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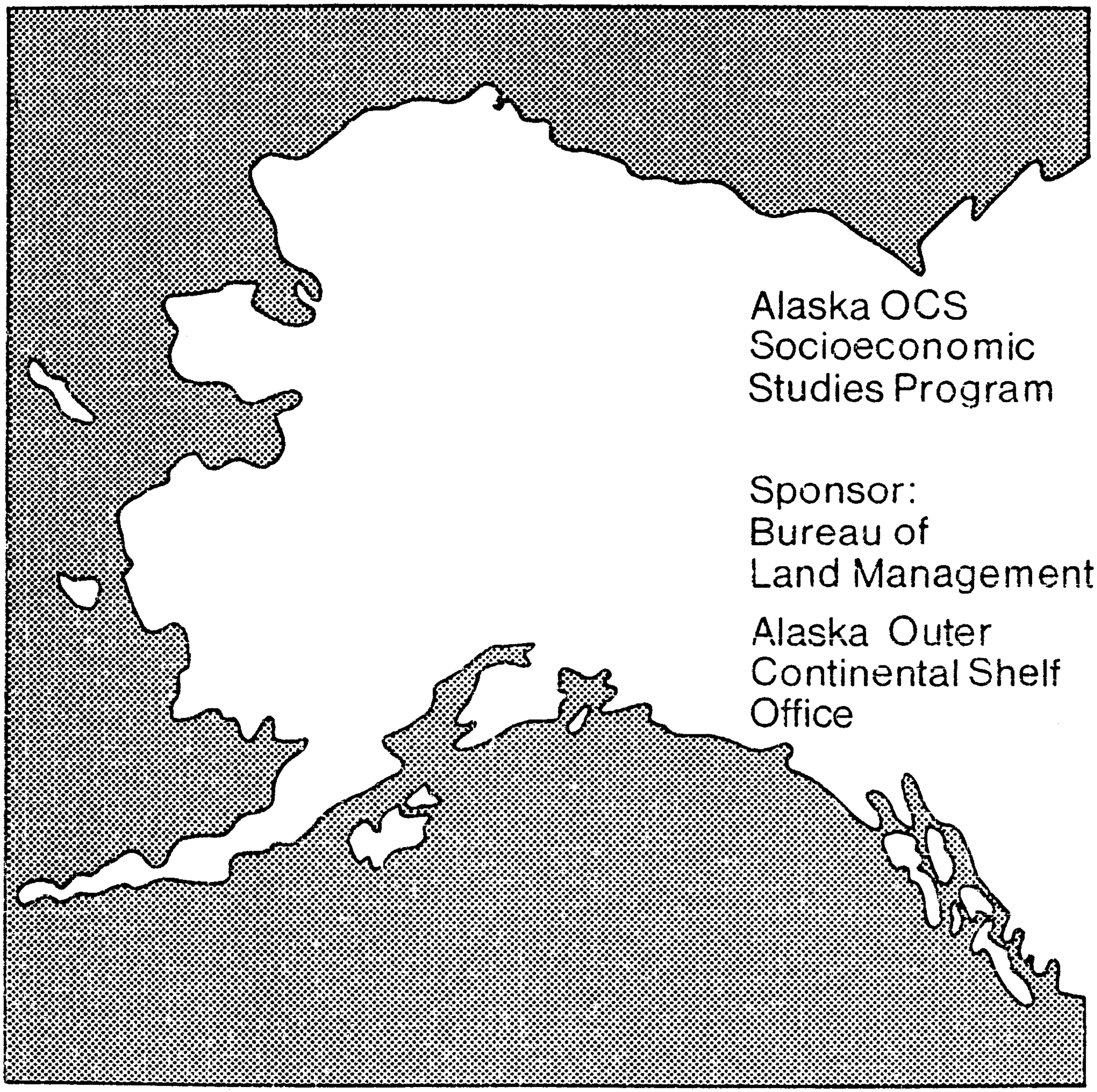
Technical Report
Number 49A



Bering – Norton Region
Petroleum Development Scenarios
Executive Summary

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 (SESP).

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 overall methodology is divided into three broad research components. The first component identifies an alternative set of assumptions regarding the location, the nature, and the timing of future petroleum events and related activities. In this component, the program takes into account the particular needs of the petroleum industry and projects the human, technological, economic, and environmental offshore and onshore development requirements of the regional petroleum industry.

The second component focuses on data gathering that identifies those quantifiable and qualifiable facts by which OCS-induced changes can be assessed. The critical community and regional components are identified and evaluated. Current endogenous and exogenous sources of change and functional organization among different sectors of community and regional life are analyzed. Susceptible community relationships, values, activities, and processes also are included.

The third research component focuses on an evaluation of the changes that could occur due to the potential oil and gas development. Impact evaluation concentrates on an analysis of the impacts at the statewide, regional, and local level.

In general, program products are sequentially arranged in accordance with BLM's proposed OCS lease sale schedule, so that information is timely to decisionmaking. Reports are available through the National Technical Information Service, and the BLM has a limited number of copies available through the Alaska OCS Office. Inquiries for information should be directed to: Program Coordinator (COAR), Socioeconomic Studies Program, Alaska OCS Office, P. O. Box 1159, Anchorage, Alaska 99510.

Technical Report No. 49A

ALASKA OCS SOCIOECONOMIC STUDIES PROGRAM
NORTON BASIN
OCS LEASE SALE NO. 57
PETROLEUM DEVELOPMENT SCENARIOS

EXECUTIVE SUMMARY

Prepared for

BUREAU OF LAND MANAGEMENT
ALASKA OUTER CONTINENTAL SHELF OFFICE

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February 1980

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2. This Executive Summary is designed to provi
development data to the groups working on th
economic Studies Program. The assumptions used
shore petroleum development scenarios may be

3. The units presented in this report are metric wit
lents except units used in standard petroleum prac
include barrels (42 gallons, oil), cubic fee
diameters (inches), well casing diameters (i
(acres).

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1.0 INTRODUCTION

1.1 Purpose

In order to analyze the socioeconomic and environmental impacts of Norton Sound petroleum exploration, development, and production, it is necessary to make reasonable and representative predictions on 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 Norton Sound petroleum development postulated in this report will be contained in subsequent reports of this study program.

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 economically and technically feasible, based upon available estimates of oil and gas resources of Norton Sound.

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 may be subject to revision as new data become 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, along with other studies conducted by or for the Bureau of Land Management, including the environmental impact statements produced preparatory to the OCS lease sales, are mandated to utilize U.S. Geological Survey estimates of recoverable oil and gas resources in any analysis requiring such resource data.

1.2 Scope

The petroleum development scenarios formulated in this report are for the proposed OCS Bering-Norton Lease Sale No. 57 currently scheduled for November 1982. This is the first lease sale scheduled for the Bering Sea OCS.

The study area considered in this report is that recommended for the lease sale area by the U.S. Geological Survey in Open-File Report 79-720 (Fisher et al., 1979, p. 37-38). This area is bounded in the east by longitude 162° W, in the west by longitude 170° W, in the north by latitude 65° N, and in the south by latitude 63° N (Figure 1-1). Along the shoreline of Norton Sound, the Seward Peninsula and northeastern St. Lawrence Island, the lease area boundary lies seaward of the 3-mile limit of state waters. This area covers approximately 40,000 sq. kilometers (15,444 sq. miles). The area of tracts actually leased will, of course, be significantly smaller due to geologic and environmental limitations[(1)].

