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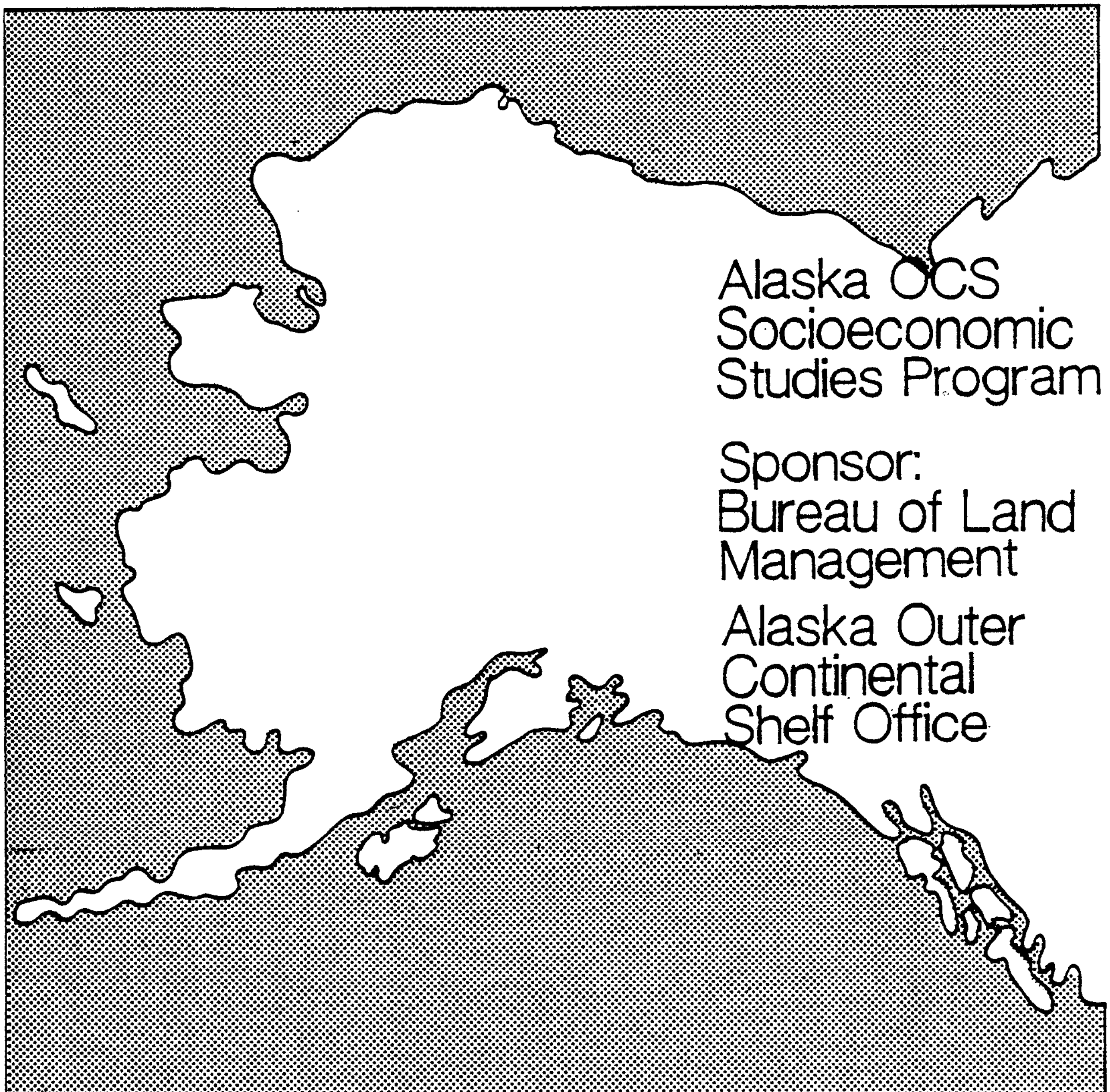
Technical Report Number 83



Alaska OCS Socioeconomic Studies Program

Sponsor: Bureau of Land Management Alaska Outer Continental Shelf Office

Navarin Basin Petroleum Technology Assessment

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

ALASKA OCS SOCIOECONOMIC STUDIES PROGRAM
NAVARIN BASIN
PETROLEUM TECHNOLOGY ASSESSMENT
OCS LEASE SALE NO. 83

Prepared for

BUREAU OF LAND MANAGEMENT
ALASKA OUTER CONTINENTAL SHELF OFFICE

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NOTICES

1. This document is sponsored by 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 contents or use thereof.

2. This report is designed to provide preliminary petroleum development data to the groups working on the Alaska OCS Socioeconomic Studies Program. The assumptions used to generate this petroleum technology assessment may be subject to revision.

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

   Values have been rounded to an appropriate significant figure to reflect the level of accuracy that the value represents.

ALASKA OCS SOCIOECONOMIC STUDIES PROGRAM
Navarin Basin
OCS Lease Sale No. 83

Technical Report No. 83

Prepared by

DAMES & MOORE

June 1982

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1.0 INTRODUCTION

1.1 Purpose

The principal purpose of this study is to identify the petroleum technology that may be used to develop oil and gas resources on the Navarin Basin OCS Lease Sale No. 83. This analysis focuses on both the individual field development components (types of platforms, pipelines, etc.) and the overall field development and transportation strategies. An evaluation of the environmental constraints (oceanography, geology, etc.) defines the most suitable engineering strategies.

The second purpose of this study is to assess the economic viability of various development strategies. In view of the remote location and harsh environment of the Navarin Basin, the economic analysis has focused on transportation alternatives. The third purpose is to estimate the manpower required to construct and operate the facilities.

This study is structured to provide "building blocks" of the petroleum facilities, equipment, costs, and employment that can be used by Bureau of Land Management Alaska OCS Office staff to evaluate nominated lease tracts. Three feasible field development strategies (types of platforms, transportation options, etc.) are specified; these development strategies are technically feasible and economically viable under the assumptions given.

Petroleum technology will determine or influence the scheduling of offshore and onshore activities, the local employment and infrastructure support requirements, and the potential risks involved in the production and transportation of hydrocarbons and related potential for environmental impacts.

Thus, the petroleum technology assessment provides the necessary framework to assess environmental and socioeconomic impacts of the Navarin Basin petroleum development.

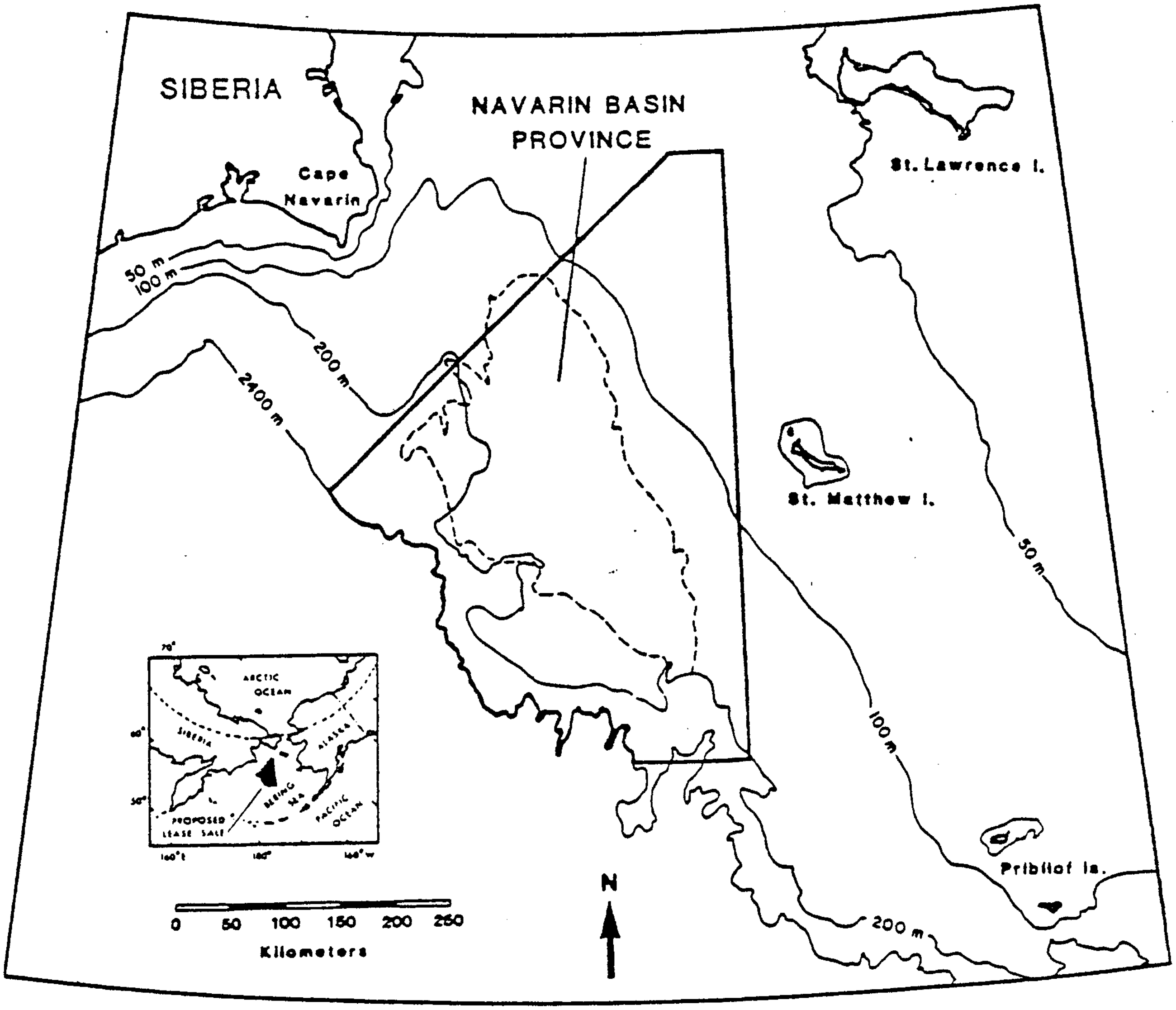
It should be emphasized that this report is specifically designed to provide petroleum development data for the Alaska OCS socioeconomic studies program. This study, along with other studies conducted by or for the Bureau of Land Management, including environmental impact statements, are required to use U.S. Geological Survey estimates of recoverable oil and gas. The assumptions used in the analysis may be subject to revision as new data become available.

1.2 Scope

This petroleum technology assessment is for the proposed Navarin Basin Lease Sale No. 83. Scheduled for March 1984, it will be the third Bering Sea OCS lease sale, following the Norton Sound Sale No. 57 and St. George Basin Sale No. 70 (scheduled for November 1982 and February 1983, respectively). The North Aleutian Shelf Sale No. 75, previously scheduled for April 1983, was deleted in the March 1982 revised schedule. This report encompasses the area shown in Figure 1-1, which is bounded on the north by 63 N latitude, on the east by the 174 W meridian, on the south by 58 N latitude, and on the southwest by the 2,400-meter (7,900-foot) isobath, and on the west by the U.S-Russia Convention Line of 1867.

The principal components of this study are:

- o An evaluation of the environmental constraints (oceanography, geology) that will influence or determine petroleum engineering and field development and transportation strategies (Chapter 3.0).
- o A description of various field development components and strategies and related technical problems (Chapter 3.0).
- o A discussion of facilities siting to identify suitable shore sites for petroleum facilities such as crude oil terminals, LNG plants and support bases (Chapter 4.0).
- o An analysis of the manpower requirements to explore, develop, and produce Navarin Basin petroleum resources in the context of projected



LOCATION OF PROPOSED NAVARIN OCS LEASE SALE NO. 83 IN THE NORTHERN BERING SEA. ALBERS EQUAL AREA PROJECTION.

FIGURE 1-1

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technology, and environmental and logistical constraints (Chapter 5.0). This includes specification of manpower requirements by individual tasks and facilities.

- A review of the petroleum geology of Navarin Basin to formulate reservoir and production assumptions necessary for the economic analysis (Appendix A).

- An economic analysis of Navarin Basin petroleum resources in the context of projected technology, facility and equipment costs, and assumed reservoir characteristics (Chapter 6.0).

- Specification of the facility and equipment requirements and probable production for a hypothetical development case corresponding to the U.S. Geological Survey statistical mean oil and gas resource estimate for the basin (Chapter 7.0).

1.3 Data Gaps and Limitations

Results of this study are preliminary and should be reviewed in the context of the constraints imposed on the analysis by significant data gaps. This study is based upon available data such as the geophysical records of the U.S. Geological Survey and the results of the oceanographic surveys conducted by the National Oceanic and Atmospheric Administration. No proprietary data were available to this study, although both agency and industry reviews of important technical, geologic, and economic assumptions were made.

The principal data gaps include:

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

- Petroleum Geology -- Insufficient geophysical data were available to identify all structures, estimate area of structural closure, and estimate thickness of reservoir rock sections.

- Facility Cost -- The petroleum facility cost estimates (for platforms, pipelines, terminals, etc.) are tentative; no petroleum exploration and production has yet taken place in areas with the same conditions that may provide operational and cost experience.

1.4 Report Content and Format

This report is written as a companion report to two earlier Bering Sea studies: St. George Basin Petroleum Technology Assessment OCS Lease Sale No. 70 (Dames & Moore, August 1980) and North Aleutian Shelf Petroleum Technology Assessment, OCS Lease Sale No. 75 (Dames & Moore, December 1980). The analytical approach was structured to accommodate all three studies. However, the Navarin Basin proved to present unique engineering and logistic considerations. Hence, the basic data set of this analysis is unique to the Navarin Basin. We have cross-referenced relevant sections in the earlier reports. Contrasts between the lease sale areas have been identified where appropriate.

This report commences with a summary of findings (Chapter 2.0). The results of the petroleum technology assessment are presented in Chapter 3.0. Onshore sites for petroleum facilities are discussed in Chapter 4.0. Chapter 5.0 details the manpower requirements by task, activity, and facilities for the particular technologies described in Chapter 3.0. The results of the economic analysis are presented in Chapter 6.0. Chapter 7.0, based upon the resources estimated by the U.S. Geological Survey, concludes the main body of the report with a description of a hypothetical development case.

Appendix A presents a description of the Navarin Basin petroleum geology and the methods and assumptions of the technology assessment.

Appendix B gives the petroleum development costs and scheduling assumptions upon which the economic analysis is based.

2.0 SUMMARY OF FINDINGS

Throughout the course of this study, we have selected assumptions regarding oil production characteristics, schedules and economic parameters that are optimistic yet possible for Navarin Basin. Therefore, the degree of favorableness of our findings should be judged with these optimistic assumptions in mind.

2.1 Petroleum Geology

The Navarin Basin province includes three major sedimentary basins and significant thicknesses of deposits. On size and volume of rock considerations alone, the area promises a good chance for hydrocarbon accumulations. The U.S. Geological Survey has prepared a revised (BLM, December 28, 1981) mean estimate of recoverable resources as follows:

Oil	1.74	billion barrels
Gas	5.426	trillion cubic feet

Our evaluation of the geologic information available to us suggests that there is a definite potential in Navarin for giant discoveries. There are several large anticlinal structures, and also indications of numerous smaller folds, diapirs and stratigraphic trap conditions.

Because of the great thicknesses of sedimentary deposits, it appears that reservoirs could occur at several depths. Structures are seen from shallow to very deep below the seafloor. There are indications that single wells might be able to tap more than one producing horizon. Such multiple completions, if possible, would increase well productivity rates. It is reasonable to assume for Navarin that the depths of potential reservoirs occur in a range that will not impose a technical or economic constraint on their development from a single platform.

An assumption regarding the physical properties of the crude oil was needed in order to assess the viability of very long pipelines. In the absence of any such data even near Navarin, analogs of other Alaska crudes (MacArthur River and Kuparuk) were assumed.

2.2 Environmental Constraints

Weather-related factors -- waves, ice, fog -- are significant design parameters in Navarin, as would be expected for a high-latitude, open-ocean area. However, Navarin's constraints due to natural phenomena are added to by its remoteness. Large geographic distances (mainly over-water), negligible infrastructure support in the region, and limited onshore sites all impose technological and economic constraints on Navarin development.

The nearest landfall is St. Matthew Island, 250 kilometers (150 miles) distant, which is currently a National Wildlife Refuge, and has no facilities or human population.

Wave and ice forces for design are both significant for the platforms examined in this study. Their magnitudes depend on water depth and structural considerations. Waves were slightly more dominant in the calculations but significant sea ice occurrences are possible in Navarin. Platforms have been designed to resist larger waves or more severe sea ice conditions in other areas but Navarin platform designs must accommodate both factors. Wave forces on gravity structures tend to be large although their point of action is relatively low so that overturning moments may not be as critical as when induced by ice loading. Although ice and wave forces are not expected to occur simultaneously, simultaneous occurrences of ice and wave loadings could result in load magnitudes more critical than either of the extreme single load events.

Water depths do not represent a particular problem, although there are no truly shallow sites. Most of the basin areas are well above the 200-meter (660-foot) shelf break. The seafloor is somewhat irregular around the shelf break due to submarine canyons, but the seafloor above 150 meters has gentle, smooth slopes. Characteristic depths over the basin areas are predominately in the 120- to 140-meter (400- to 460-foot) range.

Seafloor soils at the mudline are reported to be soft, finer-grained sediments. This is not favorable for gravity platforms, but does not eliminate their possibility. Foundations will have to be specially designed for a specific site's conditions. Earthquake acceleration forces are possible in Navarin, but are not expected to be very large.

2.3 Petroleum Technologies and Production Strategies

Exploration drilling will require semi-submersibles or large drillships in the face of both waves and long supply lines. Semis will probably be preferred. Ice conditions impose a seasonal constraint; open water season is variable, and is roughly May to November. Ice-reinforced drilling vessels and workboats would be advisable to protect against a short season or to extend the drilling into winter.

Exploration logistical support will require operating long-distance air and sea supply and crew-change transportation. Establishing support bases as near to Navarin as possible will be important to the economics, reliability and safety of the offshore operations.

Platforms could be either piled steel-jacket or gravity-type (probably concrete). The choice of platform concept will be intimately linked with the selection of the mode of production transportation. Steel-jacket platforms would be cheaper structures and could produce onto very long pipelines to shore. Concrete gravity platforms provide the storage necessary for offshore loading into shuttle tankers.

The long pipeline would probably be most feasible and economic if St. Matthew Island is the landfall. A storage facility and loading terminal would be established on the island (or alternatively, perhaps St. Paul Island in the Pribilofs). The terminal would supply ice-reinforced shuttle tankers.

Offshore loading in Navarin would be from multi-purpose (drilling/production/storage) concrete platforms, perhaps of the North Sea Condeep type. Alternatively, steel platforms with separate undersea storage and offshore loading facilities may prove advantageous. Gravity platforms offer a potential advantage in that their offshore installation time can be shorter than piled structures -- an advantage in view of Navarin's seasonal constraints.

Towing of any platform structure to Navarin will be a significant operation.

Shared transportation facilities -- trunk pipelines or shuttle tankers and terminals -- will be favored in developing Navarin finds. In any case, initial development in Navarin will require large throughputs and reserves to overcome the economic constraints.

Several important qualifications need to be kept in mind in respect to estimating petroleum facility and equipment costs for frontier areas such as the Navarin Basin. Predictions about the costs of petroleum development in frontier areas rely on extrapolation of costs from known producing areas suitably modified for local geographic, economic, and environmental conditions. No offshore area developed to date has the particular combination of waves, sea-ice, water depths, seismicity, and remoteness that characterize the Navarin. As such, there is little or no engineering and direct cost experience upon which to make these cost estimates.

2.4 Manpower

Manpower needs for Navarin offshore exploration, construction and production tasks have been identified. Significant considerations are the lack of any regional labor force and infrastructure, and the great crew transportation distances. Navarin employment may require some special demands in terms of rotations and lengths of tour. Seasonal constraints on Navarin development may make high-premium pay for total-season commitments a common operating basis.

2.5 Economics of Oil and Gas Development

Three alternative production/transportation systems were analyzed and compared for oil development in Navarin. These include:

Scenario 1	A 240-kilometer (150-mile) trunk pipeline to St. Matthew Island
Scenario 2	A 480-kilometer (300-mile) trunk pipeline to St. Paul Island
Scenario 3	Offshore loading into ice-strengthened tankers

In order to permit comparison of these three scenarios, the reservoir conditions are assumed to be identical. These characteristics for maximum production from a single-platform field are:

o Recoverable oil over platform life	365 million barrels
o Amount of recovery before decline	45 percent
o Reservoir depth	3000 meters (10,000 feet)
o Water depth	125 meters (400 feet)
o Initial productivity (IP)	2,500 BOPD per well
o Recoverable reserves per acre	60,000 barrels per acre
o Gas/Oil Ratio	500 (reinjected)
o Number of producing wells	40
o Number of service wells	8
o Peak platform production	100,000 BOPD
o Platform efficiency	96 percent

Recoverable reserves of 365 million barrels per platform imply optimistic assumptions about reservoir shape, reservoir conditions and reservoir engineering. Although feasible, these assumptions imply that our economic results should be considered optimistic.

Oil, once discovered, can be commercially developed in the Navarin Basin assuming that a field in the 300-million-barrel range is discovered. Offshore loading appears to offer some advantage over pipelines to either St. Matthew or St. Paul Islands for smaller fields. More pessimistic assumptions regarding operating efficiencies -- the scenario assumes 96 percent productivity -- for offshore loading systems would decrease the apparent advantage.

Large fields that can share a common transportation system are more economically developed with a pipeline system to a shore terminal.

Between the two pipeline systems, the pipeline to St. Matthew is considerably more economic than the pipeline to St. Paul. The high cost of the longer marine pipeline to St. Paul more than offsets the shorter shuttle tanker distance to an Aleutian terminal from St. Paul.

Most of the economies of scale are exhausted at around one billion barrels, except in the St. Paul very long pipeline scenario. Equivalent amortized cost (EAC) per barrel drops for all three scenarios between 365 million barrels recoverable reserves and 1.0 billion barrels. For the St. Matthew and offshore loading scenarios EAC essentially remains constant beyond a billion barrels. The very high cost of the long St. Paul pipeline, however, allows that scenario to exhibit decreasing unit costs out to 1.8 billion barrels of recoverable reserves.

Rates of return for the one-billion-barrel cases of the three scenarios range between 16.2 percent for the St. Paul pipeline to 18.9 percent for the St. Matthew pipeline. Offshore loading shows a 17.7 percent return. These rates are associated with $32.00 value of oil, F.O.B. the Aleutian terminal. Each $2.00 change in real 1981 crude oil prices changes the return about one percent.

Two gas scenarios were analyzed: (1) a shared trunkline to St. Matthew Island and (2) offshore loading (although the latter has not yet been done). As in the oil cases, reservoir conditions were assumed constant. The following parameters are assumed:

o Field size	1.4 trillion cubic feet
o Initial productivity	15 MMCFD per well
o Recoverable reserves per acre	200 MMCF
o Production system	Steel-jacketed platform

These conditions together with assumed reservoir engineering allowed recoverable reserves to be captured in twenty years. Assuming gas is priced at $6.15 MCF relative to the BTU equivalent of No. 2 diesel oil delivered as LNG to California, neither scenario is economic. Each yields an 8.0 percent rate of return.

Higher prices (in the $7.00/MCF range) would yield the assumed 12 percent real hurdle rate of return.

A peak year recovery of about 6 percent of reserves was assumed. If the rate of recovery could be increased without damaging the formation or causing well interference, rates of return would increase. For example, a 30 percent increase in peak year productivity yields a 2.5 percent increase in the rate of return. Larger fields would also increase the rate of return. Doubling the total reserves and the reserves per platform increases the rate of return by about 2 percent.

3.0 RESULTS OF THE PETROLEUM TECHNOLOGY ASSESSMENT

3.1 Introduction

The technology assessment has four major elements:

1. An assessment of the environmental forces and operating conditions that will influence the design, selection, and location of offshore facilities (including platforms and pipelines), and the overall field development and transportation strategy.

2. A description of individual field development components; in particular, platforms, their design parameters, and installation techniques.

3. Identification of field development strategies that may be adopted to develop the oil and gas resources of the Navarin Basin. The field development strategy involves the sum of the various field development components (platforms, wells, process equipment, pipelines, terminals, etc.) and the transportation system for either oil or gas. Included in this evaluation are discussions of offshore loading versus pipeline transport, Bering Sea terminal requirements, and the application of subsea systems.

4. Identification and selection of field development components and strategies to be evaluated in the economic analysis.

These are described in more detail in Appendix A of the St. George Basin report (Dames & Moore 1980c). This appendix describes the general approach to Dames & Moore's petroleum technology assessment.

