of Smith Bay, 4.8 kilometers (3 miles) due north of Drew Point. The most seaward point lies 19 kilometers (12 miles) from shore in 11 meters (36 feet) of water; most of the field is located in water depths of between 3 and 9 meters (12 and 30 feet). Figures 26 and 31 show the scenario location.

The field lies well shoreward of the boundary between the landfast and pack ice (stamukhi zone). Subsea ice-rich permafrost probably underlies the shallow waters of Smith Bay at depths of 1 to 20 meters (3 to 66 feet) below the mudline.

TABLE 53

MANPOWER SUMMARY SHEET

CAPE HALKETT SCENARIO

Phase	Year	PETROLEUM Man-Months	PETROLEUM Annual Monthly Average	CONSTRUCTION Man-Months	CONSTRUCTION Annual Monthly Average	TOTAL Man-Months	TOTAL Annual Monthly Average
Exploration Begins	1	358	30	0	0	358	30
	2	748	62	256	21	1,004	83
	3	943	79	406	34	1,349	113
Decision to Develop	4	195	16	150	13	345	29
	5	195	16	1,418	119	1,613	135
	6	195	16	4,989	416	5,184	432
	7	792	66	9,814	818	10,606	884
	8	1,584	132	5,687	474	7,271	606
Production Starts	9	5,904	492	416	35	6,320	527
	10	5,904	492	60	5	5,964	497
	11	5,976	498	60	5	6,036	503
	12	5,976	498	60	5	6,036	503
	13	5,976	498	60	5	6,036	503
	14	5,496	458	60	5	5,556	463
	15	5,496	458	60	5	5,556	463
	16	4,776	398	60	5	4,836	403
	17	4,776	398	60	5	4,836	403
	18	4,776	398	60	5	4,836	403
	19	4,776	398	60	5	4,836	403
	20	4,776	398	60	5	4,836	403
	21	4,776	398	60	5	4,836	403
	22	4,776	398	60	5	4,836	403
	23	4,776	398	60	5	4,836	403
	24	4,776	398	60	5	4,836	403
	25	4,776	398	60	5	4,836	403
	26	4,776	398	60	5	4,836	403
	27	3,816	318	60	5	3,876	323
	28	3,816	318	60	5	3,876	323

Source: Dairies & Moore

TABLE 54

ESTIMATED ANNUAL EMPLOYMENT AND EMPLOYMENT PEAKS

CAPE' HALKETT SCENARIO

	Years from Start of Exploration																											
	1	2	3	4	5	6	7	8	9	10	11	12	13	14	15	16	17	18	19	20	21	22	23	24	25	26	27	28
Annual Monthly Average	30	83	113	29	135	432	884	606	527	497	503	503	503	463	463	403	403	403	403	403	403	403	403	403	403	403	323	823
Employment On Jan 1	0	45	125	170	45	216	648	909	*																			
Employment On June 1	15	42	57	15	135	432	1061	606	*																			
Peak Employment	45	125	170	45	203	648	1326	909	*																			
Months of Peak	Sept Dec	Sept Dec	Sept Dec	Sept Dec	Sept.	Dec	Sept	Jan																				

* As soon as production begins, employment is expected to stabilize at the annual monthly average, year around.

NOTE : See Manpower Summary sheet for petroleum/construction breakdown and development schedule.

Source: Dames & Moore

Little data is available on the bottom sediment: in the Smith Bay area but they are probably for the most part silts and clays. Onshore sand and gravel resources in the Smith Bay area are scarce. The extensive delta of the Ikpikpuk River, located at the head of Smith Bay, is composed of fine sand, silt, and mud. Beach development is poor along the shores of Smith Bay and eastward to Point McLeod with sand resources totaling only about 100,000 cubic meters (140,000 cubic yards).

9.6.1.3 Environmental Considerations

Smith Bay lies within a major migration zone for the belukha and endangered bowhead whales. Any offshore exploration or development within this area could influence whale migration and could come under criticism (or control) by whale hunters from Barrow, city and borough governments, the Alaska Department of Fish and Game, and the National Marine Fishery Service. Whales use this area between April and late September (Fiscus et al., 1976; Outer Continental Shelf Environmental Assessment Program, 1977c).

The Plover Islands area is an extremely important shorebird staging area from mid-July to August. Red phalaropes are the most abundant species. From Pitt Point to Cape Halkett, shorebirds and molting oldsquaws form dense aggregations in mid-summer (Weller et al., 1977). Oil spills or harassment could seriously affect these large concentrations of birds.

Attraction of foxes and possibly polar bears by improper garbage handling or direct feeding will be a chronic impact requiring nearly constant attention.

Onshore above-ground pipelines between Smith and Prudhoe Bays could seriously influence the distribution and movements of the Central Arctic caribou herd.

9.6.2 Schedule

Although this scenario was selected for exploration only, discoveries are assumed during exploration, and a persistent search until 1991 is assumed. A small oil field with reserves of 0.4 Bbbl is confirmed in 1987 but production is deemed uneconomic (see Figure 31 for field location).

The activity schedule is:

Year	Barge Platform	Ice Platform	Action
1983-84			Lease sale
1985		1	
1986		2	Oil discovery
1987		1	Small field confirmed
1988		1	Oil shows continue
1989		1	Oil shows continue
1990		1	
1991		1	Final exploration

One well per platform is assumed.

9.6.3 Facilities

No permanent facilities are invested in this scenario. Available facilites at Lonely are assumed. Temporary camp sites are cleaned out after use, and all of the drilling platforms are temporary -- barges or ice.

9.6.4 Manpower Summary

Exploratory activities generate only nominal manpower impacts. The man-year and employment peak schedules are given in Tables 55 and 56. The peak is 131 in 1987.

TABLE 55

MANPOWER SUMMARY SHEET

SMITH-DEASE SCENARIO

Year	PETROLEUM Man-Months	PETROLEUM Annual Monthly Average	CONSTRUCTION Man-Months	CONSTRUCTION Annual Monthly Average	TOTAL Man-Months	TOTAL Annual Monthly Average
1	358	30	0	0	358	30
2	553	46	150	13	703	59
3	748	62	300	25	1,048	87
4	585	49	362	30	947	79
5	390	33	256	21	646	54
6	390	33	256	21	646	54
7	195	16	150	13	345	29
8	195	16	150	13	345	29

Source: Dames & Moore

*This scenario has only an exploration phase.

TABLE 56

ESTIMATED ANNUAL EMPLOYMENT AND EMPLOYMENT PEAKS

SMITH-DEASE SCENARIO

	Years from Start of Exploration							
	1	2	3	4	5	6	7	8
Annual Monthly Average	30	59	87	75	54	54	29	29
Employment On Jan 1	0	45	89	131	113	81	81	44
Employment On June 1	15	30	44	38	27	27	15	15
Peak Employment	45	89	131	113	81	81	44	44
Months of Peak	Sept Dec	Sept Dec	Sept Dec	Sept Dec	Sept Dec	Sept Dec	Sept Dec	Sept Dec

NOTE: This scenario entails exploration only. See Manpower Summary Sheet (Table 55) for petroleum/construction breakdown.

Source: Dames & Moore

CHAPTER 10.0

CONCLUSIONS

The conclusions that may be derived from the study are summarized in the following sub-sections.

10.1 TECHNOLOGY

Beaufort Sea exploration within the landfast ice zone in water depths less than 20 meters (66 feet) will be primarily conducted from artificial soil islands, barges and, to a lesser extent, artificial ice islands. No role in exploration is anticipated for drillships, other floating rigs or gravity platforms. Exploration will therefore be essentially an extension of dryland technology using dryland Arctic drill rigs.

Production will be conducted primarily from artificial soil islands, reinforced with caissons or sheet piling, and to a lesser extent, from gravity structures such as the monopod or cone constructed off-site and towed to the Alaskan Beaufort.

10.2 RESOURCE ECONOMICS

1. From U.S.G.S. estimates, it is likely that at least one billion barrels of oil and 2.5 trillion cubic feet of gas will be discovered in the central and eastern Alaskan Beaufort between the shoreline and about the 20-meter (66-foot) isobath. This same estimate projects a small likelihood (100 to 1) that over 3 billion barrels of oil and 8 trillion cubic feet of gas will be discovered in this area.

2. New discoveries in the central and eastern Beaufort within the range of present estimates will rely upon existing transport systems of the North Slope.

3. The transport cost of Beaufort Sea resource production to transport centers for oil and gas assumed available for the North Slope places increasing resource size limitations for economic feasibility. In the case of Prudhoe Bay offshore the practical minimum field size required is 400 MMbbl. In the eastern Beaufort, up to 90 kilometers (54 miles) distance from Prudhoe Bay, 700 MMbbl to 1.0 Bbbl are reasonable minimum producible deposits, depending on the productivity of an average well. In the Cape Halkett area, about 150 kilometers (90 miles) from Prudhoe Bay 700 MMbbl to 1.0 Bbbl may be necessary to justify production, provided the Beaufort Sea pipelines can be constructed within projected costs. In the western Beaufort, 200 kilometers (120 miles) or more from Prudhoe Bay, at least one billion barrels of reserves may be necessary to justify production.

4. Economically producible resource discoveries to support a new trans-Alaska oil pipeline system, in addition to the 3.6 Bbbl which can be accommodated in the present system surplus, would have to total about 3.0 Bbbl. Gas reserves in addition to the 34 tcf which can be accommodated in the proposed Alcan system would have to total at least 10 tcf. These minimum levels are predicted upon small tariff premiums over those currently envisioned for the transport systems.

5. Western Beaufort production could support a Nome oil pipeline route from NPR-A. However, the estimated 3 Bbbl of oil which would have to be found in NPR-A are not considered likely. Current estimates of one billion barrels in NPR-A could be supported by fortunate levels of discovery in the Western Beaufort for a pipeline route to the Alyeska line.

6. The most likely discovery levels for the eastern Beaufort are marginally producible under the projected economic costs. Factors which favor development projections are the cost

effectiveness demonstrated by the industry in North Slope production well drilling and the potential for reducing offshore pipeline costs relative to those incurred onshore.

7. Beaufort Sea discoveries cannot be projected as stimulating Alaskan petrochemical development because they would not alter but would follow any pattern set by present Prudhoe Bay production.

10.3 MANPOWER REQUIREMENTS

1. It is clear from this study that the actual manpower requirements of production of offshore petroleum reserves in the Arctic will hinge on the technology employed, especially the type of platforms used, the development schedule, and the number and size of fields, which determine the number of platforms and scale of production equipment that must be installed.

2. In the development scenarios described in this study, manpower requirements are modest, certainly in comparison to the manpower requirements of developing the Prudhoe Bay field; the highest peak employment is some 2,750 men for the Prudhoe Bay (1.9 Bbbl) scenario, and the smallest peak is some 1,326 for the Cape Halkett scenario.

3. It is assumed in this study that new offshore production would be shipped via the existing Alyeska pipeline as capacity becomes available (construction of a second Alyeska pipeline would require substantial employment, estimated at 50 to 60 percent of that required to build the first line); so that pipeline construction is limited to connecting lines to Alyeska Pump Station No. 1.

4. Development of new offshore fields in the Prudhoe Bay area will benefit from existing infrastructure at the Prudhoe Bay field, such as airfields, construction camps and roads; however, the other fields will benefit only marginally from Prudhoe Bay facilities and duplication of this infrastructure will be required.

10.4 SELECTED SCENARIOS

A range of U.S.G.S. resource values allocated according to a geologic assessment provided 24 skeletal scenarios. Of these, four were selected for detailed analysis. These provided a range of location and developmental magnitudes that allowed the most realistic prediction of baseline conditions (project description) for subsequent socioeconomic impact assessment. With the exception of the Prudhoe Bay scenarios, only one of which may occur, the selected scenarios, although individually analyzed, represent the cumulative petroleum development as anticipated in the Beaufort Sea within the confines of the U.S.G.S. estimates and lease sale areas.

Selected Scenario	Reserves Oil Bbbl	Lease Sale
Camden-Canning	1.3	Joint State-Federal
Prudhoe Bay Offshore (1)	0.8	Joint State-Federal
Prudhoe Bay Offshore (1)	1.9	Joint State-Federal
Cape Halkett	0.8	Federal OCS
Smith-Dease (2)	0.4	Federal OCS

Notes:

(1) For cumulative impact analysis only one scenario can be taken.

(2) Oil discoveries are deemed uneconomic - only exploration occurs.

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GLOSSARY

(Important economic, technical and environmental terms are defined in the text)

caisson - load-bearing enclosures sunk into the ground to protect excavation for a foundation, or serve as part of a permanent structure, or enclose subsurface space for machinery, constructed of steel or concrete.

gabions - wire-mesh enclosures of rock or aggregate used for slope protection, erosion control.

ice rafting - pressure process by which one ice floe overrides another forming a ridge.

ice scours or gouges - linear scars in sea bottom sediments caused by plowing of grounded ice masses.

isobath - submarine contour or line joining points of equal depth of a horizon below the surface.

lead - a navigable passage through floating ice.

Permafrost - perennially frozen ground in which a temperature below 0°C (32°F) has existed for a long time (from two years to tens of thousands of years).

piles - slender, underground columns, generally placed in groups, supporting loads, constructed of wood, steel or concrete.

pingo - large ice-cored mound, ranging from a few feet to over 60 meters (200 feet) in height, term derived from a Eskimo name for hill.

pol ynya - any water area in pack ice or fast ice other than a lead, not large enough to be called open water; some are found in the same location every year, e.g. off the mouth of a large river.

pressure ridge - ridge or wall of broken floating ice forced up by pressure [can be up to 45 meters (150 feet) thick].

pressure ridge keel - underside of pressure ridge projecting toward sea floor.

Quaternary - the latest period of geologic time encompassing the past two million years including the glacial epochs and post-glacial (Holocene) time.

sheet piles - vertical, interlocking sections driven into ground to form a wall or enclosure, commonly made of wood, steel or concrete.

spud - original meaning to dig with a spade but term adapted to cable tool drilling to describe starting a new hole with a special tool; nowadays to spud means to start a new well.

stamukhi zone - boundary between landfast ice and (westward) drifting polar pack ice characterized by linear pressure and shear ridges, and ice gouging of the bottom sediments.

strudel - from the German meaning whirlpool, irregularly-shaped drain holes in fast ice through which fresh water drainage gushes downward during breakup, commonly where rivers temporarily overflow fast ice during spring between shore and barrier islands.

thermokarst - collapse of topographic features produced by melting of ground-ice and subsequent settling or caving of the ground; degradation of permafrost caused by disturbance of thermal regime.

LIST OF ABBREVIATIONS

(Abbreviations used in the text and listed below pertain to, or are used with oil and gas units)

B -	billion
bcf -	billion cubic feet
bcfd -	billion cubic feet per day
bbl -	barrel (volumetric measure equal to 42 U.S. gallons)
bbl/d, bpd, b/d -	barrels per day
cf -	cubic feet
M -	thousand
Mb/d -	thousand barrels per day
Mcf -	thousand cubic feet
Mdf/d -	thousand cubic feet per day
MM -	million
MMbbl -	million barrels
t -	trillion
tcf -	trillion cubic feet

APPENDIX A

PETROLEUM GEOLOGY

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APPENDIX A

PETROLEUM GEOLOGY

HISTORY OF EXPLORATION

Early Navy Exploration

Oil seeps on the North Slope were long known to the Eskimos and early Arctic explorers. Seepages had been reported at Skull Cliff, Cape Simpson, Fish Creek, Barter Island, and Umiat. Modern interest in the resources of the region began in 1901 with the first geologic traverse, and by 1923 there was sufficient data to indicate the possibility of oil deposits. In that year, Naval Petroleum Reserve No. 4 (NPR-4) was established by Executive Order No 3797-A. Signed by President Harding, it put aside a 93,240-square-kilometer (36,000-square-mile) area on the western North Slope as a defense reserve under Navy jurisdiction. To evaluate the resources of NPR-4, the U.S. Geological Survey conducted a series of reconnaissance surveys in the 1920's and 1930's that mapped the geology and geography, and evaluated the petroleum potential".

With the impetus of the Second World War and the need for additional oil reserves, the Navy in 1944 commenced a vigorous exploration and drilling program which was continued after the war under a private contract until close-out in 1953. The program completed 36 test wells, 44 core tests, more than 93,000 square kilometers (36,000 square miles) of seismic survey, 54,400 square kilometers (21,000 square miles) of reconnaissance geologic mapping and 67,300 square kilometers (26,000 square miles) of gravimetric survey. This work resulted in the discovery of nine oil and gas fields, none of which contained commercial reserves. The most extensive oil field is Umiat, located in the southeastern part of NPR-4 with 70 million barrels of recoverable reserves as estimated by the Navy. The second largest oil field is the Simpson Field with 12 million barrels of recoverable reserves. Discovered in 1949, the

South Barrow Gas Field has estimated recoverable reserves of 25.2 billion cubic feet and presently supplies the village of Barrow and nearby Naval installations. Since 1949, nine wells have been drilled in the development of this gas field; and in order to meet increasing demand, two additional wells are planned. The Gubik Gas Field, located mostly outside NPR-4 on the Colville River east of Umiat, has estimated reserves of 295 billion cubic feet. An in-depth description of the 1944-53 exploration program of NPR-4 and adjacent areas is given by Reed (1958).

Eastern North Slope

After the termination of the first NPR-4 exploration program in 1953, no wells were drilled on the North Slope until 1963 when British Petroleum and other companies renewed exploration activities. Seven relatively shallow wells were drilled between 1963 and 1965, mainly in the vicinity of Umiat (Gryc, 1970). Like the original NPR-4 program, the new exploration program concentrated on the relatively shallow Cretaceus sediments. Subsequent exploration moved northward toward the Colville delta and Prudhoe Bay where deeper wells were drilled. In 1968, the 12th well, ARCO Bay State No. 1, was drilled into the deeper Sadlerochit formation of Permo-Triassic age at Prudhoe Bay and became the discovery well. The Prudhoe Bay field is estimated to contain 9.6 billion barrels recoverable oil reserves and 26.5 trillion cubic feet recoverable gas reserves, which makes this discovery the largest single find in North America (Carter et al., 1977). As a result, the Prudhoe Bay discovery has spurred significant interest in Arctic oil and gas exploration. With completion of the trans-Alaska pipeline in the summer of 1977, attention has shifted to the gas pipeline project and expansion of exploration on the North Slope and Beaufort Sea.

Exploration drilling has continued on state leases on the fringes of Prudhoe Bay including a coastal strip that extends from the Arctic National Wildlife Range in the east to the Colville River delta in the west. In the spring of 1977, Union Oil completed an exploration well from an ice island in the Beaufort Sea located 5 kilometers (3 miles) west of Oliktok Point. Also, in the winter of 1976-77, British Petroleum drilled an exploration well from a gravel island just over one mile from shore in Prudhoe Bay. Two recently announced oil discoveries near the Canning River on the eastern North Slope adjacent to the Arctic National Wildlife Range suggest considerable hydrocarbon potential in that area and adjacent areas offshore. Exxon's "Alaska State" No. 1 well on Flaxman Island, drilled in 1975, tested 1,586 barrels per day of oil and 1.4 million cubic feet per day of gas from Eocene sands (Exxon, 1977). Seven miles to the west, Exxon's "Point Thompson" No. 1 well, completed in the summer of 1977, encountered oil and gas in lower Cretaceus sands that flowed at 2,300 barrels per day and 14 million cubic feet per day, respectively (Anchorage Times, November 2, 1977). Exxon has applied for a drilling permit to drill a step-out well four miles to the west. Near Prudhoe Bay, Sohio/BP and Exxon plan offshore wells in the Sagavanirktok delta area in 1978.