Water depths in this potential lease area range from about 7.5 meters (25 feet) in inner Norton Sound to a maximum of about 55 meters (180 feet) in the Bering Sea midway between St. Lawrence Island and the Seward Peninsula; most of Norton Sound east of Nome is characterized by water depths of 18 meters (60 feet) or less. Sea ice covers most of the lease area from six to eight months of the year although multiyear floes do not occur south of the Bering Strait.

The principal components of this study which are an integral part of the scenario development include:

- A review of the petroleum technology that may be required to develop Norton Sound oil and gas reserves, including its costs, and related environmental constraints to petroleum engineering (oceanography, biology, geologic hazards, etc.).

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(1) The call for tract nominations for the Norton Basin lease sale was issued in May 1979 and at the time of writing (September 1979) tract selection was underway at the BLM, Alaska OCS Office.

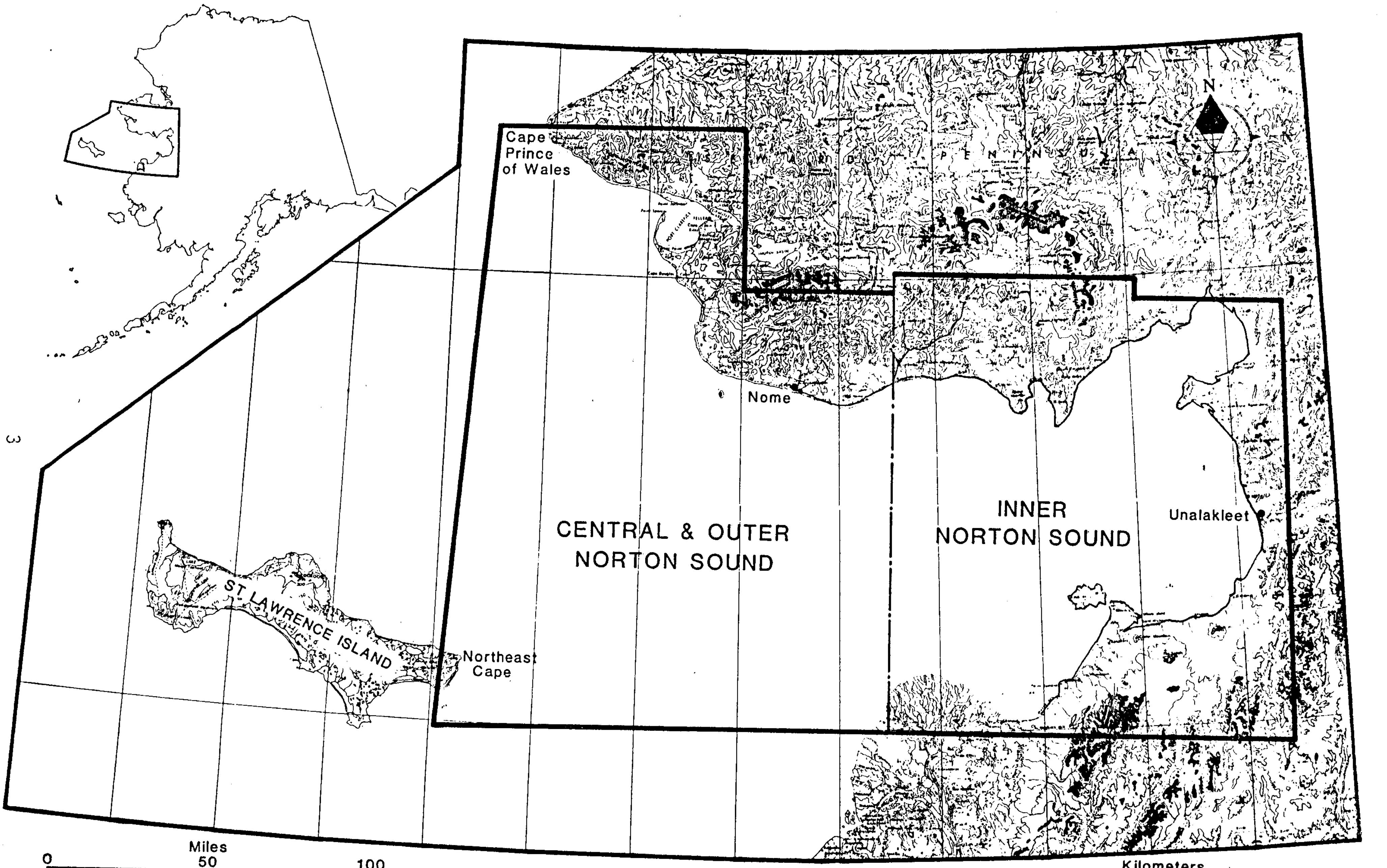

Figure 1-1
LOCATION OF THE STUDY AREA

- A review of the petroleum geology of Norton Basin to formulate reservoir and production assumptions necessary for the ecomonic analysis and, if possible, provide field size distribution data and prospect identification for scenario specification and resource allocation.

- An economic analysis of Norton Basin petroleum resources in the context of projected technology and its costs.

- An analysis of the manpower requirements to explore, develop, and produce Norton Basin petroleum resources in the context of projected technology, and environmental and logistical constraints.

- A facilities siting study to identify suitable sites for major petroleum facilities including crude oil terminals and LNG plants.

The U.S. Geological Survey resources estimates used in this study are as follows (Fisher et al., 1979):

	Minimum	Mean	Maximum
Oil (billions of barrels	0.38	1.4	2.6
Gas (trillions of cubic feet	1.2	2.3	3.2

This study describes scenarios corresponding to the minimum, mean, and maximum resource estimates and for descriptive purposes terms them "low find", "medium find", and "high find", respectively. In addition, a scenario is described which assumes exploration only with no commercial discoveries made.

1.3 Data Gaps and Limitations

In the course of this study, significant data gaps were revealed that imposed limitations on the scenario development and the related analyses listed above. These data gaps and related constraints should be kept in mind when considering the results of this study.

The data gaps to a large extent result from the fact that industry and regulatory agency interest and research is only now beginning to focus on the Bering Sea basins and Norton Sound in particular. To date, research has been principally focused on the North Slope/Beaufort Sea area, Lower Cook Inlet, and Gulf of Alaska. Norton Sound is much more a frontier area than these areas, and predictions on petroleum technology, its costs, resource economics, manpower and facility requirements, and facility siting are far more speculative. In summary, the principal data gaps include:

- Oceanography - sea ice, wave, and current data required for platform and pipeline design are limited.

- Petroleum facility costs (platforms, pipelines, terminals, etc.) - no petroleum exploration and production has yet taken place in areas with closely similar oceanographic conditions to provide a firm data base for petroleum facility costs in this sub-arctic area.

- Petroleum geology - insufficient geophysical data was available to identify structures and estimate thickness of reservoir rock sections, necessary data to estimate potential field sizes and their location.