In previous studies of the Gulf of Alaska (Dames & Moore, 1979a, b, 1980c), a detailed description of petroleum technology suitable for deep water, storm-stressed environments was presented. Included within that description was extensive discussion of steel jacket platforms and gravity structures (including design parameters, fabrication, and installation techniques), floating production systems, offshore loading, and many development issues pertinent to this study. The state-of-the-art in arctic and sub-arctic petroleum technology was extensively described in our Norton Sound report (Dames & Moore, 1980a). That report presented descriptions of upper Cook Inlet platforms, cones, and monocones that are relevant to this study.

A most important qualification with respect to this study is that the publicly available data (meteorology, oceanography, marine geology, petroleum geology) upon which our analysis is based are limited. In particular, data on ice characteristics and marine sediments (information essential to assess the feasibility of various platform designs or conceptualize on new designs) are sparse. Therefore, our approach with respect to platform design and operational constraints is conservative. Exxon and several other operators have recently initiated the Bering Sea Comprehensive Measurement Program (BS-COMP) to remedy oceanographic and meteorological data deficiencies.

This chapter begins with an evaluation of environmental constraints (oceanography and geology) and is followed by a description of various field development components. The chapter concludes with a discussion of field development strategies applicable to the Navarin Basin that warrant economic evaluation.

3.2 Environmental Constraints to Petroleum Development

3.2.1 Meteorology and Oceanography

3.2.1.1 Introduction

The Navarin Basin province is located in the Bering Sea on the western margin of the Bering Shelf. It is a remote and harsh environment; as a consequence, engineering and environmental data are sparse. The nearest land is St. Matthew Island, lying about 250 kilometers (150 miles) east of the lease sale area. Roughly twice as far away, St. Lawrence Island lies to the northeast, Cape Navarin (in Siberia) to the northwest, the Pribilof Islands to the southeast.

3.2.1.2 Meteorology

The U.S. Coast Pilot for the Bering Sea area (U.S. Dept. Commerce, 1964) describes the weather as follows:

> "The weather over the Bering Sea is generally bad and very changeable. Good weather is the exception and it does not last when it does occur. Wind shifts are both frequent and rapid. The late spring and summer seasons have much fog and considerable rain. In early fall the gales increase, the fogs lessen, and snow is likely any time after mid-September. Late fall and early winter is the time of almost continuous storminess."

The Navarin Basin area lies far offshore in a region seldom traversed by shipping; wind observations are sparse to nonexistent, and general conditions must be extrapolated from shore stations. Marlow et al. (1981) examined weather data from Gambell, an Eskimo village on St. Lawrence Island, and extrapolated the following characteristics for Navarin Basin:

- Air temperature: extremes - 33.3 to 31.7 C
  monthly means -16.2 to 9.6 C
- Relative humidity: generally high (80 to 90 percent)
- Precipitation: 275 to 300 days per year; annual total ± 37.5 cm.
- Winds: winter winds average 32 km/hour
  peak winter winds 129 km/hour
  summer average 19 km/hour
- Cloud cover: clear skies occur 2 to 3 days/month

3.2.1.3 Bathymetry

The Navarin Basin province lies almost totally on the Bering Shelf, which is characterized by relatively shallow water depths and very little bottom relief. There is a very gradual gradient from the shallower northeast corner of the lease area to the southwest side where the shelf drops steeply to depths of several thousand meters (Figure 3-1). The depths range from about 70 meters (230 feet) on the shallower side and slope gradually to 200 meters (660 feet) along the southwest edge; the bottom drops steeply to the southwest to the 2,400-meter (7,900-foot) isobath, which has been designated as the boundary of the Navarin lease area.

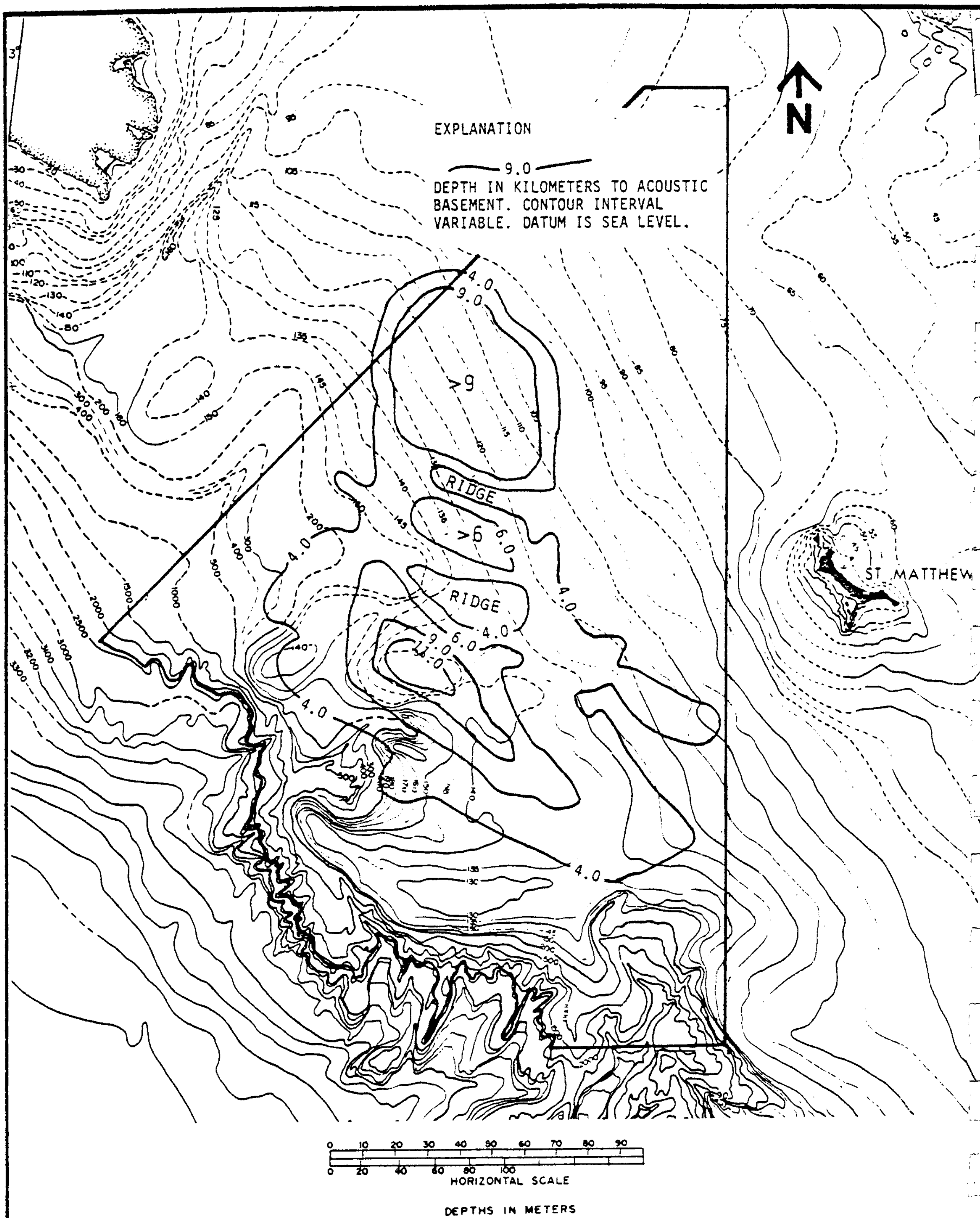
Slopes steepen dramatically below the 200-meter (600-foot) depth, and are very gentle above 140 meters (460 feet). The seafloor is very regular away from the continental shelf submarine canyons, above about 130 meters (425 feet).

3.2.1.4 Circulation

The Bering Sea is separated from the North Pacific Ocean by the Aleutian Island chain and from the Arctic Ocean by the Bering Strait. Although the Bering Sea exchanges water with both, the net flow is northward through the Aleutians and Bering Strait (Sharma, 1974). The currents northward through the Aleutian passes can attain speeds of several knots. In the open sea, however, well north of the passes, the northward velocity is probably not more than 0.5 knots (U.S. Dept. of Commerce, 1964). Based on the sparse measurements in the literature and on an assessment of the current forcing functions, Dames & Moore has postulated the general depth-dependent current design profile to be as shown in Figure 3-2.

3.2.1.5 Waves

Brower et al. (1977) estimated annual maximum winds and wave heights for portions of the Bering Sea. These data suggest that the 10-year storm (i.e., a storm with an average recurrence interval of once very 10 years) will have



NAVARIN SEDIMENTARY BASINS & BATHYMETRY

FIGURE 3-1

SOURCES: BATHYMETRY - GEOLOGICAL SOCIETY OF AMERICA, 1974. "BATHYMETRIC MAP OF THE BERING SHELF"
BASINS - BY THOMAS R. MARSHALL, JR.

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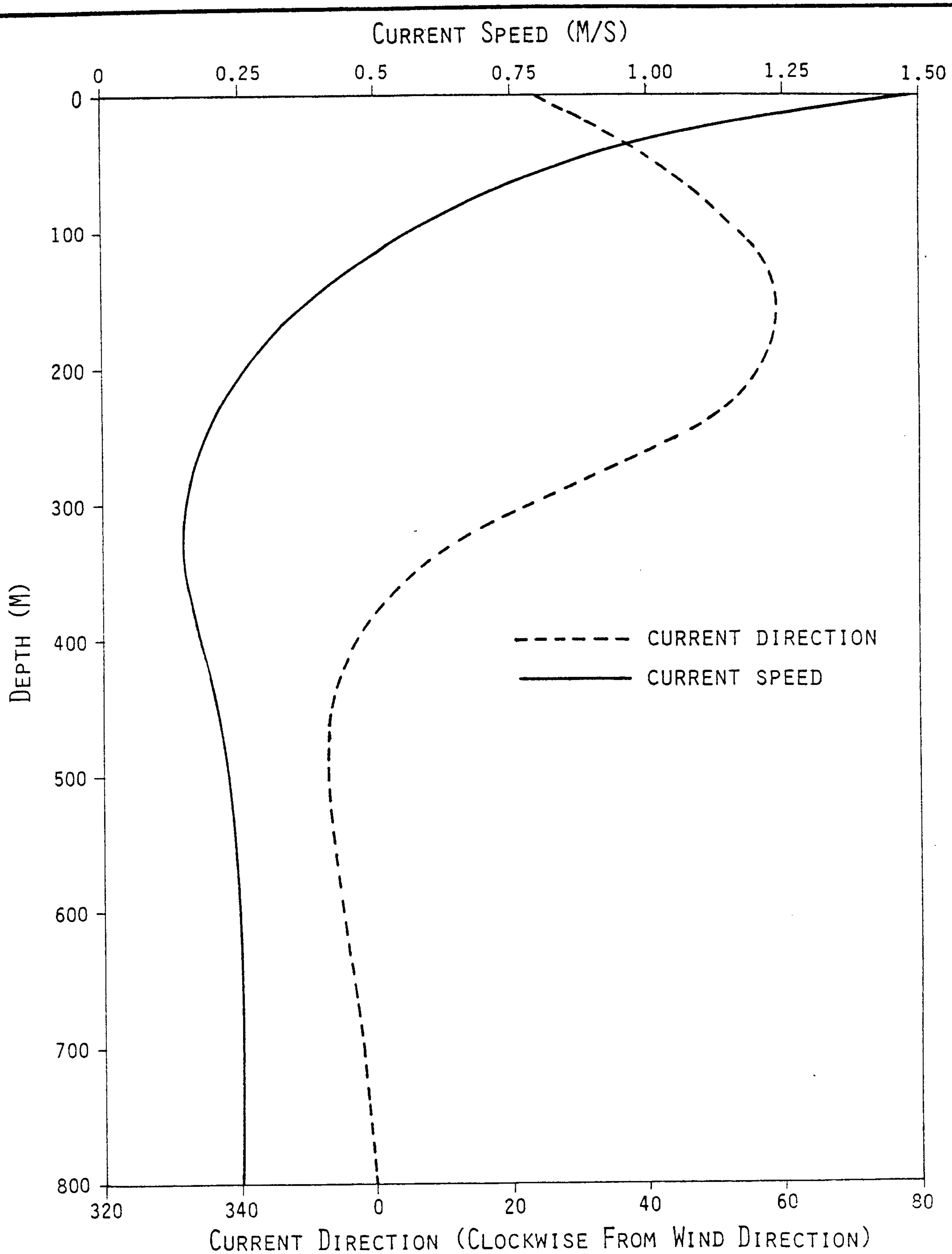


NAVARIN AREA CURRENT PROFILE

CALCULATED DESIGN CURRENT PROFILE

FIGURE 3-2

DAMES & MOORE

sustained winds of over 80 knots and extreme wave heights of about 28 meters (90 feet); the 50- and 100-year storms will have corresponding values of 102 knots and 36 meters (120 feet), and 110 knots and 42-1/2 meters (140 feet), respectively. Marlow et al. (1981) believe that these estimates of wave height are excessive, and suggest that heights closer to half of those figures would be more reasonable.

Preliminary calculations of 100-year wind and wave estimates by Dames & Moore for this study produced the following:

- o 100-year storm winds: 1-minute sustained speed of 100 knots
- o 100-year wave heights:

	Significant* Waves		Maximum Waves	
	Height	Period	Height	Period
N of 60 N. lat.	15m	15-17 sec	27m	16-17 sec
S of 60 N. lat.	18m	15-17 sec	30m	16-17 sec

(*Significant waves are the average of the highest 1/3 of all waves.)

A preliminary estimate was also made of the seasonal variation in wave conditions for three equal segments of the Navarin Basin; the following table shows estimated percent occurrences for several wave classes by zone and season.

PERCENT OCCURRENCES OF WAVE HEIGHTS BY ZONE

Month	Wave Ht. (meters)	Zone South	Zone Middle	Zone North	Ice Cover
January	less than 1.5	15	20	75	
	less than 2.5	45	60	90	
	less than 3.5	65	80	100	5/8 of the surface area Northern zone only
April	less than 1.5	45	60	80	
	less than 2.5	70	85	100	5/8 of the surface area Northern zone only
	less than 3.5	90	95	100	5/8 of the surface area Northern zone only
July	less than 1.5	50	60	70	
	less than 2.5	90	90	90	
	less than 3.5	95	95	95	
October	less than 1.5	15	20	25	
	less than 2.5	40	50	60	
	less than 3.5	70	80	85	

During that period of the year when the area is ice covered, large waves are not generated and are a much-reduced hazard.

Waves may approach the Navarin Basin area from any direction (Brower et al., 1977), but show a slight predominance from the southerly directions.

3.2.1.6 Sea Ice

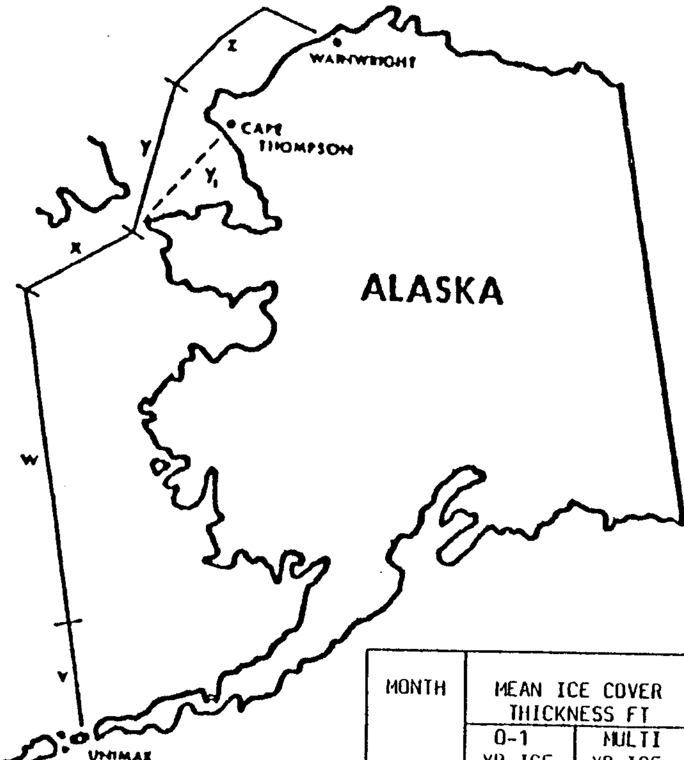
Information on sea ice characteristics for the Navarin Basin and adjacent areas can be found in several references that are in the public domain (e.g., see Figure 3-3.) Several proprietary reports of field studies conducted for oil companies also exist. Sea ice inputs for this study have been formulated by sea ice specialists with knowledge and experience in working with all available data. This provided a sound basis for our engineering analyses.

The areal extent of pack ice in the Bering Sea is controlled both by atmospheric cooling and freezing of seawater as well as by a continuous advection of ice floes southward from the north.

Sea ice starts growing in situ in the Bering Sea along the coast and over its northern waters in late October or November. This ice growth then spreads to the southwest and to the south. At the same time, ice floes formed at the northern latitudes also move southward under the influence of northerly to easterly winds.

The maximum pack ice extent usually occurs around April. An ice coverage of 6 to 8 oktas should be expected for the northern part of the Navarin Basin. Data on the pack ice edge location suggest that the southern part of Navarin Basin has a 50 percent probability of lying outside the pack ice edge in a given year. However, the entire basin lies within the limit of the observed pack ice extent in heavy ice years.

The pack ice in the Navarin Basin area consists of numerous small floes surrounded by piles of broken ice pieces. These broken pieces probably resulted from impact and crushing between the floes. Although these ice



ICE DATA FOR SECTOR W LENGTH: 484NM.

Source: John J. McMullen (1980)

Figure 3-3

MONTH	MEAN ICE COVER THICKNESS FT		ICE COVER (TENTHS)		DISTRIBUTION OF ICE IN %		RIDGE FREQ. NO/NM IN ICE	RIDGE THICK (FT.)	RIDGE FREQ. NO/NM TOTAL	FOG DAYS	CLOUD COVER	PRECIPITATION	
	0-1 YR ICE	MULTI YR ICE	MEAN	MAX.	0-1 YR ICE	MULTI YR ICE						DAYS	INCHES
JAN.	1.3	0.0	8.0	10.0	100.0	0.0	6.0	6.0	5.0	4.0	9.0	18.0	1.81
FEB.	1.8	0.0	8.0	10.0	100.0	0.0	7.0	8.0	6.0	4.0	8.0	16.0	1.23
MAR.	2.0	0.0	8.0	10.0	100.0	0.0	7.0	8.0	6.0	4.0	8.0	15.0	1.06
APR.	2.0	0.0	8.0	10.0	100.0	0.0	7.0	8.0	6.0	4.0	8.0	16.0	0.96
MAY	1.8	0.0	6.5	10.0	100.0	0.0	7.0	8.0	4.0	5.0	9.0	16.0	1.30
JUNE	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.00
JULY	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.00
AUG.	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.00
SEP.	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.00
OCT.	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.00
NOV.	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.00
DEC.	0.5	0.0	8.0	10.0	100.0	0.0	5.0	4.0	4.0	3.0	9.0	18.0	1.73

NOTE: LACK OF VALUES FOR SUMMER MONTHS REFLECTS ABSENCES OF ICE OBSERVATION ACTIVITIES features may be referred to as ice ridges, they are somewhat different from the large linear ice features frequently found in the Arctic. Voelker et al. (1981) reported the following data on ridge size and frequency:

Ridge Sail Height	Number of Ridges per Mile
less than 2 feet	6
between 2 and 6 feet	7
greater than 6 feet	1

This should be compared with a maximum level ice thickness of about 0.6 meters (2 feet) It has been estimated that these ridges will have a consolidated depth (i.e., with ice bonding) of less than two times the sail height of 3 meters (10 feet).

The pack ice in the Bering Sea, especially south of St. Lawrence Island, is very dynamic. Maximum ice movement rate occurs around March and April, and floe speeds as high as 0.3m/sec or 26 kilometers per day (1 ft/sec or 16 miles per day) have been observed. Maximum cumulative floe excursion may be as much as 320 kilometers (200 miles) per season.

The southern ice edge, however, tends to remain relatively stationary from March to May. This ice edge represents the location of dynamic equilibrium between the ablation and melting of the ice floes near the pack edge and the influx of ice from the north. Because of the near melting temperature, ice features near the ice edge are expected to be quite weak.

Breakup usually starts in May as a result of the wind shifting from cold northerly to warm southerly. The entire ice pack can become uniformly rotten in 3 to 4 weeks.

Accurate ice load prediction depends on a knowledge of ice strength, which is a complex function of salinity, crystal type and orientation, temperature, strain rate and direction of loading. API (1981) presents some guidelines and references on ice conditions, ice strength and ice loading prediction. There are, however, no published data on the engineering properties of sea ice from the Navarin Basin. However, Brian Watt Associates, Inc. (BWA) expects that the ice conditions will not be too much different from those in Cook Inlet.

Blenkarn (1970) presented some measurements and load estimates from tower structures in Cook Inlet. His data indicated that the largest ice forces result from warmer temperatures and ice ridges. When ice floes failed against the cylindrical legs, the failure pattern was observed to be ductile plastic deformation when the ice is warm. The failure of colder ice involved brittle cracking and a reduced force level. For ice ridges, the estimated failure force levels were in the range of 2 to 3 times the force levels associated with the surrounding ice floes.

Prime candidates for structures supporting drilling and production operations year-round in the Navarin Basin include floating and fixed gravity platforms with "towers" or cylindrical legs through the waterline. BWA anticipates that these structures will experience a maximum ice load of approximately 90 kips/ft of leg diameter (Table 3-1). In some cases it will be possible to reduce the total ice load by incorporating cone-shaped structural elements near the waterline so as to fail the approaching ice feastures in vertical flexure. The maximum ice load in this case depends on the cone configuration and surface friction characteristics. A maximum load of about 40 kips per foot of waterline cone diameter can be expected for a 45 degree cone with a smooth surface.

In addition to the considerations given to the maximum ice loads, all structural elements in potential ice contact zones will have to be designed for localized and very high ice pressures. These high pressures may result from quasi-static or impact loading conditions. Selecting appropriate design ice pressure criteria for structures is however a difficult task due to the lack of data and industry experience. Bruen et al. (1982) discussed the complications involved in criteria selection and suggested tentative pressure versus area curves for design. For first year ice, the suggested design ice pressure is 1000 psi for areas equal to or less than 20 square feet and reduces to 400 psi for areas greater than 300 square feet.

TABLE 3-1

SUMMARY OF ICE LOAD PREDICTION

Structural Type	Ice Type	Thickness (feet)	Strength (psi)	Load (kips per foot)*
Vertical Cylindrical Tower	1. Level Ice	2	σ_c = 600	60
	2. Rafted Ice	4	450	90
	3. Consolidated Rubble	10	120	60
Cone-Shaped Structure	1. Rafted Ice	4	σ_f = 80	15
	2. Consolidated Rubble	10	40	40

*At waterline.

$_c$ = unconfined compressive strength.

$_f$ = flexural strength.

All granular ice.

Source: Brian Watt Associates

3.2.1.7 Tsunamis

Although the Pacific, and more specifically the Aleutians, are seismically active areas, the water depths in the Navarin Basin should preclude any problems from seismically generated tsunamis. Tsunamis would only present a problem insofar as they affect any shore-based support facilities located along the Alaska or Aleutian coasts.