In addition to discovery of oil in the Permo-Triassic Sadlerochit formation at Prudhoe Bay, significant oil deposits have-been discovered in the lower Cretaceus Kuparuk River formation and Mississippian-Pennsylvanian Lisburne group. Development drilling is currently being conducted in the Kuparuk pool , which mainly lies west of the Prudhoe Bay field, to assess the reservoir characteristics and the viability of Kuparuk production (Oil and Gas Journal, October 30, 1977). If the tests prove successful, Atlantic Richfield plans a 32-well drilling program from four pads to produce about 65,000 barrels per day to commence in 1981. Total Kuparuk reserves are estimated to be as much as one billion barrels. Additional Kuparuk development could provide a substantial portion of the 300,000 barrels per day to 500,000 barrels per day needed to fill the Alyeska pipeline at its maximum capacity of 2 million barrels per day.

A listing of North Slope exploration wells between 1946 and 1977 is given in Table A-1. Existing North Slope oil and gas fields are identified in Table A-2.

TABLE A-1

EXPLORATORY WELLS ON THE NORTH SLOPE OF ALASKA

Well No.	Well Name	Location-UM TwP	RNG	SEC	Spud Date	Comp Date	Comp. Status	Total Depth(feet)	API No.
1	Kaolak 1	7N	34W		7/21/51	11/12/51	PA	6,952	2971000100
2	Mead 1	8N	22W		5/2/50	8/21/50	PA	5,305	1631000200
3	Pt. Barrow 1	23N	18W						
4	S. Barrow 1	23N	18W		8/15/48	11/11/48	PA	3,553	0231000900
5	S. Barrow 4	22N	18W		3/9/50	4/1/50	PA	2,538	
6	S. Barrow 2	22N	18W	14	12/18/48	4/15/49	GAS	2,505	0231001000
7	Avak 1	22N	17W		10/21/51	1/14/52		4,020	0231001300
8	S. Barrow 3	21N	18W		6/23/49	8/26/49	PA	2,900	0231001100
9	N. Simpson 1	20N	12W		5/6/50	6/3/50	PA	3,774	0231000400
10	W. Sak River St. 7	11N	10E	9					0292023700
11	Simpson 1	18N	13W		6/14/47	6/9/48	PA	7,002	2791003200
12	S. Simpson 1	17N	12W	36	3/9/77	4/29/77	PA	8,795	2792000100
13	Topagoruk 1	15N	15W		6/15/50	9/28/51	PA	10,503	2791003300
14	E. Topagoruk "	14N	13W		2/18/51	4/16/51	PA	3,589	2791003400
15	W.T. Foran 1	17N	2W	13	3/7/77	4/23/77	PA	8,864	1032001000
16	Cape Halkett	16N	2W	5	3/24/75	5/22/75	SUSP	9,900	1032000400
17	E. Teshekpuk '	14N	4W	16	3/12/76	5/10/76	PA	10,664	1032000600
18	Atigaru Point 1	14N	2E	19	1/12/77	3/18/77	PA	11,535	1032000800
19	S. Harrison Bay 1	12N	2E	6	12/21/76	2/8/77	PA	11,290	1032000700
20	Fish Creek 1	11N	1W	11	2/14/77	4/27/77	PA	11,427	1032000900
21	Fish Creek 1	11N	2E		5/17/49	9/4/49	PA	7,020	1031000100
22	Oumalik 1	6N	16W		6/11/49	4/23/50	PA	11,872	1191000500
23	E. Oumalik 1	5N	15W		10/23/50	1/7/51	PA	6,035	1191000600
24	Titaluk 1	1N	11W		4/22/51	7/6/51	PA	4,020	1191001100
25	Knife Blade 1	4s	13W		10/13/51	12/22/51	PA	1,805	1191001200

* Current Status
PA Plugged and Abandoned
SUSP Suspended
GAS/OIL SHUT IN = Not currently producing

TABLE A-1, Cont.

Well No.	Well Name	Location-UM TWP	RNG	SEC	Spud Date	Comp Date	Comp. Status	Total Depth(feet)	API No.
26	Knife Blade 2	4S	13W		7/26/51	8/5/51	PA	373	1191001300
27	Square Lake 1	3N	5W		1/26/52	4/18/52	PA	3,987	1191000700
28	Wolf Creek 2	1N	4W		6/6/51	7/1/51	PA	1,618	1191000900
29	Wolf Creek 3	1S	5W		8/20/52	11/3/52	PA	3,760	1191001000
30	Wolf Creek 1	1S	4W		4/29/51	6/4/51	PA	1,500	1191000800
31	Umiat 1	1N	2W		6/22/45	10/5/46	PA	6,005	2871000100
32	Umiat 2	1N	1 W		6/25/47	12/12/47	PA	6,212	2871000200
33	Umiat 3	1N	1W		11/15/46	12/26/46	OIL	572	2871000300
34	Umiat 4	1N	1W		5/26/50	6/30/50	PA	840	
35	Umiat 5	1N	1 W		7/5/50	9/15/50	PA	1,075	
36	Umiat 6	1N	1W		8/14/50	9/3/50	PA	825	
37	Umiat 7	1N	1W		12/14/50	4/12/51	PA	1,384	
38	Umiat 8	1N	1W		5/2/51	8/28/51	PA	1,080	
39	Umiat 9	1N	1W		6/25/51	1/15/52	PA	1,257	
40	Umiat 10	1N	1W		9/9/51	1/10/52	SUSP	1,573	
41	Umiat 11	1N	1W		6/13/52	8/29/52	PA	3,303	
42	Little Twist 1	3S	4W	34	5/12/64	7/7/64	PA	3,625	2871002200
43	E. Kurupa 1	7S	6W	9	12/9/75	5/1/76	PA	12,277	1372000200
44	Grandstand	5S	1E	32	5/1/52	8/8/52	PA	3,939	0571000100
45	Colville U 2	1S	1E	11	11/28/71	12/25/71	PA	3,254	2872000400
46	E. Umiat U 2	1S	1E	15	4/5/69	5/21/69	SUSP	2,841	2872000200
47	Colville U 1	1S	1E	21	1/26/70	3/11/70	PA	4,150	2872000300
48	E, Umiat U 1	1S	2E	19	1/13/64	3/28/64	GAS SHUT IN *	3,347	2871001600
49	S. Barrow #13	22N	18W		12/17/76	1/17/77	PA	2,534	0232000800
50	Gubik 1	IN	3E	21	5/20/50	8/11/51	PA	6,000	2871001300

* Current Status
PA Plugged and Abandoned
SUSP Suspended
GAS/OIL SHUT IN = Not currently producing

TABLE A-1, Cont.

Well No.	Well Name	Location-UM TWP	RNG	SEC	Spud Date	Comp Date	Comp. Status	Total Depth(feet)	API No.
51	Gubik 2	1N	3E	20	9/10/51	12/14/51	PA	4,620	2871001400
52	Itkillik 1	1N	6E	11	1/9/65	3/22/65	PA	7,751	2871002000
53	Kuparuk 1	2s	5E	1	5/1/64	11/24/64	PA	6,570	2871001800
54	E. Kuparuk U 1	2s	8E	10	3/ 30/69	7/6/69	PA	7,000	2872000100
55	Schrader 1	3s	5E	18	3/18/64	4/24/64	PA	5,129	2871002100
56	Shale Wall 1	5s	5E	2	1/15/64	3/7/64	PA	4,026	2871001700
57	Aufeis U 1	3s	11E	30	6/3/74	9/10/74	PA	7,943	2232001000
58	Lupine U 1	4s	14E	13	6/19/74	4/24/75	PA	14,268	2232001100
59	Colville Delta Station 1	3N	6E	9	2/16/70	4/22/70	PA*	9,299	1032000200
60	Colville Delta Station 2	3N	6E	12					1032000500
61	Socal 31-25	ON	14E	25	1/19/69	4/21/69	SUSP	10,269	0292000700
62	Milne Pt. 18-1	3N	10E	11	4/30/70	7/18/70	SUSP	11,074	0292006900
63	Beechey Pt. 1	12N	12E	20	11/18/69	1/19/70	PA	10,610	0292004800
64	Simpson Lagoon 32-14A	13N	9E	14	7/21/69	11 /9/69	OIL SHUT IN	8,931	0292002901
65	Kalubik Creek 1	12N	8E	10	12/16/69	3/27/70	pA*	10,107	1032000100
66	Ugnu 1	12N	9E	22	2/27/69	5/9/69	OIL	9,428	0292000900
67	E. Ugnu 1	12N	10E	17	1/24/70	5/5/70	SUSP	9,775	0292005200
68	Colville 1	12N	7E	25	11/12/65	3/8/66	PA	9,930	1031000200
69	Kookpuk 1	11N	7E	19	12/21/66	3/10/67	PA	10,193	1031000300
70	W. Sak Riv St 2	11N	10E	22	3/16/74	4/30/74	SUSP-OIL	6,700	0292013400
71	W. Sak Riv St 3	11N	9E	26	3/25/75	4/26/75	SUSP	6,370	0292003900
72	W. Sak Riv St 5	10N	10E	11	3/1/75	4/1/75	SUSP	6,702	0292014100
73	Hemi St 1	9N	11E	3	4/27/69	5/30/69	SUSP	6,032	0292001800
74	Itkillik River U 1	8N	5E	10	2/15/72	7/23/72	PA	15,321	1032000300
75	Toolik Fed 3	8N	9E	4	1/28/70	3/15/70	PA	6,020	0292005100

* Current Status
PA Plugged and Abandoned
SUSP Suspended
GAS/OIL SHUT IN = Not currently producing

TABLE A-1, Cont.

Well No.	Well Name	Location-UM TWP	RNG	SEC	Spud Date	Comp Date	Comp. Status	Total Depth(feet)	API No.
76	Toolik Fed 2	8N	12E	5	7/31/69	9/14/69	PA	8,700	0292004100
77	W. Channel 1-3	9N	15E	3	3/2/72	4/23/72	PA	9,880	0292011400
78	Kadler St 15-9-16	9N	16E	15	5/7/69	9/15/69	pA*	15,543	0292001900
79	N. Franklin U 1	8N	14E	20	3/14/73	3/24/73	PA	3,500	0292012200
80	Toolik Fed 1	8N	15E	4	1/13/69	4/15/69	PA	10,814	0292000500
81	Lake 79 Fed	8N	17E	1	7/6/69	10/22/69	PA	15,544	0292003100
82	Kad River 1	8N	18E	4	6/5/69	9/24/69	PA	13,161	0292002100
83	Mikkelson Bay St	9N	19E	13	2/20/70	9/30/70	PA	16,596	0292005500
84	E. Mikkelson Bay	9N	21E	7	1/12/71	6/16/71	PA	15,205	0892000200
85	Alaska St. A	10N	24E	27	3/23/75	9/6/75	OIL	14,206	0892000300
86	W. Staines St 1	9N	23E	18	2/8/70	8/13/70	PA*	13,329	0892000100
87	W. Staines St 2	9N	22E	25	3/8/75	5/26/75	PA	13,171	0892000400
88	Kadiero Shilik U 1	5N	14E	14	1/24/74	2/21/74	PA	4,566	2232000900
89	Bush Fed 1	4N	13E	31	1/4/70	8/9/70	PA	16,090	2232000400
90	Nora Fed 1	2N	14E	5	3/31/69	4/10/70	PA	17,658	2232000300
91	Susie U 1	2N	13E	22	2/27/66	1/9/67	PA	13,517	2231000100
92	W. Kavik U 1	5N	20E	20	2/8/69	1/13/70	PA	16,613	2232000200
93	Beli Unit 1	4N	23E	8	1/20/73	6/24/73	PA	14,584	1792000200
94	Canning Riv UB 1	4N	24E	32	12/29/74	4/22/75	PA	10,803	1792000600
95	Knife Blade 2A	4s	13W		8/6/51	10/7/51	PA	1,805	1191001400
96	Kavik 1	3N	23E	7	2/5/69	11/5/69	GAS	9,564	1792000100
97	Kavik U 3	3N	22E	11	2/14/73	4/24/73	PA	7,357	1792000300
98	Canning Riv U BA 1	3N	24E	19	3/22/74	7/7/74	PA	8,874	1792000500
99	Shaviovik Unit 1	2N	19E	8	1 /26/69	7/4/69	PA	7,995	2232000100
100	Fin Ck U 1	2N	18E	25	2/21/71	12/9/72	PA	16,119	2232000700

* Current Status
PA Plugged and Abandoned
SUSP Suspended
GAS/OIL SHUT IN = Not currently producing

TABLE A-1, Cont.

Well No.	Well Name	Location-UM TWP	RNG	SEC	Spud Date	Comp Date	Comp. Status	Total Depth(feet)	API No.
?01	Kemik Unit 1	1N	20E	17	1/1/71	6/17/72	GAS SHUT IN *	16,073	2232000500
102	Kemik U 2	1S	21E	6	1/31/75	5/6/75	PA	8,880	2232001300
103	E. Harrison Bay 1	13N	8E	10	2/14/77	4/6/77	SUSP	9,809	2502000100
104	S. Barrow #14	22N	17W		1/27/77		GAS		0232000900
105	Pt. Thomson 1	10N	23E	32	3/3/77		OIL	13,298	0892000500
106	E Chooka U 1	1N	16E	32	4/16/72	9/23/72	PA	13,015	2232000800
107	Ivishak U 1	1S	16E	6	1/21/75	3/12/'75	PA	2,855	2232001400
108	W. Kurupa U 1	6S	14W	33	12/6/75	4/14/76	PA	11,060	1372000100
109	Tulugak 1	5S	3E	26	5/15/77				0572000100
110	Gull Island 2	12N	15E	28	12/29/76	4/22/77	SUSP	10,125	0292019500
111	Kuparuk U 1A	2S	5E	1	11/26/64	12/5/64	PA	758	2871001900
112	Sag Delta 1	11N	16E	5					0292000300
113	Prudhoe Bay St 1	11N	14E	10	4/22/67	6/24/68	GAS	12,005	0292000100
114	Sag River St 1	10N	15E	4	5/3/68	11/17/68	OIL	12,942	0292000200
115	Kuparuk St 1	11N	12E	21	11/15/68	4/7/69	OIL SHUT IN *	11,099	0292000800
116	Sag Delta 4	12N	16E	35	3/30/77				0242024500
117	Put River 1	11N	14E	27	11/20/68	3/31/69	SUSP	9,240	0292000600
118	Delta State 1	10N	16E	10	12/9/68	2/27/69	SUSP	10,001	0292000400
119	Sag Delta 10-11-16	11N	16E	10	1/6/77	4/26/77	SUSP	12,535	0292023400
120	Sag Delta 35-10-16	12N	16E	35	1/23/77	3/23/77	SUSP	11,279	0292023300
121	Put River 33-11-13	11N	13E	33	1/24/69	5/5/69	SUSP	10,259	0292001000
122	Sag Delta 31-11-16	11N	16E	31	3/7/69	4/28/69	SUSP	9,094	0292001100
123	Lake St 1	10N	15E	24	3/22/69	7/8/69	SUSP	10,003	0292001200
124	Put River 24-10-14	10N	14E	24	4/14/69	7/3/69	SUSP	10,315	0292001500
125	N.W. Eileen St 1	12N	11E	28	4/15/69	7/26/69	SUSP	9,997	0292001300

* Current Status
PA Plugged and Abandoned
SUSP Suspended
GAS/OIL SHUT IN = Not currently producing

TABLE A-1, Cont.

Well No.	Well Name	Location-UM TWP	RNG	SEC	Spud Date	Comp Date	Comp. Status	Total Depth(feet)	API No.
126	Kup River St 1	12N	13E	21	4/25/69	6/27/69	SUSP	10,512	0292002200
127	W. Kuparuk St. (03-11-11)	11N	11E	3	5/5/69	8/8/69	SUSP	11,532	0292001400
128	Hurl St. 05-10-13	10N	13E	5	5/11/69	8/20/69	OIL SHUT IN *	11,420	0292002700
129	Sag Delta 31-10-16	10N	16E	31	5/11/69	10/13/69	SUSP	13,877	0292003000
130	Put River St. 1	10N	14E	7	5/12/69	7/1/69	SUSP	9,903	0292001700
131	Put River J-1	11N	13E	9	5/14/69	9/13/69	SUSP	11,871	0292002000
132	Simpson Lagoon (32-14)	13N	9E	14	5/24/69	7/24/69	PA	10,017	0292002900
133	Pt. Storkersen 1	12N	14E	7	6/9/69	11/25/69	OIL	11,473	0292001500
134	N. Kuparuk St. (26-12-12)	12N	12E	26	6/12/69	8/24/69	OIL SHUT IN *	10,311	0292003200
135	Kavearak Pt. 32-25	13N	10E	25	6/16/69	10/24/69	OIL SHUT IN *	9,799	0292002800
136	S.E. Eileen St. 1	11N	12E	35	7/22/69	9/15/69	PA	11,207	0292004000
137	S.E. Eileen St. 2	11N	12E	35	10/24/69	12/29/69	OIL SHUT IN *	9,170	0292004001
138	N. Prudhoe Bay St 1	12N	14E	23	1/29/70	4/9/70	SUSP	9,610	0292004900
139	Plaghm Beechey Pt 1	13N	11E	14	11/19/70	1/21/71	PA	11,922	0292008200
140	Pt. McIntyre 1	12N	14E	10	8/12/77	10/7/77	SUSP	13,000	0292026400
141	N.W. Eileen St 2	12N	11E	28	3/19/72	4/27/72	PA	3,033	0292011700
142	Gwydyr Bay St A	13N	13E	31	12/30/73	4/25/74	PA	11,615	0292013000
143	East Bay St 1	11N	15E	15	7/15/74	12/31/74	SUSP	10,613	0292013300
144	Gwydyr Bay South 1	12N	13E	8	11/15/74	4/6/75	OIL SHUT IN *	12,234	0292014900
145	West Beach St 1	12N	14E	25	1/25/75	5/9/75	SUSP	9,656	0292013800

* Current Status
PA Plugged and Abandoned
SUSP Suspended
GAS/OIL SHUT IN = Not currently producing

TABLE A-1, Cont.

Well No.	Well Name	Location-UM TWP	RNG	SEC	Spud Date	Comp Date	Comp. Status	Total Depth(feet)	API No.
146	Foggy Island Bay U 1	11N	17E	19	2/3/75	4/26/75	SUSP	11,202	0292014600
147	Niakuk 1	12N	15E	26	2/12/75	4/13/75	PA	11,127	0292015500
148	Delta State 2	11N	16E	35	3/5/75	5/17/75	SUSP	11,026	0292015000
149	Gull Island St. 1	12N	15E	28	3/13/75	4/1/76	SUSP	11,691	0292015100
150	W. Sak River St 6	11N	11E	29	4/11/75	5/1/75	SUSP	7,100	0292014200
151	W. Beach St. 2	12N	14E	25	5/1 7/75	8/7/75	SUSP	10,115	0292016100
152	Niakuk 2	12N	15E	26	12/23/75	3/4/76	SUSP	10,478	0292018000
153	Niakuk 1-A	12N	15E	26	3/1 3/76	4/30/76	SUSP	11,391	0292015601
154	W. Beach St. 3	12N	14E	25	4/15/76	7/26/76	SUSP	8,623	0292020300
155	Niakuk 2-A	12N	15E	26	1/3/77	3/30/77	SUSP	10,150	0292018001
156	Sag Delta 35-12-16	12N	16E	35	1/23/77	3/23/77	SUSP	11,279	0292023300
157	Iko 1	21N	16W	16	2/1/75	3/8/75	GAS	2,731	0232000700
158	Pt. McIntyre 2	12N	14E	16	10/7/77				0292026401
159	Eagle Creek 1	8S	45W	26					0732000200
160	Tiglukpuk 1	12s	2E	14					0572000200
161	W. Sak River St 8	11N	10E	23					
162	W. Sak River St 9								
163	W. Sak River St 10	10N	9E	23					
164	W. Sak River St 11								
165	Sag Delta 2	11N	16E	10					
166	Pt. Thomson 2	9N	22E	3					
167	Mikkelsen Bay St 1								
168	Inicok Ck 1	8N	5W	34					
169	Tunalik 1	10N	36W	20					
170	Kugrua River 1	14N	26W	8					
171	S. Meade River 1	15N	19W	31					
172	Drew Pt. 1	18N	8W	26					
173	N. Kolikpik Rv 1	13N	2W	3					

* Current Status
PA Plugged and Abandoned
SUSP Suspended
GAS/OIL SHUT IN = Not currently producing

Source: Alaska Department of Natural Resources, Gibson and Kerschner, (1977).