1.4 Contents of the Executive Summary

This executive summary condenses the principal findings of Alaska Socio-economic Studies Program Technical Report No. 49. These findings are summarized in Chapter 2.0 under the headings of Petroleum Geology (Section

2.1), Selected Petroleum Development Scenarios (2.2), Employment (2.3), Technology and Production Systems (2.5), Resource Economics (2.6) and Facilities Siting (2.7).

2.0 SUMMARY OF FINDINGS

2.1 Petroleum Geology and Resource Estimates

The resource estimates that form the basis of the petroleum development scenarios in this report are the U.S. Geological Survey estimates of undiscovered recoverable oil and gas resources. These are (Fisher et al., 1979):

	Minimum	Mean	Maximum
Oil (billions of barrels)	0.38	1.4	2.6
Gas (trillions of cubic feet)	1.2	2.3	3.2

These are "unrisked" estimates derived from probabilistic estimates by removing the marginal probabilities that were applied because Norton Basin is a frontier area. For descriptive purposes, the scenarios corresponding to minimum, mean, and maximum resource estimates are termed "low find", "medium find", and "high find", respectively.

A set of reservoir and production assumptions were formulated for the economic analysis based on available geologic/analog data and the need to explore the economic impact of geologic diversity. Nevertheless, the reservoir and production assumptions should bracket expectations indicated by the available geologic data and/or extrapolation from reasonable analogs.

Because detailed geophysical data was unavailable to this study and because there is no drilling history in this basin, formulation of reservoir and production assumptions has had to rely on analog basins. These analogs are producing Pacific Margin tertiary basins such as Cook Inlet in Alaska. In addition non-producing Pacific Margin Tertiary basins such as the Anadyr Basin of northeast Siberia provide analogous geologic data and valuable clues (stratigraphy, structural history and so forth) to extrapolate or better predict the geologic characteristics of the Norton Basin. The reservoir and production assumptions listed below generally fall within the geologic, reservoir and production characteristics typical of such basins. The assumptions are:

- Average reservoir depths (gas and oil) - 762 meters (2,500 feet), 1,524 meters (5,000 feet), and 2,286 meters (7,500 feet).

- Recoverable reserves per acre - 20,000 bbl and 60,000 bbl.

- Well spacing - variable, consistent with ranges in known producing fields.

- Initial well productivity, oil - 1,000, 2,000, and 5,000 bpd.

- Initial well productivity, gas - 15 and 25 mmcfd.

- Gas resource allocation between associated and non-associated - for scenario detailing and analytical simplification, all the gas resources are assumed to be non-associated (i.e. scenarios are detailed which include gas field(s) totaling the U.S.G.S. gas resource estimate);[1] oil fields are implicitly assumed, therefore, to have a low gas-oil ratio (GOR) and that associated gas is uneconomic and is used to fuel platforms with the remainder reinjected.

- A low gas-oil ratio is assumed for analytical simplification (see bullet above).

- No assumption was made on the physical properties of the oil; the range of prices used in the analysis is partly a function of the potential range in crude qualities.

(1) It is recognized, however, that in reality some portion of the gas resource will be associated.

In the absence of sufficient geologic data to make reasonable predictions on a number of prospective structures and field sizes that may be discovered in Norton basin, the field sizes selected for economic screening have, therefore, been selected to be consistent with the following factors:

- Geology (only gross structural geology and stratigraphic data are available).
- Requirement to examine a reasonable range of economic sensitivities.

The field sizes to be evaluated in this study, therefore, range from 100 million barrels to two billion barrels for oil and 500 billion cubic feet to three trillion cubic feet for non-associated gas.

Field location in the scenarios is arbitrary but designed for impact assessment to provide a range of development cases that are shown to be economically and technically realistic options.

2.2 Selected Petroleum Development Scenarios

Four scenarios are detailed describing exploration only (no commercial resources discovered), a high find case assuming significant commercial discoveries, medium find case assuming modest commercial discoveries, and low find case assuming marginal commercial discoveries. The development scenario field and shore facility locations are shown in Figure 2-1.

2.2.1 Exploration Only Scenario

The exploration only scenario postulates a low level of exploration with only eight wells drilled over a period of three years (Table 2-1). Exploration is conducted principally in the four month summer openwater season using jack-up rigs augmented by drillships. Two of the wells are drilled from gravel islands constructed in summer. No new onshore facilities are constructed. Nome serves as a forward support base for light supplies and provides aerial support for offshore activities; heavy materials are stored in freighters