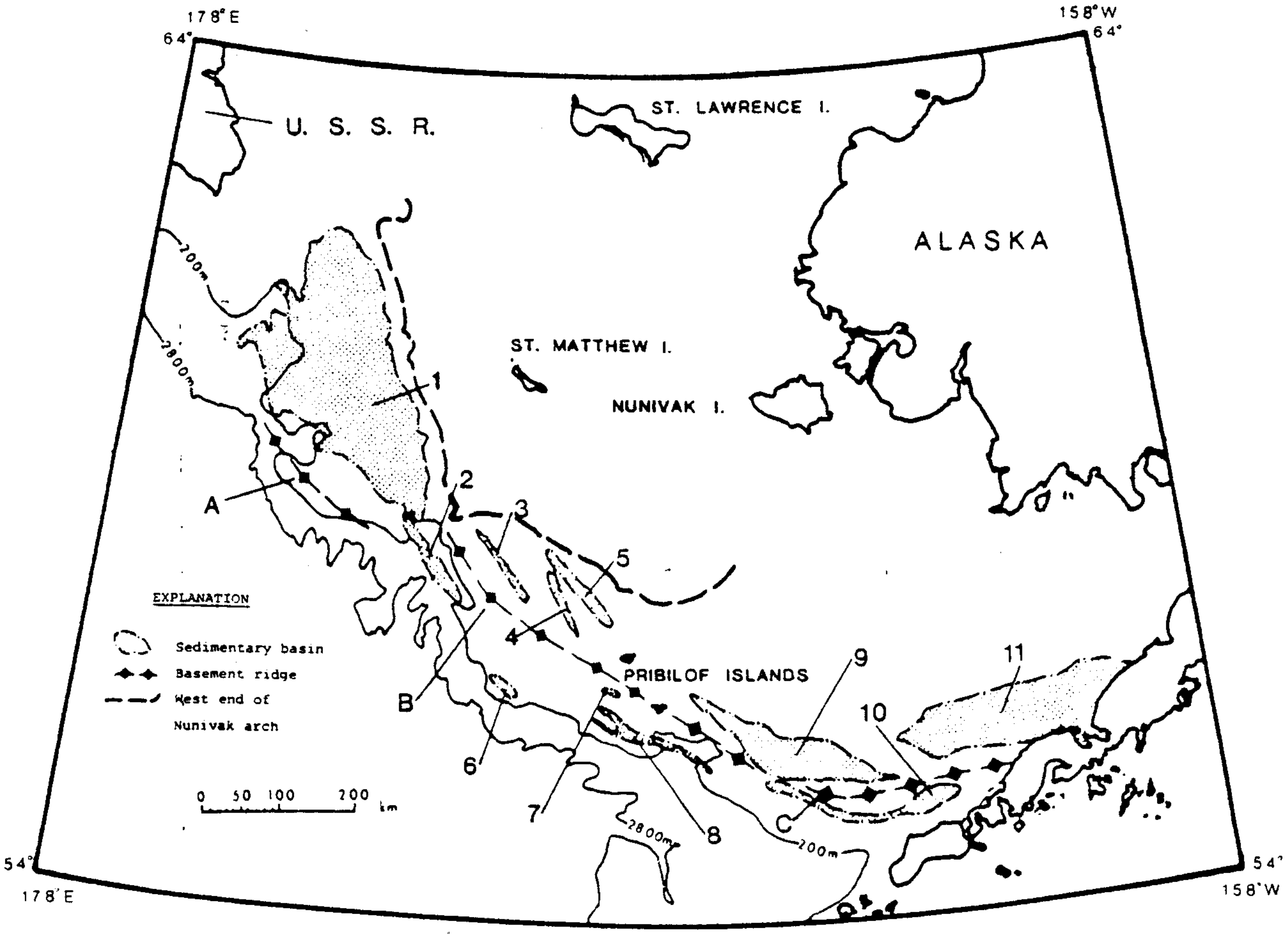
3.2.2 Geology and Geologic Hazards

3.2.2.1 Major Data Sources and Reference Materials

The Bering Sea Shelf, as a geographic and geologic unit, has received substantial attention from numerous researchers in recent years, and a large volume of knowledge has been accumulated about the structural, tectonic, and environmental geology of the area. The Navarin Basin has received somewhat less attention than other Bering Sea petroleum provinces that lie nearer to shore and, therefore, are more attractive for petroleum development; nevertheless, some information is available, primarily from research conducted by the U.S. Geological Survey. A small number of multi-channel seismic reflection profiles have been obtained by the USGS (Marlow and Cooper, 1979). Samples of sediments dredged from the continental margin in the Navarin Basin area have been briefly described by Marlow et al. (1979). Much of the available information has been synthesized into estimates of resource potential (Tremont, 1981; Dolton, et al., 1981; and Marlow, et al., 1981); at the time of this writing (early 1982) neither hazard reports nor infrastructure reports specific to the Navarin Basin have been released.

3.2.2.2 Geologic Setting

The Navarin Basin is an elongate structural depression lying on the western margin of the Bering Sea Shelf (Figure 3-4); the basin is filled with sedimentary strata and above the irregular continental shelf break there is very little seafloor relief (Figure 3-1). The principal axis of the Navarin Basin trends north-northwest by south-southeast (subparallel to



1- Navarin Basin; 9- St. George Basin; 10- Amak Basin; 11- North Aleutian Shelf Basin

SEDIMENTARY BASINS OF THE BERING SEA SHELF

(Adapted From Cooper, et al., 1979)

Figure 3-4

the edge of the Bering Sea Shelf), and has approximate dimensions of 400 by 180 kilometers (250 by 112 statute miles).

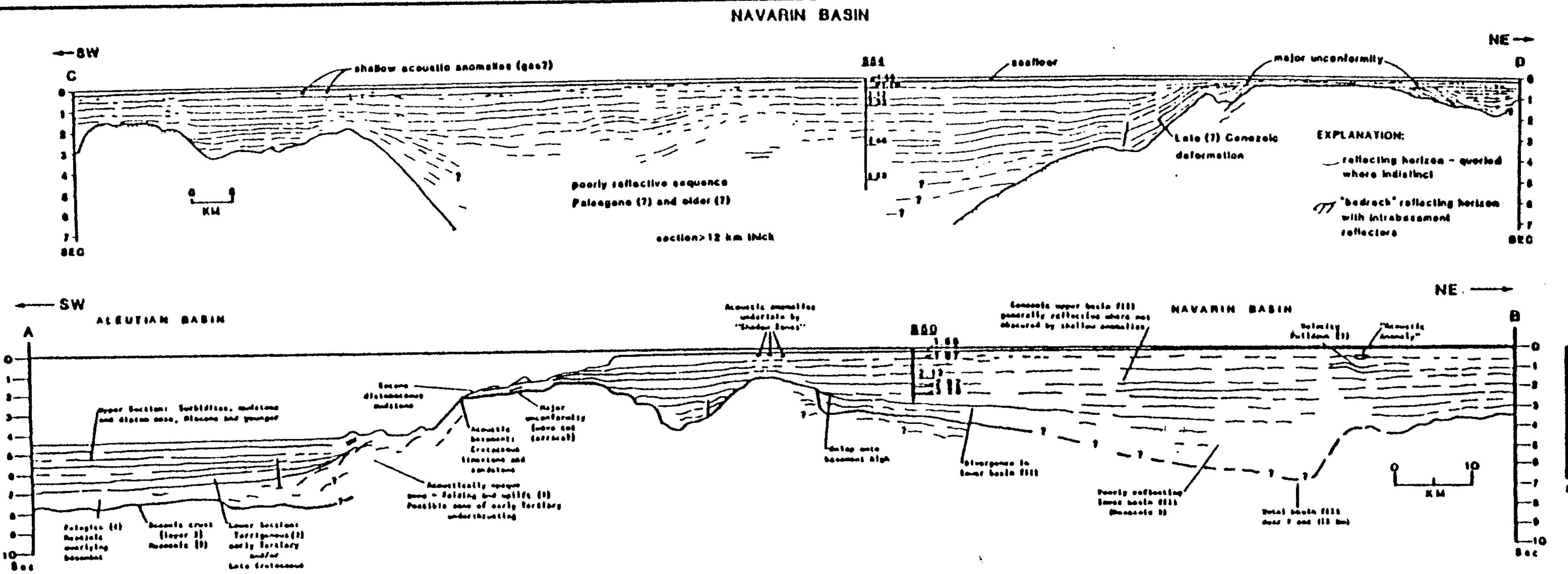
Interpretive sections have been prepared for two seismic reflection lines running across the Navarin Basin (Figure 3-5; adapted from Marlow, et al. 1981). These profiles show a considerable thickness of stratified material, reported to be as much as 15 kilometers (9 miles) thick, overlying basement rock that is postulated to be oceanic crust of Mesozoic age. The Navarin Basin is flanked to the east by the Nunivak arch, a broad basement high that is exposed on St. Lawrence and St. Matthew Islands. The basin is bounded on the southwestern margin by a basement ridge, beyond which lies the deep-water Aleutian Basin.

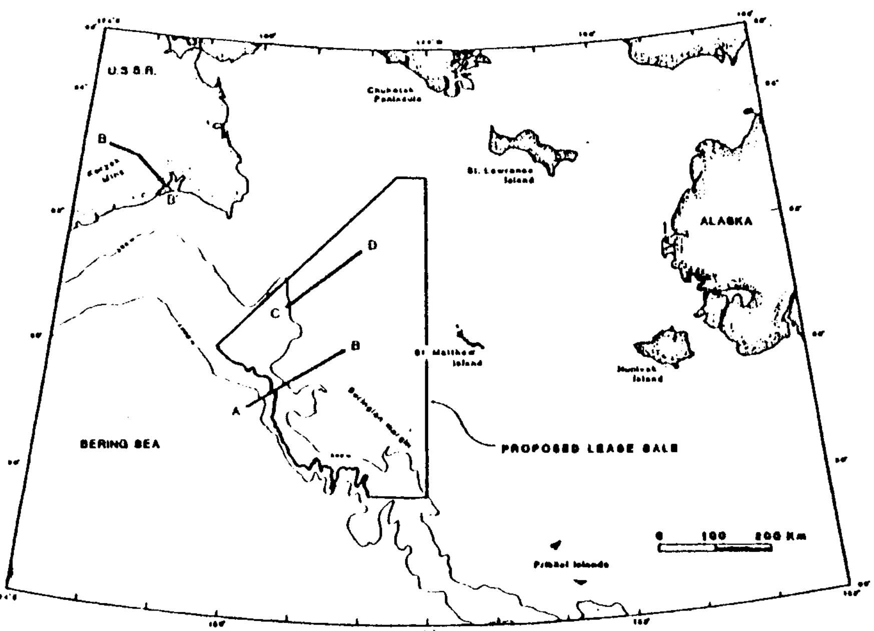
Structure contours of the Navarin Basin (Figure 3-6) have been mapped by Cooper et al., (1979), and show three smaller basins contained in the Navarin Basin province. Sediment accumulation within the basins is 10 to 15 kilometers (6 to 9 miles) thick (Marlow, et al., 1981); these sediments underlie more than 45,000 square kilometers (about 17,000 square miles) of the Bering Sea Shelf. Surficial sediments are characteristically olive grey, fine clayey silts, with greater sand content near the shelf break (Carlson and Karl, 1981); deposition rates of 25 cm/1,000 years have been postulated. Although no test wells have yet been drilled in the province, there is ample evidence of possible hydrocarbon traps, including anticlinal structures, fault closures, and stratigraphic discordances.

3.2.2.3 Geologic Hazards

Marlow et al., (1981) cite evidence of potential geologic hazards to petroleum development from faulting and earthquakes, seafloor instability, penetration of gas-charged sediments, sediment transport and erosion, and volcanism. Hazards present by sea ice have been discussed earlier in this report (see Section 3.2.1.6).

Because of the limited amount of data available from the Navarin Basin, it is difficult to map fault trends, areas of gas-charged sediments, and other



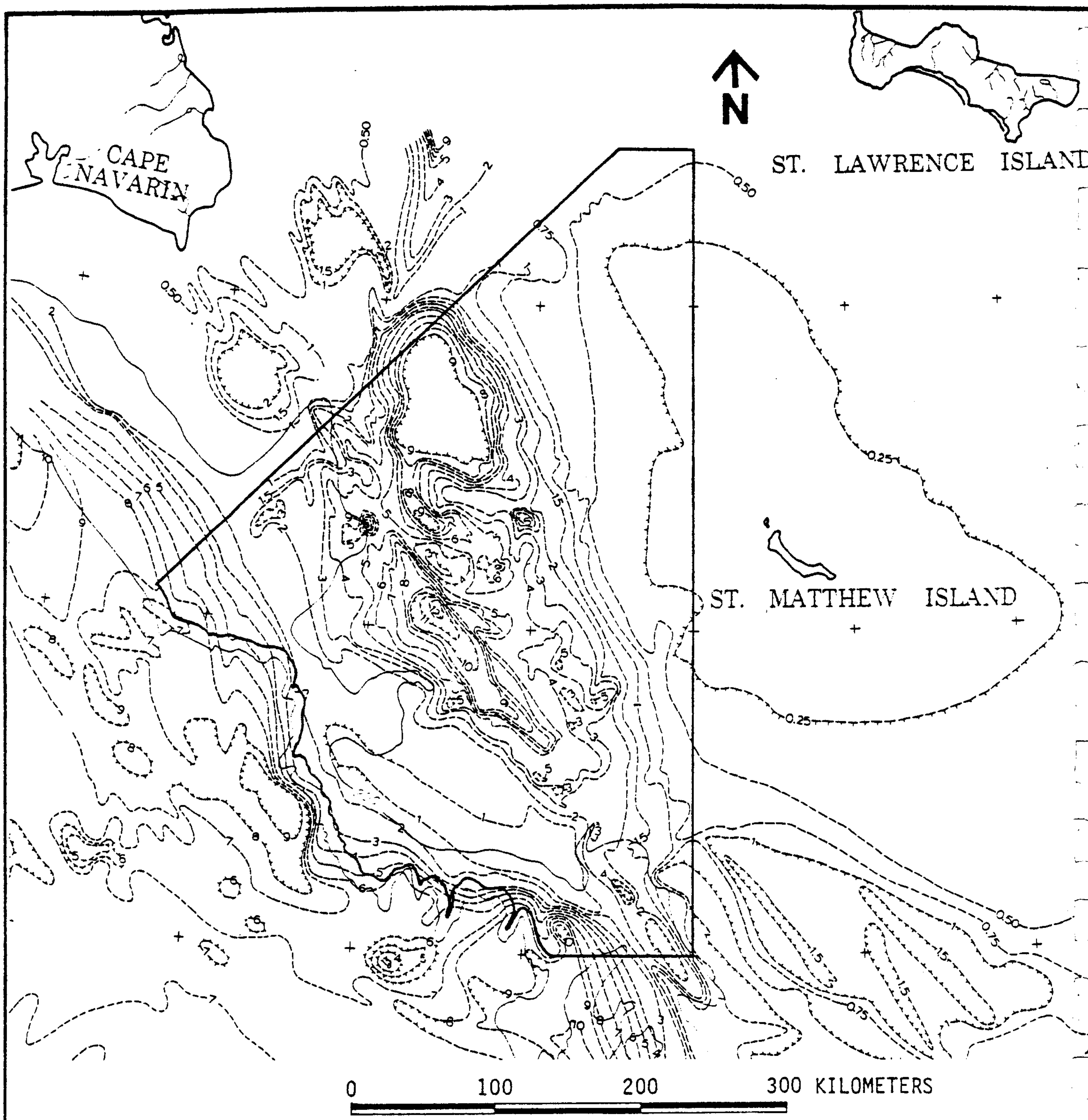


INTERPRETIVE CROSS-SECTIONS THROUGH THE NAVARIN BASIN

(ADAPTED FROM MARLOW, ET AL, 1981)

FIGURE 3-5

Dames & Moore



STRUCTURE CONTOURS ON ACOUSTIC BASEMENT FOR NAVARIN BASIN PROVINCE

(DEPTHS IN KILOMETERS)

(ADAPTED FROM COOPER, ET AL., 1979)

FIGURE 3-6

hazard features with any reasonable degree of certainty. Faulting is not uncommon, but the length, orientation, and age of displacement cannot be well defined. No evidence of seafloor displacement by subsurface faults has been found, although deeper faults can be seen to displace the basement surface and the deeper parts of the sedimentary section. Few earthquakes have been reported for the Navarin Basin, and all were less than Magnitude 6 (Meyers et al., 1976).

Seafloor instability may derive from mass movement of seafloor sediments (submarine landslides), from other sedimentary transport and erosion processes, and from gas-charged sediments, all of which are seen to some extent within the Navarin Basin (Marlow, et al., 1981). The continental margin in the Navarin Basin area is cut by three large submarine canyon systems; submarine landslides have been mapped in all three. Large sediment waves having heights of about 8 meters (25 feet) have been observed at the heads of each of the three canyon systems. It is not known whether these sediment waves are relict features or active features; if the latter, they may represent significant geologic hazards. Lastly, numerous areas of gas-charged sediment have been mapped in the Navarin Basin; the frequency of occurrence of gas-charged sediment appears higher in the northern part of the province.

No evidence of volcanic activity has been found in the Navarin Basin. Nonetheless, very recent volcanism has occurred in the Pribilof Islands, located approximately 500 kilometers (300 miles) southeast of the Navarin Basin. Some hazard may be present from eruption of lava and ash, and from associated earthquakes, but is judged to be of low probability.

3.3 Field Development Components

3.3.1 Exploration Platforms and Operations

Two constraints will strongly influence the planning and operations for Navarin oil exploration: distance and time. Another important and related consideration, as always, is weather.

Supply line distances to Navarin are great to support offshore drilling activities. This will make crew rotations and resupply more difficult and costly, so the exploration vessels must be as self-sufficient as possible. This may push the selection of vessels towards larger sizes than might otherwise be needed to operate in the anticipated weather conditions.

Time for exploration is limited by the duration of the open-water season, on the order of six or seven months. This period varies each year, and may be fully utilized by adding ice-reinforced support boats. Following the example of Dome Petroleum in the Canadian Beaufort Sea, where ice-reinforced drill-ships supported by icebreakers drill well into the fall, similar equipment and techniques could extend the drilling window into the winter season in Navarin, which has significantly less severe ice conditions. Although not currently available, ice-strengthened dynamically positioned semi-submersibles or drillships, possibly supported by ice breakers, may also be an option for winter drilling.

Even the open-water conditions are severe, though waves are not expected to be as bad as in the North Sea or Gulf of Alaska. The demands imposed by extended self-sufficency, limited drilling season, and waves may favor use of large semi-submersibles, although drillships cannot be excluded. A semi-submersible rig is proposed for the planned COST well program.

Crew rotations and critical spares will be transported by air. An airstrip and forward base at St. Matthew Island would be the most effective route. Alternatives are St. Lawrence Island or the Pribilofs, which are more distant and thus less favorable in terms of cost and safety.

Resupply of bulky materials such as mud and water would probably be by vessels from Dutch Harbor/Unalaska, or another established facility in the region. Kodiak and Anchorage might be workable for needs anticipated well in advance, but greatly increase the transit time and costs. Small harbor facilities for fishing are being planned for the Pribilofs.

Other problems facing exploratory drilling in this area include the high frequency of summer fogs and potentially severe structural icing in the winter that would pose hazards for rigs and support vessels.

With the exception of the limited facilities at Dutch Harbor and Cold Bay, the Bering Sea lacks in-place shore facilities capable of supporting a major exploration program. Development of such facilities may have to compete with the requirements of an expanding fishing industry.

Another factor that will influence the technology and schedule of exploration operations in Navarin Basin will be the domestic and worldwide availability of drilling rigs and support equipment (supply vessels etc.). The number, timing, and success related to the U.S. OCS lease sales scheduled for the early 1980s will influence this, and might make some rigs available in the Bering Sea.

3.3.2 Production Platforms

3.3.2.1 Background

Depending upon reservoir characteristics, environmental conditions (water depths, etc.) and economics, offshore platforms may serve as integrated drilling and production units, or as single function facilities (drilling, processing, pump station, compressor station, crew accommodation). In the latter case, several platforms would be required to produce a field. In deep water, economic constraints favor oil field development with as few platforms as possible and by integrated drilling/production units; this has been the trend in the North Sea. Piled steel-jacket structures have dominated since offshore oil and gas production commenced in the Gulf of Mexico in the late 1940s. Concrete gravity platforms for oil and gas production have been developed mainly for the North Sea and were pioneered by the Ekofisk oil storage tank that was installed in the Norwegian sector of the North Sea in 1973.

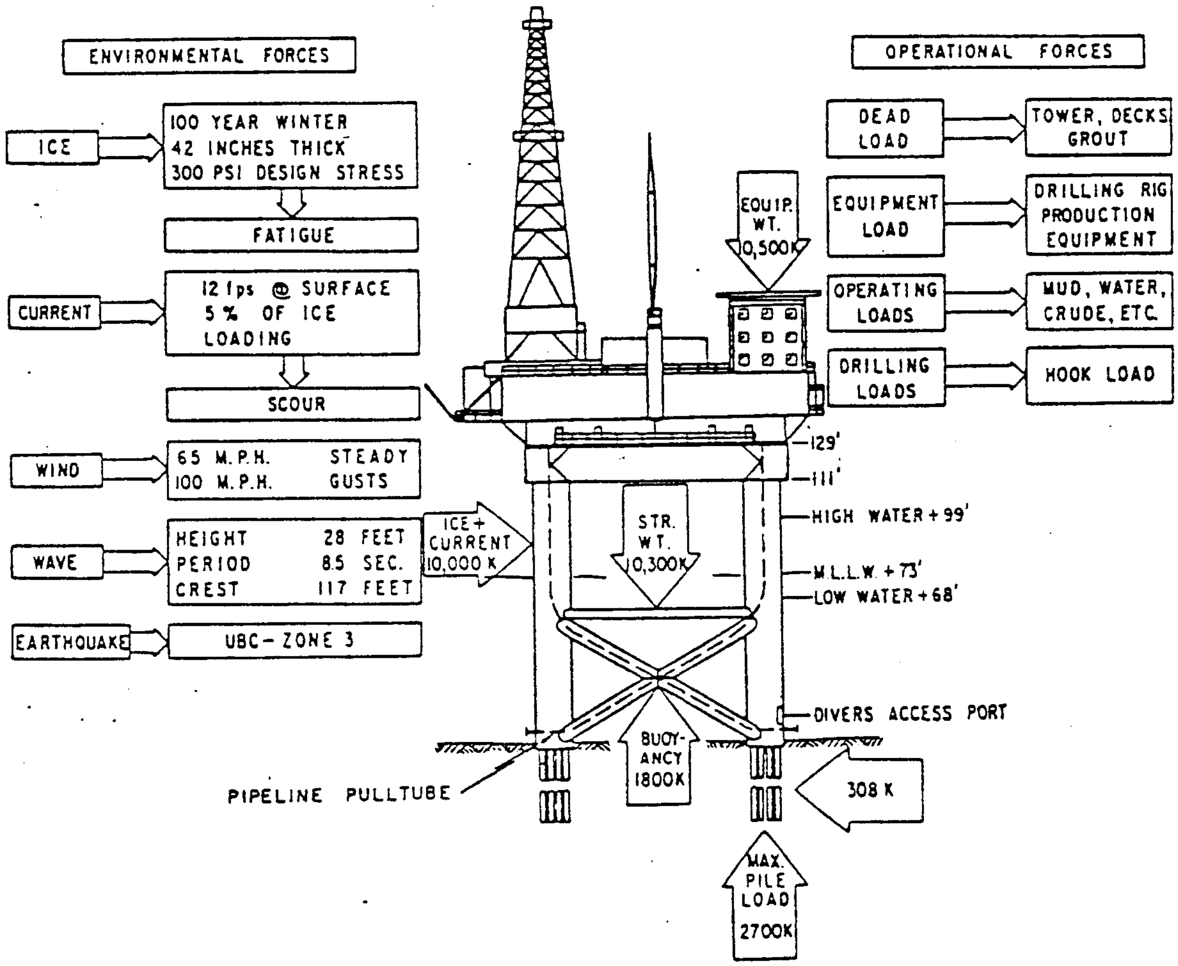
Alternatives to the steel-jacket and concrete gravity structures are a number of "hybrid" designs combining facets of the steel-jacket, concrete gravity and floating (semi-submersible) platforms. These include the guyed tower, articulated platform, tension leg platform, and steel gravity platform developed in response to the increasing costs of "conventional" platforms with increasing water depths and, concomitantly, the need to develop marginal fields. These designs minimize the amount of offshore construction work, are comparatively inexpensive, and may speed field development. This results in earlier production and cash flow to the operator. Such alternatives are unlikely to be viable in Navarin; however, quick-disconnect floating production platforms may be feasible.

Ice-resistant steel platform technology was pioneered in upper Cook Inlet in the early and mid-1960s where a total of 14 production platforms have been installed. Of these, most are four-legged structures, two have three legs, and Union installed a single-legged monopod platform (Visser, 1969). The environmental forces for which these platforms have been designed include a lateral load of 10,000 kips and vertical load of 10,500 kips (Figure 3-7). In their final design, wind, wave, and earthquake forces were found to be small compared to ice forces -- tidal variations in upper Cook Inlet are in excess of 9 meters (30 feet) and result in currents in excess of 8 knots.

To accommodate these environmental forces, Cook Inlet platforms incorporate these design principles:

- o Columnar legs without cross-bracing in the tidal zone, reinforced with concrete inside.
- o Conductors located within the legs.
- o Special "pulltubes" within the platform structure to reduce dependence on diver assistance in pipeline hook-ups.

Such ice design principles should be readily adaptable to Navarin.