TABLE A-2

OIL AND GAS FIELDS, ALASKA NORTH SLOPE

Field	Production	Producing Formation		Reservoir Lithology	Approximate Depth of Production in feet	Identified Resources (Econ. & Subecon.) Million bbls. oil Billion cf. gas
Umiat NPR-4	Oil	Lower Cret.	Nanushuk Group	Sandstone	250-1,350	70
Gubik	Gas	Upper Cret.	Prince Creek Fm.	Sandstone	1,450-1,750	22-295
		Upper Cret.	Chandler-Ninuluk Fms. undiff.	Sandstone	3,550	
South Barrow NPR-4	Gas	Jurassic	?	Sandstone	2,500	18
Meade NPR-4	Gas	Lower Cret.	Nanushuk Group	Sandstone	4,200	10
Square Lake NPR-4	Gas	Upper Cret.	Seabee Fm.	Sandstone	1,650-1,850	33-58
Wolf Creek NPR-4	Gas	Lower Cret.	Nanushuk Group	Sandstone	1,500	No est.
Simpson NPR-4	Oil	Upper Cret.	Nanushuk-Seabee Fms.	Sandstone	300	
						30
Fish Creek NPR-4	Oil	Lower Cret.	Topagoruk Fm.	Sandstone	3,000	
Prudhoe Bay	Oil	Jurassic	Kuparuk River	Sandstone	8,000	No est.
	Oil & Gas	Jurassic	Sag River Fm.	Sandstone	10,000	No est.
	Oil & Gas	U. Triassic	Shublik Fm.	Sandstone/Limestone	10,000	No est.
	Oil & Gas	L. Triassic-Perm.	Sadlerochit Grp.	Sandstone	10,500	*9.6 bill. bbls. oil 26.5 trillion cfg
	Oil & Gas	Miss. & Penn.	Lisburne Grp.	Carbonates	11,500	No est.
Kavik	Gas	Triassic	Sag River Fm.	Sandstone	4,250	No est.
	Gas	Triassic	Sadlerochit Grp.	Sandstone	4,600	No est.
Kemik	Gas	Triassic	Shublik Fm.	Limestone	8,700	No est.

* Measured Reserves

Source: Carter et al., 1977.

Later Navy and Department of the Interior Exploration in NPR-4/NPR-A

The Prudhoe Bay discovery and the Arab oil embargo of 1973 caused renewed interest in NPR-4. In 1974, after Congress had made appropriations for the exploration of the Navy Petroleum Reserves, the Navy commenced an exploration and geophysical survey program (U.S. Department of the Navy, 1977). After additional congressional appropriations in 1975, the Navy awarded an operators contract to Husky Oil to continue the program. A step-out well, Iko Bay, was drilled 26 kilometers (16 miles) southeast of Barrow in 1975 to obtain additional gas reserves for the nearby village. Cape Halkett Well No. 1, located 160 kilometers (100 miles) east-southeast of Barrow was completed to a depth of 3,020 meters (9,900 feet) on March 24, 1975. On Play 7, 1976, a second deep well, East Teshekpuk No. 1, located on a small peninsula on the eastern shore of Teshekpuk Lake, was completed to a depth of 3,250 meters (10,664 feet) after finding a noncommercial zone in Permo-Triassic and older formations.

Jurisdiction of NPR-4 was transferred from the Navy to the Department of the Interior on June 1, 1977 becoming the National Petroleum Reserve in Alaska (NPR-A). Exploration drilling continues with Husky Oil as the operator and the U.S.G.S. as the program manager. Five medium-depth exploration wells were drilled in the northeastern sector of NPR-A in the winter of 1976-77. Lonely, located on the Beaufort Sea coast between Drew Point and Pitt Point, is the staging area for the exploration program. Six wells are planned for the 1977-78 season including 4 medium depth wells (2,438 to 4,267 meters or 8,000 to 14,000 feet) and commencement of 2 deep wells (over 4,267 meters or 14,000 feet). In addition, 3 shallow natural gas wells (less than 914 meters or 3,000 feet) are to be drilled in the Barrow area (U.S. Department of the Interior, 1977a).

Peard Bay, an old DEW line site on the Chukchi Sea coast, has been adopted as a temporary staging base for exploration in the western sector of NPR-A for the 1977-78 season (U.S. Department of the Interior, 1977C) . A summary of test and development wells in NPR-4/NPR-Ato 1977 is included in Table A-1.

Speculative estimates of the oil resources of NPR-4 have ranged as high as 100 billion barrels, but a recent study (Resource Planning Associates, 1976) presents a significantly less optimistic estimate of 5 billion barrels of recoverable liquid hydrocarbons (oil, and gas condensates) and 14.3 trillion cubic feet of recoverable natural gas. More recently, with more geologic data available from the current exploration program, the potential of NPR-A appears even less, with unofficial estimates of 1 billion barrels of recoverable oil (Mull, 1977).

Beaufort Sea Exploration

Some of the existing State leases between the Colville and Canning Rivers either contain a submerged offshore portion or are wholly offshore. Since 1968 several offshore wells have been drilled in these leases, mainly in Prudhoe Bay and off the Sagavanirktok River delta. Some have been directionally drilled from shore. The offshore wells have been drilled in winter from gravel pads in shallow water.

A Federal OCS lease sale (No. 50) had been planned for the Beaufort Sea. However, a joint State-federal lease sale, as described in the introduction of this report, is now planned for December 1979. Other high-potential areas of the Beaufort Sea considered developable will probably be leased at subsequent dates. The proposed State-federal lease sale area has good potential for significant petroleum deposits. The lease area is everywhere underlain by a thick sequence of predominantly marine sedimentary rocks (Grantz et al., 1976). These formations or their correlative contain seeps and known petroleum accumulations onshore, including the giant Prudhoe Bay oil and gas field. Consequently, there are sufficient incentives to begin exploration offshore in the

Beaufort Sea, which could conceivably prove to be the new American petroleum frontier. The probability of finding another Prudhoe Bay size field either on the North Slope or beneath the offshore waters of the Beaufort Sea is statistically remote. Nevertheless, commercial reserves in the Beaufort Sea OCS area remain a distinct possibility, and if developed in conjunction with other potential finds in State waters and/or onshore areas in NPR-A and those adjacent to Prudhoe Bay, could conceivably justify another major transportation link to the south.

North Slope Leasing History

Prior to 1958, the lands of the North Slope had been closed to mineral leasing for many years by Executive Order (Alaska Department of Natural Resources, 1977). Federal mineral leasing was restored in 1958 when 3.4 million acres were offered on a noncompetitive basis. Between 1958 and 1966, when issuance of leases was suspended because of protests from Alaska Natives, a total of 22.3 million acres had been offered for leasing by the Federal Bureau of Land Management, of which about 5 million acres had been issued as leases. Applications for leases were still accepted by the Secretary of Interior after the 1966 freeze, but no leases were issued. The creation of the 8.9 million acre Arctic National Wildlife Range in 1960 also affected the availability of lands for oil and gas leasing on the North Slope. In January, 1969, all federal lands in Alaska were withdrawn from oil and gas lease applications. A summary of federal North Slope leasing is given in Table A-3.

With statehood in 1959, the State acquired the right to select about 103 million acres of lands in addition to the tide and submerged lands that were transferred automatically. On the North Slope, the State selected a block of approximately 1.75 million acres in 1964 and a block of nearly 3 million acres in 1969. A significant portion of these lands was offered for oil and gas leasing. Three State lease sales have been held for North Slope acreage: No. 13 in 1964, No. 14 in 1965, No. 18 in 1967, and No. 23 in 1969 (held after the Prudhoe discovery, the

TABLE A-3

NORTH SLOPE FEDERAL LEASING HISTORY(1)

Drawing Date	Acreage Offered	Tracts Offered	Tracts Rec'd Offers	Offers Received	Acres Leased(2)
1958	3,400,000	1364	608		1,520,000
6/11/64	3,600,000	1440	1000	14,725	2,500,000
5/13/65	4,000,000	1558	268	31,431	670,000
11/19/65	4,000,000	1960	148	1,897	‘370,000
1966	3,000,000	1247	7	8	17,500
12/30/66	4,300,000	1817	215	500	537,500(3)
Total	22,300,000				5,615,000

(1) Adapted from August- 21, 1968 Alaska Scouting Service Report

(2) Estimated on basis of 2,500 acres per parcel

(3) Leases not issued because of “land freeze”

Source: Alaska Department of Natural Resources, 1977.

sale at which over $900 million was paid in bonus bids for leases totalling 415,000 acres). Statistics on these sales is provided in Table A-4. Because most of the land offered in the North Slope sale was only tentatively patented, conditional leases were issued. A law had been passed in 1960 that provided for the extension of a conditional lease for a period equal to which the lease was conditional. The first North Slope lease was issued in 1965. Since the first patents were not received until 1974, many of the leases in this area were extended for nearly 10 years.

Listed below are some important facts on State oil and gas leases:

- All the State leases on the North Slope are competitive leases.

- Noncompetitive leases are for a primary term of 5 years and can be extended for 2 years if the lands are in a competitive classification at the time of expiration of the primary term or 5 years if noncompetitive.

- Competitive leases are issued for a primary term of 10 years (except in Cook Inlet sedimentary basin).

- There is a minimum royalty rate of 12.5 percent in amount or value of production on competitive leases.

- Until 1969, there was a reduction of the royalty rate to 5 percent for the entire lease for 10 years following the date of discovery, for the first discovery of oil or gas in commercial quantities in any geologic structure on the lease the discovery was made.

TABLE A-4

NORTH SLOPE COMPETITIVE LEASE SALES

Sale No.	Acres Offered	Acres Leased	Percent Leased	Bonus Paid	$ Per Acre
13	624,457.00	466,180.00	74.65	$ 4,376,523.30	9.39
14	754,033.00	403,000.00	53.44	6,145,472.59	15.25
18	37,662.00	37,662.00	100.00	1,469,645.39	13.11
23	450,858.47	412,548.47	91.50	900,041,605.30	2,181.66
Total	1,867,010.47	1,319,390.47	70.67	$912,033,246.58	691.25

Source: Alaska Department of Natural Resources, 1977.

- Maximum tract size is 5,760 acres for tide and submerged lands and 2,560 acres for upland tracts (revised in 1964 from the original 640 acres). After the early Cook Inlet sales, the standard offshore tract has been 4 sections (about 2,560 acres).

As indicated in the introduction, tentative agreement has been reached between the State and federal governments on tract size (2,560 acres) and the area to be presented in calls for nominations. Other details of the joint sale including environmental stipulations have yet to be decided.

GEOLOGIC HISTORY

The evolution of the main structural elements of the North Slope and Beaufort Sea, including the Barrow Arch, Colville geosyncline, Camden Basin, and Beaufort Shelf, is shown sequentially in Figure A-1, and the geology of the North Slope is given in Figure A-2 (Brosge and Tailleur, 1970; Rickwood, 1970).

Late Paleozoic-Triassic sediments were laid down on a platform (the Arctic Platform) of mildly metamorphosed early Paleozoic (Cambrian to Devonian) rocks from a northerly (Canadian Shield) source area located to the north of the present continental shelf. Pennsylvanian-Mississippian deposits consisting of continental and shallow-marine elastic sediments and shallow water shelf carbonates were laid down on the platform (Morgridge and Smith, 1972). In some areas, an erosional interval is indicated between Mississippian time and the Middle Triassic since the Sadlerochit Formation rests upon an eroded Lisburne carbonate surface. Permian and Triassic sedimentation includes deposition of the Sadlerochit Formation sandstones, conglomerates and subordinate mudstones, limestone and sandstones of the overlying Shublik Formation. Jurassic and lowermost Cretaceus sediments include shales and sandstones.

Figure A-1

Diagrams Illustrating the Development of the Northern Continental Margin of Alaska

Figure A-2

Generalized Geologic Map of Northern Alaska

In latest Jurassic and earliest Cretaceus time, northern Alaska was reshaped by tectonism. Orogenic movements occurred in the Brooks Range causing the formation of large nappes that were thrust northward onto the Arctic Platform. At the same time, depression of the southern half of the Arctic Platform resulted in the formation of a foredeep, the Colville geosyncline. The northern portion of the Arctic Platform was rifted away as northern Alaska and the Canadian Shield separated, forming the Arctic Ocean Basin. Uplift occurred on the southern flank of the rift where a series of normal tensional faults were formed with downthrows toward the developing Arctic Ocean. During this period of uplift and erosion, much of the Mississippian to earliest Cretaceus rocks (Ellesmerian sequence) were removed in the area northeast of Prudhoe Bay. There is, therefore, a widespread angular unconformity between lowermost Cretaceus, Mesozoic and late Paleozoic sediments and younger Cretaceus and Tertiary sediments on the North Slope. These events resulted in the replacement of northern sources of detrital sediment with southern ones from the Brooks Range. Subsequent sagging of the continental margin of northern Alaska toward the Arctic Ocean caused the formation of the Barrow Arch.

Continued uplift of the Brooks Range during the Cretaceus provided voluminous detritus to the Colville geosyncline where up to 6,100 meters (20,000 feet) of Cretaceus sediments were deposited. A series of thick, northward-shingling upper Lower Cretaceus to the Tertiary molasse wedges were formed which graded north and into deltaic and, paralic and shallow marine elastic forms that in part lapped and in part over-stepped the Barrow Arch. The depocenters of the elastic wedges progressively migrated northward and northeastward through early Tertiary time.

GEOLOGIC FRAMEWORK

Arctic Platform

The Arctic Platform is an erosional surface across a variety of contorted and mildly metamorphased elastic and carbonate geosyncline sediments comprising the Franklinian (pre-Missi ssippian) sequence (Carter, et al, 1977). On the North Slope, this sequence constitutes the economic basement for petroleum exploration. The Arctic Platform lies at depths of 6,100 meters (20,000 feet) or more in the southern part of the Colville geosyncline, rising to depths of 3,050 meters (10,000 feet) in the Prudhoe Bay area and 760 meters (2,500 feet) in the Barrow area.

Colville Geosyncline

The Colville geosyncline was formed as a foredeep of the Brooks Range orogen during late Jurassic, early Cretaceus times. The bulk of the sediments in the Colville geosyncline are Cretaceus in age, consisting of a thick sequence of elastic deposits derived from uplift and erosion of the Brooks Range. Early deposition in the geosyncline in the early Cretaceus (Neocomian) consisted of graywacke turbidites of the Okpikruak Formation and its northward equivalent, the organically-rich "Pebble Shale." Later Cretaceus and Tertiary sedimentation consisted of periodic influxes of coarse terriginous debris producing elastics wedges (separated by shale units), the depocenters of which spread successively farther to the northeast. Tertiary rocks consisting of non-marine sandstones and conglomerates of the Sagavanirktok Formation are restricted in outcrop to the northern North Slope east of the Colville River.

Barrow Arch

The Barrow Arch is an important regional structure that has influenced sedimentation on the North Slope since its formation in late Jurassic, earliest Cretaceus time. The arch is essentially a structural "high" of the Franklinian basement rocks, the axis of which follows the Beaufort Sea coastline from Camden Bay to Point Barrow. The Barrow Arch plunges southwestward] at Barrow basement rocks lie at a depth of about 760 meters (2,500 feet) increasing to about 3,050 meters (10,000 feet) in the Prudhoe Bay area. Dips on the southern flank of the Arch are about 2 degrees and somewhat steeper on the faulted northern flank, which for the most part lies offshore. Uplift of the Arch resulted in erosion and truncation of the Ellesmerian sequence (Mississippian and Jurassic) in the arch area. Subsequent Cretaceus and Tertiary sedimentation prograded the continental terrace north from the Arch across the newly formed continental margin.

Camden Basin

Basement rocks (Franklinian?) along the axis of the Barrow Arch deepen east of Prudhoe Bay to about 5,000 meters (16,400 feet) near Camden Bay where the arch loses identity amid the foreland folds of the Brooks Range (Grantz, Holmes and Kososki, 1975). The eastern shelf of the Beaufort Sea is characterized by a deep basin filled with Late Cretaceus and Tertiary Sediments. The basin extends onshore between Prudhoe and Camden Bays where it overlies and deeply buries basement rocks of the Arctic Platform at the eastern end of the Barrow Arch. The stratigraphy of the Camden Basin is essentially a landward extension of the progradational sequence underlying the outer Beaufort Shelf. Tertiary strata compose a much greater portion of the stratigraphic section than on the outer shelf. Cretaceus rocks are both marine and non-marine; the Tertiary sediments are predominantly non-marine but with some shallow marine beds in the upper part of the section near the coast, becoming increasingly, or predominantly, marine offshore. At the coast, the Late Cretaceus and Tertiary sediments are about 4,000 meters (13,120 feet) thick.

Between Camden Bay and the Canadian Border, east-northeast striking folds have been mapped on the continental terrace, including three large anticlines, one a possible extension of the Marsh Creek anticline (Grantz, Holmes and Kososki, 1975). These folds may be late Tertiary in age, formed by the same earth movements that created the Romanzof Mountains salient of the northeastern Brooks Range. The western part of the Camden basin, however, is structurally similar to the western Beaufort outer shelf with relatively flat-lying strata.

Western Beaufort Outer Shelf

The western Beaufort outer shelf is the outer half of the continental shelf of the Beaufort Sea west of about 150° W, which lies for the most part beyond the potential State-federal and federal OCS lease sale areas. This part of the shelf is underlain by a thick progradational sequence of Cretaceus and Tertiary rocks that are drapped over the rifted and down-faulted north flank of the Barrow Arch. The Cretaceus and Teritary rocks thicken seaward of the arch from about 500 to 2,000 meters (1,640 to 6,560 feet) at the axis of trough to more than 5,000 meters (16,400 feet) beneath the outer shelf, dipping about one degree northward. The Cretaceus strata, which are both marine and non-marine beneath the Arctic Coastal Plain, become increasingly marine beneath the outer Beaufort shelf. The Tertiary strata, which are predominantly non-marine onshore, are probably both non-marine and marine beneath the Beaufort shelf.

Recent seismic data suggest that the Prudhoe Bay structure (located near the axis of the Barrow arch) extends offshore (Radlinski, 1977). Large structures associated with faulting occur beneath the shelf, and, on the outer shelf and upper continental shelf, diapiric structures are present.

POTENTIAL PETROLEUM RESERVOIRS

The identification of potential reservoir rocks is but one element in the assessment in the petroleum potential of a region. A knowledge of petroleum source rocks, their relationship to potential reservoir rocks, trapping mechanisms, and geologic history are also required. The supergiant Prudhoe Bay oil and gas field is the result of a favorable juxtaposition of organically rich, thermally mature Cretaceus source beds with older reservoir beds of good to excellent porosity and permeability. Replication of the Prudhoe Bay accumulation on the North Slope on Beaufort is highly unlikely since the field resulted from the most favorable relationships among geologic history, thermal history, and geochemical conditions.