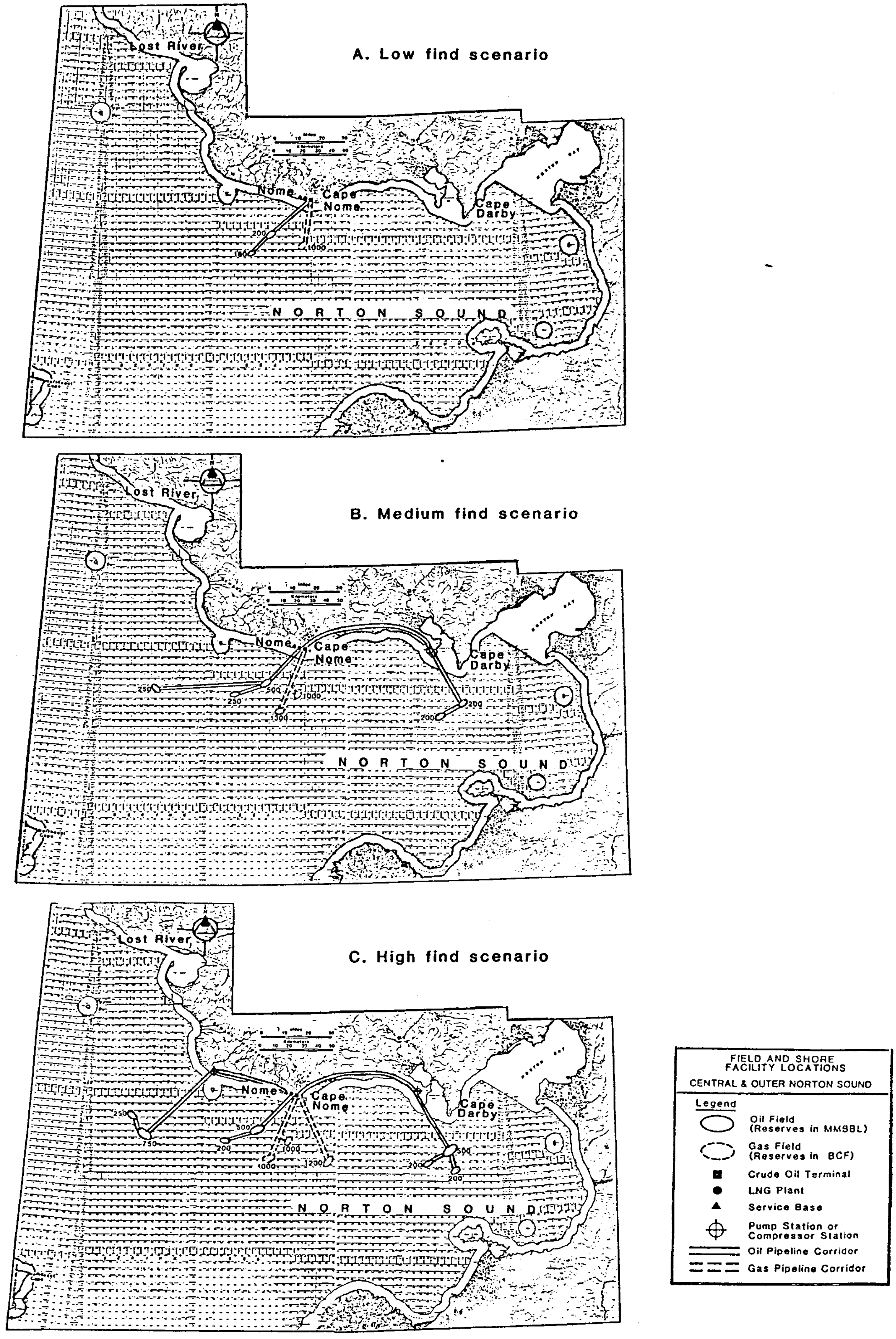

Figure 2-1

AREAS OF PETROLEUM DEVELOPMENT IN NORTON SOUND

TABLE 2-1

EXPLORATION ONLY SCENARIO - LOW INTEREST LEASE SALE

YEAR AFTER LEASE SALE					
1		2		3	
Rigs	Wells	Rigs	Wells	Rigs	Wells
2	2	3C 1G	4	1C 1G	2
TOTAL WELLS = 8					

C = Conventional rigs (jack ups or drillships)
G = Gravel island

Assumptions:

1. An average well completion rate of approximately 4 months.
2. An average total well depth of 3,048 to 3,692 meters (10,000 to 13,000 feet).
3. Year after lease sale = 1983.
4. Rigs include jack ups and drillships in summer and some summer-constructed gravel islands in shallow water.

Source: Dames & Moore

and barges moored in Norton Sound and transshipped to the rigs via supply boats and there is a rear base located in the Aleutian Islands.

2.2.2 High Find Scenario

The high find scenario assumes significant commercial discoveries of oil and gas. The total reserves discovered and developed are:

Oil (MMBBL)	Non-Associated Gas (BCF)
2,600	3,200

These resources are distributed in three "clusters" of fields located respectively in inner Norton Sound south of Cape Darby, central Norton Sound south of Nome, and outer Norton Sound about 64 kilometers (40 miles) southwest of Cape Rodney.

All oil and gas production is brought to shore by pipeline to a large crude oil terminal and LNG plant located at Cape Nome. Production from the central Norton Sound fields involves a direct offshore pipeline to Cape Nome while production from the outer and inner Norton Sound fields involves a significant onshore pipeline segment.

Oil production from Norton Sound commences in year 7 (1989) after the lease sale, peaks at 764,000 b/d in year 13 (1995), and ceases in year 34 (2016). Gas production also commences in year 7 (1989), peaks at 691,200 mmcfd in years 13 through 16 (1995 through 1999), and ceases in year 34 (2016).

The basic characteristics of this scenario are summarized in Tables 2-2 and 2-3.

2.2.3 Medium Find Scenario

The medium find scenario assumes modest discoveries of oil and non-

TABLE 2-2

HIGH FIND OIL SCENARIO

Field Size Oil (MMBBL)	Location	Reservoir Depth		Production System	Platforms No./Type*	Number of Production Wells	Initial Well Productivity (B/D)	Peak Production Oil (MB/D)	Water Depth		Pipeline Distance to Shore Terminal		Trunk Pipeline Diameter (inches) Oil	Shore Terminal Location
		Meters	Feet						Meters	Feet	Kilometers	Miles		
500	Inner Sound	2,286	7,500	Gravel island shared pipeline to shore terminal	2 G	80	2,000	153.6	18	60	133	83	20	Cape Nome
200	Inner Sound	2,286	7,500	Gravel island with shared pipeline to shore terminal	1 G	40	2,000	76.8	18	60	146	91	20	Cape Nome
200	Inner Sound	2,286	7,500	Gravel Island shared pipeline to shore terminal	1 G	40	2,000	76.8	18	60	150	93	20	Cape Nome
500	Central Sound	2,286	7,500	Steel platforms with shared pipeline to shore terminal	2 S	80	2,000	153.6	18	60	34	21	16-18	Cape Nome
200	Central Island	2,286	7,500	Steel platform with shared pipeline to shore terminal	1 S	40	2,000	76.8	21	70	58	36	16-18	Cape Nome
750	Outer Sound	2,286	7,500	Steel platforms with shared pipeline to shore terminal	3 S	120	2,000	230.4	30	100	129	80	20	Cape Nome
250	Outer Sound	2,286	7,500	Steel platform with shared pipeline to shore terminal	1 S	40	2,000	76.8	30	100	140	87	20	Cape Nome

* S = Ice reinforced steel platform.
G = Caisson retained gravel island.

Fields in same bracket share trunk pipeline.

Source: Dames & Moore

TABLE 2-3

HIGH FIND NON-ASSOCIATED GAS SCENARIO

Field Size Gas (BCF)	Location	Reservoir Depth		Production System	Platforms No./Type*	Number of Production Wells	Initial Well Productivity (MMCFD)	Peak Production Gas (MMCFD)	Water Depth		Pipeline Distance to Shore Terminal		Trunk Pipeline Diameter (inches) Gas	LNG Plant
		Meters	Feet						Meters	Feet	Kilometers	Miles		
1,000	Central Sound	2,286	7,500	Steel platforms with shared pipeline to LNG plant	1 S	16	15	240	20	66	51	32	24-28	Cape Nome
1,000	Central Sound	2,286	7,500	Steel platform with shared pipeline to LNG plant	1 S	16	15	240	18	60	43	27	24-28	Cape Nome
1,200	Central Sound	2,286	7,500	Steel platform with unshared pipeline to LNG plant	1 S	16	15	240	20	66	51	32	20-24	Cape Nome

* S = Ice reinforced steel platform.

Fields in bracket share same trunk pipeline.

Source: Dames & Moore

associated gas. The basic characteristics of the scenario are summarized in Tables 2-4 and 2-5. The total reserves discovered and developed are:

Oil (MMBBL)	Non-Associated Gas (BCF)
1,400	2,300

Five oil fields comprise the total reserves. They are located in two groups of fields, one in inner Norton Sound, the second in the central sound south of Nome, plus a single field in the outer sound southwest of Cape Rodney. The gas reserves are contained in two fields located close to each other about 48 kilometers (30 miles) south of Nome.

All crude is brought to a single terminal located at Cape Nome. For the inner sound fields, this involves a 100-kilometer (62-mile) onshore pipeline segment from Cape Darby to Cape Nome; the trunk pipeline from the central and outer sound fields makes landfall close to the terminal site and, therefore, involves minimal onshore pipeline construction.

The non-associated gas fields share a single trunk pipeline to a LNG plant located adjacent to the crude oil terminal at Cape Nome.

Oil production from Norton Sound commences in year 8 (1990) after the lease sale, peaks at 463,000 b/d in year 12 (1994), and ceases in year 29 (2011). Gas production commences in year 7 (1989), peaks at 460.8 mmcfd in years 12 through 18 (1994 through 2000), and ceases in year 28 (2010).