DESIGN LOADS ON TOWER-TYPE STRUCTURE, COOK INLET

SOURCE: VISSER, 1969

FIGURE 3-7

DAMES & MOORE

3.3.2.2 Platforms for Navarin Basin

The water depths over the sedimentary basins within the lease sale area do not preclude either jacket or gravity platforms. Steel jacket platforms generally are more economical relative to gravity-type as water depth increases. The range of depths over areas of interest is fairly narrow and not deep.

Platform selection for Navarin is intimately tied to the type of transportation chosen to send oil production to market. If a long pipeline is planned, then either a steel jacket or a gravity-type platform would work; however, the jacket-type would be favored because pipelines would eliminate the need for platform. Gravity-type platforms would be favored for offshore loading transportation because of their inherent storage capacity, although gravity platforms may also be selected independent on their storage capabilities.

Gravity platforms offer an important advantage for Navarin environmental conditions: faster offshore installation. More of the construction, including deck equipment, can be accomplished at an onshore facility. The platform is therefore nearer completion when it is towed to the lease area. Installaton is primarily set-down onto the seafloor, whereupon the structure is essentially stable from the start. Although some special ballasting might be included in the design, there is no protracted period of pile driving to achieve design stability. This is a valuable asset in a remote area with limited construction season and short weather "windows."

Wave and ice loading forces on hypothetical platforms for Navarin were nearly equal to each other based on preliminary rough-order-of-magnitude engineering analysis. Therefore, the actual controlling design factor will depend upon design details and site-specific parameters. Maximum ice and wave loads are not expected to occur together (sea ice inhibits wave growth and waves break up ice), although simultaneous ice and wave loadings are possible.

The principal design criteria for a Navarin Basin structure are listed below:

(1) Wave loading;
(2) Ice loading;
(3) Competent seafloor soils for gravity base structures;
(4) Oil storage capacity, if appropriate;
(5) Installation and fabrication capabilities;
(6) Number of conductors and spacing;
(7) Crude transportation means (pipeline or tanker);
(8) Seismic loading;
(9) Topside facilities.

Wave and ice forces on the large diameter columns (20 ft or 60 ft) result in about the same overturning moments and shears on these structures proposed for the Navarin Basin. The platform deck elevation will be set by the wave heights. Design of the platform through the ice zone will require large diameters with no diagonal or intersecting members.

If offshore loading is selected, then the ice forces may dictate that tanker loading be accomplished directly from the platform, which may require a unique design to achieve ship weathervaning. Alternately, it may be more feasible to install a separate storage facility away from the drilling/production platform that would also load the ships.

The primary constraint on the number of well slots for these Navarin Basin platforms is the space provided within the platform leg. There is another constraint, which is the maximum number of wells that can be directionally drilled from one platform into the reservoir. We have assumed 48 wells, of which 8 wells are reserved for water and gas reinjection. Fewer than eight service wells may suffice for gas reinjection only and more than eight would probably be needed for a complete waterflood program. Based on 48 wells, a monopod of 60-foot diameter or a four-legged structure with 20-foot diameter legs would be needed. More wells would require a greater diameter at the waterline, increasing environmental forces and thus platform design and costs.

Some alternatives for increasing the number of wells are:

- If more wells can be drilled into the reservoir from a single platform, the leg diameters might be increased. However, allowance must be made in this case for increased wave forces and ice loading on the structure.

- Subsea satellite wells can be drilled with flowlines back to the drilling/production platform. Maintenance for these wells might include TFL (through flowline) methods.

- Independent drilling (only) platforms can be installed and the unprocessed crude flowed back to the production platform for processing.

The water depths that we are considering for this study are 100-200 meters. This water depth range is very similar, up to about 170 meters, to the depth ranges of the larger North Sea platforms as well as the platforms presently being designed for Australia's Northwest Shelf. The wave heights and forces are similar to the North Sea wave conditions. We visualize the following types of production platforms as being feasible for the Navarin Basin in the 100-200 meter water depth range.

- <u>Steel Template Type (Jacket)</u>

  A steel template-type structure may be the most attractive structure type if either a long pipeline or a separate storage facility are planned. The jacket legs will need to be quite large to house the well conductors, which must be protected from the ice. The 100-year return period wave heights are very similar to North Sea wave conditions. However, the ice conditions will dictate that the structure be free of joints and intersecting members in the ice zone. The jacket may therefore resemble a North Sea jacket with 3 or 4 large-diameter legs, but with no intersecting members in the ice zone. The well conductors will be housed within the legs. The lowest part of the superstructure will clear the maximum wave crest by an appropriate air gap. Foundation support for this steel structure will most likely be by external skirt piles (piles driven around the large-diameter main legs). The main legs must be reinforced through the waterline for ice loading conditions. It may also be necessary to extend the skirt piles completely around the perimeter of the structure in order to resist the wave and ice forces.

- Concrete or Steel Gravity-Base Structure

  If integral oil storage facilities are being considered (as for offshore loading) for the production platform, then a gravity-base structure may be appropriate. The gravity-base structure requires competent sea floor soil to be structurally stable. Preliminary soils information from Navarin suggests soft seafloor soils, but this does not rule out gravity structures. Competent soils may be found at a discovery site, or at a shallow depth below the seafloor. Also, there are possible alternative foundation designs to deal with softer soils.

  The platform-with-storage concept adopted for the North Sea is the gravity base concrete or steel structure. If competent soil strengths are found, then this concept should be feasible in the Navarin Basin and the structure would look very much like the North Sea gravity structures. It could be a cylindrical monopod supporting the deck, and interlocking cylindrical oil storage tanks located well below the maximum wave. The structure might have two or more smaller diameter columns through the water surface, but in any case, all conductors must be housed within the legs to prevent exposure to ice forces.

- Steel-Jacket Platform with Separate Storage

  Another concept would be a steel structure without storage capability linked by pipelines to a submerged storage facility. The submerged storage would have an integral tanker loading tower and boom projecting above the water line; tankers would weathervane about the loading tower. This concept eliminates the difficulty of weathervaning a tanker about a drilling/production platform.

Any concept that includes submerged storage tanks will require that oily ballast water be treated at the production facilities before discharge or alternatively that tankers transport their own ballast away from the platform, significantly reducing their crude capacity.

Gravity Platform

There are many different concepts of gravity platforms, both steel and concrete. Although ice is an important design factor, a cone-shaped structure is not necessary in this area. (A cone-type ice deflector may be appropriate with some designs.) An attractive concept for a gravity structure would be the monopod, although more than one leg could certainly be considered. This is along the lines of a North Sea "Condeep" platform, which is state-of-the-art.

We visualize the following types of production platforms as being feasible for these specific sites:

- Steel Jacketed Platform[1]
  This would be a hybrid "Cook Inlet" structure that would have minimal bracing through the water line area. It probably would be supported by external or skirt piles and have four legs. All conductor wells would be inside these legs.

- Concrete or Steel Gravity Platform[1]
  This structure would probably be a North Sea gravity structure. It may have a single "leg" (monopod) or several legs. Preliminary bottom conditions indicate such a structure would be feasible. Again, all conductors would be internal in the leg(s).

[1]For a detailed description of steel jacket and North Sea concrete gravity platforms, their design parameters, fabrication and installation, the reader is referred to Dames & Moore (1979a, p. 47-64).

3.3.2.3 Well Slot Limitations

One of the technical constraints of a platform design with conductors located within legs is a limitation on the number of well slots that can be housed on a production platform. In a conventional (e.g., Gulf of Mexico) platform, there are few constraints as to the number of well slots that can be incorporated into the design since the conductors are open and pass through conductor guides at horizontal bays in the jacket. However, in an area affected by sea ice, such as the Navarin Basin, open-well conductors cannot be considered. In the Cook Inlet designs, the larger the legs can be made, the greater the number of conductors that can be accommodated. However, as the diameter increases, so do the ice forces; therefore, additional internal stiffening is required, which reduces the number of conductors inside the legs. The same analogy is true for the monopod gravity-base structure.

At this time we feel the largest legs that could be considered on a steel-jacket structure would be on the order of magnitude of 4 to 5 meters (13 to 17 feet) outside diameter. The diameter of a monopod shaft would be on the order of 10 to 18 meters (30 to 60 feet).

In both cases, the total number of well slots would be limited to on the order of 32 to 48, depending on the size of the conductors and design criteria.

Based on these ice-resistant design considerations, the maximum number of well conductors that we have assumed in a closed conductor platform design is 48. Anything over 48 could become a considerable design problem.

3.3.2.4 Platform Transportation and Installation Techniques

Techniques for installing these platforms in the Navarin are a sensitive part of the project development.

Steel Platform

Three methods that could be employed to transport the steel platform to the installation site are:

1. Self-floated to the site, using its own legs as pontoons and upended into position.

2. Barge transport to the site and launching, either one or two pieces.

3. Floated to the site on a raft foundation, upended into position, and the raft foundation removed.

Of these three schemes, the latter is least attractive for the Navarin Basin. The structure will require large diameter legs to house the well conductors, which can double as buoyancy tanks for floating the structure to the offshore site. Of the three transportation methods, we prefer a method of barge transporting the structure to the site. A barge can be more rapidly and safely towed through the Aleutian Chain. With proper preplanning, the size and configuration of the structure can be tailored to a barge tow and launch.

If the structure is towed to the offshore site via barge and launched as a one-piece structure, the installation procedure would follow the steps listed below:

1. Upend and set on bottom by controlled flooding;

2. Drive piles to required penetration;

3. Set decks and modules with either one or two derrick barges.

Gravity Platform

The gravity structure would be partially constructed in a deepwater "graving dock" that is dry during construction, then flooded and floated out and moored at a sheltered deep water site for completion of concrete work. The completed structure would then be towed vertically at a deep draft to the site, and ballasted down to the bottom. A construction site large enough for an oil platform does not now exist, either in Alaska or the U.S. west coast, and therefore the selection and construction of the site must be considered in the economics and scheduling of such a platform installaion.

The decks for both the steel and gravity platforms could be modularized and lifted into place with a crane ship similar to the platform deck construction in the North Sea.

Two support bases for such a platform installation could probably be required. The first could be Anchorage, which could serve as a "home base" for derrick barge/construction crews, although the workers may be rotated from residences elsewhere. We would assume that the onshore facility point would serve as a supply base for construction materials offshore. The supply base would be set up prior to the platform installation and all supplies stockpiled.

Platform installation would require at least one large derrick vessel and one smaller crane vessel. If the platform is piled in place, one vessel would be required to operate the pile installation equipment. Several deck cargo barges, work boats and tugs would be required. The following are representative equipment requirements and typical daily rates (1981) for an equipment spread required to install a steel platform:

Item	Number	Daily Rate
Large Crane Ship	1	$160,000
Smaller Derrick Barge	1	80,000
Deck Cargo Barge	12	3,500 each
Work Boats	6	6,000 each
Tugs	4	7,000 each

Actual costs will depend on the size of vessel required, where it originates, market demand, and various other factors. The rates do not include mobilization or demobilization.

3.3.3 Wells

Most production wells will be drilled directionally from the production platforms. As noted in Section 3.3.2.3, the platform designs suggested for Navarin Basin place constraints on the maximum number of wells that can be housed on the platforms (about 48). Furthermore, slant drilling is not possible from these platforms. In contrast, the current record for well slots in conventional steel jacket designs is over 90.

There are also technical limitations (as well as cost premiums) on directional drilling for angles of over 50 . A graph showing a typical rate of increase in drift for the generally adopted maximum slant angle of 60 is shown on Figure 3-8. Depending on seabottom soil conditions, a typical kick-off point[(1)] would be about 150 to 300 meters (500 to 1,000 feet). With conductors located within the legs of the structure, directional drilling is a part of the constraints to total number of wells. Further discussion of directional drilling and its role in the analysis is presented in Appendix A, Section III.

Development well drilling will begin as soon as feasible after platform installation. If regulations permit, the operator may elect to begin drilling while offshore construction is still underway, accepting some interference between the two activities. The operator has to weigh the economic advantages of early production versus delays and inefficiencies in platform commissioning. Development drilling could commence about 10 months after the platform is installed on site[(2)]. Development wells may be drilled in a "batch" where a group of wells are drilled first to the surface casing depths, then drilled to the next smaller casing depth, etc. (Kennedy, 1976). The batch approach not only improves drilling efficiency but also improves material-supply scheduling. However, this does not provide timely geological information for planning the later wells.

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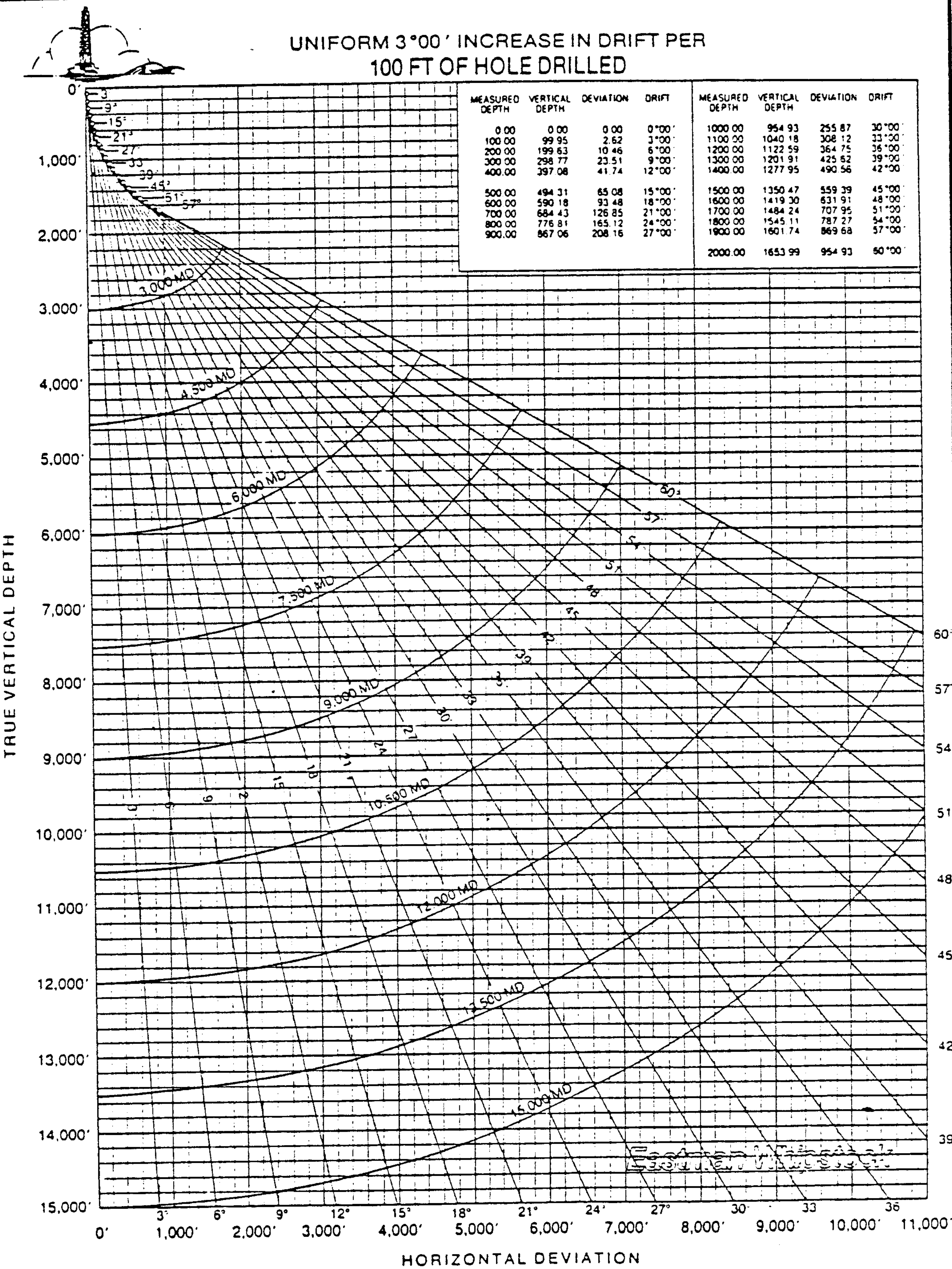
(1) Kick-off point = the depth where the traverse departs from the vertical in the direction of the target.

(2) Our scenario assumes the platform is installed in the fourth year after decision to develop; deck installation continues that year and into the fifth. Wells are drilled beginning in the fifth year.



MEASURED DEPTH	VERTICAL DEPTH	DEVIATION	DRIFT	MEASURED DEPTH	VERTICAL DEPTH	DEVIATION	DRIFT
0.00	0 00	0 00	0°00′	1000 00	954 93	255 87	30°00′
100 00	99 95	2.62	3°00′	1100 00	1040 18	308 12	33°00′
200 00	199.63	10 46	6°00′	1200 00	1122 59	364 75	36°00′
300 00	298 77	23.51	9°00′	1300 00	1201 91	425 62	39°00′
400.00	397.08	41.74	12°00′	1400.00	1277 95	490.56	42°00′
500.00	494 31	65 08	15°00′	1500 00	1350 47	559 39	45°00′
600.00	590 18	93 48	18°00′	1600 00	1419 30	631 91	48°00′
700 00	684 43	126 85	21°00′	1700.00	1484 24	707 95	51°00′
800 00	776 81	165.12	24°00′	1800 00	1545.11	787 27	54°00′
900.00	867 06	208.16	27°00′	1900 00	1601.74	869 68	57°00′
				2000.00	1653 99	954 93	60°00′

DIRECTIONAL DRILLING CHART

FIGURE 3-8

SOURCE: EASTMAN WHIPSTOCK, INC.

DAMES & MOORE

On large platforms, two drill rigs may be used for development well drilling, thus accelerating the production schedule. One rig may be removed after completion of all the development wells, leaving the other rig for drilling injection wells and performing well maintenance.

3.3.4 Pipelines

Long pipelines will be required to transport Navarin Basin oil and gas production to shore terminals for further processing and tanker transport to market. For a large diameter pipeline (36- to 42-inch), however, the present state-of-the-art pipelaying is around 200 meters (650 feet). Santa Fe Engineering has made preliminary calculations suggesting that if crude oil characteristics are favorable (similar to North Slope crude), the required very long pipelines can be feasible. These would require increased diameter and pumping pressures; otherwise, booster pump and compressor stations may be required.

Some of the important engineering design considerations for pipelines in the Navarin Basin are:

- Water depth

- Possible requirement for booster station(s).

- Diameter and wall thickness. Given the characteristics of this area, such as water depth, pipeline diameters larger than 40 inches are not recommended. If the throughput required it, a second line might have to be built, which would increase field development costs.

- Water, crude, and gas temperatures. Preliminary information indicates that pipeline insulation would not be effective. However, if insulation were appropriate, the pipeline cost (and possibly the schedule) would be affected.

For installing large diameter pipelines, the most suitable vessel would be one of the "third generation" semi-submersible lay barges such as Viking Piper. Such a barge can lay about 1-1/2 kilometers (1 mile) per day of large diameter line, and about 3 kilometers (2 miles) per day of small diameter (16-inch or less) line. One advantage of the semi-submersible lay barge is that it can operate in waves up to 4-1/2 meters (15 feet) while a conventional lay barge is restricted to waves of about 2 meters (7 feet). Smaller diameter gathering and spur lines could be laid by reel barges that are now (1982) capable of laying pipe up to 16 inches in diameter. Landfall portions of the lines could be pulled to shore. Small pipelines starting at the platforms would be connected using a conventional "J" tube. Burial would be required at landfalls to maintain stability at the beach line. Although regulations have not been established for this area, trenching or burial could be required to the 60-meter (200-foot) contour or for the entire length of the line. Cost of pipeline burial could easily exceed $1 million per mile, and be much greater at the shoreline crossing.

Support of pipelaying operations requires a service base with dock and storage area for pipeline materials. At this base, protection and weight coatings would be applied to the pipes. Typical pipe requirements for a lay barge are about 100 to 200 lengths of 12 meters (40 feet) per day with a weight of 1,000 to 2,000 tons per day. The voyage to the center of Navarin Basin from an Aleutian support base (about 1,000 kilometers or 600 miles) would take about two days each way. About 20 supply vessels would be required to transport pipe to one pipeline spread for the Navarin Basin. However, specialized pipe supply vessels can handle up to 150 lengths of pipe corresponding to a deck load of as much as 2,500 tons. A major problem in pipe resupply is transfer of pipe from the supply boat to the lay barge. This operation can experience considerable downtime due to bad weather.

3.3.5 Offshore Loading

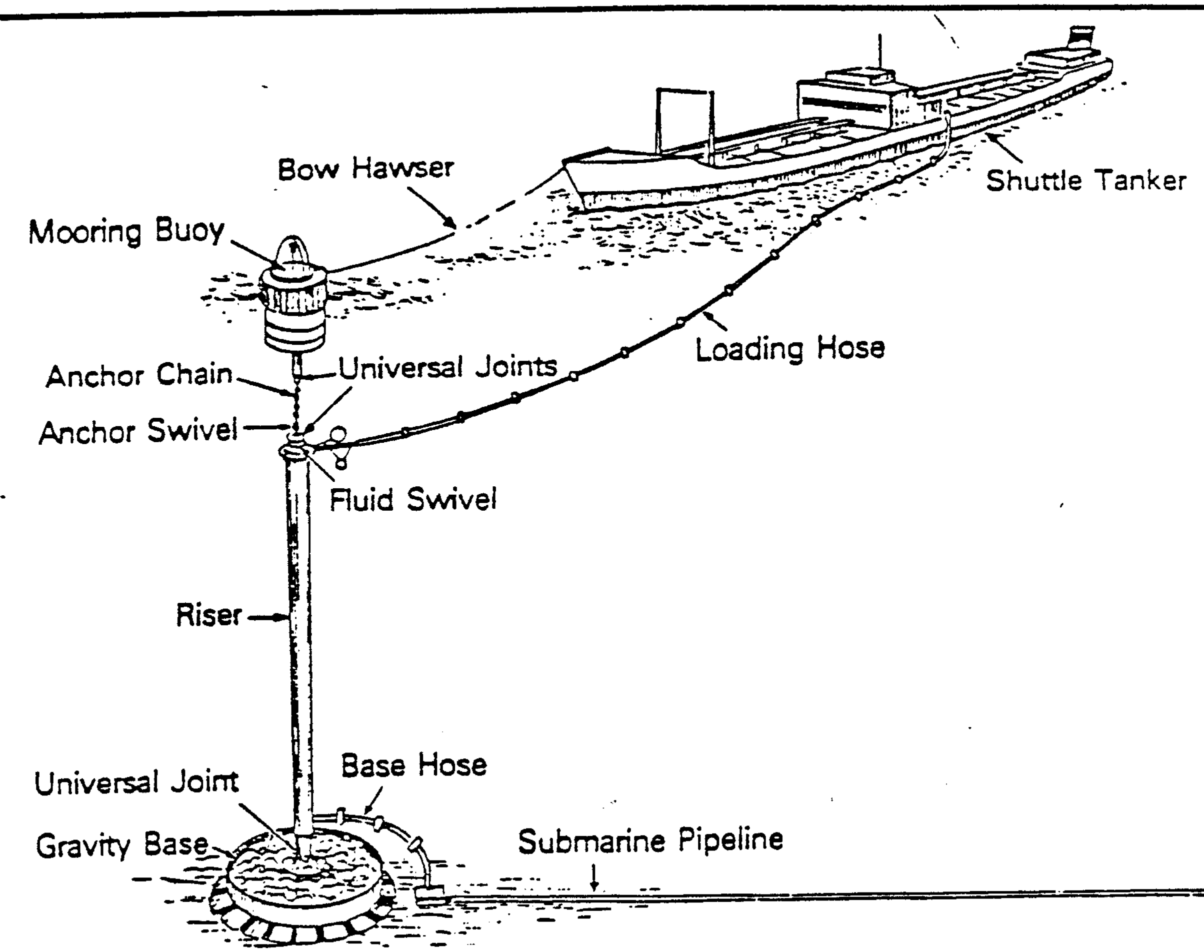
An alternative to a pipeline is offshore loading of crude directly to tankers tied up at a mooring and oil transfer buoy. A number of single point mooring and oil transfer systems have been developed including the Catenary

Anchor Leg Mooring (CALM), the Single Anchor Leg-Mooring (SALM), Exposed Location Single Buoy Mooring (ELSBM) and Spar buoy (which has storage capability). Two examples of offshore loading systems are shown on Figure 3-9. Offshore loading systems have been used both as early production systems (prior to pipeline hookup) and as permanent parts of the field development strategy. In the latter case, offshore loading may be employed to develop an isolated field that cannot justify investment in a pipeline. The potentially long pipeline distances involved in development of Navarin Basin will certainly make pipeline investment a major factor in the economics of field development. Thus, the alternative of offshore loading becomes very attractive. However, there are some general disadvantages with offshore loading and there are some problems specific to Navarin Basin with respect to the feasibility of such systems.