A hydrocarbon play analysis of NPR-A has identified the potential of various reservoirs and indicates that the most promising plays are of limited extent, confined to a narrow coastal strip in the northeastern section of the reserve (Carter, et al., 1977). That analysis is the most recent published assessment of the reserve and is particularly relevant to an appreciation of the petroleum potential in the nearshore area of the western Beaufort Sea.

Briefly described below are the principal petroleum reservoirs of the North Slope, some of which may be potential offshore reservoirs.

Lisburne Group

The Mississippian-Pennsylvanian Lisburne group, comprising a " thick carbonate unit, is a potential major hydrocarbon objective on the North Slope (Bird and Jordan, 1976, 1977). Potential reservoirs in the Lisburne are dolomite and sandstone. The Lisburne subcrop generally follows the trend of the Barrow Arch and probably extends offshore between Camden Bay and Cape Halkett. Its northern termination on the arch is the result of both erosional truncation and depositional pinch out. From its northern margin at depths of about 2,750 meters (9,000 feet), the Lisburne slopes southward to depths greater than 7,625 meters (25,000 feet) along the axis of the Colville geosycline. Offshore there is the possibility of a sandstone facies of the Lisburne between Prudhoe Bay and Cape Halkett.

Drill stem tests have recovered both hydrocarbons and saltwater from the Lisburne; three wells have recovered hydrocarbons in the Prudhoe

Bay field and one well has recovered them from southeast of the field. Possible source rocks for petroleum in the Lisburne Include overlying Cretaceus shales, shales within the Lisburne, and the underlying Kayak Shale (Mississippian). Coal in the Kekiktuk Conglomerate may be a source for dry gas in the Lisburne.

Structural traps related to complex folding and faulting may be present in the foothills of the Brooks Range. Broad, gentle folds associated with numerous normal faults may occur along the trend of the Barrow Arch.

Sadlerochit Group

The Permo-Triassic Sadlerochit Group contains the major part of the Prudhoe Bay reserves (Morgridge and Smith, 1972). The Sadlerochit Group consists of sandstone, siltstone, and shale and has a maximum thickness of about 200 meters (850 feet) at Prudhoe Bay (Jones and Speers, 1976). The lower part of the Sadlerochit was deposited in a deltaic shallow-marine environment and consists of a basal laminated, silty claystone and shale unit that grades upward into an interbedded, fine-grained, laminated sandstone and shale. The upper part of the Sadlerochit is an alluvial complex consisting of sandstone, pebble conglomerate and shale. Recently, it has been proposed that the Sadlerochit be elevated to Group status at Prudhoe and be divided into three formations (Jones and Speers, 1976): the basal Echooka Formation (sandstones with thin laminae of clay and shale), the Kavik Shale (shales, mudstones and silstones) and the Ivishak Sandstone (sandstones, conglomerate and minor mudstones). The Ivishak Sandstone is the principal Sadlerochit reservoir with an oil column of more than 137 meters (450 feet).

The Sadlerochit reservoir is a combination structural-stratigraphic trap comprising a west-plunging anticlinal nose, faulted on the north and south, and truncated and sealed by unconformity on the east. The seal is provided by Lower Cretaceus marine shale. The

Lower Cretaceus "Pebble Shale" is believed to be the most likely source rock for the Sadlerochit petroleum accumulation.

The northern limit of the Sadlerochit Group lies offshore west of Prudhoe Bay where it is truncated on the flank of the Barrow Arch. In NPR-A the Sadlerochit's northern limit is due to onlap. The Sadlerochit was not encountered in wells at Barrow and Simpson but was found in a well at Topagoruk (Carter, et al., 1977; Alaska Geological Society, 1971).

Shublik Formation

The Shublik Formation of Triassic age consists of argillaceous and pelletal limestones, slightly calcareous sandstones and mud stones and phosphatic beds (Jones and Speers, 1976). At Prudhoe, the Shublik is a reservoir rock with a maximum thickness of 59 meters (192 feet); no reserve figures are available for the Shublik at Prudhoe Bay. Shublik limestone is a gas producer in the Kemik gas field in the Brooks Range foothills. Oil shows are reported in the Barrow Bay sandstone member of the Shublik near Barrow. Shublik plays are probably restricted to a narrow coastal strip in northeastern NPR-A and adjacent areas offshore.

Sag River Formation

The Sag River Formation (Upper Triassic) is a sandstone interval lying between the limestones of the Shublik Formation below and Jurassic Kingak Shale above. The formation may be a correlative of the Karen Creek Sandstone identified in the foothills of the Brooks Range (Detterman, et al., 1975). At Prudhoe Bay, the formation consists of an upper shale member and lower sandstone member. The Sag River Formation is a potential reservoir rock and contains both oil and gas at Prudhoe Bay.

Kingak Shale

The Jurassic Kingak Shale has a thin sandstone bed at its base (9 to 46 meters or 30 to 150 feet thick) which is a potential reservoir rock. Gas is produced from the Kingak Shale or equivalent at the South Barrow field.

Kuparuk River Formation

The Lower Cretaceus Kuparuk River Formation contains significant oil reserves at Prudhoe Bay, which are currently being evaluated by a test drilling program to asses the feasibility of commercial production (Oil and Gas Journal, October 30, 1977). The Kuparuk, which consists of interbedded sandstone and shale is 15 to 30 meters (50 to 100 feet) thick at Prudhoe Bay and lies at a depth of 1,830 meters (6,000 feet). The Kuparuk Formation is believed to be a correlative of the Okpikruak Formation, Kemik Sandstone Member, of the Brooks Range (Detterman, et al., 1975). The Kuparuk River sandstone appears to absent in the northern part of NPR-A.

Other Cretaceus Reservoirs

A number of reservoirs of Cretaceus age are potential reservoirs on the North Slope and contain several small oil and gas fields. As described above, Cretaceus sedimentation on the North Slope consists of thick elastic wedges deposited in the Colville geosyncline from Brooks Range sources.

The Umiat oil field has 70 million bbl of reserves in the Middle Cretaceus Nanushuk Group. Other Cretaceus oil and gas fields are indicated in Table A-2.

Cretaceus sandstones derived from southerly (Brooks Range) sources have lower porosities and permeabilities than northern source sandstones (e.g. Sadlerochit), because they contain relatively high percentages of clay minerals and soft-rock fragments (Carter, et al., 1977). Improved porosity and permeability are evident in the younger Cretaceus strata such as the Upper Createaceous Colville Group.

Source Rocks

A number of potential source rocks for hydrocarbon generation on the North Slope have been identified. These include:

- Cretaceus marine shales including the Lower Cretaceus "Pebble Shale"
- Jurassic marine shales including the Kingak Shale
- Mississippian coals (potential gas source)

Trapping Mechanisms

Stratigraphic, structural, and combination stratigraphic-structural traps are likely to occur on the North Slope and Beaufort Sea. Sealing beds, predominantly shale, are present between and within each major reservoir unit described above to provide seals for the trapping mechanisms.

On the south flank of the Barrow Arch (which includes the nearshore portion of the Beaufort Sea) up dip wedge outs of candidate reservoir formations may provide trapping mechanisms (Grantz, et al., 1976). Beneath the western Beaufort outer shelf, on the north flank of the Barrow Arch, numerous stratigraphic and structural traps related to faulting and possibly growth faulting may be present. In the Camden Basin offshore, structural traps in the form of large east-northeast trending anticlines present attractive prospects east of 146° W longitude in Cretaceus and Tertiary strata. West of that longitude, down-to-the-basin normal faults and fault blocks are likely trapping mechanisms.

INDEPENDENT RESOURCE ESTIMATES

As discussed in Section 5.2.1, estimates of Beaufort Sea oil and gas resources are the basis for the formulation of petroleum development scenarios and economic analysis. In addition, certain assumptions have to be made with respect to existing and potential onshore (North Slope) recoverable oil and gas resources in order to project transportation facilities for offshore production. For example, additional North Slope oil production can be anticipated from the Kuparuk River formation and recent discoveries at Pt. Thompson and Flaxman Island.

The Beaufort Sea oil and gas estimates that are utilized in the scenario development are official U.S. Geological Survey estimates contained in Open File Report 76-830 (Grantz, et al., 1976) and memorandum EGS 214436 (Radlinski, October 11, 1977).

Other recent petroleum resource evaluations of the North Slope and Beaufort Sea regions include Lowell (1976) for natural gas on the North Slope, Resource Planning Associates (1976) for NPR-A and Klein et al. (1974) for the major Alaska sedimentary basins.

An independent assessment of Beaufort Sea oil and gas resources was conducted by the research team to supplement the U.S. Geological Survey estimates. The reasons for this assessment were:

1. To provide an independent comparison with U.S.G.S. estimates through the interpretation of the most recent available data;

2. To give geologic reality to the location of hypothetical hydrocarbon discovery sites (the U.S.G.S. estimates are not geographically specific about the distribution of the resources);

3. To predict reservoir characteristics in order to give geologic reality to such scenario parameters as well depths and spacing, fill factors, oil-gas ratios, and production characteristics.

The assessment of Beaufort Sea oil and gas resources encompassed the area between Barter Island and Point Barrow from the shoreline to the 20-meter (66-foot) isobath, an area essentially the same as that considered by the U.S. Geological Survey. The scope of the study was to determine in each known and potential producing area the estimated , recoverable reserves of oil and gas. Potential producing horizons identified in the study area consist of the following:

1. Tertiary Eocene Sands

2. Cretaceus sands including Upper to Lower Cretaceus

3. Jurassic “Sag River” Sands

4. Triassic Shublik Limestone

5. Permo-Triassic "Sadlerochit" sand and conglomerates

6. Paleozoic Lisburne group carbonates

Seven areas of potential production are detailed in this report. These are:

1. Camden Bay to Barter Island (Tertiary objectives).

2. Canning River, Staines River Delta (Cretaceus objectives).

3. Offshore Prudhoe Bay (Cretaceus and Permo-Triassic Sands objectives).

4. Simpson Lagoon-Milne Pt. (Cretaceus objectives).

5. Offshore Cape Halkett (Cretaceus and Sadlerochit sands and Lisburne group carbonate objectives).

6. Smith Bay northwestward extension of Drew Point structure into State waters. (Cretaceus and Permo-Tri assic Sands and Lisburne group carbonate objectives).

7. Dease Inlet (Cretaceus and Triassic sands objectives).

Oil in place calculations for each of the areas identified in this analysis were made for what is considered the major objectives within that area. Average porosities were assigned for these calculations on the basis of known core analysis. A primary recovery factor of 25 percent was assigned to each of the potential horizons. Where applicable, a secondary recovery figure of 20 percent was used. Well performance using test and limited production data (in the form of extended tests only) was considered. In considering overall reserves, it was recognized that thin horizons such as the Sag River sandstone (varying between 3 and 6 meters [10 and 20 feet] in thickness) and the Shublik limestone ±15 meters (± 50 feet) in thickness, although present in many areas, could not be individually assessed and could not be included in the recoverable reserve figures for those areas.

Individual well data evaluated in this assessment included:

- Exxon "Alaska State" No. 1, Flaxman Island.
- Exxon "Pt. Thompson" No. 1.
- Mobil-SoCal "Gwydyr Bay" No. 1, Prudhoe Bay.
- Husky-U.S.N. "W. T. Foran" No. 1, Cape Halket.
- Husky-U.S.N. "So. Barrow" 14. Pt. Barrow.
- Selected we'l1s throughout the study area.

1. Camden Basin Tertiary; Canning River to Barter Island

This area is characterized by a sequence of Late Cretaceus and Tertiary sediments 4,000 meters (13,120 feet) thick at the coast becoming thicker seaward, which are of mixed marine and non-marine origin becoming predominantly marine offshore. Source of the sediments was the Brooks Range to the south.

Known offshore structures include northeast striking folds, one of which is up to 100 kilometers (62.5 miles) in length and over one kilometer (0.6 miles) in amplitude. Several large Tertiary structures, including the structure defined by the recently completed Exxon “Alaska State” No. 1 well, Sec. 27, T. 10 N, R. 24 E, UM, are considered to be present offshore in the Camden Bay, Barter Island areas. These structures may be capable of producing from one or more horizons in Teritary sediments. The “Alaska State” No. 1 well produced at a rate of 1,586 bpd of 23.1° API gravity oil and 1,390 MMcfd of gas from approximately 41.5 meters (136 feet) of Eocene sediments (Exxon, 1977). Reservoir sediments were derived from the Brooks Range and are considered to be relatively clean sands with fair to good permeability, and porosity in the 15 percent range. Bottom hole pressures at 3863 meters (12,675 feet) indicate a high pressure gradient of 161 kilograms per square meter/meter (.77 psi/ft).

Estimating a minimum of 3 fields in this basin using 38.4 meters (126 feet) of Tertiary reservoir, average length of producing structure 19.3 kilometers (12 miles), average width of 6.4 kilometers (4 miles), average porosity 15 percent, recoverable oil reserves are calculated to be as much as 200 MMbbl of Eocene production per field by primary recovery with another 120 MMbbl by secondary recovery methods. Eocene recovery totals for the 3 fields are estimated at 960 MMbbl of oil and 82 Bcf of gas. Drilling for Eocene objectives may involve wells as deep as 4,570 meters (15,000 feet). Oil accumulation is considered to be both structurally and stratigraphically controlled. Deep Cretaceus sediments may add additional oil but are only considered as a plus to the main objective Tertiary sediments.

2. Canning River Offshore Cretaceus; State and Federal OCS

The offshore area between the Canning River and Prudhoe Bay contains one known structure capable of producing from Cretaceus sediments, as indicated by the recently completed Exxon "Pt. Thompson" well, Sec. 32, T. 10 N, R. 23 E, UM. Additional northwest trending structures are present in this area offshore, with several structures possibly capable of production.

For the purposes of reserve calculations, the following parameters were used:

a. Reservoir consisting of fine to very fine grains of greywacke sands, which are variable but generally clay-surrounded;

b. Fair to good porosity (estimated at 18 percent) and fair to good permeability; and

c. Maximum net sand thickness of 76 meters (250 feet).

At Point Thompson an eight hour test from Lower Cretaceus sands within the perforated interval of 3951 to 3978 meters (12,963 to 13,050 feet) produced at the rate of 2,300 bpd (stock tank oil), 18.5° API gravity but varying from a low of 13° API gravity, and gas at maximum produced rate of 14,000 MMcfd, with high pressures suggesting a gradient of 1,724 kilograms per square meter/meter (.75 psi/ft). This gas-oil ratio (GOR) is considered somewhat anomalous in view of the low gravity oil produced. The suggestion has been made that the gas is primarily methane. The accumulation of both oil and gas is considered primarily stratigraphically controlled in the discovery well but with structure playing a significant role as well.

Traps are postulated along structures developed across the northwest-southeast trending Barrow Arch. Reservoir calculations suggest recoverable oil reserves from primary sources of approximately 90 MMbbl per field for a total of approximately 270 MMbbl, plus approximately 54 MMbbl per field by secondary recovery means for a total of approximately 144 MMbbl oil per field or approximately 430 MMbbl total. Based on test results, gas may possibly be produced at the rate of 5,800 cf/bbl for an estimated total reserve amount of 2.5 tcf.

3. Offshore Prudhoe; Permo-Triassic Sadlerochit Group, Primary Objective

The Mobil-SoCal "Gwydyr Bay" well, Sec. 8, T. 12 N, R. 13 E, UM, tested horizons through the Mississippian Lisburne Carbonates. The well was completed through an approximate 76 meter (250 feet) section of Sadlerochit sands and conglomerates. Lithographic chert was an abundant grain constituent, with porosities in the sands in the 25 percent range; permeabilities ranged from 0.5 to 1.0 d'Arty. . Normal Prudhoe Bay pressure, gradients, oil gravity and GOR were encountered. The reserve estimates given below are based upon the above parameters. The hydrocarbons encountered in the Gwydyr Bay well were within northwest-southeast-trending faulted anticlines aligned across the Barrow Arch with down dropped fault blocks to the north.

Several of these faulted anticlinal traps are considered to exist in this offshore area. (Due to the close spacing of the faulted anticlinal traps, the scenario analysis considered a single larger field.) Possible potential producing horizons are Cretaceus age sands, Jurassic Sag River sands (gas with some condensate), Triassic Shublik limestone (gas), Permo-Triassic Sadlerochit sand and conglomerates (gas and oil). The Gwydyr Bay well did not encounter a productive carbonate section but some carbonate production may exist along the Barrow Arch in this vicinity and should be considered as a plus.

Three possible producing structures are considered for reserve calculations. These vary from a length of 17.7 to 35.4 kilometers (11 to 22 miles) and a width of 1.6 to 3.2 kilometers (1 to 2 miles). Recoverable Sadleochit oil reserves are estimated as follows:

Structure No. 1: 250 MMbbl by primary recovery, 110 MMbbl by secondary recovery, 360 MMbbl total.

Structure No. 2: 300 MMbbl by primary recovery, 175 MMbbl by secondary recovery, 475 MMbbl total.

Structure No. 3: 45 MMbbl by primary recovery, 27 MMbbl by secondary recovery, 72 MMbbl total.

Total of all 3 structures is estimated at 900 MMbbl recoverable oil and 675 Bcf of gas. Cretaceus oil could add an additional 700 MMbbl of oil by primary recovery, and 200 MMbbl of oil by secondary recovery methods to bring the total of recoverable Cretaceus oil to approximately 900 MMbbl on these structures. Total Sadlerochit and Cretaceus reserves are estimated at 1.8 Bbbl of oil, 1.3 tcf of gas.

4. Offshore Cretaceus; Simpson Lagoon-Milne Pt. Area

One or more Cretaceus structures trending in a northwest-southeast direction may exist offshore in the Simpson Lagoon-Milne Pt. area. Onshore Cretaceus sediments are presently under development to the south for potential production in the West Sag River area. As the Sadlerochit sand of the Prudhoe Bay area is well below the oil/water interface, the sole objective in onshore and offshore areas is Cretaceus sands. The relatively low gravity of the oil and lesser permeability of the reservoir in this area (SoCal "Simpson Lagoon" and "Kavearak Pt." wells) does not enhance the prospect of offshore exploration with its attendant high costs for this sole objective. Any offshore Cretaceus development will probably be the result of extending production along structures in the adjacent offshore Prudhoe Bay area. For these reasons, no attempt was made to estimate possible Cretaceus production in this area.

5. Offshore Cape Halkett; State and Federal Acreage

During the winter of 1976-77, Husky Oil drilled the U.S. Navy "W. T. Foran" well west of Cape Halkett, prospecting Permo-Triassic Sadlerochit sands and Mississippian Lisburne Carbonates. A discussion with U.S. Navy personnel at the time of completion of operations yielded information that an approximate 91-meter (300-foot) thick section of oil saturated Sadlerochit sand had been penetrated and that cores had been taken. Porosities in the range of 25 percent and permeabilities to as much as 2 d'Arcys were reported. Further penetration of the Lisburne Carbonates was said to have indicated good primary and secondary porosities and suggested good permeabilities in an oil saturated section. Tests of both objective horizons were reported to have produced water. Elaborating on results obtained from evaluation of these two objectives, Navy personnel stated that they considered both objectives to have been immediately below an oil water interface (100 percent water production) but within a highly saturated residual oil section. Further information from Navy personnel suggested that the "W. T. Foran" well was situated on the south flank of an offshore structure trending roughly northwest-southeast.

Parameters considered for reserve calculations in this area are:

a. A prospective structure with an estimated length of 19.3 kilometers (12 miles), a width of 2.4 kilometers (1.5 miles);

b. Reservoir thickness of 46 meters (150 feet) of Permo-Triassic objective, 91 meters (300 feet) of carbonate, and 30 meters (100 feet) of Cretaceus objective.