2.2.4 Low Find Scenario

The low find scenario assumes small commercial discoveries of oil and non-associated gas. The basic characteristics of the scenario are summarized in Tables 2-6 and 2-7. The total reserves discovered and developed are:

Oil (MMBBL)	Non-Associated Gas (BCF)
380	1,200

TABLE 2-4

MEDIUM FIND OIL SCENARIO

Field Size Oil (MMBBL)	Location	Reservoir Depth		Production System	Platforms No./Type*	Number of Production Wells	Initial Well Productivity (B/D)	Peak Production Oil (MB/D)	Water Depth		Pipeline Distance to Shore Terminal		Trunk Pipeline Diameter (inches) Oil	Shore Terminal Location
		Meters	Feet						Meters	Feet	Kilometers	Miles		
200	Inner Sound	2,286	7,500	Gravel island with shared pipeline to shore terminal	1 G	40	2,000	76.8	18	60	133	83	14	Cape Nome
200	Inner Sound	2,286	7,500	Gravel island with shared pipeline to shore terminal	1 G	40	2,000	76.8	18	60	146	91	14	Cape Nome
500	Central Sound	2,286	7,500	Steel platforms with shared pipeline to shore terminal	2 S	80	2,000	153.6	18	60	34	21	18	Cape Nome
250	Central Sound	2,286	7,500	Steel platform with shared pipeline to shore terminal	1 S	40	2,000	76.8	21	70	58	36	18	Cape Nome
250	Outer Sound	2,286	7,500	Steel platform with shared pipeline to shore terminal	1 S	40	2,000	76.8	30	100	95	59	18	Cape Nome

* S = Ice reinforced steel platform.
G = Caisson retained gravel island.

Fields in same bracket share trunk pipeline.

Source: Dames & Moore

TABLE 2-5

MEDIUM FIND NON-ASSOCIATED GAS SCENARIO

Field Size Gas (BCF)	Location	Reservoir Depth		Production System	Platforms No./Type*	Number of Production Wells	Initial Well Productivity (MMCFD)	Peak Production Gas (MMCFD)	Water Depth		Pipeline Distance to Shore Terminal		Trunk Pipeline Diameter (inches) Gas	LNG Plant
		Meters	Feet						Meters	Feet	Kilometers	Miles		
1,300	Central Sound	2,286	7,500	Steel platform with shared pipeline to LNG plant	1 S	16	15	240	20	66	48	30	20	Cape Nome
1,000	Central Sound	2,286	7,500	Steel platform with shared pipeline to LNG plant	1 S	16	15	240	18	60	32	20	20	Cape Nome

* S = Ice reinforced steel platform.

Fields in bracket share same trunk pipeline.

Source: Dames & Moore

TABLE 2-6

LOW FIND OIL SCENARIO

Field Size Oil (MMBBL)	Location	Reservoir Depth		Production System	Platforms No./Type*	Number of Production Wells	Initial Well Productivity (B/D)	Peak Production Oil (MB/D)	Water Depth		Pipeline Distance to Shore Terminal		Trunk Pipeline Diameter (inches) Oil	Shore Terminal Location
		Meters	Feet						Meters	Feet	Kilometers	Miles		
200	Central Sound	2,286	7,500	Steel platform with shared pipeline to shore terminal	1 S	40	2,000	76.8	21	70	34	21	14	Cape Nome
180	Central Sound	2,286	7,500	Steel platform with shared pipeline to shore terminal	1 S	40	2,000	76.8	21	70	58	36	14	Cape Nome

* S = Ice reinfornced steel platform.

Fields in same bracket share trunk pipeline.

Source: Dames & Moore

TABLE 2-7

LOW FIND NON-ASSOCIATED GAS SCENARIO

Field Size Gas (BCF)	Location	Reservoir Depth		Production System	Platforms No./Type*	Number of Production Wells	Initial Well Productivity (MMCFD)	Peak Production Gas (MMCFD)	Water Depth		Pipeline Distance to Shore Terminal		Trunk Pipeline Diameter (inches) Gas	LNG Plant
		Meters	Feet						Meters	Feet	Kilometers	Miles		
1,200	Central Sound	2,286	7,500	Single steel platform with unshared pipeline to LNG plant	1 S	16	15	240	16	54	34	21	14	Cape Nome

* S = Ice reinforced steel platform.

Source: Dames & Moore

These reserves, especially the gas, are barely economic to develop. The oil reserves comprise two fields located between 34 and 58 kilometers (21 and 36 miles) southwest of Nome while the non-associated gas reserves occur in a single field located about 34 kilometers (21 miles) south of Nome. No discoveries are made in the inner or outer sounds.

Two trunk pipelines, both about 34 kilometers (21 miles) long, transport the oil and gas production direct to a crude oil terminal and LNG plant, respectively, located at Cape Nome. Minimal onshore pipeline construction is involved in the development of these fields.

Oil and gas production from Norton Sound both start in year 8 (1990). Oil production peaks at 153,000 b/d in year 11 (1993) and ceases in year 27 (2009). Gas production peaks at 230.4 mmcfd in years 11 through 19 (1993 through 2001), and ceases in year 32 (2014).

2.3 Employment

Estimates of manpower requirements are presented in a series of four tables for each scenario. These are found in Sections 5.0 through 8.0 of the main report. Definition of terms used to describe manpower requirements are found in Appendix E of the main report.

Maximum employment is created in year 9 of the High Find Scenario, when 63,307 man-months of work will be generated (equivalent to an average of 5,276 people per month during the year; peak employment during the year would be higher). Maximum employment is created in year 8 of the Medium Find and Low Find Scenarios, and year 2 of the Exploration Only Scenario, generating 42,649 man-months, 16,506 manmonths, and 3,445 man-months of employment, respectively.

Manpower requirements for onshore activities peak earlier than for offshore activities in the three scenarios that involve field development. Onshore (on site) labor requirements peak in year 5 in the High Find Scenario at 16,498 man-months, and offshore (on site) labor requirements peak in year 9 at 27,328 man-months. In the Medium Find Scenario, onshore (on site) labor requirements peak in year 5 with 9,138 man-months, and offshore (on site) in year 9 with 17,802 man-months. In the Low Find Scenario, onshore (on site) peaks in year 7 with 4,173 man-months, offshore (on site) a year later with 6,978 manmonths. This pattern occurs because construction of the major onshore facilities is begun before most of the platforms are installed, pipeline laid, and production wells drilled, activities that cluster in years 6 through 9.

During the middle of the production phase, onshore labor will average 525 people per month (on site; 810 people total), and offshore labor will average 1,605 people per month (on site; 3,120 people total) in the High Find Scenario. In the Medium Find Scenario and Low Find Scenario, onshore labor will average 327 and 135 people per month respectively (on site; 523 and 222 people total), and offshore labor will average 1,056 and 321 people per month respectively (on site; 1,964 and 624 people total).

Manpower requirements for each scenario are summarized in Tables 2-8 through 2-11.