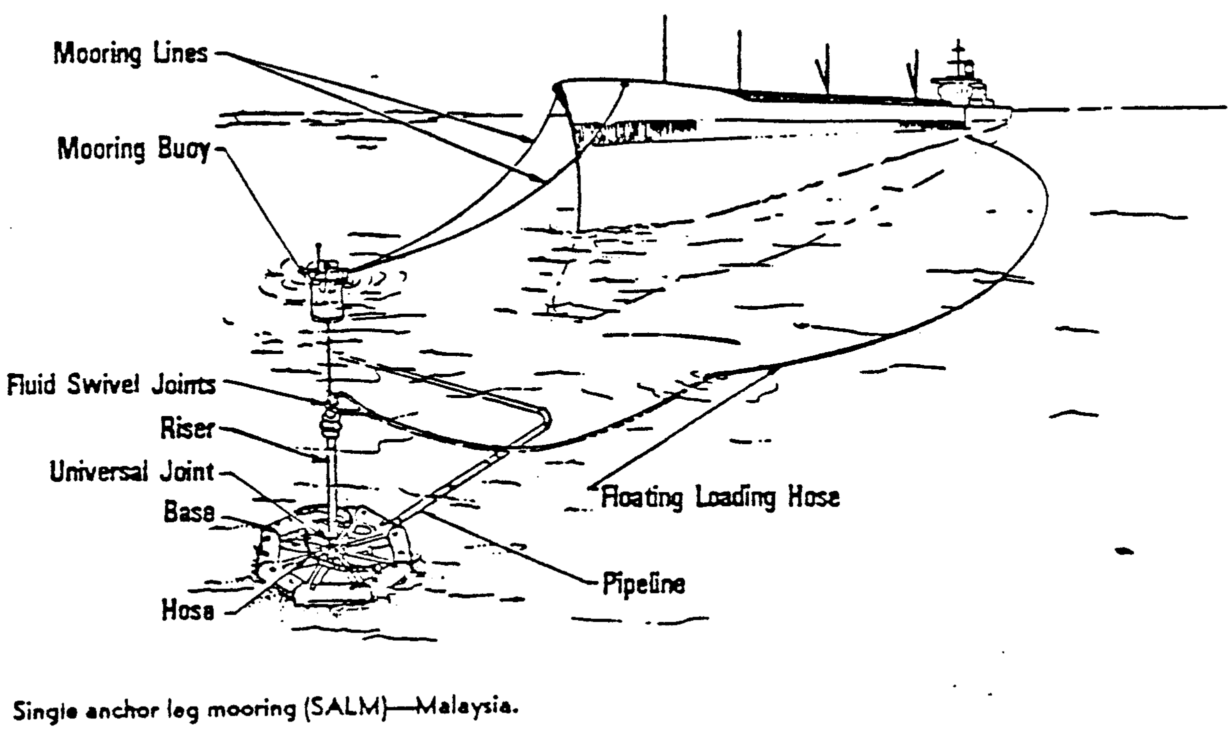
For offshore tanker loading the vapor pressure of the crude must be limited to 8 to 14 pounds Reid Vapor Pressure (RVP) since tankers can only carry oil with a limited vapor pressure (Penick and Thrasher, 1977). Consequently, condensates have to be removed and reinjected into the reservoir, thus reducing the sales value of the produced fluid. On the other hand, a pipeline can be designed as a high vapor pressure system to accommodate gas liquid components mixed with the crude oil and thereby increase the value realized of produced fluids.

Offshore loading systems operate best in good to moderate environmental areas. Systems that have been installed to date in moderate to severe environmental areas such as the North Sea have experienced much greater downtime and repairs than calmer areas.

Two environmental elements in the Navarin Basin would make installation of such a system a difficult challenge: sea ice and fog. Fog occurs in the summer, up to 20 percent of the time. These factors could limit or shut down operations completely. In order for a system to function in an area affected by sea ice, design features that are not state-of-the-art would have to be developed. Ice forces are more constant than transitory wave forces and thus require new design considerations. Ice-breaking tugs would probably be



Single buoy mooring—Esso Standard Libya.



Single anchor leg mooring (SALM)—Malaysia.

EXAMPLES OF SINGLE POINT MOORING OFFSHORE LOADING SYSTEMS

SOURCE: SANTE FE ENGINEERING SERVICES CO.

FIGURE 3-9

DAMES & MOORE

required during the winter months. The system would have to contend with the severe temperatures. Structural icing is also a problem in winter.

A fleet of shuttle tankers reinforced for ice would be required. Only a few offshore loading systems have been installed in water depths over 100 meters (330 feet), which corresponds to the shallower water depths in areas of interest in the Navarin Basin.

In the Navarin Basin, a high production rate will be needed to justify the large cost of development. A large amount of offshore storage will be required in the form of storage vessel facilities -- as part of the platform, or as a separate submerged storage tank. In order for the system to be economic, the throughput (e.g., 100,000 barrels per day loaded into shuttle tankers) would have to be dependable and substantial. This is a challenging operation due to the ice, fog, and various storm conditions.

Although the cost of offshore loading systems appears at first to be much less than the cost of a very long pipeline, there are additional costs to consider. These costs include extra storage, a fleet of shuttle tankers, work boats, and possibly ice breakers, hiring of crews, and the construction and maintenance of shore facilities. In Alaska, offshore loading does not necessarily obviate the costs of a shore terminal; such is the Navarin case. This is because shuttle tankers would offload their cargoes at an Aleutian transshipment facility where the crude would be transferred to large tankers destined for the Lower 48.

The economics of offshore loading are not obvious, and remain to be established by proven operations. Our economic analysis (Chapter 6.0) shows that size of field is an important determinant in offshore loading viability.

3.3.6 Subsea Completions

Subsea technology has evolved in response to the increasing water depths and cost of fixed platform production systems. Theoretically, a subsea production system can either be an adjunct in a field development strategy involving fixed platforms or a complete production system. As a complete system, most surface equipment functions (oil/gas separation, storage, etc.) are conducted on the sea floor and production is conveyed directly to shore or to a floating terminal for offshore loading to tankers.

The principal design problems in subsea production systems are maintenance and operation. In the design of subsea wells two principal concepts have been employed -- "wet" Christmas trees and "dry" Christmas trees. The wet Christmas tree exposes all the components and requires divers for installation and maintenance. Typically the wet Christmas tree is completely assembled and tested before installation on the sea floor from a drilling rig. The dry Christmas tree is totally enclosed in a chamber and can be serviced by men working in an atmospheric environment on the sea floor. A number of subsea productions systems have been developed including those by Exxon, Lockheed, Deep Oil Technology, and Subsea Equipment Associates Ltd. (SEAL). These systems variously employ single well-head completions, multiple well templates, and combinations of "wet" and "dry" subsea equipment.

The advantages of subsea production systems include (Ocean Industry, 1978):

- Early production can be established. Fabrication, installation of a fixed platform, and development drilling can take 5 years or more, whereas subsea equipment can be fabricated and installed in 1 - 2 years. This not only enables an early cash flow but also permits evaluation of the reservoir prior to investment in permanent structures and equipment.

- Exploratory and delineation wells, which are normally plugged and abandoned, can be turned into satellite subsea producers.

- Subsea production equipment, in contrast to platforms, can be inexpensively salvaged after production diminishes below economic limits.

- Fields with insufficient reserves to justify investment in fixed platforms can be developed relatively inexpensively (especially if exploration/delineation wells can be utilized) by a subsea system with a temporary floating rig or jackup platform.

- In the case of shallow or complex reservoirs, subsea wells can drain those parts of the reservoir that cannot be reached by directional drilling from a fixed platform. Also, subsea wells can be used for secondary recovery operations.

- Subsea systems extend production into water depths beyond the limits of platforms.

- Subsea systems can be used in arctic regions (below ice gouging) where surface structures are exposed to the potentially damaging forces of sea ice.

- In areas of incompetent sea floors unable to support bottom founded structures, subsea systems provide a solution.

Complete subsea production systems are not yet considered state-of-the-art. However, subsea satellite well heads, with pipelines to a mother platform, do appear to be feasible with shallow/low production reservoirs. They are being used presently in various areas of the world, and we feel they could be applicable to development of the Navarin Basin.

3.3.7 Marginal Field Development

With the high costs of facilities and equipment (see Appendix B) required to develop oil and gas resources in a remote sub-arctic area such as Navarin Basin, some significant discoveries will remain undeveloped because they cannot economically justify production. Such "marginal fields" will remain shut-in pending higher oil prices, cost-saving technological advances, or further discoveries close by with which pipelines and other facilities can be shared. Delayed development of marginal fields has occurred in the North Sea. As noted in a series of articles on marginal fields in Offshore (April, 1978, p. 76):

"The factors which determine whether a field is marginal include the obvious producing characteristics such as reservoir size, shape, and depth below the ground, well producing rates, oil and/or gas quality, and the existence of production problems such as H_2S or CO_2 and sand productions. The status of technology required for development, availability of competent and efficient construction facilities in the area, nearness to market, accessibility for supplies and transport of production to market, plus environmental problems such as earthquakes and hurricanes must also be taken into account."

The search for more cost-effective engineering solutions is particularly important as offshore petroleum development moves into deeper waters with the cost of fixed platforms rising exponentially with water depth. Listed below are some possible solutions and trends in petroleum technology for marginal field development; not all of these, however, are applicable to Navarin Basin. The trends and solutions include:

- o Development of "slimmer" steel-jacket platforms requiring less steel.

- o Development of floating or tethered platform systems such as the tension leg platform, converted or specially-designed semi-submersible platforms, and various floating concrete designs. These would be utilized in combination with subsea completed wells.

- o Use of subsea production systems either as an adjunct to fixed platforms or as a complete production system (see Section 3.3.6).

- o Two-stage development programs using an early (temporary) production system while further reservoir evaluation assesses the viability of a development plan employing fixed platforms, pipelines and major shore facilities.

- o Employment of offshore loading in conjunction with a floating system, subsea system, or fixed platform with storage when long pipelines cannot be economically justified or shared.

3.4 Production Selection and Field Development Strategies for the Navarin Basin

This section briefly reviews some of the principal criteria influencing an operator's selection of a field development plan in the Navarin Basin and discusses our selection of the production systems and development issues evaluated in the economic analysis.

A number of factors influence an operator's decision on the production and transportation strategies to be used in field development. These include: field size, reservoir and production characteristics, physical properties and quality of oil or gas, location of the field, distance to shore, distance to other fields, oceanographic conditions, destination of production, availability of existing terminals and economics.

3.4.1 Field Size

The economic analysis (see Section 6.0) suggests the necessary reserve size thresholds to justify production under alternative production systems including pipeline versus offshore loading. Other factors being equal, the more distant from shore and the more isolated the field, the more attractive it may be to produce directly to tankers, sea ice and meteorologic conditions aside. For Navarin, it has been assumed that a major field must be discovered to initiate petroleum developments.

3.4.2 Reservoir and Production Characteristics

Reservoir and production characteristics are major determinants of transportation (pipeline capacity, storage requirements) and platform equipment requirements. A field development plan will identify the optimal platform requirements, and identify and schedule the development well program, gas and water reinjection wells and rates, and platform equipment processing requirements that are, in part, determined by the transportation option selected. For Navarin, a relatively high production rate has been assumed because of the need for favorable economics to initiate development; this rate was selected based upon our review of the petroleum geology as being optimistic but entirely possible.

3.4.3 Quality and Physical Properties of Oil and Gas

The characteristics of oil produced in Navarin will have a significant influence on the feasibility and economics of the very long pipeline distances. Important crude properties to be considered in the design of a transportation system (pipeline and/or tanker) include:

- Viscosity -- This dictates how well the oil will flow at a given temperature. Variations in viscosity will influence the pumping power required in pipeline transport. Cooling of oil in pipeline transport may lead to wax build-up in the pipeline and reduce effective pipeline diameter. For a waxy crude, direct loading to a tanker may be favored over pipeline transport.

- Salt water -- Some water may still be present in the crude oil after treatment on the platform. It is costly to separate the water from the oil, and it is even more costly to separate residual oil from water so that it can be discharged offshore. It is also unattractive economically to transport salt water with the crude because of pipe corrosion and reduced oil capacity, although removal of the water onshore may be less expensive than offshore.

- Sulphur -- Sulphur or hydrogen sulphide is a contaminant that, if left in the crude, can cause rapid deterioration to steel pipelines.

These and other factors influence pipeline and processing equipment design. There are trade-offs between the cost advantages of onshore crude stabilization and processing, and the upgrading requirements for offshore platform processing equipment for pipeline transport to shore.

Gas produced in association with the oil can either be transported to shore by pipeline or reinjected into the reservoir. If the crude is produced directly to tankers, associated gas could be reinjected or flared. Some will be used as platform fuel. Gas reinjection equipment is a major cost component. Reinjected gas can be marketed later as economic circumstances change. Associated gas may be reinjected into the reservoir to maintain pressure and to prolong the life of the field. Further, reinjection of associated gas is the only viable solution to the flaring ban imposed upon producing fields if natural gas production is not economically feasible.

As the gas-oil ratio increases, the size of the pressure or production vessels and pipelines increases. Large and more sophisticated equipment is required to handle the gas. At some point, depending on the amount of gas handled, the amount of entrained liquids, and costs, it becomes economical to take the natural gas liquids, stabilize them, and inject this stream into the oil pipeline.

On offshore platforms, space requirements for larger process vessels, pipelines, and the increased equipment requirements for gas processing, are usually not great enough to significantly affect the platform costs. Natural gas pipelines are usually trunklines as large quantities of gas reserves are required to produce sufficient revenue to pay back the capital investment (even without a return on the capital).

Navarin Basin shows potential for large gas fields. LNG technology must play a role in bringing Navarin gas to market. The question of what and where the markets are for LNG will influence the economics of a long gas trunk pipeline or offshore LNG production. The latter has not been done for large-scale production.

3.4.4 Distance to Shore

Other factors being equal, the closer a field is to shore the more likely that production will be transported to shore by pipeline than by tanker. The unit transportation costs for oil increase with greater pipe length whereas the transportation cost per barrel in an offshore loading system is similar for all locations with only a slight increase with water depth. However, the ultimate destination of the crude and the number of terminal handlings are also important considerations.

3.4.5 Meteorologic Conditions

The most important contrast between pipeline transport and offshore loading is the contraints placed on the latter by weather. Offshore loading onto tankers in the Navarin Basin, like the North Sea, will be restricted by weather conditions. There is insufficient meteorological and sea state data for the Navarin Basin to accurately estimate the amount of weather downtime when tankers cannot load. Large shuttle tankers can remain on station in seas up to 8 meters (25 feet); it should be noted, however, that the tankers cannot moor to the loading system in these sea states. In the North Sea, total downtime, including weather, of offshore loading production systems ranges from 20 to 30 percent. Santa Fe Engineering has conceptually designed the Navarin systems with 15 days storage with the assumption that this is sufficient to allow continuous production.

In addition to weather, there is downtime related to maintenance and repair. These factors are considered in the design of a platform to estimate storage requirements. With technical and cost constraints on the maximum amount of storage that could be provided on a platform, there may still be times when production will have to be curtailed. It is assumed in the assessment of offshore loading system economics in Chapter 6.0 that production amounts to 96 percent of capacity, because a large amount of offshore storage is specified.

Without storage capability an offshore system experiences costly production interruptions. Further, some reservoirs may be damaged and production potential may be limited by such stop-and-go production. Therefore, the operator has to compare the economic benefits of storage versus the additional investment costs of storage facilities.[1] Design of offshore storage facilities has to match production rates, frequency and size of tankers, and expected weather and maintenance (of the single point moorings) downtime. Furthermore, the storage and loading system must allow for very high pumping rates when a tanker is available to load.

Another weather and sea-state problem concerns the ability to repair and maintain single point moorings and subsea equipment in an area such as Navarin Basin where the waear and tear on such offshore facilities will be high.

3.4.6 Environmental Conditions

Because information on sea ice in the Navarin area is very limited, the ice forces estimated and platform designs postulated are tentative. Nevertheless, sea ice will be a significant factor in selection of production systems, including the feasibility of offshore loading. It will also be a factor to consider in year-round exploration operations and resupply logistics. Ice-breaker support may be required.

Water depths in the Navarin Basin are comparable to the central North Sea, and do not present any special problems for platform design, pipelaying, or subsea completions.

3.4.7 Location of Terminals

Virtually all Navarin Basin crude will be exported to the Lower 48. A very small amount may be refined in Alaska at Kenai Peninsula plants. One or more onshore pipeline terminals will serve as transshipment facilities. The

(1) To date only concrete platforms have provided sufficient storage capability to permit sustained, maximum production rates. However, a steel gravity structure with storage capability is under construction for Phillip's Maureen field in the North Sea. Storage capacities of concrete platforms in the North Sea have ranged from 800,000 to 1,200,000 barrels. Shell/Esso's Brent spar storage buoy, an interim production and back-up storage facility, has 300,000 barrels of storage, but it is not intended to handle peak production since the Brent field produces into a pipeline.

terminal(s) will stabilize the crude, recover liquid petroleum gas (LPG), treat tanker ballast, and provide storage for about 10 days' production. An Aleutian Island or Alaska Peninsula terminal that serves fields in the Navarin Basin could also serve fields in other Bering Sea lease sale areas, such as the St. George Basin, North Aleutian Shelf, and Norton Sound areas. In fact, the Aleutian Islands and southwestern tip of the Alaska Peninsula are strategically placed for support and transshipment functions for most of the Bering Sea and Chukchi Sea basins. Tankers reinforced for ice breaking may shuttle crude from offshore fields to a terminal in the Aleutians where the crude will be transferred to larger tankers destined for the U.S. west coast.

3.4.8 Navarin Production Strategies Selected for Economic Analysis -- Summary

Navarin Basin geography and environment offer few options in development strategies. Further, these same factors imply that a find of only a major field would provide a viable economic investment. The petroleum geology does in fact hold out prospects for giant fields (see Appendix A-II). We have assumed that the initial development of Navarin, like the North Slope, will require a major find to justify the risks of starting the petroleum technology infrastructure needed to bring Navarin hydrocarbons to market.

The major alternatives for Navarin petroleum development are two:

1. A very long pipeline to either St. Matthew Island (about 240 kilometers or 150 miles) or to St. Paul Island (480 kilometers or 300 miles); construction of storage and transshipment facilities on the island; ice-resistant shuttle tankers; an Aleutian transshipment terminal for VLCC's carrying to market.

2. Offshore loading system(s) at or near the production/drilling platforms, with offshore storage facilities; ice-resistant shuttle tankers; an Aleutian transshipment VLCC terminal.

Note that the Bering Sea shuttle tankers and Aleutian Island transhippment terminals are common to either strategy. Therefore, the technological and economic tradeoffs are actually based on comparison between:

Strategy 1	vs.	Strategy 2
Very long pipeline Onshore (island) storage		Offshore storage facility
Nearshore transshipment terminal		Offshore loading operations

Strategy 1 promises more favorable operations characteristics once facilities are installed. However, the pipeline costs will be high, and such a long pipeline may not be feasible. Adverse crude oil characteristics could eliminate the long pipeline alternative. This could be offset using intermediate pumping platforms, at an even greater capital and operating cost. This more complex alternative might prove technically feasible, but is not included in our economic analysis.

Strategy 2 eliminates an intermediate (island) transshipment terminal, but implies potential operational constraints. These include sea ice, waves and fog, all of which reduce the effectiveness of offshore loading activities. Accessibility of the offshore facility for mooring will be less and operational costs increased (more crews, more wear). The economic viability of this option depends on the assumed rate of oil delivery that actually can be achieved.

Strategy 2 does have another variation. That is to do the offshore loading into large tankers that would go directly to the market. This implies ice-strengthening of this large fleet, a larger capacity offshore loading facility, and perhaps more offshore storage capacity. Offsetting these factors are fewer docking operations and elimination of two transshipment terminals. The transportation economics of this scenario are dependent upon such unknown conditions as the prevailing world tanker fleet, the actual wave, ice and fog conditions at the offshore loading site, where the market is, and the existence of transshipment facilities in the Bering

Sea region. Studies currently underway are evaluating the cumulative developments associated with the several Bering Sea lease sales that will precede the Navarin sale (Dames & Moore, 1982b, in progress). Since it is a reasonable assumption that the costs of an Aleutian Island transshipment terminal may be borne in part by other activities, this possible variation is not analyzed in this study.

4.0 PETROLEUM FACILITIES ONSHORE SITING

4.1 Onshore Facilities

Siting of onshore facilities is an especially critical factor in assessing Navarin technology and economics. For this assessment, onshore facilities have been assumed (per BLM letter dated October 19, 1981) to be feasible at St. Matthew Island, the Pribilofs (St. Paul Island) and the Aleutian Islands. Specific locations and sites have not been evaluated for this study; however, it is relevent to include some comments about onshore siting for the Navarin lease sale area.

Remoteness is a particularly challenging characteristic for Navarin even by Alaska standards. The closest landfall is St. Matthew Island, an uninhabited wildlife refuge about 240 kilometers (150 miles) distant (see Figure 4-1).

The next closest U.S. land is also islands -- St. Lawrence and the Pribilofs -- about 500 kilometers (300 miles) away. St. Lawrence is to the north, away from markets and into worse ice conditions. To the southeast, St. Paul Island is the larger and more populated of the Pribilofs. Nevertheless, it has little infrastructure and no notable natural harbor sites. The Bering Sea weather regularly batters these islands from all directions.

The Aleutian Islands chain to the south is essentially ice-free, and has several natural harbor sites and some infrastructure, as at Unalaska/Dutch Harbor.[1] The Aleutians are on the way to markets, but have a deep water trench separating most of them from the Bering Sea shelf. Therefore, the Aleutians are not attractive for pipeline terminals, but might provide sites for an exploration base and/or a tanker transshipment terminal.

Although St. Matthew Island (Figure 4-2 is a National Wildlife Refuge, BLM requested that it be considered for onshore facilities in this study. This

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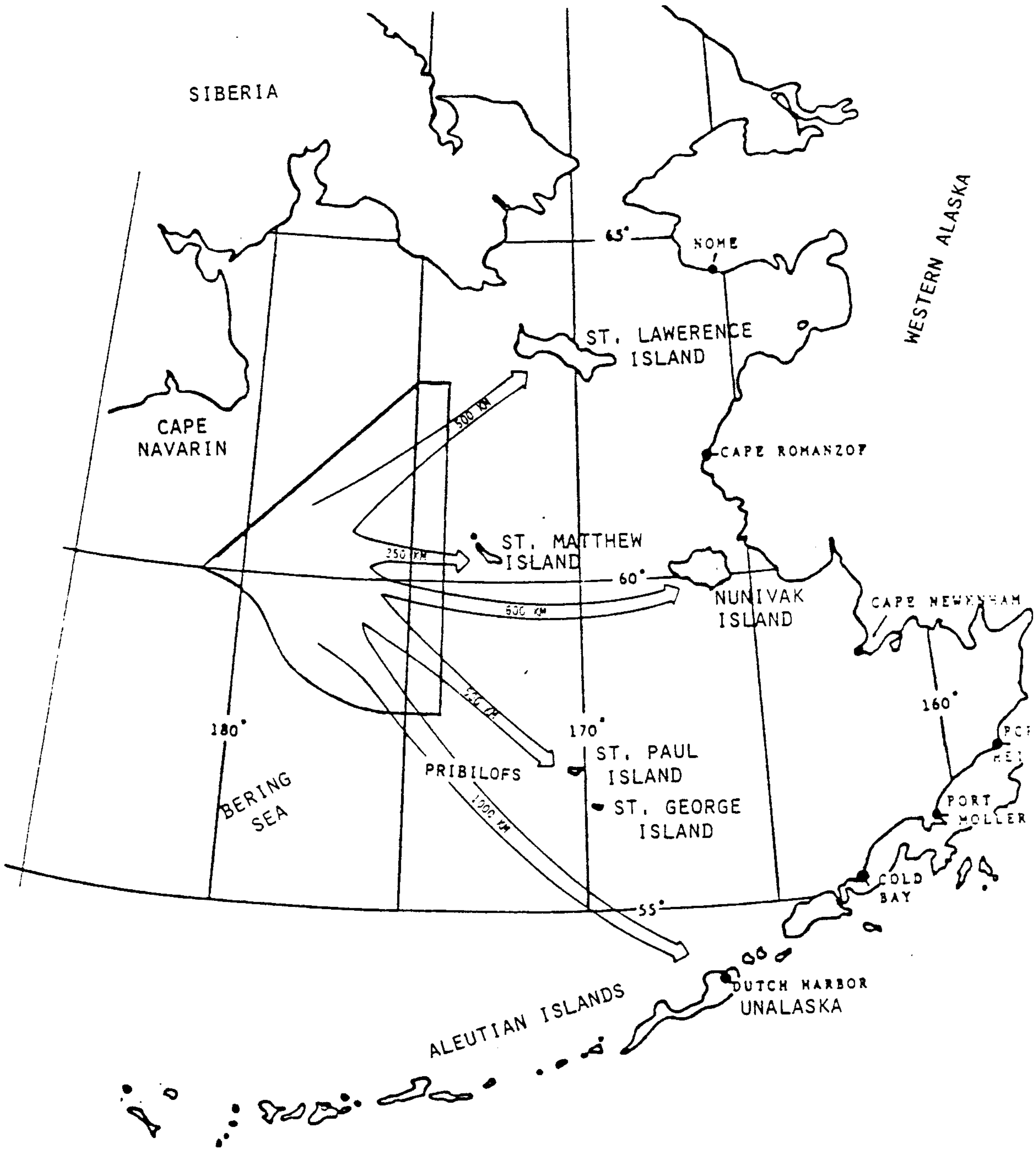
(1) See Dames & Moore, 1980c for a more detailed discussion of Aleutian Island siting considerations.