Reserve calculations are based on Navy findings discussed above. Primary Sadlerochit oil recovery is calculated at 140 MMbbl and secondary recovery at 80 MMbbl for a total of 220 MMbbl. Sadlerochit gas reserves are calculated at 165 Bcf. Total recovery from the carbonate section is estimated at 55 MMbbl and 41 Bcf of gas. Cretaceus oil and gas reserves are estimated at 55 MMbbl and 50 Bcf, respectively. Total recoverable oil for the Cape Halkett structure is estimated to be 300 MMbbl for oil and 260 Bcf for gas.

6. Smith Bay; Cretaceus, Permo-Triassic Sands and Paleozic Carbonate Objectives. State Acreage

A possible northwest-southeast trending structure is postulated onshore in the Drew Point area, continuing offshore northwesterly into Smith Bay. Objectives on this structure are Cretaceus sands, Permo-Triassic sands and Paleozoic Carbonates. '--"

Parameters considered in estimating potential reserves are as follows:

a. An estimated structural length of 16 kilometers (10 miles) (with 8 kilometers or 5 miles onshore) and width of 1.6 kilometers (1 mile);

b. Reservoir thicknesses of 30 meters (100 feet) for the Cretaceus objective, 30 meters (100 feet) for the Permo-Triassic objective, and 91 meters (300 feet) for the carbonate objective.

Cretaceus reserves are estimated at 18 MMbbl oil by primary recovery and 11 MMbbl oil by secondary recovery, for a total of 29 MMbbl of oil and 22 Bcf of gas. Permo-Triassic reserves are estimated at 26 MMbbl of oil by primary recovery, and 15 MMbbl of oil by secondary recovery, for a total of 41 Bbbl, and 31 Bcf of gas. Carbonate reserves are estimated at 15 MMbbl of oil (total) and 11 Bcf of gas. Total estimated recoverable reserves for the Smith Bay are, therefore, 85 MMbbl of oil and 64 Bcf of gas.

7. Dease Inlet; State Acreage Only

Additional structures or stratigraphic traps across the Barrow Arch are considered possible in the Dease Inlet area with Cretaceus sands as a gas objective similar to the Barrow accumulations. If one or more traps are present, Cretaceus sand reservoirs may have a maximum aggregate thickness of 15 meters (50 feet). Triassic oil sands about 18 meters (60 feet) in thickness, which were stated by U.S. Navy personnel to be present in the Barrow No. 14 gas well that was drilled during the winter of 1976-77, would also be an objective.

For purposes of reserve calculations, the Triassic objective at this location is estimated to be 23 meters (75 feet) in thickness and to be similar in lithology, porosity, and permeability to the Permo-Triassic Sadlerochit sand of Prudhoe Bay. A maximum trap (structural or stratigraphic) length of 13 kilometers (8 miles) and maximum width of 1.6 kilometers (1 mile) are anticipated. Based upon these assumptions, reserves are estimated as follows: 18 Bcf of Cretaceus gas; 30 MMbbl of oil by primary recovery; 18 MMbbl of oil by secondary recovery; and 36 Bcf of gas in Triassic sand.

Conclusions

Major structural and stratigraphic traps aligned across the Barrow Arch between Barter Island and Pt.. Barrow are considered to exist in at least the following offshore areas: Camden Bay, Canning River-Staines River Delta, Prudhoe Bay (Sagavanirktok to Colville River Deltas), Cape Halkett (West Harrison Bay), Smith Bay, and Dease Inlet. Potential oil and gas producing horizons are considered to exist at these locations, varying in age from Tertiary to Upper Paleozoic including Tertiary Eocene sands, Cretaceus "Kuparuk River" (and younger) sands, Jurassic "Sag River" sands, Triassic "Shublik" limestone, Permo-Triassic "Sadlerochit" sand and conglomerate, and Paleozoic Lisburne group limestones and dolomites. For purposes of this assessment, the westward limit of Tertiary sand production is considered to be in the vicinity of the Canning-Staines River Delta area. Potential Cretaceus production is considered to extend from this area to Pt. Barrow. Sag River sand, Shublik limestone, Sadlerochit sand and conglomerate, and Lisburne carbonates are considered present and potentially productive from Prudhoe Bay to Smith Bay. A Triassic sand is reported present in the Barrow No. 14 well and is considered an objective sand in the Dease Inlet area.

In summary, the reservoir and hydrocarbon properties for the study area as used in this analysis are, or can be anticipated to be:

1. Reservoir sand thicknesses in a range from a low of 23 meters (75 feet) to a high of 76 meters (250 feet); carbonate thicknesses averaging 91 meters (300 feet);

2. Porosities in a range from 18 to 25 percent;

3. Gas-to-oil ratios (GOR) averaging 750 cf/bbl with the exception of the high GOR in the Pt. Thompson well of 5,800 cf/bbl;

4. Primary recovery to be 25 percent;

5. Secondary recovery, where applicable, to be 20 percent.

Total recoverable oil in the study area by both primary and secondary methods is considered as approximately 3.6 Bbbl. Total recoverable gas in the study area is considered to be approximately 4.3 tcf.

APPENDIX B

ALTERNATIVE SCENARIO DEVELOPMENT

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APPENDIX B

ALTERNATIVE SCENARIO DEVELOPMENT

In an interim report[1] on petroleum scenarios, 15 skeletal scenarios were developed for the Beaufort Sea OCS, using the U.S.G.S. 1976 resource estimates[2] and a "building block" approach of varying resource sizes and locations. Capital cost assumptions and investment requirements were then determined for these "building blocks." The objective of this approach was to emphasize the basic cost per barrel of oil over a broad range of field sizes separate from Prudhoe Bay. The study was based on an internally consistent unit cost for all scenarios.

B.1 RESOURCE BUILDING BLOCKS

Each of the 15 skeletal scenarios represents 1 of 5 unique levels of resource concentration to be found in any of 3 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" was limited to 15. Only 2 variables were considered: resource size and location of discovery. These 2 variables correspond to the scale dimension and the spatial dimension that are critical to onshore (community) impact analysis.

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(1) Beaufort Sea Basin Development Scenarios for the Federal Outer Continental Shelf, Alaska OCS Socioeconomic Studies Program Technical Report No. 3, Interim Report prepared for the Bureau of Land Management Alaska OCS office by Dames & Moore, Peat, Marwick, Mitchell & Co., CCC/HOK, December 1977.

(2) See Grantz et al., 1976.

The nine geographic concentrations, as shown in the second column in Table B-1 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 was 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 were 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 were presumed to be found in the ratio of 2,500 cubic feet of gas per barrel of oil (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.

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

TABLE B-1

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

Source: Dames & Moore

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 analysis required a higher level of geographic specificity than simply east, west and central "basins." The locations of hypothetical discovery used in the analysis were therefore 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 2304 hectares (5,693 acres), 4,800 by 4,800 meters (3 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 are detailed below:

- Central and North of Jones Island (40 tracts, about 84,178 hectares or 208,000 acres)

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

- 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.

- 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 was assumed that the oil and gas would 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 in 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 a subsequent analysis of pipeline costs, these ranges of distances were 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 In Kilometers (Miles)

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

The 15 skeletal 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.

Skeletal 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

B.2 PRODUCTION PROFILE

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.

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

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 were:

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

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 B-2. It is typical of a field with water drive and some gas production for sale. The pattern is based upon studies of the Sadlerochit reservoir by H.K. van Poollen Associates (1976). It 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 an optimum BTU (British Thermal Unit) recovery (oil plus gas).

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

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

TABLE B-2

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

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 was as follows:

Maximum Flow Rate Per Day

Building Block	Oil	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 averaged 2,500 barrels of oil per day for all building blocks, which was dictated by using an average production profile as fixed for all wells. This figure was calculated by dividing the maximum output for each building block above the corresponding number of production wells. For example, the 3.5 billion barrel case yielded:

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

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

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

*OCS gas production could be delayed beyond oil production.

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

B.3 INVESTMENT REQUIREMENTS

The capital cost assumptions used in developing the investment requirements for each scenario are summarized in Table B-3. They were prepared with both a high and low set of values. The high values correspond to current experience; they were extrapolated from estimates of return on Prudhoe Bay oil, construction costs on the Alyeska line, estimated construction costs for the Arctic, Northwest, and El Paso gasline projects, and reported expenditures of Canadian projects. The low estimates were arbitrarily extrapolated from the high estimates by assuming lower labor costs, economies of scale, and improvements in scheduling. With regard to the latter, labor and machine productivity are not likely to be improved, but schedule productivity gains may be assumed from reductions in downtime, better parts scheduling, improvements in logistical coordination, etc.

Although the high cost values reflect more closely the demonstrated frontier costs in arctic exploration, and could be assumed to be the "most likely," the lower cost range may reflect more closely industry expectations of cost which might be achieved in field groups of over a billion barrel reserve units.

Tables B-4 through B-8 represent 5 sets of tables, 1 set for each reserve level (building block), which: (1) summarize the major developmental requirements, (2) itemize the high cost investment requirements for the 3 geographic locations, and (3) itemize the low cost

TABLE B-3

CAPITAL COST ASSUMPTIONS FOR THE
BEAUFORT SEA OCS SCENARIOS
(Price Base: millions of 1975-76 dollars)

CAPITAL EQUIPMENT	ESTIMATED COST (millions of dollars) Low	High
Tract Costs (each)	5	10
Production Platforms:		
Gravity Structures @ 15m (50 ft.) (each)[1]	35	65
Gravity Structures @ 6m (20 ft.) (each)	20	40
Gravel Island @ 4.5-5m (15-25 ft.) (each)	15	30
Production Wells (each):		
First 20 per field group	8	10
Remainder, including development wells:	"3	6
Processing Equipment (per Mbd capacity)[2]	0.5	0.7
Gas Plant (per 100 MMcfd)[3]	10	14
Transportation:		
Barges (each)	0.7	1.2
Supply Vessels (each)	0.2	0.2
Supply Tractors (each)	0.1	0.1
Harbor (each)	4	6
Crew Base (each)	8	12
Roads:		
Long Roads per kilometer (per mile)[4]	0.22 (0.35)	0.25 (0.4
Short Roads per kilometer (per mile)	0.16 (0.25)	0.19 (0.3

TABLE B-3 (Cont.)

	Low Cost Flow Rate in MMbd (.1-.4)	(.4-1.0)	(1.0+)	High Cost Flow Rate in MMbd (.1-.4)	(.4-1.0)	(1.0+)
Oil Pipelines:						
Offshore per kilometer (per mile)	5 (8)	5 (8)	6.2 (10)	5 (8)	5.6 (9)	7.5 (12)
North Slope per kilometer (per mile)	4.3 (7)	5 (8)	5.6 (9)	4.3 (7)	5.6 (9)	6.8 (11)
Gas Pipelines per kilometer (per mile):	Estimated at 70% of oil pipeline costs for equivalent flow rates.					

(1) Gravity structure is a generic term for all bottom resting structures (i.e. monopods) that are currently in the conceptual design stage. Meters (feet) refers to water depth.

(2) Includes all processing equipment: oil/water separation, desanding, H_2S stripping, turbines, etc., as well as a share of crew quarters.

(3) Shares a portion of the cost of platform crew quarters with processing equipment.

(4) Long roads incur increased hauling costs for the transport of construction materials.

Source: Dames & Moore

TABLE B-4a

DEVELOPMENT SUMMARY - 3.5 BILLION BARREL RESERVE

FIELD	RESERVES (BILLION BBL	TRACTS	PLATFORMS	PRODUCTION WELLS	DEVELOPMENT WELLS
1 large	1.2	4	3	140	22
2 medium	0.8	2	2	85	12
	0.6	2	2	75	10
4 small	0.3	1	2	50	8
	0.2	1	1	30	8
	0.2	1	1	30	8
	0.2	1	1	30	8
	3.5	12	12	440	76

Max; output, 1.1 MMbd Oil, 1.3 Bcfd Gas

Tracts held 20

Source: Dames & Moore

TABLE B-4b

HIGH COST INVESTMENT REQUIREMENTS FOR 3.5 BILLION BBL RESERVE - ($ MILLIONS - 1975-76)

CAPITAL EQUIPMENT (units)	LOCATION	BASE CALCULATION (Units @ cost/unit)	BASE	ESCALATION TIME (YR)	FINANCIAL COST(1)
Production Platforms (each)			490	5.5	641
Gravity Structures @ 15m (50 ft.)		2 @ $65			
Gravity Structures @ 6m (20 ft.)		6 @ $40			
Gravel Islands @ 4.5m (15 ft.)		4 @ $30			
Production Wells (each)		60 @ $10	600	4.5	747
		380 @ $ 6	2,280	2.5	2,576
Development Wells (each)		76 @ $ 6	456	2.5	515
Processing equipment (MBD)		1,100 @ $ 0.7	770	0.5	789
Gas Plant (100 MMcfd)		13 @ $14	182	0.5	187
Offshore Oil Lines kilometers (miles)	EAST	113 @ $ 4.9 (70 @ $ 8)	560	1.5	603
	CENTRAL	113 @ $ 4.9 (70 @ $ 8)	560	1.5	603
	WEST	169 @ $ 4.9 (105 @ $ 8)	840	1.5	904
Onshore Oil Lines kilometers (miles)	EAST	145 @ $ 6.8 (90 @ $11)	990	2.5	1,118

" 'Financial Cost = Base X $(1.05)^{yr}$; except for tracts where Financial Cost = Base X $(1.08)^{9.5}$

TABLE B-4b, Cont.

CAPITAL EQUIPMENT (units)	LOCATION	BASE CALCULATION (Units @ cost/unit)	BASE	ESCALATION TIME (YR)	FINANCIAL COST(1)
	CENTRAL	39 @ $ 6.8 (24 @ $11)	264	1.5	298
	WEST	274 @ $ 6.8 (170 @ $11)	,870	2.5	2,113
Gas Lines (kilometers) (miles)	EAST	@ 70% of oil lines	1,085		1,205
	CENTRAL		577		631
	WEST		1,348		2,112
Roads (kilometers (miles)	EAST	145 @ $0.25 (90 @ $0.4)	36	5.5	47
	CENTRAL	39 @ $0.19 (24 @ $0.3)	7	5.5	9
	WEST	274 @ $0.25 (170 @ $0.4)	68	5.5	89
Harbor, Base camp (each)		@ $40	40	5.5	52
Booster Station (each)	WEST only	1 @ $ 8	8	1.5	9

Source: Dames & Moore

TABLE B-4c

LOW COST INVESTMENT REQUIREMENTS FOR 3.5 BILLION BBL RESERVE - ($ MILLIONS - 1975-76)

CAPITAL EQUIPMENT (units)	LOCATION	BASE CALCULATION (Units @ cost/unit)	BASE	ESCALATION TIME (YR)	FINANCIAL COST[1]
Production Platforms (each)			250	5.5	327
Gravity Structures @ 15m (50 ft.)		2 @ $35			
Gravity Structures @ 6m (20 ft.)		6 @ $20			
Gravel Islands @ 4.5m (15 ft.)		4 @ $15			
Production Wells		60 @ $ 8	480	4.5	598
		380 @ $ 3	1,140	2.5	1,288
Development Wells (each)		76 @ $ 3	228	2.5	254
Processing Equipment (Mbd)		1,100 @ $ 0.5	550	0.5	564
Gas Plant (100 MMcfd)		13 @ $10	130	0.5	133
Offshore Oil Lines (kilometers) (miles)	EAST	113 @ $ 4.9 (70 @ $ 8)	560	1.5	603
	CENTRAL	113 @ $ 4.9 (70 @ $ 8)	450	1.5	603
	WEST	169 @ $ 4.9 (105 @ $ 8)	840	1.5	904
Onshore Oil Lines (kilometers) (miles)	EAST	145 @ $ 5.6 (90 @ $ 9)	810	2.5	915

[1] Financial Cost = Base X $(1.05)^{yr}$; except for tracts where Financial Cost = Base X $(1.08)^{9'5}$

TABLE B- c, Cont.

CAPITAL EQUIPMENT (units)	LOCATION	BASE CALCULATION (Units @ cost/unit)	BASE	ESCALATION TIME (YR)	FINANCIAL COST (1)
	CENTRAL	39 @ $ 5.6 (24 @ $ 9)	216	.5	232
	WEST	274 @ $ 5.6	1.530	2.5	1,728
Gas Lines (kilometers) (miles)	EAST	@ 70% of oil lines	959	2.5	641
	CENTRAL		543	1.5	585
	WEST		1,659	2.5	1,842
Roads (kilometers) (miles)	EAST	145 @ $ 0.22 (90 @ $ 0.35)	32	5.5	42
	CENTRAL	39 @ $ 0.16 (24 @ $ 0.25)	6	5.5	8
	WEST	274 @ $ 0.16 (170 @ $ 0.25)	60	5.5	78
Harbor, Base camp (each)			22	5.5	29
Booster Station (each)	WEST only		6	5.5	8

Source: Dames & Moore

TABLE B-5a

DEVELOPMENT SUMMARY - 2.3 BILLION BARREL RESERVE

FIELD	RESERVES (BILLION BBL)	TRACTS	PLATFORMS	PRODUCTION WELLS	DEVELOPMENT WELLS
1 large	1.2	4	3	140	22
2 medi urn	.6	2	2	75	10
	.3	1	2	50	8
2 small	.2	1	1	30	8
	2.3	8	8	295	48

Max; output, 0.7 MMbd Oil, 0.9 Bcfd Gas

Tracts held 12-16

Source: Dames & Moore

TABLE B-5b

HIGH COST INVESTMENT REQUIREMENTS FOR 2.3 BILLION BBL RESERVE - ($ MILLIONS - 1975-76)

CAPITAL EQUIPMENT (units)	LOCATION	BASE CALCULATION (Units @ cost/unit)	BASE	ESCALATION TIME (YR)	FINANCIAL COST (1)
Production Platforms (each)			325	5.5	426
Gravity Structures @ 15m (50 ft.)		1 @ $65			
Gravity Structures @ 6m (20 ft.)		5 @ $40			
Gravel Islands @ 4.5m (15 ft.)		2 @ $30			
Production Wells (each)		40 @ $10	400	4.4	498
		255 @ $ 6	1,530	2.5	1,730
Development Wells (each)		48 @ $ 6	288	2.5	325
Processing Equipment (Mbd)		700 @ $ 0.7	490	0.5	502
Gas Plant (100 MMcfd)		9 @ $14	126	0.5	129
Offshore Oil Lines (kilometers) (miles)	EAST	64 @ $ 5 (40 @ $ 8)	320	1.5	344
	CENTRAL	64 @ $ 5 (40 @ $ 8)	320	1.5	344
	WEST	46 @ $ 5 (60 @ $ 8)	480	1.5	516
Onshore Oil Lines (kilometers) (miles)	EAST	145 @ $ 5.6 (90 @ $ 9)	810	2.5	915

(1) Financial Cost = Base X $(1.05)^{yr}$; except for tracts where Financial Cost = Base X $(1.08)^{yr}$

TABLE B-5b, Cont.