2.4 Technology and Production Systems

In an oceanographic comparison with Upper Cook Inlet, on the one hand, and the Beaufort Sea, on the other, Norton Sound and adjacent areas of the Bering Sea have certain attributes of both and yet are unique in other aspects. Norton Sound is shallower than Upper Cook Inlet, deeper in general than the Beaufort Sea lease area, and has ice conditions in terms of duration intermediate to both. Water depths range from 7.5 meters (25 feet) off the Yukon Delta (i.e. at the three mile limit) to over 46 meters (150 feet) in the outer sound between St. Lawrence Island and the Seward Peninsula. Pack ice up to 12 meters (40 feet) thick has been reported in the Bering Sea although floe ice within Norton Sound is generally up to 2 meters (6.5 feet) thick. Shorefast ice extends shoreward of the 10-meter (33-foot) isobath. A maximum wave of about 4.3 meters (14 feet) can be anticipated in Norton Sound.

EXPLORATION ONLY
09/23/79

TABLE 2-8

SUMMARY OF MANPOWER REQUIREMENTS FOR ALL INDUSTRIES
ONSITE AND TOTAL **

YEAR AFTER LEASE SALE	ONSITE (MAN-MONTHS) OFFSHORE	ONSHORE	TOTAL	TOTAL (MAN-MONTHS) OFFSHORE	ONSHORE	TOTAL	TOTAL MONTHLY AVERAGE (NUMBER OF PEOPLE) OFFSHORE	ONSHORE	TOTAL
1	706.	108.	814.	1258.	148.	1406.	105.	13.	118.
2	1812.	246.	2058.	3116.	329.	3445.	260.	28.	288.
3	1106.	138.	1244.	1858.	181.	2039.	155.	16.	170.

** TOTAL INCLUDES ONSITE AND OFFSITE

HIGH FIND SCENARIO
05/23/79

TABLE 2-9

SUMMARY OF MANPOWER REQUIREMENTS FOR ALL INDUSTRIES
ONSITE AND TOTAL **

YEAR AFTER LEASE SALE	ONSITE (MAN-MONTHS)			TOTAL (MAN-MONTHS)			TOTAL MONTHLY AVERAGE (NUMBER OF PEOPLE)		
	OFFSHORE	ONSHORE	TOTAL	OFFSHORE	ONSHORE	TOTAL	OFFSHORE	ONSHORE	TOTAL
1	[illegible]	324.	2642.	3774.	444.	4218.	315.	37.	352.
2	[illegible]	[illegible]	5314.	8146.	921.	9069.	679.	77.	756.
3	8754.	1152.	[illegible]	14922.	1532.	16454.	1244.	128.	1372.
4	7060.	6366.	[illegible]	13780.	7347.	21127.	1149.	613.	1761.
5	7520.	[illegible]	24018.	13286.	18520.	31806.	1106.	1544.	2651.
6	15754.	12219.	27973.	28398.	13771.	42169.	2367.	1148.	3514.
7	24372.	[illegible]	33176.	44591.	12230.	56821.	3716.	1020.	4736.
8	24342.	4632.	[illegible]	46502.	13151.	59653.	3876.	1096.	4971.
9	27323.	7004.	[illegible]	53013.	10293.	63307.	4418.	858.	5276.
10	[illegible]	6644.	[illegible]	50990.	10031.	61020.	4250.	836.	5085.
11	22052.	6441.	[illegible]	43054.	9807.	52861.	3588.	818.	4405.
12	19344.	6474.	25818.	37608.	9894.	47502.	3134.	825.	3959.
13	19058.	6340.	25416.	37056.	9768.	46824.	3088.	814.	3902.
14	18676.	6336.	25012.	36672.	9756.	46428.	3056.	813.	3869.
15	19080.	6300.	25380.	37080.	9720.	46800.	3090.	810.	3900.
16	19080.	6300.	25380.	37080.	9720.	46800.	3090.	810.	3900.
17	19260.	6300.	25560.	37440.	9720.	47160.	3120.	810.	3930.
18	19260.	6300.	25560.	37440.	9720.	47160.	3120.	810.	3930.
19	19260.	6300.	25560.	37440.	9720.	47160.	3120.	810.	3930.
20	19260.	6300.	25560.	37440.	9720.	47160.	3120.	810.	3930.
21	19260.	6300.	25560.	37440.	9720.	47160.	3120.	810.	3930.
22	19260.	6300.	25560.	37440.	9720.	47160.	3120.	810.	3930.
23	17976.	6048.	24024.	34944.	9408.	44352.	2912.	784.	3696.
24	17976.	6048.	24024.	34944.	9408.	44352.	2912.	784.	3696.
25	17976.	6048.	24024.	34944.	9408.	44352.	2912.	784.	3696.
26	17976.	6048.	24024.	34944.	9408.	44352.	2912.	784.	3696.
27	15408.	5544.	20952.	29952.	8764.	38736.	2496.	732.	3228.
28	12660.	5040.	17700.	26600.	6160.	32760.	2050.	680.	2730.
29	7524.	4032.	11556.	14616.	6912.	21528.	1218.	576.	1794.
30	6240.	3780.	10020.	12120.	6600.	18720.	1010.	550.	1560.

** TOTAL INCLUDES ONSITE AND OFFSITE

MEDIUM FIND SCENARIO
09/24/79

TABLE 2-10

SUMMARY OF MANPOWER REQUIREMENTS FOR ALL INDUSTRIES
ONSITE AND TOTAL **

YEAR AFTER LEASE SALE	ONSITE (MAN-MONTHS) OFFSHORE	ONSITE (MAN-MONTHS) ONSHORE	ONSITE (MAN-MONTHS) TOTAL	TOTAL (MAN-MONTHS) OFFSHORE	TOTAL (MAN-MONTHS) ONSHORE	TOTAL (MAN-MONTHS) TOTAL	TOTAL MONTHLY AVERAGE (NUMBER OF PEOPLE) OFFSHORE	TOTAL MONTHLY AVERAGE (NUMBER OF PEOPLE) ONSHORE	TOTAL MONTHLY AVERAGE (NUMBER OF PEOPLE) TOTAL
1	2243.	334.	2577.	3899.	454.	4353.	325.	38.	363.
2	5342.	786.	6128.	9406.	1069.	10475.	784.	90.	873.
3	6448.	924.	7372.	11264.	1251.	12515.	939.	105.	1043.
4	5036.	4044.	9080.	8748.	4658.	13406.	729.	389.	1118.
5	4090.	9138.	13229.	7095.	10210.	17306.	592.	851.	1443.
6	13194.	4531.	17726.	23843.	5132.	28975.	1987.	428.	2415.
7	11228.	3209.	14437.	20638.	5158.	25796.	1720.	430.	2150.
8	17290.	7962.	25252.	32161.	10489.	42649.	2680.	874.	3555.
9	17802.	4520.	22322.	33782.	6751.	40532.	2816.	563.	3378.
10	16224.	4116.	20340.	30672.	6344.	37016.	2556.	529.	3085.
11	13320.	4062.	17382.	24864.	6290.	31154.	2072.	525.	2597.
12	12108.	3960.	16068.	22440.	6188.	28628.	1870.	516.	2386.
13	12132.	3924.	16056.	22488.	6152.	28640.	1874.	513.	2387.
14	12492.	3924.	16416.	23208.	6152.	29360.	1934.	513.	2447.
15	12672.	3924.	16596.	23568.	6152.	29720.	1964.	513.	2477.
16	12672.	3924.	16596.	23568.	6152.	29720.	1964.	513.	2477.
17	12672.	3924.	16596.	23568.	6152.	29720.	1964.	513.	2477.
18	12672.	3924.	16596.	23568.	6152.	29720.	1964.	513.	2477.
19	12672.	3924.	16596.	23568.	6152.	29720.	1964.	513.	2477.
20	12672.	3924.	16596.	23568.	6152.	29720.	1964.	513.	2477.
21	12672.	3924.	16596.	23568.	6152.	29720.	1964.	513.	2477.
22	11388.	3672.	15060.	21072.	5840.	26912.	1756.	487.	2243.
23	10104.	3420.	13524.	18576.	5528.	24104.	1548.	461.	2009.
24	10104.	3420.	13524.	18576.	5528.	24104.	1548.	461.	2009.
25	10104.	3420.	13524.	18576.	5528.	24104.	1548.	461.	2009.
26	10104.	3420.	13524.	18576.	5528.	24104.	1548.	461.	2009.
27	7356.	2916.	10272.	13224.	4904.	18128.	1102.	409.	1511.
28	6072.	1944.	8016.	10728.	3152.	13880.	894.	263.	1157.
29	3684.	432.	4116.	6096.	512.	6608.	508.	43.	551.
30	2400.	180.	2580.	3600.	200.	3800.	300.	17.	317.