NAVARIN LEASE AREA - GEOGRAPHIC DISTANCES

FIGURE 4-1

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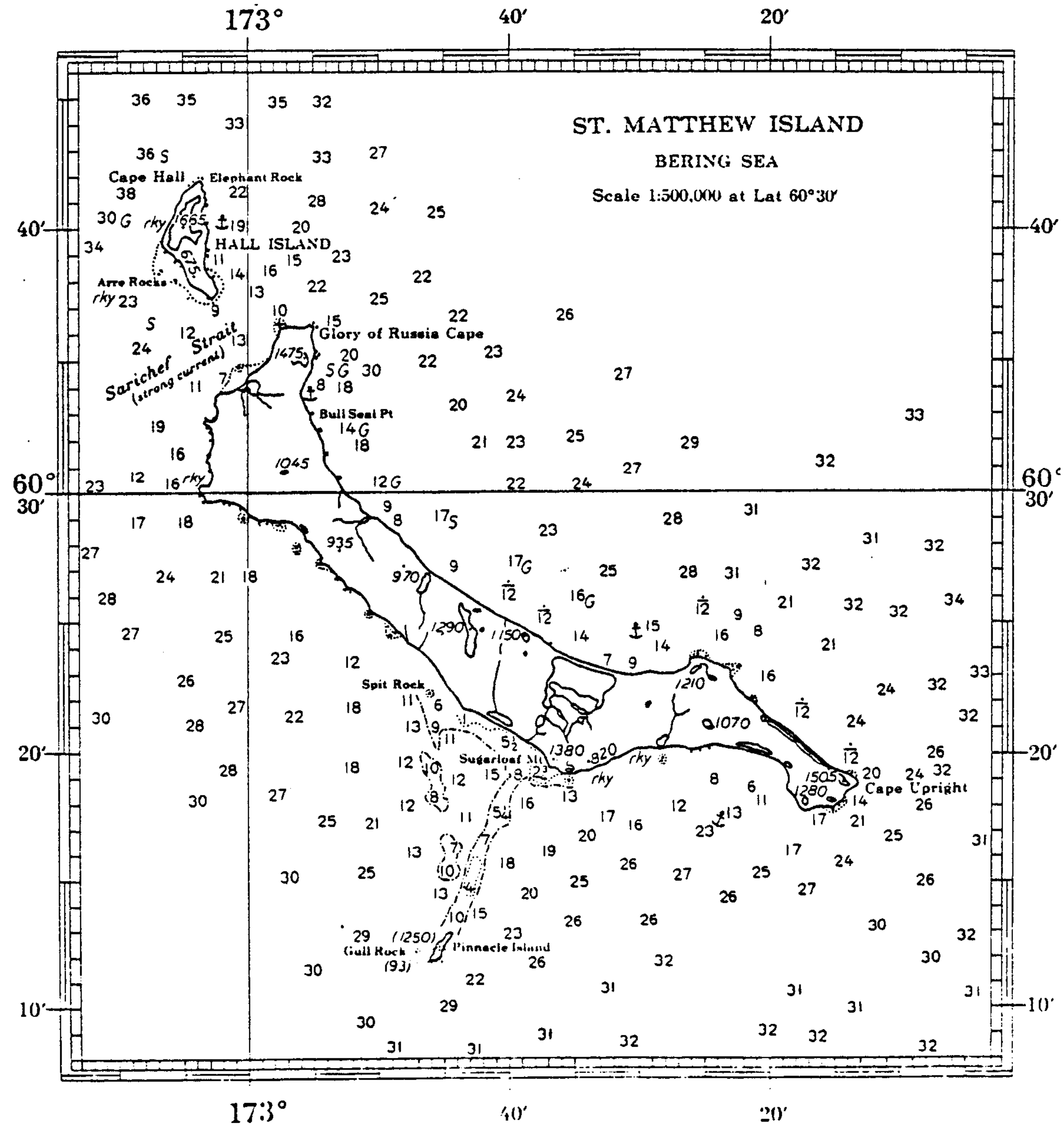

SOUNDINGS IN FATHOMS
AT MEAN LOWER LOW WATER

ST. MATTHEW ISLAND
BATHYMETRY AND ELEVATIONS

SOURCE: NOS CHART No. 16006

FIGURE 4-2

is a reasonable request for Navarin, which has few viable alternatives. Land-based operations are essential during exploration for airborne support of offshore rigs. Even the newer long-range helicopters are limited considering the Bering Sea weather and the lack of alternatives in an emergency. A forward base at St. Matthew for workboat support would also be advantageous in view of the long transit to offshore drilling areas from the developed alternatives. The flat area at the southeastern end of St. Matthew Island is considered attractive for support facilities.

Assuming that St. Matthew Island is available greatly enhances the developability of Navarin in terms of economics and safety. It also reduces risks associated with the limited weather season for drilling operations.

The Pribilofs are assumed as a back-up case, and to provide a comparative economic case. While they are about twice the distance, there are few options for land-based support to Navarin development. However, this option is not without some possible institutional constraints of its own; the island community has not encouraged local petroleum activities as of this writing.

Other alternatives are the mainlands of the USSR and the west coast of Alaska. The former has been mentioned by BLM. The west coast of Alaska has disadvantages of much longer distances to Navarin and few deepwater sites. It offers little more than the island options in terms of infrastructures.

5.0 MANPOWER REQUIREMENTS

5.1 Introduction

The purpose of this chapter is to provide a general discussion of the manpower requirements of petroleum development in the Navarin Basin, and to estimate the number of jobs that are likely to be required for each of several major exploration, development, and production tasks. Unlike previous reports in the series of OCS Socioeconomic Studies Program technology assessments, this report does not project a total pattern of manpower demand for individual development scenarios.

5.2 Scale of Activities Similar to that of North Sea Developments

Manpower requirements for offshore activities in the Navarin Basin will be generally comparable to those for similar activities in the northern sector of the British North Sea. For example, exploration drilling vessels, pipelaying barges, and derrick barges that will be required in the Navarin Basin are the large, third-generation semi-submersible type developed for the harsh climate and deep water of the North Sea. As in the North Sea, distances from shore will be great in the Navarin Basin; seasonal considerations for development and maintenance work will be critical; the logistics of resupply and crew changes will require a major effort; platforms will be large and functionally complex. Thus, manpower levels associated with representative offshore projects in the North Sea are a general indication of the manpower levels that can be expected in the Navarin Basin.

5.3 Special Characteristics of Manpower Utilization in the Navarin Basin

While the scale of offshore structures in the Navarin Basin may be considered generally comparable to those found in the North Sea, and therefore the labor demand for individual projects is also comparable, petroleum development in the Navarin Basin will have unique aspects of manpower utilization. These special characteristics stem from the presence of sea ice for much of the year, and from the extreme distance of the producing areas from cities and industrial/service centers.

5.3.1 Seasonality of Operations

Exploration field development work and maintenance of production facilities will be regulated by a seasonal schedule because of winter ice. Semi-submersible drilling vessels, lay barges, and derrick barges, as well as general purpose construction vessels and maintenance boats will have to leave the offshore fields with the appearance of winter ice. Offshore construction and maintenance work in the North Sea is also concentrated in the summer months, but there the largest vessels continue to operate during the winter storm season (although with reduced productivity). In the Navarin Basin, on the other hand, offshore work that requires large support vessels will ordinarily be halted by the end of November each year. Ice-breaking work boats could extend the working season for some operations.

Because of this seasonal constraint, manpower utilization will fluctuate dramatically between summer and winter. Employment at the shore base will, of course, reflect the seasonal fluctuation of offshore work. Extreme seasonability of labor demand will also characterize the production phase because annual inspection, repair, and maintenance work on offshore structures will occur during the summer. Well workovers may also be scheduled for the open water months because of the difficulty of resupplying the platform during the winter. Also, scheduled maintenance, repair, and capital improvements of the oil terminal(s) and LNG facilities will occur during the milder summer months. Stockpiling of material and equipment at the forward support base on St. Matthew Island or the Pribilofs will take place by substantial "sea lifts" during the open water months.

5.3.2 Self-Sufficiency of Platforms

Because of the distance of the platforms from the shore base, the distance of the shore base from Anchorage, and the uncertainty of flying conditions for much of the year (fog in summer, wind and blowing snow in winter), the platforms may be isolated for many days at a time. Therefore, they must be capable of continuous operation for long periods without resupply. A high degree of redundancy in key mechanical and electrical systems must be built into the deck equipment, and skilled technicians must be onboard the platform around the clock. These platforms must also have a larger inventory of spare parts and a greater emergency equipment repair capability than platforms that are located within easy reach of shore-based shops and equipment vendors. These platforms may also require more emergency medical facilities than conventional platforms, such as a large sick bay and the continuous presence of a physician's assistant.

5.3.3 Larger Crew Rotations

A typical crew rotation at Prudhoe Bay is 7 days on and 7 days off. A typical North Sea crew rotation is 14 days on and 7 days off. Operators in the Navarin Basin may consider even longer rotations, particularly during the winter when flying may be especially more hazardous. Rotations of 4 to 6 weeks on duty may be possible. Long rotations will reduce flying requirements and thereby lessen the danger of accidents. They will also reduce the cost of changing crews from Anchorage, which in the remote Navarin Basin will be a significant operational expense (however, crews will have to be compensated for longer rotations with higher pay).

Assuming a crew of 80 men on a platform, a rotation of 7 days on and 7 days off would require two landings per week with a Boeing Vertol Chinook helicopter (44-passenger capacity), whereas a rotation of 4 weeks on and 4 weeks off would require only two landings in the 4-week period.

5.3.4 Major Shore Facilities are Required

Development of oil and gas resources of the Navarin Basin will require the construction and operation of major shore installations. These are a shore base with an all-weather runway of at least 1,800 meters (6,000 feet) for Lockheed Hercules and Boeing 737 aircraft; a crude oil marine terminal in the Aleutian Islands and perhaps another (with crude stabilization functions) on either St. Matthew Island or one of the Pribilof Islands. These facilities will make the Navarin Basin a labor intensive frontier area to develop and operate in contrast to other, less remote offshore fields.

5.4 Estimates of Manpower Demand

Estimates of the demand for labor created by major development activities in the Navarin Basin are shown in Table 5-1. Table 5-2 shows the estimated requirement for support vessels and helicopters for major activities, which will create labor demand in addition to that shown in Table 5-1. These tables are similar to those used in previous reports in the OCS technology assessment series, except that the shore-based component of offshore activities is here lumped into a new general category of "Shore Base Operation" rather than identified as a separate element of each offshore task.

TABLE 5-1

ESTIMATES OF LABOR REQUIREMENTS FOR PETROLEUM ACTIVITIES IN THE NAVARIN BASIN

ACTIVITY	ONSITE LABOR (NUMBER OF JOBS)	DURATION OF EMPLOYMENT	SEASONAL FACTORS
Exploratory Drilling	75/vessel	4 mos./well	June-November[1)]
Geophysical Survey	30/year of exploratory drilling	during exploration drilling	June-November
Shore Base Construction:			
Exploration Phase	350/mo. (peak) 200/mo. (average)	12 mos.	Summer peak
Development Phase	450/mo. (peak) 250/mo. (average)	18 mos.	Summer peak
Oil Terminal Construction:			
St. Matthew or Pribilof Island Site	1400/mo. (peak) 800/mo. (average)	24 mos.	Summer peak
Aleutian Island Site	1000/mo. (peak) 550 mo. (average)	24 mos.	Summer peak
Platform Installation and Hook-Up:			
Steel:			
Oil[2)]	300/mo. (average)	10 mos.	Begin in June
Gas	200/mo. (average)	6 mos.	Begin in June
Concrete	300/mo. (average)	12 mos.	Begin in June

TABLE 5-1 (Continued)

ACTIVITY	ONSITE LABOR (NUMBER OF JOBS)	DURATION OF EMPLOYMENT	SEASONAL FACTORS
Development Drilling,[3] Oil and Gas Wells	112/mo./platform	72 mos./platform	Year-round
Submarine Pipeline Construction, Trunk:			
Oil	350/mo. (average)	5 mos.	June-October
Gas	350/mo. (average)	5 mos.	June-October
Submarine Pipeline Construction, Gas Feeder Lines	150/mo. (average)	5 mos.	June-October
LNG Platform Installation and Hookup	600 (average)	12 mos.	Begin June
Shore Base Operation[4]			
Exploration Phase	40/mo. (average)	6 mos./yr. of exploratory drilling	June-November
Development Phase	200/mo. (average)	6 mos./yr. of development activity	
Production Phase			
Year round	100/mo. (average)	12 mos./yr. of production	Year-round
Seasonal	100/mo. (average) additional	6 mos./yr. of production	June-November

TABLE 5-1 (Continued)

ACTIVITY	ONSITE LABOR (NUMBER OF JOBS)	DURATION OF EMPLOYMENT	SEASONAL FACTORS
Production Platform Operation			
Oil	80/mo.	12 mos.	Year-round
Gas	30/mo.	12 mos.	Year-round
Production Platform Maintenance, Oil and Gas	15/platform	6 mos.	June-November
Oil Terminal Operations			
St. Matthew Site	100/mo.	12 mos.	Year-round
Transshipment Facility Aleutian Site	50/mo.	12 mos.	Year-round
LNG Production Platform Operation	100/mo.	12 mos.	Year-round

Notes:

1. Ice-breaking vessels could extend the drilling season to some extent.
2. Includes offshore loading equipment, if applicable.
3. Assumes 48 wells, 2 rigs, 3 months/well.
4. Includes all shore support for platforms, supply boats, and air transport.

Source: Dames & Moore

TABLE 5-2

ESTIMATES OF HELICOPTER AND SUPPORT VESSEL
REQUIREMENTS FOR OFFSHORE ACTIVITY IN THE NAVARIN BASIN

ACTIVITY	BOATS[1] TYPE	BOATS[1] NUMBER	HELICOPTERS[2] (NUMBER)
Exploration	Supply-Anchor Handling	2/drilling vessel	2/drilling vessel
Platform Installation and Hookup	Supply Tug-Tow	3/platform 4/platform	2/platform
Pipelaying	Supply Tug-Tow	2/spread 2/spread	1/spread
Platform Operation[3]	Supply	2/platform	1/platform
Platform Maintenance	Supply	1/platform	0
Oil Terminal Operation	Tug	1/terminal	0
LNG Production Platform[3]	Tug/Supply	2/platform	1/platform

Notes:

1. Assume an average crew of 10 for supply boats, tow boats and tugs; these vessels will be ice-reinforced.
2. Assume crew of 3 for Boeing Vertol Chinook; 2 for other helicopter types.
3. One vessel will be committed to the platform at all times; it will have oil spill containment and/or fire fighting equipment; if offshore loading occurs, it will assist tanker loading.

Source: Dames & Moore

6.0 THE ECONOMICS OF NAVARIN BASIN PETROLEUM DEVELOPMENT

6.1 Introduction: Modelling Approach

This chapter presents the results of an economic analysis of OCS oil and gas development in the Navarin Basin. These results indicate how alternative transportation and production systems affect the rate of return and economic feasibility of developing petroleum in the remote Navarin Basin. The distribution of costs between onshore and offshore facilities is analyzed, both in terms of total costs, and in terms of their individual contribution to the cost per barrel of oil or thousand cubic feet (MCF) of gas. Equivalent amortized costs (EAC) per unit of product are also presented.

The economic viability of OCS oil and gas fields in the Navarin Basin depends on several conditions including location, reservoir size, depth, well productivity, and production method used to accommodate ice, waves and distances. Since no offshore oil production has taken place and only limited onshore exploration has been conducted in the region, reservoir conditions are uncertain. Not only is the Navarin a frontier area with a hostile climate, it is also located in an area which is remote even by arctic standards. The nearest landfall is uninhabited St. Matthew Island, about 250 kilometers (150 miles) from the probable pay zones. The nearest inhabited landfall is St. Paul Island, about 500 kilometers (300 miles) from the Navarin Basin. Both these locations have problems that affect their use and economics.

Due to the remoteness of the Navarin, economic viability depends as much on transportation links as on reservoir conditions. For this reason, the economic analysis of the basin focuses on the economic comparison of different transportation scenarios, rather than on assumed differences in reservoir characteristics (as was typical of earlier OCS technology assessments). This approach will facilitate comparison of the important policy considerations involved in location of shore facilities and comparisons with offshore loading production systems.

Because transportation is such an important consideration transportation capital investment costs have been included within the boundries of the analysis. The Navarin Basin is assumed to require a dedicated fleet of ice-reinforced shuttle tankers and ice breaker support. Prior studies considered tankers to be available from the world fleet. Thus, in addition to offshore production system costs, this analysis includes pipeline, receiving and storage terminal, shuttle tankers, ice breakers and transshipment terminal costs. Revenues reflect the values of oil F.O.B. a VLCC terminal in the Aleutians and gas (LNG) C.I.F California.

The oil development scenarios are discussed in Section 6.2. The results of the economic analysis are presented in Section 6.3. Section 6.4 describes the gas production scenarios and the economic analysis of gas production. Section 6.5 presents the equivalent amortized cost of oil and gas development. Finally, hypothetical petroleum development scenarios are presented in Chapter 7.0.

6.2 Oil Development Scenario Descriptions

Three alternative production/transportation systems are modelled and compared for oil development in the Navarin. These include:

Scenario 1	A 240-kilometer (150-mile) trunk pipeline to St. Matthew Island
Scenario 2	A 480-kilometer (300-mile) trunk pipeline to St. Paul Island
Scenario 3	Offshore loading into ice-strengthened tankers

In order to permit comparison of these three scenarios, the reservoir conditions are assumed to be identical. These characteristics for maximum production from a single-platform field are:

o Recoverable oil over platform life	365 million barrels
o Amount of recovery before decline	45 percent
o Reservoir depth	3000 meters (10,000 feet)

o Water depth	120 meters (400 feet)
o Initial productivity (IP)	2,500 barrels per day (BOPD) per well
o Recoverable reserves per acre	60,000 barrels per acre
o Gas/Oil Ratio	500 (reinjected)
o Number of producing wells	40
o Number of service wells	8 (gas injection)
o Peak platform production	100,000 B/D
o Platform efficiency	96 percent

These assumed parameters represent very optimistic, but possible, values for the Navarin Basin. Thus the economics results are likewise optimistic.

The 365-million barrel field size was selected to represent the most economic case because this is the largest field that can be produced from a single 48-wells platform (assuming maximum) within twenty-five years given 2500 IP barrels of oil per day (BOPD) and other conditions shown above. The 48-well specification represents the existing state-of-the-art ability to drill conductors within the platform legs, which is necessary in ice-infested waters. The 8 service wells are assumed to be used for reinjection of produced gas and formation water. This will help maintain reservoir pressures as well as solve the disposal problems. An actual ratio of producer to service wells may vary considerably depending on the needs for gas reinjection or water flooding.

The selection of an initial well productivity of 2500 BOPD is based on an analysis of the petroleum geology (see Appendix A-II.3.1.1). The oil price is assumed to be $32.00 per barrel F.O.B. an Aleutian Island terminal (as discussed in Appendix A-IV). This oil price is also optimistic; this assumption should be kept in mind when reviewing the results of this analysis. (Cook Inlet oil is selling for no more than $28 per barrel at this writing.)

Our schedule of development assumptions do not include allowances for unpredictable delays. The following paragraphs describe elements of the scenarios modelled specifically focused to the three transportation alternatives. The equipment and capital investment required for the one-billion-barrel case in each scenario is shown in Table 6-1.

Scenario 1 - Pipeline to St. Matthew Island

St. Matthew Island is currently a National Wildlife Refuge and as such, is not open to private development. However, its strategic location as the landfall nearest to Navarin basin provides a stimulus to use at least a small area of the island. See Chapter 4.0 for discussion of this consideration. In order to evaluate economic impacts, we assume that the island will be available to provide a terminal for Navarin oil production.

Scenario 1 total production is assumed to occur in 365-million-barrel units using steel-jacket production platforms. The platforms are emplaced one per year beginning in the fourth year after decision to develop with topside completion of the first platform also in the fourth year. Well drilling begins in the fifth year.

Two rigs per platform drill 12 wells per year on the first platform during the fifth through eighth years after discovery. In the sixth year, the production is assumed to begin from ten wells on the first platform. The analysis follows the convention that production begins in the year after a group of 12 wells is drilled. Peak production begins (100,000 BOPD) for the first platform in the ninth year. Each successive platform reaches peak in the tenth and eleventh years. Thus, after ten years following discovery the entire system is at peak and has been producing at increasing rates since the sixth year. Production continues until 45 percent of the recoverable reserves are produced. Decline begins in the thirteen year and continues at 15-percent decline rate for 19 years.

Oil is produced into a 240-kilometer (150-mile) pipeline to a St. Matthew storage/loading terminal. The diameter of the shared pipeline depends on the number of platforms it serves, as shown in Table 6-2. Three platforms require a 30-inch diameter pipeline.

TABLE 6-1

EQUIPMENT AND CAPITAL INVESTMENT FOR ONE-BILLION-BARREL OIL DEVELOPMENT SCENARIOS[1] FOR NAVARIN

	ST. MATTHEW PIPELINE (Scenario 1-3)	MILLION DOLLARS 1981	ST. PAUL PIPELINE (Scenario 2-3)	MILLION 1981 Dollars	Offshore Loading (Scenario 3-3)	Million 1981 Dollars
OFFSHORE FACILITIES						
Platform Type[2/]	3 Steel Jackets, Ice-reinforced	480	3 Steel Jackets, Ice-reinforced	480	3 Concrete Gravity with 1.5 MB Storage per platform	1350
Wells[3/] (costs total for 3 platforms)	48 (per platform)	950	48 (per platform)	950	48 (per platform)	950
Deck Equipment[4/] (costs total for 3 platforms)	100,000 BOPD (per platform)	495	100,000 BOPD (per platform)	495	100,000 BOPD (per platform)	600
Pipelines[5/]	150 miles of 28" trunkline	375	300 miles of 32" trunkline	810	Minor spur lines	(Included in Platform)
SHIPS						
Tankers[6/]	1.7 tankers	265	1.3 tankers	204	1.9 tankers	287
Workboats[7/]	2 boats	80	2 boats	80	3 boats	120
TERMINALS[8/]						
Storage and loading facilities	On St. Matthew	545	On St. Paul	545	Offshore	(Included in Platform)
Transshipment	On Aleutians	580	On Aleutians	580	On Aleutians	580
TOTAL CAPITAL INVESTMENT[9/]		4147		4558		4276

Source: Dames & Moore/Santa Fe Engineering

(Notes on follcwing page)

NOTES TO TABLE 6-1

1. Peak throughput for the three-platform system is 300,000 BOPD. Total recoverable oil is 365 million barrels per platform, 1.095 billion in total.

2. Steel-jacket platforms have no storage; concrete gravity platforms are assumed to store 1.5 million barrels, or 15 days production.

3. Each platform has 40 producing wells and 8 reinjection/service wells. Each platform produces 100,000 BOPD at peak.

4. Deck equipment is sized for peak production rates -- assumed to be 100,000 BOPD. The gravity structures include $35 million each for tanker loading facilities.