CAPITAL EQUIPMENT (units)	LOCATION	BASE CALCULATION (Units @ cost/unit)	BASE	ESCALATION TIME (YR)	FINANCIAL COST (1)
	CENTRAL	39 @ $ 5.6 (24 @ $ 9)	216	1.5	232
	WEST	274 @ $ 5.6 (170 @ $ 9)	1,530	2.5	1,730
Gas Lines (kilometers) (miles)	EAST	@ 70% of oil lines	791		881
	CENTRAL		375		403
	WEST		1,410		1,850
Roads (kilometers) (miles)	EAST	145 @ $ 0.25 (90 @ $ 0.4)	36	5.5	47
	CENTRAL	39 @ $ 0.19 (24 @ $ 0.3)	7	5.5	9
	WEST	113 @ $ 0.25 (70 @ $ 0.4)	68	5.5	89
Harbor, Base camp (each)		1 @ $40	40	5.5	52
Booster Station (each)	WEST only	1 @ $ 8	8	1.5	9

Source: Dames & Moore

TABLE B-5c

LOW COST INVESTMENT REQUIREMENTS FOR 2.3 BILLION BBL RESERVE - ($ MILLION - 1975-76)

CAPITAL EQUIPMENT (units)	LOCATION	BASE CALCULATION (Units @ cost/unit)	BASE	ESCALATION TIME (YR)	FINANCIAL COST(1)
Production Platforms (each)			65	5.5	216
Gravity Structures @ 15m (50 ft.)		@ $35			
Gravity Structures @ 6m (20 ft.)		5 @ $20			
Gravel Islands @ 4.5m (15 ft.)		2 @ $15			
Production Wells (each)		40 @ $ 8	320	4.5	399
		255 @ $ 3	765	2.5	864
Development Wells (each)		48 @ $ 3	144	2.5	163
Processing Equ[illegible] M		700 @ $ 0.5	350	0.5	359
Gas Plant (100 MMcfd)		9 @ $10	90	0.5	92
Offshore Oil Lines (kilometers) (miles)	EAST	64 @ $ 5 (40 @ $ 8)	320	1.5	344
	CENTRAL	64 @ $ 5 (40 @ $ 8)	320	1.5	344
	WEST	96 @ $ 5 60 @ $ 8)	480	1.5	516
Onshore Oil Lines (kilometers) (miles)	EAST	145 @ $ 5 (90 @ $ 8	720	2.5	813

(1) Financial Cost = Base X $(1.05)^{yr}$; except for tracts where Financial Cost = Base $(1.08)^{9.5}$

TABLE B-5c Cont.

CAPITAL EQUIPMENT (units)	LOCATION	BASE CALCULATION (Units @ cost/unit)	BASE	ESCALATION TIME (YR)	FINANCIAL COST (1,
	CENTRAL	39 @ $ 5 (24 @ $ 8)	192	1.5	207
	WEST	168 @ $ 5 (105(?$8)	840	2.5	949
Gas Lines (kilometers) (miles)	EAST	@ 70% of oil lines	728		810
	CENTRAL		358		385
	WEST		924		1,030
Roads (kilometers) (miles)	EAST	145 @ $0.22 (90 @ $ 0.35)	32	5.5	42
	CENTRAL	39 @ $ 0.16 (24 @ $ 0.25)	6	5.5	8
	WEST	274 @ $ 0.22 (170 @ $ 0.35)	60	5.5	78
Harbor, Base camp (each)			22	5.5	29
Booster Station (each)	WEST only		6	5.5	8

Source: Dames & Moore

TABLE B-6a

DEVELOPMENT SUMMARY - 1.5 to 1.2 BILLION BBL RESERVE[1]

	FIELD	RESERVES (BILLION BBL)	TRACTS	PLATFORMS	PRODUCTION WELLS	DEVELOPMENT WELLS
I.	1 large	1.1	4	3	130	20
	2 small	0.2	1	1	30	8
		0.2	1	1	30	8
		1.5	6	5	190	36

Tracts held 9 - 12

Max. output; 1.5 MMbd Oil, 0.6 Bcfd Gas

	FIELD	RESERVES (BILLION BBL)	TRACTS	PLATFORMS	PRODUCTION WELLS	DEVELOPMENT WELLS
II.	1 medium	0.8	2	2	100	15
	1 small	0.4	2	2	60	10
		1.2	4	4	160	25

Tracts held 6 - 8

Max. output; 0.4 MMbd Oil, 0.46 Bcfd Gas

(1) III. Scenario Composite: 1.4 billion BBL

3 units, 5 platforms, 16 exploration platforms, 180 production wells;

30 development wells.

Max. output; 0.45 MMbd Oil, 0.5 Bcfd Gas

Source: Dames & Moore

TABLE B-6b

HIGH COST INVESTMENT REQUIREMENTS FOR 1.4 BILLION BBL RESERVE - ($ MILLIONS - 1975-76)

CAPITAL EQUIPMENT (units)	LOCATION	BASE CALCULATION (Units @ cost/unit)	BASE	ESCALATION TIME (YR)	FINANCIAL COST(1)
Production Platforms (each)			215	5.5	282
Gravity Structures @ 15m (50 ft.)		1 @ $65			
Gravity Structures @ 6m (20 ft.)		3 @ $40			
Gravel Islands @4.5m (15 ft.)		1 @ $30			
Production Wells (each)		40 @ $10	400	4.5	498
		140 @ $ 6	840	2.5	949
Development Wells (each)		30 @ $ 6	180	2.5	203
Processing Equipment (Mbd)		450 @ $ 0.7	315	0.5	323
Gas Plant (100 MMcfd)		5@ $14	70	0.5	72
Offshore Oil Lines (kilometers) (miles)	EAST	64 @ $ 5 (40 @ $ 8)	320	1.5	344
	CENTRAL	64 @ $ 5 (40 @ $ 8)	320	1.5	344
	WEST	96 @ $ 5 (60 @ $ 8)	480	1.5	516
Onshore Oil Lines (kilometers) (miles)	EAST	145 @ $ 5.6 (90 @ $ 9)	810	2.5	915

(1) Financial Cost = Base X $(1.05)^{yr}$; except for tracts where Financial Cost = Base X $(1.08)^{yr}$

TABLE B-6b, Cont.

CAPITAL EQUIPMENT (units)	LOCATION	BASE CALCULATION (Units @ cost/unit)	BASE	ESCALATION TIME (YR)	FINANCIAL COST(1)
	CENTRAL	39 @ \$ 5.6 24 @ \$ 9)	216	1.5	232
	WEST	274 @ \$ 5.6 (170 @ \$ 9)	1,530	2.5	1,730
Gas Lines (kilometers) (miles)	EAST	@ 70 % of oil lines	791		881
	CENTRAL		375		403
	WEST		1,410		1,850
Roads (kilometers) (miles)	EAST	145 @ \$ 0.25 (90 @ \$ 0.4)	36	5.5	47
	CENTRAL	39 @ \$ 0.19 (24 @ \$ 0.3)	7	5.5	9
	WEST	113 @ \$ 0.25 (70 @ \$ 0.4)	68	5.5	89
Harbor, Base camp each)		1 @ \$40	35	5.5	46
Booster Station (each)	WEST only	1 @ \$ 8	8	1.5	9

Source: Dames & Moore

TABLE B-6c

LOW COST INVESTMENT REQUIREMENTS FOR 1.4 BILLION BBL RESERVE - ($ MILLION - 1975-76)

CAPITAL EQUIPMENT (units)	LOCATION	BASE CALCULATION (units @ cost/unit)	BASE	ESCALATION TIME (YR)	FINANCIAL COST(1)
Production Platforms (each)			110	5.5	144
Gravity Structures @ 15m (50 ft.)		1 @ $35			
Gravity Structures @ 6m (20 ft.)		3 @ $20			
Gravel Islands @ 4.5m (15 ft.)		1 @ $15			
Production Wells (each)		40 @ $ 8	320	4.5	399
		140 @ $3	420	2.5	474
Development Wells (each)		30 @ $ 3	90	2.5	102
Processing Equipment (Mbd)		450 @ $ 0.5	225	0.5	231
Gas Plant (100 MMcfd)		5 @ $10	50	0.5	51
Offshore Oil Lines (kilometers) (miles)	EAST	64 @ $ 5 (40 @ $ 8)	320	1.5	344
	CENTRAL	64 @ $ 5 (40 @ $ 8)	320	1.5	344
	WEST	96 @ $ 5 (60 @ $ 8)	480	1.5	516
Onshore Oil Lines (kilometers) (miles)	EAST	145 @ $ 5 (90 @ $ 8)	720	2.5	813

(1) Financial Cost = Base X $(1.05)^{yr}$; except for tracts where Financial Cost = Base X $(1.08)^{9.5}$

TABLE B-6c, Cont.

CAPITAL EQUIPMENT (units)	LOCATION	BASE CALCULATION (Units @ cost/unit)	BASE	ESCALATION TIME (YR)	FINANCIAL COST (1)
	CENTRAL	39 @ \$ 5 (24 @ \$ 8)	192	1.5	207
	WEST	168 @ \$ 5 (105 @ \$ 8)	840	2.5	949
Gas Lines (kilometers) (miles)	EAST	@ 70% of oil lines	728		810
	CENTRAL		358		386
	WEST		924		1,030
Roads (kilometers) (miles)	EAST	145 @ \$ 0.22 (90 @ \$ 0.35)	32	5.5	41
	CENTRAL	39 @ \$ 0.16 24 @ \$ 0.25)	6	5.5	8
	WEST	274 @ \$ 0.22 (170 @ \$ 0.35)	60	5.5	78
Harbor, Base camp (each)			8	5.5	24
Booster Station (each)	WEST only		6	1.5	6

Source: Dames & Moore

TABLE B-7a

DEVELOPMENT SUMMARY- 0.7 BILLION BARREL RESERVE

FIELD	RESERVES (BILLION BBL)	TRACTS	PLATFORMS	PRODUCTION WELLS	DEVELOPMENT WELLS
1 medium	0.7	2	2	90	13

Tracts held 2 - 3

Max. output: 0.2 MMbd Oil, 0.3 Bcfd Gas

Source: Dames & Moore

TABLE B-7b

HIGH COST INVESTMENT REQUIREMENTS FOR 0.7 BILLION BBL RESERVE - ($ MILLIONS - 1975-76)

CAPITAL EQUIPMENT (units)	LOCATION	BASE CALCULATION (Units @ cost/unit)	BASE	ESCALATION TIME (YR)	FINANCIAL COST[1]
Production Platforms (each)			95	5.5	124
Gravity Structures @ 15m (5○ ft.)		1 @ $65			
Gravel slands @ 4.5m (5 ft.)		1 @ $30			
Production Wells (each)		20 @ $10	200	4.5	249
		70 @ $ 6	420	2.5	474
Development Wells (each)		13 @ $ 6	78	2.5	88
Processing Equipment (Mbd)		200 @ $ 0.7	140	0.5	144
Gas Plant (100 MMcfd)		3 @ $14	42	0.5	43
Offshore Oil Lines (kilometers) (miles)	EAST	32 @ $ 5 20 @ $ 8)	160	1.5	172
	CENTRAL	32 @ $ 5 20 @ $ 8)	160	1.5	172
	WEST	32 @ $ 5 (20 @ $ 8)	240	1.5	258
Onshore Oil Lines (kilometers) (miles)	EAST	145 @ $ 4.3 (90 @ $ 7)	630	2.5	712

(1) Financial Cost = Base X $(1.05)^{yr}$; except for tracts whe-e Financial Cost = Base X $(1.08)^{9.5}$

TABLE B-7b, Cont.

HIGH COST INVESTMENT REQUIREMENTS FOR 0.7 BILLION BBL RESERVE - ($ MILLIONS - 1975-76)

CAPITAL EQUIPMENT (units)	LOCATION	BASE CALCULATION (Units @ cost/unit)	BASE	ESCALATION TIME (YR)	FINANCIAL COST(1)
	CENTRAL	39 @ $ 4.3 (24 @ $ 7)	168	1.5	181
	WEST	274 @ $ 4.3 170 @ $ 7)	1, 90	2.5	1,340
Gas Lines (kilometers) (miles)	EAST	@ 70% of oil lines	553		619
	CENTRAL		230		248
	WEST		,000		1,120
Roads (kilometers) (miles)	EAST	145 @ $ 0.25 (90 @ $ 0.4)	36	5.5	47
	CENTRAL	39 @ $ 0.19 (24 @ $ 0.3)	7	5.5	9
	WEST	74 @ $ 0.25 70 @ $ 0.4)	68	5.5	89
Harbor, Base camp (each)		1 @ $40	35	5.5	46
Booster Station (each	WEST only	1 @ $ 8	8	.5	9

1) Financial Cost = Base X $(1.05)^{yr}$; except for tracts where Financial Cost = Base X $(1.08)^{9.5}$

Source: Dames & Moore

TABLE B-7c

LOW COST INVESTMENT REQUIREMENTS FOR 0.7 BILLION BBL RESERVE - ($ MILLIONS - 1975-76)

CAPITAL EQUIPMENT (units)	LOCATION	BASE CALCULATION (Units @ cost/unit)	BASE	ESCALATION TIME (YR)	FINANCIAL COST[1]
Production Platforms (each)			50	5.5	66
Gravity Structures @ 15m (50 ft.)		1 @ $35			
Gravel Islands @ 4.5m (15 ft.)		1 @ $15			
Production Wells (each)		20 @ $ 8	160	4.5	199
		70 @ $ 3	210	2.5	237
Development Wells (each)		13 @ $ 3	39	2.5	44
Processing Equipment (Mbd)		200 @ $ 0.5	100	0.5	103
Gas Plant (100 MMcfd)		3 @ $10	30	0.5	31
Offshore Oil Lines (kilometers) (miles)	EAST	32 @ $ 5 (20 @ $ 8)	160	1.5	173
	CENTRAL	32 @ $ 5 (20 @ $ 8)	160	1.5	173
	WEST	48 @ $ 5 (30 @ $ 8)	240	1.5	259
Onshore Oil Lines (kilometers) (miles)	EAST	145 @ $ 4.3 (90 @ $ 7)	630	2.5	712

[1] Financial Cost = Base X $(1.05)^{yr}$; except for tracts where Financial Cost = Base X $(1.08)^{9.5}$

TABLE B-7c, Cont.

LOW COST INVESTMENT REQUIREMENTS FOR 0.7 BILLION BBL RESERVE - ($ MILLIONS - 1975-76)

CAPITAL EQUIPMENT (units)	LOCATION	BASE CALCULATION (Units @ cost/unit)	BASE	ESCALATION TIME (YR)	FINANCIAL COST [1]
	CENTRAL	39 @ $ 4.3 (24 @ $ 7)	168	1.5	181
	WEST	274 @ $4.3 (170 @ $ 7)	1,190	2.5	1,340
Gas Lines (kilometers) (miles)	EAST	) @ 70% of	553		620
	CENTRAL	) oil lines	230		248
	WEST	)	1,001		1,119
Roads (kilometers) (miles)	EAST	145 @ $ 0.22 (90 @ $ 0.35)	32	5.5	41
	CENTRAL	39 @ $ 0.16 (24 @ $ 0.25)	6	5.5	8
	WEST	274 @ $ 0.22 (170 @ $ 0.35)	60	5.5	78
Harbor, Base camp (each)			18	5.5	24
Booster Station (each)	WEST only		6	1.5	6

(1) Financial Cost = Base X $(1.05)^{yr}$; except for tracts where Financial Cost = Base X $(1.08)^{9''5}$

Source: Dames & Moore

TABLE B-8a

DEVELOPMENT SUMMARY - 0.4 BILLION BBL RESERVE

FIELD	RESERVES (BILLION BBL)	TRACTS	PLATFORMS	PRODUCTION WELLS	DEVELOPMENT WELLS
1 small	0.4	2	1	50	10

Tracts held 2

Max. output: 0.1 MMbd Oil, 0.15 Bcfd Gas

Source: Dames & Moore

TABLE B-8b

HIGH COST INVESTMENT REQUIREMENTS FOR 0.4 BILLION BBL RESERVE - $ MILLIONS - 1975-76)

CAPITAL EQUIPMENT (units)	LOCATION	BASE CALCULATION (Units @ cost/unit)	BASE	ESCALATION TIME (YR)	FINANCIAL COST(1)
Product on Platforms (each)		1 @ 40	30	5.5	52
Production We s each)		20 @ $10	200	4.5	249
		30 @ $ 6	180	2.5	203
Development Wells (each)		0 @ 6	60	2.5	68
Process ng Equipment (Mbd)		[illegible] @ $ [illegible] 7	70	0.5	72
Gas Plant ([illegible] MMcfd)		2 @ $14	28	0.5	29
Offshore [illegible] nes (kilometers) (miles)	EAST	32 @ $ 5 (20 @ $ 8)	160	1.5	172
	CENTRAL	32 @ $ 5 (20 @ $ 8)	60	1.5	172
	WEST	48 @ $ 5 (30 @ $ 8)	240	1.5	258
Onshore Oil Lines (kilometers) (miles)	EAST	145 @ $ 4.3 (90 @ $ 7)	630	2.5	712
	CENTRAL	39 @ $ 4.3 (24 @ $ 7)	168	1.5	181
	WEST	274 @ $ 4.3 (170 @ $ 7)	1,190	2.5	.340

(1) inancial Cost = Base X .05)^{yr}; except for tracts where F nancial Cost = Base X (1.08 9.5

TABLE B-8b, Cont.

HIGH COST INVESTMENT REQUIREMENTS FOR 0.4 BILLION BBL RESERVE - ($ MILLIONS - 1975-76)

CAPITAL EQUIPMENT (units)	LOCATION	BASE CALCULATION (Units @ cost/unit)	BASE	ESCALATION TIME (YR)	FINANCIAL COST (1)
Gas Lines (kilometers) (miles)	EAST	@ 70% of oil lines	553		619
	CENTRAL		230		247'
	WEST		1,000		1,120
Roads (kilometers) (miles)	EAST	145 @ $ 0.25 (90 @ $ 0.4)	36	5.5	47
	CENTRAL	39 @ $ 0.19 (24 @ $ 0.3)	7	5.5	9
	WEST	274 @ $ 0.25 (170 @ $ 0.4)	68	5.5	89
Harbor, Base camp (each)		1 @ $40	40	5.5	52
Booster Station (each)	WEST only	1 @ $ 8	8	1.5	9

(1) Financial Cost = Base X $(1.05)^{yr}$; except for tracts where Financial Cost = Base X $(1.08)^{9.5}$

Source: Dames & Moore

TABLE B-8c

LOW COST INVESTMENT REQUIREMENTS FOR 0.4 BILLION BBL RESERVE - ($ MILLIONS - 1975-76)

CAPITAL EQUIPMENT (units)	LOCATION	BASE CALCULATION (Units @ cost/unit)	BASE	ESCALATION TIME (YR)	FINANCIAL COST(1)
Production Platforms (each)		1 @ $20	20	5.5	26
Production Wells (each)		20 @ $ 8	160	4.5	200
		30 @ $ 3	90	2.5	102
Development Wells (each)		lo @ $ 3	30	2.5	34
Processing Equipment (Mbd)		100 @ $ 0.5	50	0.5	51
Gas Plant (100 MMcfd)		2 @ $10"	20	0.5	21
Offshore Oil Lines (kilometers) (miles)	EAST	32 @ $ 5 (20 @ $ 8)	160	1.5	173
	CENTRAL	32 @ $ 5 (20 @ $ 8)	160	1.5	173
	WEST	48 @ $ 5 (30 @ $ 8)	240	1.5	259
Onshore Oil Lines (kilometers) (miles)	EAST	145 @ $ 4.3 (90 @ $ 7)	630	2.5	712
	CENTRAL	39 @ $ 4.3 (24 @ $ 7)	168	1.5	181
	WEST	274 @ $ 4.3 (170 @ $ 7)	1,190	2.5	1,340

" 'Financial Cost = Base X (1 .05)^{yr}; except for tracts where Financial Cost = Base X (1 .08)$^{9"5}$

Source: Dames & Moore

TABLE B-8c, Cont.