** TOTAL INCLUDES ONSITE AND OFFSITE

LOW FIND SCENARIO
09/24/79

TABLE 2-11

SUMMARY OF MANPOWER REQUIREMENTS FOR ALL INDUSTRIES
ONSITE AND TOTAL **

YEAR AFTER LEASE SALE	ONSITE (MAN-MONTHS) OFFSHORE	ONSITE (MAN-MONTHS) ONSHORE	ONSITE (MAN-MONTHS) TOTAL	TOTAL (MAN-MONTHS) OFFSHORE	TOTAL (MAN-MONTHS) ONSHORE	TOTAL (MAN-MONTHS) TOTAL	TOTAL MONTHLY AVERAGE (NUMBER OF PEOPLE) OFFSHORE	TOTAL MONTHLY AVERAGE (NUMBER OF PEOPLE) ONSHORE	TOTAL MONTHLY AVERAGE (NUMBER OF PEOPLE) TOTAL
1	1412.	216.	1628.	2516.	296.	2812.	210.	25.	235.
2	2518.	354.	2872.	4374.	477.	4851.	365.	40.	405.
3	3624.	492.	4116.	6232.	659.	6891.	520.	55.	575.
4	5036.	708.	5744.	8748.	955.	9703.	729.	80.	809.
5	2212.	1154.	3366.	3716.	1337.	5053.	310.	112.	422.
6	4262.	2454.	6716.	7817.	2774.	10591.	652.	232.	883.
7	6098.	4173.	10272.	11555.	4:34.	16189.	963.	387.	1350.
8	6978.	1820.	8797.	13622.	2884.	16506.	1136.	241.	1376.
9	6384.	1692.	8076.	12552.	2736.	15288.	1046.	228.	1274.
10	4656.	1764.	6420.	9096.	2808.	11904.	758.	234.	992.
11	3480.	1638.	5118.	6744.	2682.	9426.	562.	224.	786.
12	3312.	1620.	4932.	6408.	2664.	9072.	534.	222.	756.
13	3852.	1620.	5472.	7488.	2664.	10152.	624.	222.	846.
14	3852.	1620.	5472.	7488.	2664.	10152.	624.	222.	846.
15	3852.	1620.	5472.	7488.	2664.	10152.	624.	222.	846.
16	3852.	1620.	5472.	7488.	2664.	10152.	624.	222.	846.
17	3852.	1620.	5472.	7488.	2664.	10152.	624.	222.	846.
18	3852.	1620.	5472.	7488.	2664.	10152.	624.	222.	846.
19	3852.	1620.	5472.	7488.	2664.	10152.	624.	222.	846.
20	3852.	1620.	5472.	7488.	2664.	10152.	624.	222.	846.
21	3852.	1620.	5472.	7488.	2664.	10152.	624.	222.	846.
22	3852.	1620.	5472.	7488.	2664.	10152.	624.	222.	846.
23	2748.	1368.	4116.	5352.	2352.	7704.	446.	196.	642.
24	2748.	1368.	4116.	5352.	2352.	7704.	446.	196.	642.
25	2658.	1368.	4026.	5172.	2352.	7524.	431.	196.	627.
26	2568.	1368.	3936.	4992.	2352.	7344.	416.	196.	612.
27	2568.	984.	3552.	4992.	1584.	6576.	416.	132.	548.
28	1284.	732.	2016.	2496.	1272.	3768.	208.	106.	314.
29	1284.	732.	2016.	2496.	1272.	3768.	208.	106.	314.
30	1284.	732.	2016.	2496.	1272.	3768.	208.	106.	314.

** TOTAL INCLUDES ONSITE AND OFFSITE

These preliminary oceanographic findings in conjunction with design criteria for Upper Cook Inlet steel platforms indicate that modified Upper Cook Inlet type platforms may be feasible for operation in Norton Sound. This conclusion is tentative since sufficient oceanographic data to adequately assess platform design requirements does not yet exist. However, such platforms, as opposed to the monocone proposed for Beaufort Sea operations, may be the more likely development strategy. In shallower waters (less than 18 meters [60 feet]), gravel islands may also be a development alternative especially the caisson-retained design. The economic analysis, therefore, has evaluated the economics of these platform types for the following water depths.

Platform Type	Water Depth meters	Water Depth feet
Ice reinforced steel platform (modified Upper Cook Inlet Design)	15	50
	30	100
	46	150
Gravel Island	7.6	25
	15	50

Pipeline distances representative of potential discovery situations relative to potential shore facility sites were identified for economic screening as shown on Table 2-12. In addition to development cases assuming pipelines to an onshore crude oil terminal or LNG plant, offshore loading from a production/storage/loading island was considered in the economic analysis for comparative purposes although the costs of such a system are highly speculative.

Given the estimated oil and gas resources of the Norton Basin, all the development options considered in the analysis assumed tankering of crude or LNG to lower 48 markets.

Construction schedules and manpower estimates assumed extensive modularization and integration of onshore and offshore facilities to minimize local construction and speed construction schedules because of the short summer weather window of four to six months.

TABLE 2-12

REPRESENTATIVE PIPELINE DISTANCES TO NEAREST TERMINAL SITE EVALUATED IN ECONOMIC ANALYSIS

Case	Water Depth of Field	Pipeline Length	
		Offshore	Onshore
	meters (feet)	kilometers (miles)	kilometers (miles)
No. 1	15 (50), 30 (100), 46 (150)	128 (80)	3 (2)
No. 2	15 (50), 30 (100), 46 (150)	64 (40)	3 (2)
No. 3	15 (50)	32 (20)	48 (30)
No. 4	15 (50)	32 (20)	3 (2)
No. 5	15 (50)	16 (10)	3 (2)

Note: Both shared and unshared pipeline cases are screened in the economic analysis.

Source: Dames & Moore

2.5 Resource Economics

The economic characteristics of several likely oil and gas production systems suitable for the harsh and icy conditions of the Norton Sound are analyzed in this report with the model described in Chapter 3.0. The model is a standard discount cash flow algorithm designed to handle uncertainty among the variables and driven by the investment and revenue streams associated with a selected production technology.