5. Pipelines estimated to cost $2.5 million per mile to St. Matthew and $2.6 million per mile to St. Paul.

6. 150,000 DWT ice-reinforced shuttle tankers are assumed to trade in the Bering Sea between Navarin and a transshipment terminal the Aleutians. Fractional tankers imply the assumption that either other fields will take up the slack to optimize tanker usage, or that there is space capacity to allow for contingencies.

7. Ice-breaking workboats are assumed to be required at either St. Matthew or St. Paul. One is required to serve the three steel platforms; one for each concrete gravity structure is required. These are 290 feet long, 2000 DWT, and cost $40 million each.

8. Terminals are sized to calculate Navarin costs only; cost interaction with other Bering Sea lease sale areas is assumed. Both the terminals on either island and the VLCC terminal in the Aleutians are assumed to be capable of three million barrels of storage, loading/unloading tankers and treating ballast water. Costs assumed are for a 300,000 BOPD throughput terminal.

9. Total capital investment is the sum of the above plus a 10 percent contingency. No working capital is included.

GENERAL NOTE: This Total Capital Investment estimate may be on the order of 10 percent too optimistic (platform and transshipment costs low; storage and loading facilities slightly high). However, our separate study on regional offshore lease sale economics (Dames & Moore, 1982) suggests that the rate of return is relatively insensitive to capital costs.

TABLE 6-2

RELATIONSHIP OF PIPELINE DIAMETER TO NUMBER OF PLATFORMS

No. of Platforms	Total Recoverable Reserves (million BBLS)	Maximum Throughput (BOPD)	Pipeline Diameter (inches)
1	365	100,000	20
2	730	200,000	26
3	1095	300,000	30
4	1460	400,000	32
5	1825	500,000	36

The St. Matthew terminal has storage capacity for roughly ten days production, as well as facilities for treatment of tanker ballast, crude stabilization and LPG recovery. An ice-breaking workboat serves the terminal and assists in docking maneuvers. A second such workboat serves logistical and safety needs of the offshore platforms. A single point mooring is used to load crude into 150,000-DWT (1.2 MMBBL) ice-strengthened shuttle tankers. These tankers transport the crude 800 kilometers (500 miles) to a transshipment terminal in the Aleutians.

The shuttle tankers require 30 hours of loading time, 30 hours of unloading and 62 hours steaming round-trip (at 14 knots). Assuming 25 percent down time for weather or maintainance, 0.57 shuttle tankers is required for each 100,000 BOPD of throughput. Each tanker is assumed to cost $155 million to purchase and $16 million per year to operate, exclusive of annual cost of ownership (Santa Fe Engineering, 1981).

The shuttle tankers will dock at the Aleutian transshipment terminal where they will unload into storage tanks. From those tanks, the crude will be loaded through a short offshore pipeline to a single point mooring in water with sufficient depth to accommodate VLCC tankers. These tankers will carry the crude to refineries on the U.S. West Coast or other ports.

The economic analysis takes into account costs and revenues F.O.B. a VLCC in the Aleutians. Total capital costs for the one-billion-barrel production and transport system through St. Matthew is $4.147 billion. This is the lowest cost pipeline alternative, assuming St. Matthew can be used.

Scenario 2: Pipeline to St. Paul Island

Scenario 2 is essentially identical to Scenario 1 except for the location of the pipeline landfall. In Scenario 2, crude is piped 480 kilometers (300 miles) to St. Paul Island in the Pribilofs. Although this island is inhabited, it does not have an infrastructure which could support OCS development. Its principle advantage over the St. Matthew scenario is that it is not a wildlife refuge, has some infrastructure, and slightly more favorable ice conditions.

Santa Fe Engineering calculates that by using a pipeline with large enough pressures and diameter (importantly, also assuming favorable crude oil characteristics, such as very low wax content), it is possible to avoid the necessity for an intermediate booster pump station. Pipeline diameter depends on throughput as a function of number of platforms as shown in Table 6-3.

Terminal facilities (including workboats) required at the pipeline terminus and in the Aleutians are the same as in Scenario 1. The shuttle fleet requirements differ slightly because the distance from St. Paul to the Aleutians is about 320 kilometers (200 miles) shorter in Scenario 2. The round trip requires about 37 hours transit time plus the same 60 hours for loading and unloading. This results in a requirement for 0.44 shuttle tankers per unit field (100,000 BOPD), or 1.32 tankers for a one-billion-barrel development project.

Total capital cost for the one-billion-barrel system is $4.558 billion. This is about 10 percent more costly than the St. Matthew alternative. Doubling the pipeline distance overwhelms the small reduction in the tanker fleet possible by pipelining the oil further south.

<u>Scenario 3</u> Offshore Loading

The third scenario assumes that the oil, produced by 100,000 BOPD gravity platforms, is stored on the platform and offshore loaded (OSL) directly onto shuttle tankers bound for an Aleutian transshipment terminal.

The platforms could be similar in design to the Condeep-type concrete gravity structures used in the North Sea. In order to provide sufficient on-platform storage to permit continuous production operations, we assume that 15 days storage (1.5 million barrels) could be held in the base of the platform. This allows contingency for continuous operation even if weather or ice

TABLE 6-3

RELATIONSHIP OF PIPELINE DIAMETER AND NUMBER OF PLATFORMS

Number of Platforms	Total Recoverable Reserves (million BBLS)	Maximum Daily Throughput (BOPD)	Pipeline Diameter (Inches)
1	365	100,000	22 - 24
2	730	200,000	28 - 30
3	1095	300,000	32 - 34
4	1460	400,000	36 - 38
5	1825	500,000	38 - 40

prevented off-loading for an unusually long period of time. Santa Fe Engineering (personal communication, 1981) estimates 10 days is the longest likely time span during which these large shuttle tankers could not moor for loading. Therefore, with 15 days storage, the same production efficiency (96 percent) is assumed for both pipeline and offshore loading (OSL) scenarios. This is a critical assumption; lower effective lifting rates, due to lower OSL efficiencies, could dramatically impact the economic results.

Apart from the difference in platform type, the same production facilities are assumed under the OSL scenario as for the pipeline scenarios. The platform, however, requires a mooring for OSL oil production. This mooring could also be spearate, located far enough from the platform to allow the shuttle tankers to "weathervane" around the mooring in response to wind and current.

The shuttle tankers are ice-strengthened and assumed to be of the same design described for use between St. Matthew or St. Paul and the Aleutian terminal. These tankers could make the 2,000-kilometer (1,200-mile) round trip in 75 hours. Allowing for loading/unloading and 25 percent down time, 0.62 tankers are needed for each 100,000 BOPD of production. In addition, an ice-breaking workboat is needed at each OSL platform. This boat would assist during docking manoeuvers as well serving normal workboat functions.

The production schedule for offshore loading (See Appendix B) is lagged a year behind that of the pipeline cases (see Appendix 3, Table B-10 for exact scheduling differences). This lag is due to the greater construction and tow-out time for installing concrete gravity platform. Constructing these structures requires a specialized "graving dock" which would have to be built for this purpose in either Alaska or the West Coast. No such facility currently exists.

The same Aleutian transshipment terminal described under Scenarios 1 and 2 is be used in Scenario 3. Total capital cost for the 1.0 billion barrel production system costs $4.276 billion. This cost is about 10 percent lower than the St. Paul pipeline alternative. However, production starts a year later.

6.3 Economic Results of Oil Production Scenarios

The Dames & Moore EAC computer model (on the Scientific Softwear GUESS system) was used to simulate the cash flow and economic rates of return for each of the three oil development scenarios. The results of all oil development model runs are summarized in Table 6-4. These model runs permit the following comparisons to be made:

1. Comparison of the economics of each of the three oil development scenarios.

2. Comparison of the economic effects of the number of fields sharing a given production system.

These comparisons are discussed in Subsections 6.3.1 and 6.3.2, based on data shown in Table 6-4. Platforms are each assumed to produce 365 million barrels. Reserves of this size can be recovered in about twenty-five years assuming 2,500 BOPD wells, 40 producing wells per platform and idealized reservoir geometry to allow 40 wells to reach pay zone. Optimistic reservoir conditions and reservoir engineering are required for each platform to be able to produce 365 million barrels. Although feasible, these assumptions imply that our economic results should be considered "optimistic" given the geologic assumptions the analysis is based on. The recent drop in world oil prices has weakened our assumption that the real price of oil will equate to $32.00 per barrel in 1981 dollars by the time Navarin comes on line. Hence, the $32.00 oil price could be considered optimistic as well.

Our analysis has focused on the economics of petroleum development of giant fields and production systems. Development sequences recognize that logistic difficulties make it necessary to stagger installation of offshore production equipment. Within each analytical case, only one platform is installed per year. Subsequent topside equipment installation and well drilling is also staggered accordingly. Transportation systems (pipelines, if any, and terminals) are sized, however to their ultimate capacity, but are phased to come on line with the first field. Thus, initially they are under-utilized.

TABLE 6-4

RESULTS OF ECONOMIC ANALYSIS OF NAVARIN BASIN PETROLEM DEVELOPMENT

Case	Recoverable Reserves 1/ (MMBBL)	Number of Platforms (units)	Net Present Value at 12 Percent (MM$)	After-Tax DCF Rate of Return 2/ (Percent)	Equivalent Amortized Total Cost ($/BBL)	Equivalent Amortization Capital Investment Cost 3/ ($/BBL)	Equivalent Amortized Operating Cost ($/BBL)	Total Capital Investment (MM$)
Scenario 1: St. Matthew Pipeline								
1-1	365	1	346	14.8	28.94	12.63	5.86	1,788
1-3	1,095	3	1,881	18.9	25.83	9.56	3.72	4,147
1-5	1,825	5	2,856	18.8	25.84	9.59	3.41	6,216
Scenario 2: St. Paul Pipeline								
2-1	365	1	204	13.2	30.18	14.45	5.93	2,022
2-3	1,095	3	1,396	16.2	27.42	11.96	3.69	4,558
2-5	1,825	5	2,611	17.7	26.19	10.36	3.32	6,694
Scenario 3: Offshore Loading								
3-1	365	1	395	15.7	28.04	11.63	5.29	1,568
3-3	1,095	3	1,535	17.7	26.35	10.39	3.61	4,276
3-5	1,825	5	2,267	17.4	26.39	10.65	3.34	6,870

1/Recoverable reserves over the lifetime of the project are assumed to be 365 million barrels per platform. This is an optimistic assumption about idealized field geometry to allow maximum recovery justified by other reservoir engineering assumptions. Hence, results represent upper limit estimates. Recoverable reserves ranging between 365 and 1825 million barrels are pegged to the number of platforms in each analytical case. The upper limit case exceeds the mean resource estimate. The analytical cases are not constrained by the mean resource estimate.

2/Oil price is assumed to be $32.00 BBL FOB Aleutian terminal. A $2.00 change in oil price swings rate of return about 1.0 percent.

3/General overhead and administration expenses are included.

The full costs of the transportation system must be invested one or more years sooner relative to peak production. A goal of the design of our systems and the economic analysis, however, is to assume production as early as possible. This allows early cash flows even though pipelines and terminals are initially under-utilized. With smaller systems, the transportation system reached peak utilization sooner. However, the Navarin Basin will require mega-fields to stimulate initial development and seasonal constraints are an essential element of the logistics.

Investment sequences are shown in Appendix B, Table B-9. These apply to single platforms. Subsequent platforms are staggered as indicated.

6.3.1 Economic Comparison of the Three Oil Development Scenarios

Comparison of similar size production systems among the three development scenarios reveals interesting economic rankings (refer to Table 6-4). For large fields, 1.095 and 1.825 billion barrels of recoverable reserves sharing a common production system, Scenario 1 (St. Matthew) is more economic than Scenario 2 (St. Paul) and Scenario 3 (Offshore Loading).

For example, assuming that five platforms share a common terminal and pipeline, the after tax rate of return is 18.8, 17.7 and 17.4 percent for Scenarios 1, 2, and 3.

Small fields, however, are more economically developed with offshore loading. For example, assuming one platform produces 365 million barrels, the after-tax rate of return is 14.8, 13.2, and 15.7 percent for Scenarios 1, 2 & 3. The cost of the pipeline significantly impacts the economics. Even though OSL begins production a year later, the vast difference in total capital cost -- $1.568 billion compared to $1.788 billion for St. Matthew alternative and $2.022 billion for St. Paul -- makes OSL preferable.

Under the analytical assumptions, the differences in the two pipeline scenarios rest on the relative cost and cash flow impacts of moving oil a longer distance in a pipeline to St. Paul or a longer distance in a tanker from St.

Matthew. All other costs (platforms, wells, equipment, terminals, etc.) are identical between the two scenarios.

Conventional wisdom in most existing offshore oil producing regions indicates that pipelines are more economic than tankers for moving crude ashore. The results for the Navarin seem to contradict this wisdom.

In Scenario 1, crude is moved by pipeline for a shorter distance than in Scenario 2. In both cases, the remainder of the trip to the Aleutians is via shuttle tanker. Despite the fact that the total distance over which the oil is transported is slightly longer in Scenario 1 versus Scenario 2 (650 miles versus 600 miles), the large cost of the doubling the pipeline length and slightly increasing its diameter overcomes the additional tanker cost. Comparing the 1.095-billion-barrel cases, Table 6-4 shows that the discounted capital cost per barrel is $9.56 for Scenario 1 versus $11.96 for Scenario 2. This reflects the higher cost of a longer pipeline. Operating cost differences ($3.72 and $3.69) approximately "wash." The longer shuttle tanker distance and associated costs in the first scenario offsets the longer pipeline costs of the second scenario.

Ignoring inflation as does our analysis, the very high initial cost of marine pipeline in the arctic is a more significant consideration than transportation operating costs.

6.3.2 Economic Comparison of the Number of Fields Sharing a Delivery System

As shown in Table 6-4, the equivalent amortized cost per barrel decreases and the rate of return increase as the number of fields sharing a transportation system increase. This is a result of the economies of scale inherent in pipelines, terminals, and shared workboats (in pipeline scenarios).

Although the size (diameter) of the pipeline needed increases as a function of throughput, the increase is less than proportional. Thus the cost per kilometer for tripling throughput from 100,000 BOPD to 300,000 BOPD is only about 1.6 (rather than 3) times greater. Obviously, this contributes significantly to economies of scale in the pipeline to St. Matthew and even more to the longer pipeline to St. Paul.

In Scenarios 1 and 2, there are terminals both at the end of the pipeline and in the Aleutians to transship oil to convential VLCC tankers. In the third scenario (offshore loading) only the transshipment terminal is required. Larger terminals offer some economies of scale in initial investment costs and greater economies in operating costs.

Initial investment economies reflect the high cost of mobilizing construction equipment in remote areas. Such start-up costs are fairly insensitive to the size of the terminal (throughput). Support facilities are likewise insensitive to throughput. These factors create some economies of scale. Other facilities such as crude loading, dockage, and storage tanks are roughly proportional to throughput and offer little or no economies of scale.

Operating costs do offer pronounced economies of scale. Crew requirements for operation and maintainance of a terminal would be almost as large for a throughput of 100,000 BOPD as for 500,000 BOPD. Since the equipment is highly automated, the crew is needed mainly for routine maintenance and emergency response.

A further economy of scale is derived from the greater utilization of the ice-breaking workboat needed at the Bering Sea island terminal under Scenarios 1 and 2. One such ship serves either a larger or a smaller terminal; another serves several as well as a single platform. In the offshore loading scenario, this economy is not manifest as one ice-breaker is needed for each platform.

As seen in Table 6-4, all scenarios exhibit economies of scale. In Scenario 1, for example, after-tax rate of return ranges from a high 18.8 for a 500,000 BOPD throughput to a 14.8 percent ROR for 100,000 BOPD; Equivalent amortized cost per barrel drops from $28.94 to $25.64 in Scenario 1.

6.3.3 Minimum Economic Field Size

Cases 1-1, 2-1, and 3-1 on Table 6-4 indicate the economic results for single field production systems. Each field is assumed to have 365 million barrel reserves and a peak production rate of 100,000 BOPD. Single fields of this size are apparently adequate to support the investment in production and transportation equipment necessary for development--assuming the idealized reservoir engineering of the cases, and 12 percent real hurdle rates.

6.3.4 Economic Conclusions Regarding Oil Development in the Navarin

Based on the economic analysis and assumptions, oil, once discovered, can be commercially developed in the Navarin Basin assuming that a field in the 300-million-barrel range is discovered. Offshore loading appears to offer some advantage over pipelines to either St. Matthew or St. Paul Islands for smaller fields. More pessimistic assumptions regarding operating efficiencies -- the case assumes 96 percent productivity -- for OSL systems could decrease the apparent advantages of OSL.

Between the two pipeline systems, the pipeline to St. Matthew is considerably more economic than the pipeline to St. Paul. The high cost of marine pipeline more than offsets the shorter shuttle tanker distance to an Aleutians terminal.

6.4 Economic Analysis of Non-Associated Natural Gas Development

6.4.1 Assumptions

The production assumptions used to analyze the economics of gas development are identical to those used in analyzing oil development with regard to water depth, reservoir depth and distance from shore. In addition, the following parameters are assumed:

o Field size	1.4 trillion cubic feet
o Initial productivity	15 MMCFD per well
o Recoverable reserves per acre	200 MMCF
o Production system	Steel jacketed platform
o Laid-in price (as LNG)	$6.15 MCF

6.4.2 Scenario Description of Non-Associated Gas Development

Two gas scenarios were modelled: a shared trunkline to St. Matthew Island and offshore loading. These scenarios are described in the following paragraphs:

Scenario 4: Pipeline to St. Matthew Island

Four identical 1.4 TCF fields are assumed to exist within an 80-kilometer (50-mile) radius of each other. Three of the fields pipe their gas to a fourth, central platform from which a 36-inch-diameter trunk line delivers the combined production to St. Matthew Island. On St. Matthew an LNG terminal liquifies the gas and loads it onto ice-reinforced LNG tankers which go directly to a hypothetical regassification terminal in California.

Scenario 5: Offshore Loading

This scenario is identical to Scenario 1 except that the central platform has offshore liquifaction facilities. Once liquified, the LNG is stored in a floating storage tank which has capacity for 15 days peak production. From this storage tank, gas is loaded directly onto ice-reinforced LNG tankers. These tankers shuttle between the Navarin and a California gasification facility.

6.4.3 Economic Analysis of Gas Development Scenarios

The economics of the two scenarios modelled proved very similar. Neither scenario proved able to make the assumed 12-percent real hurdle rate. The after-tax rate of returns (see Table 6-5) are 8.1 and 8.0 percent for the pipeline and offshore loading cases respectively.

TABLE 6-5

RESULTS OF ECONOMIC ANALYSIS OF NAVARIN BASIN GAS DEVELOPMENT

Case	Recoverable Reserves[1/] (TCF)	Number of Platforms (units)	Net Present Value at 12 Percent (MM$)	After-Tax DCF Rate of Return[2/] (Percent)	Equivalent Amortized Total Cost ($/MCF)	Equivalent Amortized Capital Investment Cost ($/MCF)	Equivalent Amortized Operating Cost[3/] ($/MCF)	Total Capital Investment (MM$)
St. Matthew Pipeline								
	5.5	4	-1,112	8.1	7.00	4.35	1.16	6,994
	5.5 (faster recovery)	4	-1,015	10.6	6.77	4.24	1.01	8,440
	11.0 (high reserves)	4	-1,194	9.5	6.59	3.86	1.05	12,756
Offshore LNG Loading								
	5.5	4	-1,151	8.0	7.02	4.31	1.25	7,032

1/ Recoverable reserves are assumed to be 1.4 TCF per platform. This is an optimistic assumption about idealized field geometry to allow maximum recovery justified by other reservoir engineering assumptions. Hence, results represent upper limit estimates.

2/ Gas price is assumed to be $6.15/MCF gassified in California F.O.B. Aleutian terminal.

3/ General overhead and administration expenses are included.

The equivalent amortized cost per MCF is $7.00 and $7.02 for the two scenarios. This indicates that, other things being equal, the landed value of the gas would have to rise about $0.85 per MCF above its assumed value of $6.15 to prove viable. Whether this will happen depends on a number of factors such as the speed and extent to which domestic gas prices are decontrolled, and the consequent domestic (Lower 48) supply response.

It is interesting to note that the two cases result in almost identical costs. Capital expenditures for the two cases are within $38 million of each other. This is not too surprising since the platform, ship and well investments are assumed to be identical. However, it happens that the cost of offshore processing and loading equipment plus the cost of spur pipelines is only slightly more costly than the deck equipment, spur plus trunklines and onshore terminal required under the pipeline scenario.

If the costs for a pipeline to St. Paul were modelled, the economics would be distinctly less favorable than the two cases analyzed. Since these more optimistic cases proved uneconomic, there did not appear to be any reason for considering a St. Paul pipeline.

Two additional cases were modelled to determine whether even more optimistic assumptions regarding field conditions would improve the economics of gas development. However, these cases also proved to be uneconomic (see Table 6-5).

In the first case, a faster recovery is assumed. Peak annual production is assumed to be 8 percent (versus 6 percent) of reserves. This results in a 16-year productive life for the field (versus about 20 years at 6 percent). This is a faster recovery than normal practice. Problems of well interference and reduction of ultimate recovery which could occur at this high recovery rate are assumed away. Nonetheless, the real after-tax rate of return (10.6 percent) still falls short of the 12 percent real hurdle rate.

In the second case, we return to the usual 6 percent peak year recovery, but double the reserves per platform (and the total reserves in the lease sale) from 5.5 to 11.0 TCF. The number of wells and the cost for the terminals also double and thus, do not contribute to economics of scale. Savings do occur since production from each platform is doubled and economies of scale are realized on deck equipment and pipelines. These savings increase the after-tax rate of return to 9.6 percent (from 8.1 percent), but are still not sufficient to reach the 12 percent real hurdle rate.

6.5 Equivalent Amortized Cost of Oil and Gas Development

6.5.1 Oil

The GUESS system, as modified by Dames & Moore, is capable of disaggregating the distinct components comprising development cost on a per barrel and per MCF, discounted, after-tax basis. Although this information is available for every case run, display of the EAC disaggregated cost is confined to the three field cases. The EAC for those cases is shown in Table 6-6.

Development costs per barrel of the selected cases shown on Table 6-6 range from $25.82 (St. Matthew Pipeline) to $27.42 (pipeline to St. Paul). Development costs are comprised of capital charge, G&A expenses, operating costs, royalties and federal tax components. By far the largest component is capital charge (interest plus principle).

Capital cost (capital recovery plus interest) is shown in parenthesis in Table 6-6. General and administrative and operating costs vary with the number fields in a given case, there being pronounced economies of scale. Royalties are uniform over all cases. Federal taxes vary in a complex manner, but in general the tax is highest for the most lucrative cases and lowest for marginally profitable case with high operating and capital costs.

Transportation costs were estimated at $2.65, including terminaling charge at a West Coast destination. This charge is based on current shipping charges from Valdez to California multiplied by a factor of 1.5 to reflect greater shipping distance plus $0.40 to reflect higher costs of Aleutian operations.

TABLE 6-6

EQUIVALENT AMORTIZED COST OF OIL PRODUCTION IN THE NAVARIN BASIN
($ Per Barrel - 1981)

	St. Matthew	St. Paul	Offshore Loading
Scenario	1-3	2-3	3-3
Field Size (million barrels)	1,095	1,095	1,095
Present Barrel Equivalent (million BBLS)	305	305	272
Number of Platforms Sharing Transportation System	3	3	3
Pipeline Length (km)	240	480	0
Capital Charge	9.56	11.96	10.39
(of which Capital Cost at 12 percent)	(6.35)	(8.01)	(6.96)
General and Administrative Expenses	0.93	0.93	1.11
Operating Costs	2.79	2.76	2.50
Royalty at 16.67 percent	5.33	5.33	5.33
Federal taxes - Net of Tax Credits	7.21	6.44	7.02
SUBTOTAL DEVELOPMENT COSTS	25.82	27.42	26.35
Transport to Los Angeles	2.65	2.65	2.65
TOTAL - LAID-IN COST	28.47	30.07	29.00
Allocation of Capital Charge			
Offshore Production	5.01	5.01	7.97
Pipeline to Shore	0.98	3.45	0
Terminal	2.67	2.67	1.29
Ships	0.90	0.83	1.12
TOTAL	9.56	11.96	10.39

Source: Dames & Moore

Shipping costs from Valdez to California were $1.50/barrel in March 1981 (PIW 3/16/81). Thus, the estimated transport charge: $1.50 x 1.5 + $0.40 = $2.65.