LOW COST INVESTMENT REQUIREMENTS FOR 0.4 BILLION BBL RESERVE - ($ MILLIONS - 1975-76)

CAPITAL EQUIPMENT (units)	LOCATION	BASE CALCULATION (Units @ cost/unit)	BASE	ESCALATION TIME (YR)	FINANCIAL COST (1)
Gas Lines (kilometers) (miles)	EAST	@ 70% of oil lines	553		620
	CENTRAL		230		248
	WEST		1,001		1,119
Roads (kilometers) (miles)	EAST	145 @ $ 0.22 (90 @ $ 0.35)	32	5.5	41
	CENTRAL	39 @ $ 0.16 (24 @ $ 0.25)	6	5.5	8
	WEST	274 @ $ 0.22 (170 @ $ 0.35)	60	5.5	78
			16	5.5	21
			6	1.5	6
Harbor, Base camp (each)			16	5.5	21
Booster Station (each)	WEST only		6	1.5	6

(1) Financial Cost = Base X $(1.05)^{yr}$; except for tracts where Financial Cost = Base X $(1.08)^{9.5}$

Source: Dames & Moore

investment requirements for the same 3 locations. The investment requirements were obtained by multiplying the developmental requirements by the appropriate "unit costs," which are the capital cost assumptions already detailed in Table B-3.

The base costs (expressed in constant 1975-76 dollars) were escalated to the date of initial production at the rate of 5 percent per annum to reflect the "net opportunity loss" of capital over and above general inflation.

From Tables B-4 through B-8, it can be seen that for any given building block, the itemized costs of development are independent of location, with the exception of pipelines and roads. Thus, each of 5 sets of investment tables (1 for each reserve level) yields 3 geographically specific cost summaries. These are shown for each of the resulting 15 scenarios in the summary Table B-9.

The unit investment requirements (per barrel of oil or per 2.5 Mcf of gas) for each of the 15 scenarios are shown in Table B-10. The unit totals were obtained by dividing the total investment figures by the appropriate reserve sizes. The unit investment for gas was obtained by adding the total investment requirements for the gas plant and gas lines, plus an arbitrary allocation of 10 percent of the "shared" investment (platforms, wells, roads, harbor and base camp), and then dividing by the total reserves. Subtracting the unit investment requirements for gas from the total unit investment yielded the unit investment requirements for oil.

Examination of Table B-10 reveals a number of significant cost relationships. First, the unit costs tend to increase as the hypothetical reserve levels decrease, since there are fewer "units" over which to amortize fixed investment. Second, the unit costs for any given reserve level are uniformly lowest in the central location and highest in the western location, with the eastern location always falling in the

TABLE B-9

SUMMARY OF INVESTMENT REQUIREMENTS(1)
($ Millions-1975-76)

		High Cost	Low Cost
West	3.5 Bbbl	$10,734	$ 7,753
	2.3 Bbbl	7,856	4,703
	1.4 Bbbl	6,521	4,004
	0.7 Bbbl	3,984	3,506
	0.4 Bbbl	3,528	3,257
Central	3.5 Bbbl	$ 7,048	$ 4,621
	2.3 Bbbl	4,650	3,066
	1.4 Bbbl	3,361	2,370
	0.7 Bbbl	1,778	1,310
	0.4 Bbbl	1,321	1,065
East	3.5 Bbbl	$ 8,480	$ 5,394
	2.3 Bbbl	5,858	4,131
	1.4 Bbbl	4,560	3,433
	0.7 Bbbl	2,718	2,250
	0.4 Bbbl	2,262	2,001

(1) Geographic cost summaries derived from Tables B-4 through B-8

Source: Dames & Moore

TABLE B-10

SUMMARY OF UNIT INVESTMENT REQUIREMENTS
($1975-76 per barrel oil, per 2.5 Mcf gas)

		High Cost			Low Cost		
		Oil	Gas (2)	Total (1)	Oil	Gas (2)	Total (1)
West	3.5 Bbbl	2.28	.79	3.07	1.58	.64	2.22 (3)
	2.3 Bbbl	2.42	1.00	3.42	1.48	.56	2.04 (3)
	1.4 Bbbl	3.14	1.52	4.66	2.00	.86	2.86
	0.7 Bbbl	3.88	1.81	5.69	3.27	1.74	5.01
	0.4 Bbbl	5.77	3.05	8.82	5.18	2.96	8.14
Central	3.5 Bbbl	1.65	.36	2.01	1.04	.28	1.32
	2.3 Bbbl	1.66	.36	2.02	1.05	.28	1.33
	1.4 Bbbl	1.92	.48	2.40	1.30	.39	1.69
	0.7 Bbbl	1.98	.56	2.54	1.40	.48	1.88
	0.4 Bbbl	2.45	.85	3.30	1.90	.77	2.67
East	3.5 Bbbl	1.89	.53	2.42	1.25	.29	1.54
	2.3 Bbbl	1.98	.57	2.55	1.33	.47	1.80
	1.4 Bbbl	2.43	.83	3.26	1.76	.69	2.45
	0.7 Bbbl	2.79	1.09	3.88	2.19	1.02	3.21
	0.4 Bbbl	3.88	1.78	5.66	3.30	1.70	5.00

(1) Obtained by dividing total investment requirements shown in Table B-9 by appropriate field sizes.

(2) Gas allocated 10% of shared costs

(3) Unit price variation reflects utilization of offshore lines assumed in scenario

Source: Dames & Moore

intermediate position. This latter relationship is a reflection of the relative distances to the central interconnection near Prudhoe Bay, with the west averaging 274 kilometers (170 miles), the east 145 kilometers (90 miles), and the central location 39 kilometers (24 miles). In fact, the relative investment requirements are closely proportional to the length of connecting pipeline since pipeline investment represents such a large proportion of total cost. Pipeline investment as a percentage of total investment is roughly 50 percent in the western and eastern locations (always greater in the west) and roughly 33 percent in the central location.

Table B-11 represents a summary of the recalculated unit investment requirements for oil for these scenarios with insufficient gas reserves to warrant development. It was found in the parametric market price analysis that the gas for these scenarios would have to sell for more than $10/unit (greater than $4.00/Mcf) to justify the required investment, and that such a market price (in constant dollars) would exceed the feasible market limit as determined by the research staff. Consequently, the unit investment requirements for oil for these particular scenarios were then recalculated by: 1) removing the costs for the gas plant and gas lines, 2) reapplying the 10 percent gas allocation of shared investment for such items as platforms, wells, roads, harbor and base camp to the total oil investment, and 3) dividing by the appropriate reserve size. .

TABLE B-n

UNIT OIL INVESTMENT REQUIREMENTS
FOR SCENARIOS WITH INSUFFICIENT
GAS RESERVES FOR DEVELOPMENT[1]
($1975-76 per barrel oil)

Scenario Location	Reserve Level	High Cost Investment	Low Cost Investment
West	2.3 Bbbl	2.47	NA
	1.4 Bbbl	3.20	NA
	0.7 Bbbl	3.95	3.33
	0.4 Bbbl	5.88	5.26
East	0.7 Bbbl	2.86	2.24
	0.4 Bbbl	3.97	3.37

(1) Oil carries total burden of investment -- gas production facilities excluded and shared costs reapplied to oil investment requirements..

Source: Dames & Moore

APPENDIX C

SCENARIO MANPOWER REQUIREMENTS AND ACTIVITY SCHEDULE TABLES

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TABLE C-1

CAMDEN-CANNING SCENARIO

PLATFORM CONSTRUCTION AND DRILLING PROGRAM--EXPLORATION PHASE

(Labor Requirements in Man-Months)

Year	Number of Platforms Built	Type	Construction Labor Requirements	Platform Maintenance Labor Requirements	Construction Camp Support Labor	Number of Wells Drilled	Drilling Labor Requirements	Shore Support Labor Requirements
1	1	barge	80	18	8	1	180	15
2	2	1 barge 1 soil	530	36	53	2	360	30
3	3	2 barge 1 ice	280	54	28	3	540	45
4	3	2 barge 1 soil	610	54	61	3	540	45
5	3	2 soil 1 ice	1020	54	102	3	540	45
6	3	3 soil	1350	54	135	3	540	45
7	2	2 soil	900	36	90	2	360	30
8	1	1 ice	120	18	12	1	180	15

Source: Dames & Moore

TABLE C-2

PRUDHOE OFFSHORE (0.8Bbbl) SCENARIO

PLATFORM CONSTRUCTION AND DRILLING PROGRAM--EXPLORATION PHASE

(Labor Requirements in Man-Months)

Year	Number of Platforms Built	Type	Construction Labor Requirements	Platform Maintenance Labor Requirements	Construction Camp Support Labor	Number of Wells Drilled	Drilling Labor Requirements	Shore Support Labor Requirements
1	0	0	0	0	0	0	0	0
2	3	2 barge 1 soil	610	54	61	3	540	45
3	2	2 barge	160	36	16	2	360	30
4	2	2 soil	900	36	90	2	360	30
5	2	2 soil	900	36	90	2	360	30
6	1	1 ice	120	18	12	1	180	15
7	1	1 soil	450	18	45	1	180	15
8	1	1 ice	120	18	12	1	180	15

Source: Dames & Moore

TABLE C-3

PRUDHOE OFFSHORE (1.9 Bbbl) SCENARIO

PLATFORM CONSTRUCTION AND DRILLING PROGRAM--EXPLORATION PHASE

(Labor Requirements in Man-Months)

Year	Number of Platforms Built	Type	Construction Labor Requirements	Platform Maintenance Labor Requirements	Construction Camp Support Labor	Number of Wells Drilled	Drilling Labor Requirements	Shore Support Labor Requirements
1	0	0	0	0	0	0	0	0
2	3	2 barge 1 soil	610	54	6	3	540	45
3	2	2 barge	160	36	16	2	3[illegible]0	30
4	2	2 soil	900	36	90	2	360	30
5	2	2 soil	900	36	90	2	360	30
6	2	1 soil 1 ice	570	36	57	2	360	30
7	1	1 soil	450	8	45	1	80	15
8	2	2 ice	240	36	24	2	360	30

Source: Dames & Moore

TABLE C-4

CAPE HALKETT SCENARIO

PLATFORM CONSTRUCTION AND DRILLING PROGRAM--EXPLORATION PHASE

(Labor Requirements in Man-Months)

Year	Number of Platforms Built	Type	Construction Labor Requirements	Platform Maintenance Labor Requirements	Construction Camp Support Labor	Number of Wells Drilled	Drilling Labor Requirements	Shore Support Labor Requirements
1	0	0	0	0	0	0	0	0
2	2	1 barge 1 ice	200	36	20	2	360	30
3	3	1 barge 2 ice	320	54	32	3	540	45
4	1	1 ice	120	8	12	1	180	15
5	1	1 ice	120	8	12	1	80	15
w	1	1 ice	120	8	12	1	180	15

Source: Dames & Moore

TABLE C-5

SMITH-DEASE SCENARIO

PLATFORM CONSTRUCTION AND DRILLING PROGRAM--EXPLORATION PHASE

(Labor Requirements in Man-Months)

ear	Number of Platforms Built	Type	Construction Labor Requirements	Platform Maintenance Labor Requirements	Construction Camp Support Labor	Number of Wells Drilled	Drilling Labor Requirements	Shore Support Labor Requirements
1	0	0	0	0	0	0	0	0
2	1	1 ice	120	18	12	1	180	15
3	2	2 ice	240	36	24	2	360	30
4	3	2 barge 1 ice	280	54	28	3	540	45
5	2	1 barge 1 ice	200	36	20	2	360	30
6	2	1 barge 1 ice	200	36	20	2	360	30
7		1 ice	20	18	12	1	180	15
8	1	1 ice	120	8	12		180	5

Source: Dames & Moore

TABLE C-6

PLATFORM CONSTRUCT ION AND DRILL ING PROGRAM--DEVELOPMENT PHASE

CAMDEN-CANNING SCENARIO (CAMDEN FI ELD)

Year of Development Phase	Number of Platforms Built	Type	Construction Labor (Man-Months)	Number of Wells Drilled	Drilling Labor (Man-Months)	Number of Platforms to be Maintained	Maintenance Labor (Man-Months)
1	0	0	0	0	0	0	0
2	2	1 soil 1 barge/ gravity	1220	0	0	0	0
3	2	1 soil 1 barge/ gravity	1220	16	1440	2	144
4	1	1 soil	900	32	2880	4	288
5	1	1 soil	900	40	3600	5	360
6	0	0	0	48	4320	6	432
7	0	0	0	36	3240	6	4 3 2
8	0	0	0	40	3600	6	432
9	0	0	0	28	2520	6	432

'TABLE C-6, Cont.

PLATFORM CONSTRUCTION AND DRILLING PROGRAM--DEVELOPMENT PHASE

CAMDEN-CANNING SCENARIO (CAMDEN FIELD)

Year of Development Phase	Number of Platforms Built	Type	Construction Labor (Man-Months)	Number of Wells Drilled	Drilling Labor (Man-Months)	Number of Platforms to be Maintained	Maintenance Labor (Man-Months)
10	1	1 soil	900	14	1260	7	0
11	0	0	0	12	1080	7	504
12	1	1 soil	900	10	900	7	504
13	0	0	0	16	1440	8	576
14	0	0	0	8	720	8	576
15	0	0	0	8	720	8	576
16	0	0	0	8	720	8	576
17	0	0	0	0	0	8	576
18	0	0	0	0	0	8	576
19	0	0	0	0	0	8	576
20	0	0	0	0	0	8	576

Source: Dames & Moore

TABLE C-7

PLATFORM CONSTRUCTION AND DRILLING PROGRAM--DEVELOPMENT PHASE

CAMDEN-CANNING SCENARIO (CANNING FIELD)

Year of Development Phase	Number of Platforms Built	Type	Construction Labor (Man-Months)	Number of Wells Drilled	Drilling Labor (Man-Months)	Number of Platforms to be Maintained	Maintenance Labor (Man-Months)
1	0	0	0	0	0	0	0
2	0	0	0	0	0	0	0
3	0	0	0	0	0	0	0
4	1	barge/ gravity	320	0	0	0	0
5	1	soil	900	8	720	1	72
6	0	0	0	16	1440	2	144
7	1	soil	900	28	2520	2	144
8	0	0	0	24	2160	3	216
9	1	soil	900	36	3240	3	216
10	1	barge/ gravity	320	34	3060	4	288
11	0	0	0	20	1800	5	360

TABLE C-7, Cont.

PLATFORM CONSTRUCTION AND DRILLING PROGRAM--OEWELOPMENT PHASE

CAMDEN-CANNING SCENARIO (CANNING FIELD)

Year of Development Phase	Number of Platforms Built	Type	Construction Labor (Man-Months)	Number of Wells Drilled	Drilling Labor (Man-Months)	Number of Platforms to be Maintained	Maintenance Labor (Man-Months)
12	0	0	0	22	1980	5	360
13	0	0	0	8	720	5	360
14	0	0	0	8	720	5	360
15	0	0	0	0	0	5	360
16	0	0	0	0	0	5	360
17	0	0	0	0	0	5	360
18	0	0	0	0	0	5	360
19	0	0	0	0	0	5	360
20	0	0	0	0	0	5	360

Source: Dames & Moore

TABLE C-8

PLATFORM CONSTRUCTION AND DRILLING PROGRAM--DEVELOPMENT PHASE

PRUDHOE OFFSHORE (0.8Bbbl) SCENARIO

Year of Development Phase	Number of Platforms Built	Type	Construction Labor (Man-Months)	Number of Wells Drilled	Drilling Labor (Man-Months)	Number of Platforms to be Maintained	Maintenance Labor (Man-Months)
1	0	0	0	0	0	0	0
2	2	1 barge/ gravity 1 soil	1220	0	0	0	0
3	2	1 barge/ gravity 1 soil	1220	16	440	2	44
4	0	0	0	32	2880	4	288
5	0	0	0	32	2880	4	288
6		soil	900	32	2880	4	288
7		soil	900	32	2880	5	360
8		barge/ gravity	320	32	2880	6	432
9		soil	900	32	2880	7	504

TABLE C-8, Cont.

PLATFORM CONSTRUCTION AND DRILLING PROGRAM--DEVELOPMENT PHASE

PRUDHOE OFFSHORE (0.8Bbbl) SCENARIO

Year of Development Phase	Number of Platforms Built	Type	Construction Labor (Man-Months)	Number of Wells Drilled	Drilling Labor (Man-Months)	Number of Platforms to be Maintained	Maintenance Labor (Man-Months)
10	0	0	0	32	2880	8	576
11	0	0	0	32	2880	8	576
12	0	0	0	24	2160	8	576
13	0	0	0	16	1440	8	576
14	0	0	0	16	1440	8	576
15	0	0	0	0	0	8	576
16	0	0	0	0	0	8	576
17	0	0	0	0	0	8	576
18	0	0	0	0	0	8	576
19	0	0	0	0	0	8	576
20	0	0	0	0	0	8	576

Source: Dames & Moore

TABLE C-9

PLATFORM CONSTRUCTION AND DRILLING PROGRAM--DEVELOPMENT PHASE

PRUDHOE OFFSHORE (1.9 Bbbl) SCENARIO

Year of Development Phase	Number of Platforms Built	Type	Construction Labor (Man-Months)	Number of Wells Drilled	Drilling Labor (Man-Months)	Number of Platforms to be Maintained	Maintenance Labor (Man-Months)
1	0	0	0	0	0	0	0
2	[illegible]	1 barge/ gravity 1 soil	1220	0	0	0	0
3	2	soil	1800	6	1440	2	288
4	2	1 soil 1 barge/ gravity	1220	[illegible]	2880	4	288
5	0	0	0	48	4320	6	432
6	0	0	0	48	4320	6	432
7	0	0	0	48	4320	6	432
8	0	0	0	48	4320	6	432
[illegible]	0	0	0	[illegible]	2880	6	432

TABLE C-9, Cont.

PLATFORM CONSTRUCT ION AND DRILLING PROGRAM--DEVELOPMENT PHASE

PRUDHOE OFFSHORE (1.9 Bbbl) SCENARIO

Year of Development Phase	Number of Platforms Built	Type	Construction Labor (Man-Months)	Number of Wells Drilled	Drilling Labor (Man-Months)	Number of Platforms to be Maintained	Maintenance Labor (Man-Months)
10	0	0	0	16	1440	6	20
11	0	0	0	2	180	6	20
12	0	0	0	0	0	6	20
13	0	0	0	0	0	6	20
14	0	0	0	0	0	6	20
15	0	0	0	0	0	6	20
16	0	0	0	0	0	6	20
17	0	0	0	0	0	6	20
18	0	0	0	0	0	6	20
19	0	0	0	0	0	6	20
20	0	0	0	0	0	6	20

Source: Dames & Moore

TABLE C-10

PLATFORM CONSTRUCTION AND DRILLING PROGRAM--DEVELOPMENT PHASE

CAPE HALKETT SCENARIO

Year of Development Phase	Number of Platforms Built	Type	Construction Labor (Man-Months)	Number of Wells Drilled	Drilling Labor (Man-Months)	Number of Platforms to be Maintained	Maintenance Labor (Man-Months)
1	0	0	0	0	0	0	0
2	1	soil	900	0	0	0	0
3	1	soil	900	8	720	1	72
4	1	barge/ gravity	320	16	1440	2	144
5	0	0	0	24	2160	3	216
6	1	barge/ gravity	320	24	2160	3	216
7	0	0	0	24	2160	4	288
8	0	0	0	24	2160	4	288
9	0	0	0	24	2160	4	288
10	0	0	0	8	720	4	288
11	0	0	0	0	0	4	288

TABLE C-10, Cont.