The analysis focuses attention on: (1) the engineering technology required to produce reserves in the Norton Sound, and (2) the uncertainty of the interrelated values of the economic and engineering parameters. In view of the uncertainty, it is important to emphasize that there is no single-valued solution for any calculation reported in the analysis. Field development costs associated with the different production systems as well as oil and gas prices have been estimated as a range of values. Sensitivity and Monte Carlo procedures have been used to bracket rather than pin-point the decision criteria calculated with the model.

Two vital pieces of information are estimated in the analysis:

- The minimum economic field size to justify development of a known field with a selected technology in Norton Sound.

- The minimum required price to justify development of a field in Norton Sound.

Both are very sensitive to the location of the discovered field in Norton Sound and the decision to offshore load or pipeline to a shore terminal as well as the value of money used to discount cash flows. The calculated minimum field sizes for different production technologies are bracketed between 10 percent and 15 percent discount rates. Tables A-2 through A-8 in Appendix A of the report show the results. The calculated minimum required price for representative oil production systems assuming a 15 percent discount rate is shown on Figure A-3 in Appendix A of the main report. Figure A-4 in Appendix A of the main report shows the representative minimum required gas price.

The essential findings of this report are summarized below. The single value calculations discussed are based on the mid-range parameter values. Monte Carlo distributions and sensitivity analyses showing the range of values for the after tax return on investment are discussed in the main report in Section II.4 of Appendix A. The technology, financial, reservoir, and production assumptions of the analysis are detailed of Chapter 3.0 of the main report.

- The magnitude of the investment costs together with high operating costs in the Norton Sound imply that very good reservoir conditions -- regardless of size of field -- will be required to earn in excess of 15 percent return on investment.

- Platform production facilities are so costly in the Norton Sound that shallow reservoirs which allow only eight producing oil wells or four gas wells (assuming standard industry well-spacing) are not economic to develop given the other assumptions of the analysis.

- Intermediate depth reservoir targets that restrict oil platforms to 24 producing wells (assuming standard industry well-spacing) are only marginally economic to develop -- given the other assumptions of the analysis.

- Either faster recovery than 2,000 b/d per well initial production rate or wellhead prices higher than $18.00 are required to justify development of shallow to intermediate reservoir targets in the Norton Sound.

- The minimum field size to justify development of a deep reservoir field depends on the production technology -- offshore loaded or pipeline to shore -- and the length of the pipeline. For a field with an unshared 32 kilometers (20 miles) pipeline, and a 40 producing well platform, mid-range development costs would be $803.5 million and minimum field size would be 160 million barrels to earn 10 percent; 240 million barrels to earn 15 percent.

- In the relatively shallow waters of the Norton Sound, minimum field size to earn 15 percent varies between 200 and 240 million barrels as water depth increases from 15 to 45 meters (50 to 150 feet). Platform development costs rise from $704.5 million to $803.5 million as water depth increases from 15 to 45 meters (50 to 150 feet) -- assuming a 40 well platform and 32 kilometers (20 miles) pipeline.

- In the Norton Sound where geologic conditions suggest 1,000 b/d initial production rates might be expected, platforms will need to house more than 40 producing wells to earn 15 percent, or oil will have to be priced in excess of $20.00 a barrel.

- A deep reservoir with 2,000 b/d initial production rate requires a 40 producing well platform with a mid-range investment cost of $759.1 and requires 215 million barrels to earn 15 percent.

- A deep reservoir with 5,000 b/d initial production rate requires only 20 producing wells to drain efficiently and has a mid-range cost of $595.5 million. Minimum field size to earn 15 percent is 190 million barrels. With 5,000 b/d initial production rate a 250 million barrel field is able to earn 20 percent return on investment.

- Unless fields are discovered in the Norton Sound which allow sharing pipelines to shore, investment cost of an unshared pipeline longer than 48 km (30 miles) is so large that no production system is able to earn 15 percent hurdle rate of return.

- Production start-up in the Norton Sound could be delayed by any number of environmental hazards ranging from bad weather to inability to secure permits in a timely manner. When the delay occurs relative to money invested is critical to the impact on the economics of the project. A one year "worse case" delay can reduce a 15.5 percent project to 13.5 percent. If 15 percent is the hurdle rate, this changes a "go-ahead" to "no development". A two-year "moderate impact" delay reduces the payout to 10 percent.

- There are economies of scale of developing a "giant" reservoir with two or more platforms. The minimum field size that will support two platforms and earn a 15 percent hurdle rate of return is 425 million barrels -- assuming 2,000 b/d wells and a 16 kilometers (10 miles) pipeline.

- If the bottom conditions, water depth, and gravel availability allow, gravel islands are less costly and more economic than steel platforms as a development option. The gravel island in 18-meters (50-feet) water earns 18 percent with maximum recoverable reserves compared to the steel platform -- both with 32 kilometers (20 miles) pipeline to shore.

- For the isolated field too far from shore for a pipeline, offshore loading with storage to allow full production is extremely economic. The minimum field size to earn 15 percent is less than 200 million barrels.

- The economic screening of gas production facilities assumed that gas was sold at the end of the pipeline-to-shore to an LNG processor. The analysis did not include LNG investment costs. These costs and the cost to transport-to-market must be added to assess the marketability of natural gas discovered in the Norton Sound.

- Gas production is sensitive to reservoir target depth and location of the field relative to pipeline costs.

- Shallow gas reservoirs that restrict the number of wells that can be drilled from a platform are not economic unless the wells are highly productive or prices approximate $3.25 mcf.

- Gas reservoirs 16 to 32 kilometers (10 to 20 miles) from shore require gas to be priced at $2.00 to $2.25 mcf to earn a 15 percent hurdle rate of return. A large gas field with a single 16 well platform could support nearly a 100 kilometers (60 miles) pipeline unshared and still earn the 15 percent hurdle rate.

- The standard gas platform with 16 wells initially producing 15 mmcfd/well would require a wellhead price of about $2.35 mcf for a 750 bcf field and $2.00 mcf for 1,350 bcf field to earn 15 percent.

- With initial productivity of 25 mmcfd minimum required price for the 1,350 bcf field is $1.35 mcf instead of $2.00 mcf.

- The minimum required price to develop an oil field that will earn 15 percent in the Norton Sound ranges between $26.00 and $36.00 barrel for 100 million barrel field depending on the development technology; between $15.00 and $18.00 barrel for a 250 million barrel field.

- The Monte Carlo analysis reveals that there is a wide range to the potential payout of either oil or gas development as a result of the range of uncertainty built into the estimates of cost and estimates of resource prices.

2.6 Facilities Siting

A facilities siting analysis was conducted to identify suitable sites in the Bering/Norton area for location of crude oil terminals, LNG plants and support bases (see Appendix D of the main report). The following sites were identified principally on the basis of technical feasibility:

- Cape Nome

- Nome

- Cape Darby

- Northeast Cape (St Lawrence Island)
- Lost River

To develop these sites to permit access for crude oil or LNG tankers would require long trestles to reach adequate water depths, offshore loading structures or major dredging. The Cape Nome site was selected as the most suitable of the five sites identified.