PLATFORM CONSTRUCTION AND DRILLING PROGRAM--DEVELOPMENT PHASE

CAPE HALKETT SCENARIO

Year of Development Phase	Number of Platforms Built	Type	Construction Labor (Man-Months)	Number of Wells Drilled	Drilling Labor (Man-Months)	Number of Platforms to be Maintained	Maintenance Labor (Man-Months)
12	0	0	0	0	0	4	288
13	0	0	0	0	0	4	288
14	0	0	0	0	0	4	288
15	0	0	0	0	0	4	288
16	0	0	0	0	0	4	288
17	0	0	0	0	0	4	288
18	0	0	0	0	0	4	288
19	0	0	0	0	0	4	288
20	0	0	0	0	0	4	288

Source: Dames & Moore

TABLE C-n

MANPOWER WORKSHEET--EXPLORATION PHASE

CAMDEN-CANNING SCENARIO

(Manpower Requirements in Man-Months/Year and Annual Average Employment)

	Exploration Begins								Decision to Develop							
	Year 1		Year 2		Year 3		Year 4		Year 5		Year 6		Year 7		Year 8	
	MM(a)	ANAV(b)	MM	ANAV	MM	ANAV	MM	ANAV	NM	ANAV	MM	ANAV	MM	ANAV	MM	ANAV
PETROLEUM																
Rig Crews	180	15	360	30	540	45	540	45	540	45	540	45	360	30	180	15
Geophysical	716	60	716	6D	716	60	0	0	0	0	0	0	D	0	0	0
Field Support	15	1	30	3	45	4	45	4	45	4	45	3	30	3	15	1
Subtotal	911	76	1,106	93	1,301	109	585	49	585	49	585	48	390	33	195	16
CONSTRUCT ION																
Pad/Pi at form	80	7	530	44	280	23	610	51	1,020	85	1,350	113	900	75	120	10
Maintenance	18	2	36	3	54	5	54	5	54	5	54	5	36	3	18	2
Support	8	1	53	4	28	2	“61	5	102	9	135	11	90	8	12	1
Subtotal	106	10	619	51	362	30	725	61	1,176	99	1,539	129	1,026	86	150	13
GRAND TOTAL	1,017	86	1,725	144	1,663	139	1,310	110	1,761	148	2,124	177	1,416	119	345	29

(a) MM = Man-Months
(b) ANAV = Annual Average

Source: Dames & Moore

TABLE C-12

MANPOWER WORKSHEET--EXPLORATION PHASE

PRUDHOE OFFSHORE (0.8 Bbbl) SCENARIO

(Manpower Requirements in Man-Months/Year and Annual Average Employment)

	Exploration Begins Year 1		Year 2		Year 3		Year 4		Decision to Develop Year 5		Year 6		Year 7		Year 8	
	MM(a)	ANAV(b)	MM	ANAV	MM	ANAV	MM	ANAV	MM	ANAV	MM	ANAV	MM	ANAV	MM	ANAV
PETROLEUM																
Rig Crews	0	0	540	45	360	30	360	30	360	30	180	15	180	15	180	15
Oil Field	0	0	54	5	36	3	36	3	36	3	18	2	18	2	18	2
Geophysical	716	60	716	60	716	60	0	0	0	0	0	0	0	0	0	0
Field Support	0	0	45	4	30	3	30	3	30	3	15	1	15	1	15	1
Subtotal	716	60	1,355	114	1,142	96	426	36	426	36	213	18	213	18	213	18
CONSTRUCTION																
Pad/Platform	0	0	610	51	160	13	900	75	900	75	120	10	450	38	120	10
Maintenance	0	0	54	5	36	3	36	3	36	3	18	2	18	2	18	1.5
Support	0	0	61	5	16	1	90	8	90	8	12	1	45	4	12	1
Subtotal	0	0	725	61	212	17	1,026	86	1,026	86	150	13	513	44	150	13
GRAND TOTAL	716	60	2,080	175	1,354	113	1,452	122	1,452	122	363	31	726	62	363	31

(a) MM = Nan-Months
(b) ANAV - Annual Average

Source: Dames & Moore

TABLE C-13

MANPOWER WORKSHEET--EXPLORATION PHASE

PRUDHOE OFFSHORE (1.9 Bbbl) SCENARIO

(Manpower Requirements in Man-Months/Year and Annual Average Employment)

	Exploration Begins Year 1		Year 2		Year 3		Year 4		Decision to Develop Year 5		Year 6		Year 7		Year 8	
	MM[a]	ANAV[b]	MM	ANAV	MM	ANAV	MM	ANAV	MM	ANAV	MM	ANAV	MM	ANAV	MM	ANAV
PETROLEUM																
Rig Crews	0	0	540	45	360	30	360	30	360	30	360	30	180	15	360	30
Geophysical	716	60	716	60	716	60	0	0	0	0	0	0	0	0	0	0
Field Support	0	0	45	4	30	3	30	3	30	3	30	3	15	1	30	3
Subtotal	716	60	1,301	109	1,106	93	390	33	390	33	390	33	195	16	390	33
CONSTRUCTION																
Pad/Platform	0	0	610	51	160	13	900	75	900	75	570	48	450	38	240	20
Maintenance	0	0	54	5	36	3	36	3	36	3	36	3	18	2	36	3
Support	0	0	61	5	16	1	90	8	90	8	57	5	45	4	24	2
Subtotal	0	0	725	61	212	17	1,026	86	1,026	86	663	56	513	43	300	25
GRAND TOTAL	716	60	2,026	170	1,318	110	1,416	119	1,416	119	1,053	89	708	59	690	58

(a) MM = Man-Months
(b) ANAV = Annual Average

Source: Dames & Moore

TABLE C-14

MANPOWER WORKSHEET--EXPLORATION PHASE

CAPE HALKETT SCENARIO

(Manpower Requirements in Man-Months/Year and Annual Average Employment)

	Exploration Begins Year 1		Year 2		Year 3		Year 4		Decision to Develop Year 5		Year 6		Year 7		Year 8	
	MM(a)	ANAV(b)	MM	ANAV	MM	ANAV	MM	ANAV	MM	ANAV	MM	ANAV	MM	ANAV	MM	ANAV
PETROLEUM																
Rig Crews	0	0	360	30	540	45	180	15	180	15	180	15				
Geophysical	358	30	358	30	358	30	0	0	0	0	0	0				
Field Support	0	0	30	3	45	4	15	1	15	1	15	1				
Subtotal	358	30	748	63	943	79	195	16	195	16	195	16				
CONSTRUCTION																
Pad/Platform	0	0	200	17	320	27	120	10	120	10	120	10				
Maintenance	0	0	36	3	54	5	18	2	18	2	18	2				
Support	0	0	20	2	32	3	12	1	12	1	12	1				
Subtotal	0	0	256	21	406	35	150	13	150	13	150	13				
GRAND TOTAL	358	30	1,004	84	1,349	114	345	29	345	29	345	29				

(a) MM = Man-Months
(b) ANAV = Annual Average

Source: Dames & Moore

TABLE C-15

MANPOWER WORKSHEET--EXPLORATION PHASE

SMITH-DEASE SCENARIO

(Manpower Requirements in Man-Months/Year and Annual Average Employment)

	Exploration Begins Year 1		Year 2		Year 3		Year 4		Decision to Develop Year 5		Year 6		Year 7		Year 8	
	MM(a)	ANAV(b)	MM	ANAV	MM	ANAV	MM	ANAV	MN	ANAV	MM	ANAV	MN	ANAV	MM	ANAV
PETROLEUM																
Rig Crews	0	0	180	15	360	30	540	45	360	30	360	30	180	15	180	15
Geophysical	358	30	358	30	358	30	0	0	0	0	0	0	0	0	0	0
Field Support	0	0	15	1	30	3	45	4	30	3	30	3	15	1	15	1
Subtotal	358	30	553	46	748	63	585	49	390	33	390	33	195	16	195	16
CONSTRUCTION																
Pad/Platform	0	0	120	10	240	20	280	23	200	17	200	17	120	10	120	10
Maintenance	0	0	18	2	36	3	54	5	36	3	36	3	18	2	18	2
Support	0	0	12	1	24	2	28	2	20	2	20	2	12	1	12	1
Subtotal	0	0	150	13	300	25	362	30	256	21	256	21	150	13	150	13
GRAND TOTAL	358	30	703	59	1,048	88	947	79	646	54	646	54	345	29	345	29

(a) MM= Man-Months
(b) ANAV = Annual Average

Source: Dames & Moore

TABLE C-16 MANPOWER WORKSHEET DEVELOPMENT PHASE: CAMDEN-CANNING SCENARIO (CAMDEN FIELD) (MANPOWER REQUIREMENTS EXPRESSED IN MAN-MONTHS/Y EAR & ANNUAL AVERAGE EMPLOYMENT)

	Year 1 MM	Year 1 AAAV	Year 2		3		4		5		6		-1	
Petroleum														
Rig crews	0	0	0	0	1440	120	2880	240	3600	300	4320	360	3240	270
Platform Maintenance					144	12	288	24	360	30	432	36	432	36
Subtotal					1584	132	3168	264	3960	330	4752	396	3672	306
Construction														
Air strip	120	12												
Roads	340	28												
Harbor & Storage Pads	100	8.3												
Camp	275	22 ,	275	22.9										
Drill Pads/ Platforms			,2,0	101 6	1220	10 I 6	900	15	900	75				
Power Plant & Distribution	126	10.5	378	31 5										
Ware houses & Shops	320	26.,												
Flow Stations	0	0	0	0	2520	210	2520	210						
Pump Sta tions														
Oil			500	41.6	500	41.6								
Gas			500	41 6	500	41,6								
Gas Conditioning					2048	171	2048	171						
Pipelines:														
Gathering			500	41.6	500	41.6								
Mainline														
Oil			207"	173	2070173									
Gas					1035	86.3	1035	86.3						
Operation Center					504	42	504	42						
Camp Support	138	11 5	540	45	1092	91	6%	58	90	7.5				
Miscellaneous	71	5.9	272	22 7	550	45.8	385	32.1						
Subtotal	1490	126	6255	521	12,538	1045	8088	674	990	83				
GRAND TOTAL	1490	126	6255	521	14,122	1177	11,256	938	4950	413	4752	396	36,6	306

	8		9		10		11		12		13		14	
Rig crews	3600	300	2520	210	1260	105	1080	90	900	75	1440	120	720	60
Platform Maintenance	432	36	432	36	432	36	504	42	504	42	576	48	576	48
Subtotal	4032	336	2952	246	1692	141	1584	132	1404	117	2016	168	1296	108
Drill Pads/ Platforms					900	75			900	75				
Camp Support					90	7,5			90	7.5				
Subtotal					990	83			990	83				
GRAND TOTAL	4032	336	2952	246	2682	22,	1584	132	2394	200	2016	168	1296	108

	15		16		17		18		19		20		21	
Rig crews	720	60	720	60										
Platform Maintenance	576	48	516	48	576	48	576	48	576	48	576	48	576	48
Subtotal	1296	108	1296	108	576	48	576	48	576	48	576	48	576	48
GRAND TOTAL	12%	108	1296	108	576	48	576	48	576	48	576	48	516	48

Source: Dames & Moore

TABLE C-17 MANPOWER WORKSHEET DEVELOPMENT PHASE: CAMDEN-CANNING SCENARIO (CANNING FIELD) (MANPOWER REQUIREMENTS EXPRESSED IN MAN-MONTHS/YEAR & ANNUAL AVERAGE EMPLOYMENT)

	3(1)		4(2)		5(3)		6(4)		7		8		9	
Petroleum														
Rig crews					720	60	1440	120	2520	210	2160	180	3240	270
Platform Maintenance					72	6	144	12	144	12	216	18	216	18
Subtotal					792	66	1584	132	2664	222	2376	198	3456	
Construction														
Air strip	0													
Roads	117	9,75												
Harbor & Storage Pads														
Camp	275	22.9												
Drill Pads/ Platforms			320	?6.6	900	75	0	0	900	75	0	0	900	75
Power Plant & Distribution			78	6.5	234	19.5								
Warehouses & Shops	320	26.6												
Flow station,					1560	130	1560	130						
Pump Stations:														
Oil					300	25								
Gas					300	25								
Gas Conditioning					1268	105.6	1268	105.6						
Pipelines:										4				
Gathering			300	25	300	25								
Mainline														
Oil			0	0	0	0								
Gas			0	0	0	0								
Operation Center					312	26	312	26						
Camp Support	72	6	72	6	516	43	312	26	90	7.5				
Miscellaneous	39	3.3	39	3.3	288	24	180	15					90	7.5
Subtotal	823	69	809	67	5978	498	3632	303		83			9'30	83
GRAND TOTAL	823	,	809	67	6770	54	5216	435	3654		2376	198	4446	.

	10		11		12		13		14		15		16	
Rig crews	3060	255	1800	150	1980	165	720	60	720	60				
Platform Maintenance	288	24	360	[illegible]	360	30	360	30	360	30	360	30	360	30
Subtotal	3348	279	2160	180	2340	195	1080	90	1080	90	360	30	360	30
Drill Pads/ Platforms	320	26.6												
Miscellaneous	36	3												
Subtotal	356	30												
GRAND TOTAL	3704	306	2160	[illegible]	2340	195	1080	90	1080	90	360	30	360	30

	17		18		19		20		21	
Platform Maintenance	360	30	360	30	360	30	360	30	360	30
Subtotal	360	30	360	30	360	30	360	30	360	30
GRAND TOTAL	360	30	360	30	360	30	360	30	360	30

TABLE C-18 MANPOWER WORKSHEET DEVELOPMENT PHASE: PRUDHOE OFFSHORE (0.8 Bbbl) SCENARIO
(MANPOWER REQUIREMENTS EXPRESSED IN MAN-MONTHS/YEAR & ANNUAL AVERAGE EMPLOYMENT)

	Year 1 MM	AAAV	Year 2		3		4		5		6		7		8		9		10	
Petroleum Rig crews					1440	120	2880	240	2880	240	2880	240	2880	240	2880	240	2880	240	2880	240
Platform Maintenance					144	12	288	24	288	24	288	24	360	30	432	36	504	42	576	48
Subtotal					1584	132	3168	264	3168	264	3168	264	3240	270	3312	276	3384	282	3456	288
Construction Air strip	0																			
Roads	117																			
Harbor & Storage Pads	0																			
Camp	0																			
Drill Pads/ Platforms			1220	101.6	1220	101.6	0	0	0	0	900	75	900	75	320	26.6	900	75		
Power Plant & Distribution	120	10.5	378	31.5																
Warehouses & Shops	320	26.6																		
Flow Stations	0	0	0	0	3600	300	3600	300												
Pump Stations: Oil	0	0	0	0	0	0	0	0												
Gas	0	0	0	0	0	0	0	0												
Gas Conditioning					2048	171	2048	171												
Pipelines Gathering	0	0	516	43	516	43														
Mainline Oil					570	47.5														
Gas					285	23.8														
Operation Center					504	42	504	42												
Camp Support	56.4	4.7	216	18	876	73	612	51			90	7.5	90	7.5	36	3	90	7.5		
Miscellaneous	31	2.6	117	9.75	481	40	338	28												
Subtotal	650	54	2447	204	10,100	842	7102	592			990	83	990	83	356	30	990	83		
GRAND TOTAL	650	54	2447	204	11,684	974	10,270	856	3168	264	4158	347	4230	353	3668	306	4374	365	3456	288

	11		12		13		14		15		16		17		18		19		20		21	
Petroleum Rig crews	2880	240	2160	180	1440	120	1440	120														
Platform Maintenance	576	48	576	48	576	48	576	48	576	48	576	48	576	48	576	48	576	48	576	48	576	48
Subtotal	3456	288	2736	228	2016	168	2016	168	576	48	576	48	576	48	576	48	576	48	576	48	576	48
GRAND TOTAL	3456	288	2736	228	2016	168	2016	168	576	48	576	48	576	48	576	48	576	48	576	48	576	

Source: Dames & Moore

TABLE C-19 MANPOWER WORKSHEET DEVELOPMENT PHASE: PRUDHOE OFFSHORE (1.9 Bbbl) SCENARIO
(MANPOWER REQUIREMENTS EXPRESSED IN MAN-MONTHS/YEAR & ANNUAL AVERAGE EMPLOYMENT)

	Year 1 MM	AAAV	Year		3		4		5		6		7		8		9		10	
Petroleum Rig crews					1440	120	2880	240	4320			360	4320	360	4320	360	2880	240	1440	120
Platform Maintenance					144	12	288	24	432	36	432	36	432	36	432	36	432	36	432	36
Subtotal					1584	132	3168	264	4752	396	4752	396	4752	396	4752	396	3312	276	1872	156
Construction Air strip																				
Roads	117	9.75																		
Harbor & Storage Pads	0	0																		
Camp	0	0																		
Drill Pads/ Platforms			1220	101.6	1800	150	1220	101.6												
Power Plant & Distribution	0	0	300	25	900	75														
Warehouses & Shops	320	26.6																		
Flow Stations	0	0	0	0	7200	600	7200	600												
Pump Stations Oil																				
Gas																				
Gas Conditioning					4875	406	4875	406												
Pipelines Gathering			530	44	530	44														
Mainline Oil					570	48														
Gas							285	24												
Operation Center					1200	100	1200	100												
Camp Support	43	3.6	204	17	1704	142	1476	123												
Miscellaneous	0	0	113	9.4	939	78	813	67.8												
Subtotal	480	40	2367	197	19,718	1643	17,069	1422	4752	396	4752	396	4752	396	4752	396	3312	276		
GRAND TOTAL	480	40	2367	197	21,302	1775	20,237	1686	4752	396	4752	396	4752	396	4752	396	3312	276	1872	154

	11		12		13		14		15		16		17		18		19		20		21	
Petroleum Rig crews	180	15																				
Platform Maintenance	432	36	432	36	432	36	432	36	432	36	432	36	432	36	432	36	432	36	432	36	432	36
Subtotal	612	51	432	36	432	36	432	36	432	36	432	36	432	36	432	36	432	36	432	36	432	36
GRAND TOTAL	612	51	432	36	432	36	432	36	432	36	432	36	432	36	432	36	432	36	432	36	432	36

Source: Dames & Moore

TABLE C-20 MANPOWERWORKSHEET DEVELOPMENT PHASE: CAPE HALKETT SCENARIO
(MANPOWER REQUIREMENTS EXPRESSED IN MAN-MONTHS/YEAR & ANNUAL AVERAGE EMPLOYMENT)

	Year 1		Year 2		3		4		5		6		7		8		9		10		11	
	MM	ANAV																				
Petroleum																						
Rig crews					720	60	1440	120	2,60	180	2160	180	2160	180	2160	180	2160	180	720	60	720	60
Platform Maintenance					72	6	144	12	216	18	216	,8	288	24	288	24	288	24	288	24	288	24
Subtotal					792	66	,584	132	2376	198	2376	198	2448	204	2448	204	2448	204	008	84	, 008	84
Construction																						
Air strip	120	10																				
Roads	285	23.8																				
Harbor & Storage Pads	100	8 3																				
Camp	275	22 9	550	45 8																		
Drill Pads / Platforms			900	75	900	75	,20	26 6	0	0	320	26 6										
Power Plant & Distribution			126	10 ,	378	31 5																
Warehouses & Shops	320	26 6																				
Flow Stations					3600	300	3600	300														
Pump Stations: Oil																						
Gas					500	41.6	500	41.6														
Gas Conditioning	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A				
Pipelines Gathering			933	77 ,	933	77 8																
Mainline Oil			1680	140	1680	140																
Gas	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A				
Operation Center					504	42	504	42														
Camp Support	108	9	420	35	852	71	492	41			36	3										
Miscellaneous	60	5	230	19	467	39	271	22 6														
Subtotal	1268	106	4839	403	,8, $	810	5687	474			356	30										
GRAND TOTAL	1268	106	4839	403	10.606	884	7271	606	2376	198	2732	228	2448	204	2448	204	2448	204	1008	84	1008	84

	12		13		14		15		16		17		18		19		20		21	
Platform Maintenance	288	24	288	24	288	24	288	24	288	24	288	24	288	24	288	24	288	24	288	24
Subtotal	288	24	288	24	288	24	288	24	2U8	24	288	24	288	24	289	24	288	24	288	24
GRAND TOTAL	2.?s	24	288	24	288	24	288	24	288	24	288	24	288	24	288	24	288	24	288	24

Source: Dames & Moore