The bottom five rows of Table 6-6 allocate the capital charge in each case among the following capital investment categories: offshore production, pipeline to shore, terminal and ships. The cost are allocated in proportion to the initial capital investment in each category.

The allocation of capital charge reveals a very significant insight. Pipeline to shore must be in place to transport the first barrel. Hence, doubling the length doubles the captial cost but increases 3.5 times the equivalent amortized cost per barrel. The reason for this is that the proportionate share of early capital investment is more than doubled while flows of oil production are identical. The Present Barrel Equivalent of production in cases 1-3 and 2-3 are identical at 305 million BBLS.

6.5.2 Gas

Equivalent amortized costs calculated for the two base-case gas scenarios (pipeline to a St. Matthew Island terminal and offshore liquification and loading) are shown in Table 6-7. This table is interesting in that it shows how the savings due to omitting the pipeline to shore is offset by higher offshore terminal costs.

The cost of offshore liquification ($2.59 per MCF) is $0.54/MCF higher than onshore liquification. This almost exactly offsets the $0.53/MCF cost of the pipeline to shore. In addition, the capital charge due to tankers is slightly higher in the OSL scenario, since in this case the LNG tankers transport the gas slightly further (i.e., the additional distance represented by the pipeline to shore).

The cost of unloading and regasification in California (estimated to add $0.70) is not included in this analysis. This cost would be the same under all gas scenarios.

TABLE 6-7

EQUIVALENT AMORTIZED COST OF GAS PRODUCTION IN THE NAVARIN BASIN

	($ per MCF-1981)	
	St. Matthew Pipeline	Offshore Loading
Field size (BCF)	5,500	5,500
Present MCF Equivalent (BCF)	1,315	1,325
Number of Platforms Sharing Transport System	4	4
Trunk Pipeline Length (Km)	240	0
Capital Charge	4.35	4.31
(of which capital @ 12 percent)	(3.08)	(3.07)
General & Administrative Cost	0.16	0.16
Operating Costs	1.16	1.25
Royalties @ 16.67%	1.03	1.03
Federal Taxes	0.29	0.27
Subtotal Development Costs(1)	7.00	7.02
ALLOCATION OF CAPITAL CHARGE		
Offshore Production(2)	1.98(4)	1.98(4)
Pipeline to Shore	0.53	0.00
Terminal(3)	2.09	2.63
Ships	2.39	2.41
TOTAL	7.00	7.02

Source: Dames & Moore

1. Includes transport to California.
2. Includes wells, platforms and deck equipment.
3. In offshore loading scenario, costs of liquification facilities are included in "terminal" although these facilities are offshore.
4. Includes pipelines interconnecting the platforms.

7.0 HYPOTHETICAL PETROLEUM DEVELOPMENT SCENARIOS FOR THE U.S. GEOLOGICAL SURVEY STATISTICAL MEAN OIL AND GAS RESOURCE ESTIMATE

7.1 Introduction

This chapter presents a hypothetical oil and gas development case for the Navarin Basin corresponding to the revised U.S. Geological Survey conditional statistical mean oil and gas resource estimate provided by the Alaska OCS office (BLM, 1981). Mean estimates of undiscovered recoverable oil and gas for this basin are 1.7 million barrels of oil and 7.3 TCF of gas. For the purposes of formulating a development case, natural gas resources have been assumed to be about 75 percent non-associated and 25 percent associated.

The development case hypothesized here assumes a relatively rapid exploration and development schedule. The schedule is characterized by a high level of exploratory activity with a commensurate rate of discovery that results in five commercial oil fields and four gas fields discovered within seven years of the lease sale.(1) Many factors could alter the speed and course of events such as the availability of drill rigs following the lease sale or environmental restrictions on drilling.

7.2 Development Strategy and Production Facilities

In keeping with our analytical approach for the Navarin of focusing on transportation rather than production variables, two hypothetical development scenarios are hypothesized: one for pipeline to shore (St. Matthew Island)

(1) Alternate exploration schedules, discovery timings, field development strategies, reservoir characteristics, and assumptions on the ratio of associated to non-associated gas reserves (comprising the U.S. Geological Survey estimate) were evaluated to assess their effects on facility and equipment requirements and production (including peak production and field lives). We recognize that facility and equipment requirements are very sensitive to certain assumptions. The number of platforms required for a given reservoir size is very sensitive to the reservoir depth assumption. For deeper reservoirs where reservoir depth is not a limiting factor, the technical constraints of platform design on number of well slots of the selected platform design place a similar penalty. Other important sensitivities relate to optional economic constraint of oil or gas and infrastructure sharing arrangements.

and one for offshore loading. These two hypothetical scenarios are illustrated in Tables 7-1 and 7-2, respectively. To provide a basis for comparison of onshore versus offshore differences, production and field condition assumptions including location, are basically similar to each other and follow the scenario descriptions detailed in Section 6.2 for oil and 6.4 for gas.

Oil is assumed to be discovered in two clusters of fields. Those clusters of oil fields are separated by both distance and timing of discovery. Therefore two separate production and transportation systems are assumed to be developed.

The assumptions for the hypothetical development scenario for a pipeline to St. Matthew Island are as follows:

OIL: PIPELINE TO SHORE

ASSUMPTION 1. All fields discovered are produced from one or more drilling/production platform. Each platform produces a total of 365 million barrels of economically recoverable reserves. Peak daily throughput for each platform is 100,000 BOPD from 40 production and 8 services wells.*

ASSUMPTION 2. There are roughly 1.7 billion barrels of recoverable oil reserves in the Navarin basin.

ASSUMPTION 3. All wells have an initial production of 2500 BOPD.

ASSUMPTION 4. The Lease Sale is held in March, 1984.

ASSUMPTION 5. Exploration begins in 1985, the first year following the lease sale. The first field is discovered one year later (1986). In

* Except for the last field discovered which is a scaled down "unit field" with 70 percent of the reserves wells and peak production of the unit field. This size field was assumed to create a hypothetical scenario which exhausts the mean resource estimate for the Navarin.

TABLE 7-1

NAVARIN BASIN
HYPOTHETICAL PETROLEUM DEVELOPMENT CASE:
PIPELINE TO SHORE
(for U.S.G.S. Mean Estimate of Resources)

Calendar Year	Year After Lease Sale	Exploration Wells(1)	Delineation Wells	Exploration Rigs Operating(1)	Commercial Field Discovered		Installation of Offshore Production Platforms			Development Wells		Pipeline Construction KM (Miles)		Production	
					Oil	Gas	Oil Gravity	Oil Steel	Gas Steel	Oil	Gas	Oil	Gas	Oil (MMB/YR)	Gas (BCF/YR)
1985	1	3		2											
1986	2	6		3	1										
1987	3	4	2	3	2										
1988	4	6	2	3	1*	1									
1989	5	6	3	4	1**	0									
1990	6	3	3	3	*	2*									
1991	7	1	2	2	*	1									
1992	8		2	1		**									
1993	9					*		1				272(170)			
1994	10							2		12		256(160)			
1995	11							1	1	36			240(150)	9	
1996	12							1	0	48	6		240(150)	35	
1997	13								2	60	6			70	29
1998	14								1	48	17			111	58
1999	15									24	17			143	146
2000	16									12	17			157	233
2001	17										5			163	322
2002	18													160	352
2003	19													150	352
2004	20													136	352
2005	21													120	352
2006	22													104	352
2007	23													92	352
2008	24													81	352
2009	25													71	352
2010	26													54	337
2011	27													30	325
2012	28													12	284
2013	29														237
2014	30														196
2015	31														163
2016	32														136
2017	33														93
2018	34														77
															24
TOTALS		29	14		5	4		5	4	240	68	528(330)	480(300)	1699	5476

* Decision to develop; follows discovery by two years.

(1) This assumes exploration starts one year after the sale; this is optimistic as it is quite possible that more time will be needed for start-up.

TABLE 7-2

NAVARIN BASIN
HYPOTHETICAL PETROLEUM DEVELOPMENT CASE:
OFFSHORE LOADING
(for U.S.G.S. Mean Estimate of Resources)

Calendar Year	Year After Lease Sale	Exploration Wells(1)	Delineation Wells	Exploration Rigs Operating(1)	Commercial Field Discovered		Installation of Offshore Production Platforms			Development Wells		Pipeline Construction KM (Miles)		Production	
					Oil	Gas	Oil Gravity	Oil Steel	Gas Steel	Oil	Gas	Oil	Gas	Oil (MMB/YR)	Gas (BCF/YR)
1985	1	3		2											
1986	2	6		3	1										
1987	3	4	2	3	2										
1988	4	6	2	3	1*	1									
1989	5	6	3	4	1**	0									
1990	6	3	3	3	*	2*									
1991	7	1	2	2	*	1									
1992	8		2	1		**									
1993	9					*	1								
1994	10						2		1	12					
1995	11						1		0	36				9	
1996	12						1		2	48	6			35	29
1997	13								1	60	6			70	58
1998	14									48	17			111	146
1999	15									24	17			143	233
2000	16									12	17			157	322
2001	17										5			163	352
2002	18													160	352
2003	19													150	352
2004	20													136	352
2005	21													120	352
2006	22													104	352
2007	23													92	352
2008	24													81	352
2009	25													71	337
2010	26													54	325
2011	27													30	284
2012	28													12	237
2013	29														196
2014	30														163
2015	31														136
2016	32														93
2017	33														77
2018	34														24
TOTALS		29	14		5	4	5		4	240	68		240(150)	1699	5476

* Decision to develop; follows discovery by two years.
(1) This assumes exploration starts one year after the sale; this is optimistic as it is quite possible that more time will be needed for start-up.

1987 two fields are discovered, and an additional two fields are discovered in 1988 and 1989. Exploration continues through 1991 with no new fields discovered. The decision to develop a field follows discovery by two years. Thus, the first "go" decision is 1988.

ASSUMPTION 6. Steel-jacket platforms are emplaced in the fourth year following the decision to develop (the first in 1992). Deck load equipment is installed during the fourth year and into the fifth. Well drilling begins in the fifth year. Two rigs drill 12 wells annually during the fifth through eight years. Production begins in the sixth year, 1994, ten years after the sale.

ASSUMPTION 7. Wells are assumed to reach their initial peak production (2500 BOPD) in the year after they are drilled. Thus, production begins in 1994, peaks at 163 MMB/YR in 2000 and ends in 2011.

ASSUMPTION 8. The production from the first three fields discovered is assumed to feed a common 150-mile 36-inch pipeline to St. Matthew Island. Two of the first three fields discovered feed their production to the third field through 15-mile 20-inch gathering (spur) lines. The last two fields discovered produce to a second 150-mile trunkline to St. Matthew Island with 15 miles of spur line joining the two fields. The pipelines are laid in two years, 1992 and 1993, to be in place for production in 1994. Terminals are designed and built over five years to be in place by 1994.

ASSUMPTION 9. All fields produce to a common terminal on St. Matthew Island with a 5-million-barrel storage capacity.

ASSUMPTION 10. The stored oil is loaded through a single point mooring into fleet of three ice-strengthened 150,000 DWT (1.2 MMB) tankers. These tankers shuttle to a transshipment terminal in the Aleutian Islands. From there the crude is transported to market in VLCC tankers.

GAS: PIPELINE TO SHORE

ASSUMPTION 1. Seventy-five percent of the 7.3 TCF mean estimated reserves are assumed to occur as non-associated gas. Furthermore, it is optimistically assumed that these reserves (5.6 TCF) will be occuring in four 1.4 TCF fields located such that three platforms can pipe their gas to a fourth central drilling production/gathering/compressor platform.

ASSUMPTION 2. The first of these fields is discovered in 1988, with the next two discovered in 1990 and the last (fourth) field discovered in 1991. Decision to develop lags discovery by two years. This would be a fast-track schedule, and is an optimistic assumption.

ASSUMPTION 3. Steel-jacket-type drilling/production platforms are emplaced in years 1994, 1996 (two), and 1997. Pipelines from three of the fields deliver gas to the central platform where a trunkline carries the gas to St. Matthew Island for liquefication, storage, and loading into a dedicated fleet of ice-reinforced LNG tankers. These tankers travel directly to a hypothetical California LNG terminal where it is regassified.

ASSUMPTION 4. Well drilling and production schedules parallel those described for the oil production scenarios, except one rig drills six wells per year on gas platforms and five the third year: 17 wells total per platform. Drilling begins in 1995; production begins in 1996 and ends in 2018.

OIL: OFFSHORE LOADING

The assumptions for the oil offshore loading hypothetical development scenario are identical to those for Oil: Pipeline to Shore with the following exceptions:

ASSUMPTION 6: Concrete gravity platforms (of the Condeep type) are emplaced in the fifth year following decision to develop. Well drilling begins in the year following emplacement, 1994. Two rigs drill 12 holes during the sixth thru ninth years after decision to develop.

ASSUMPTION 7: Production begins in 1995, peaks at 163 MMB per year in 2001 and ends in 2012.

ASSUMPTION 8: The production from all five fields are offshore loaded from each platform onto ice-reinforced 1.2 MMBBL shuttle tankers bound for a common transshipment terminal in the Aleutian Islands. From there the crude is transported to market in VLCC tankers.

ASSUMPTION 9: DELETE.

ASSUMPTION 10: DELETE.

GAS: OFFSHORE LOADING

The assumptions for this hypothetical development scenario are identical to those for Gas: Pipeline to Shore with the following exception:

ASSUMPTION 3. Pipelines from three of the fields deliver gas to the central platform, which has facilities for liquefication, storage, and loading into a dedicated fleet of ice-reinforced LNG tankers. These tankers travel directly to a hypothetical California LNG terminal where it is regassified.

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APPENDIX A

PETROLEUM GEOLOGY, AND ANALYTICAL ASSUMPTIONS

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PETROLEUM GEOLOGY AND ANALYTICAL ASSUMPTIONS

I. INTRODUCTION

This appendix describes the reservoir, production, and technical assumptions that are the essential parameters for the economic analysis. The role of these assumptions and the overall study methodology are described in more detail in Appendix A of our final report entitled "St. George Basin Petroleum Technology Assessment OCS Lease Sale No. 70" (Dames & Moore, August 1980). Many of the assumptions of this study, except most of the economic assumptions, are unique to the Navarin Basin. This appendix is devoted to a description of the petroleum geology of the Navarin lease sale area and related reservoir engineering assumptions, and technical assumptions that are specific to the Navarin analysis. Economic assumptions that differ from prior studies are also described.

II. PETROLEUM GEOLOGY, RESERVOIR, AND PRODUCTION ASSUMPTIONS

II.1 Introduction

The following section (II.2) reviews the petroleum geology of the Navarin Basin province to provide the geologic specifications for the reservoir and production assumptions that are essential parameters for the technology assessment and economic analysis. These assumptions are presented in Section II.3.

No C.O.S.T wells have been drilled in this province. It cannot be overemphasized that there is no data from exploratory wells, and insufficient geologic and geophysical data to support predictions on reservoir characteristics in the Navarin Basin province. Our approach in this study was to explore the economic and engineering impacts of logistic alternatives given a complex -- but not fixed -- set of geological and reservoir characteristics. The reservoir characteristics fall within the range of conditions indicated by the available data and data from producing basins with similar geologic settings.

II.2 Summary of Navarin Basin Petroleum Geology

II.2.1 Regional Framework

The Navarin Basin province is a very large area of 45,000 square kilometers (11 million acres or 17,000 square miles) lying west of St. Matthew Island and southeast of the U.S.A.-Russia Convention Line of 1867. Seismic studies indicate 3 subparallel basins overlying the acoustic basement filled with as much as 15 kilometers (49,000 feet) of sediments. Additional pre-Tertiary sediments may exist below the acoustic basement. The axis of the basins trend northwest-southeast and were filled with sediments during the Tertiary. Basement ridges separate the basins. Normal faults along the basin flank of the southern basin exhibit growth structures caused by an increasing amount of offset with depth.

The north basin is circular. It is the largest of the three and covers an area of 10,000 square kilometers (2,560,000 acres). Very large anticlines near the western limits of this basin are of interest as prospective hydrocarbon traps.

The Navarin Basin province lies mainly on the Bering Sea continental shelf but does not include a small marginal area lying in waters deeper than 200 meters. The southwest boundary of the lease sale area is defined by the 2,400-meter (7,900-foot) bathymetric contour defining the base of the slope of the Bering Sea continental margin. The lease sale area is about three times larger than the Navarin Basin province but a very small portion (3 percent) of this province is not included in the lease sale area because it lies west of the U.S.A.-Russia Convention line of 1867.

Regional geology of the western Bering shelf is made more difficult because the Mesozoic rocks exposed in the Kuskokwim River area of the Alaska mainland north of Bristol Bay either disappear to the southwest beneath the Bering shelf or curve to the northwest and merge with the belt of shallow water, indurated Mesozoic rocks that underlies the outer part of the the Bering Sea shelf (Scholl et al., 1975; Marlow and Cooper, 1980). These may form the Nunivak arch, a very broad basement high lying east of the Navarin Basin province. This deeply eroded arch served as part of the sediment source, principally the early Tertiary (Paleogene) sediments, for the Bering Sea basins. During later Tertiary time (Neogene), the Yukon River may have flowed southwesterly over this now submerged arch and contributed sediments to the Navarin Basin province.

The outcrop and subsurface geology of the Alaska Peninsula and Koryak region of the U.S.S.R. provide important clues with which to decipher the age of formation of the Bering Sea basins and the character of the sediments contained in these offshore basins. Nine wells drilled along the northern coast of the Alaska Peninsula relate directly to the offshore Bering Sea basins. Although all of these wells were abandoned as dry holes, shows of oil and gas were recorded. In addition, Soviet drilling in the Anadyr Basin resulted in the discovery of "non-commercial" gas from Miocene sands and "non-commercial" quantities of oil from Tertiary sands (Oil & Gas Journal, March 1982).

The same belt of ingneous rocks that underlies St. Matthew Island and the western part of St. Lawrence Island extends to the northwest and underlies the southern Chukotsk and Anadyr River region in northeast Siberia (Patton et al., 1976). The eastern Koryak Range (between the Anadyr Basin on the north and the Khatyrka Basin on the south) is underlain by structurally juxtaposed blocks of different age and lithology and has been compared to the McHugh and Uyak complexes of southcentral and southwestern Alaska (Clark, 1973).

The Koryak Range probably developed as a result of the subduction of oceanic crust moving north relative to the continental crust of Siberia during much of Mesozoic and earliest Tertiary times.

The general tectonic pattern and distribution of rock types in the Chukotsk and Koryak belts are similar to the Alaska Peninsula, Kodiak Island and Kodiak shelf regions as first noted by Burk (1965). Similarities are to be expected because northeastern Siberia and southwestern Alaska are believed to have been subjected to convergence by the Kula crustal plate during the same period of time (Scholl et al., 1975).

II.2.2 Structures

A U.S. Geological Survey reconnaissance seismic reflection survey, using a sparker sound source, was run in 1970, and produced 1,000 kilometers of single channel records in the Navarin province.

This survey indicated the rough outline of the province. More sophisticated and higher energy seismic surveys using five air guns and 24-channel instrumentation were run in 1967, 1977 and 1980 by the U.S. Geological Survey and enabled them to construct an acoustic basement structural contour map. Subsequent industry seismic surveys employing 76-channel equipment produced over 10 times the line coverage as the previous 24-fold U.S. Geological Survey work. The industry surveys further refined the structural picture and provided critical information on details relating to the closure of suspected hydrocarbon traps.

The Navarin Basin province consists of three filled basins separated by basement ridges that trend to the northwest parallel to the adjacent Bering Sea shelf margin. The southern basin is a filled elongate trough 200 kilometers long (7,700 square kilometers; 1,900,000 acres in area). The southern basin is filled with more than 11 kilometers (7 miles) of strata that are broken by normal faults along the basin flank that exhibit growth structures (Marlow and Cooper, unpublished data).

The central basin in the Navarin province, like the southern basin, is also an elongate and filled depression that trends to the northwest. The central basin is smallest of the three basins and encompasses an area of 1,500 square kilometers (370,000 acres).

A large circular basin underlies the northwestern Navarin Basin province adjacent to the U.S.A.-Russian Convention Line of 1867. This basin is the largest feature in the province, covering an area of 10,000 square kilometers (2,560,000 acres) and containing 12 to 15 kilometers (40,000 to 50,000 feet) of sedimentary section. Near the Convention Line, strata in the basin are folded into large anticlines 10 to 15 kilometers (6 to 9 miles) across that may have diapiric cores (Marlow, 1979).

Within the acoustic basement, a number of dipping reflectors, which strongly diverge from the overlying and relatively undisturbed Tertiary reflecting strata, indicate that the Mesozoic "basement" includes folded sediments much like that on the Alaska Peninsula and eastern Siberia.

Closely related to the structure of the Navarin Basin are two eastern Siberian basins, the Anadyr and the Khatyrka. The Anadyr basin is a large (about 100,000 square kilometers (25 million acres)) structural depression filled with Upper Cretaceous and Tertiary sedimentary rocks lying partly onshore and partly offshore. In a general way it is twice as large as the Navarin province but about half as deep.

Offshore reconnaissance geophysical work by the Soviets has defined a large southeast-trending structure known as the east Anadyr trough. Smaller offshore basins have been defined along the coastal area between Cape Navarin and the Anadyr Basin. These small basins may be interconnected and join the north end of the Navarin Basin province (McLean, 1979).

Structural traps in the Anadyr Basin are predominantly anticlinal folds that exhibit low-amplitude closure over large areas. Structures in the central part of the basin are associated with uplifted blocks of basement rock. As a result, the degree of folding formed by draping of the Upper Cretaceous to Neogene section diminishes upward so that Pliocene deposits are almost undeformed. Along the southern edge of the basin, linear anticlinal structures were apparently formed by compressional folding.

Gas and oil have been recovered from the Anadyr Basin, as discussed in Section II.2.4.

The Khatyrka Basin is located south of the Koryak Range, which separates this basin from the Anadyr Basin. Reconnaissance seismic data indicates that the area of the basin is about 40,000 square kilometers (10 million acres) most of which is offshore along the Bering Sea shelf. This basin is elongated in an east-west direction and lies about 325 kilometers (200 miles) from the Navarin province. Only the north edge of the Khatyrka Basin is exposed onshore, but this fact makes this basin the closest onshore basin to the Navarin province. Oligocene sandstones were reported to produce up to 1.06 MMCF/day of gas from three intervals in a well, the location of which is not known other than it was within the Khatyrka Basin.

Anticlinal structures within the Cenozoic fill of the Khatyrka Basin are generally oval (3 to 4 by 5 to 6 kilometers). Locally, the fold axes strike northwestward, and some of the structures have diapiric upwellings of Paleogene clay.

II.2.3 Stratigraphy

There is no direct information on the stratigraphy and no C.O.S.T well has been drilled in the Navarin Basin province. The closest C.O.S.T. well is the ARCO C.O.S.T. Well #1 located 800 kilometers (500 miles) southeasterly in the

St. George Basin area (latitude 55 32' 41" N, longitude 116 57' 20" W). This well was located on a sharp magnetic anomaly, and required only 90 days to drill to a total depth of 4,196 meters (13,766 feet). Although the data from this well are confidential, the relatively fast drilling rate (about the same as the drilling rates of the onshore test wells drilled on the Alaska Peninsula) strongly indicates only moderately indurated sediment.

The St. George C.O.S.T well reportedly bottomed in Eocene volcanic rocks. Based on the stratigraphic relationships of the Tertiary outcrop geology onshore in the Alaska Peninsula and on the Koryak Peninsula, it seems probable that the major part of the unfolded basin fill of the Navarin Basin province consists of an interbedded sequence of Pliocene and Miocene sand and shale, and the deeper parts of the basins are believed to contain Oligocene and Eocene sediments. Cretaceous and older rocks may be near the base of the section.

Nearer subsurface stratigraphic information is found in the Anadyr Basin lying on the north side of the Koryak Range in Eastern Siberia. The Anadyr Basin's wells lie about 370 kilometers (230 miles) northwest from the Navarin Basin province. Here, lower Cretaceous strata consist of moderately clean sandstone interbedded with organically-rich shale and siltstone. The combination of petroleum source rocks and reservoir rocks makes this sequence an exploration target. Upper Cretaceous and early Tertiary rocks are both of non-marine and marine origin. Miocene and Holocene rocks consist of thick conglomerates, shales and siltstones. This stratigraphic section is rather well documented; at least 21 onshore wells had been drilled by 1975.

The nearest stratigraphic information is from the Khatyrka Basin lying on the south side of the Koryak Range in eastern Siberia. This basin is approximately 325 kilometers (200 miles) long. The stratigraphy appears to be somewhat similar to that of the Anadyr Basin, but far fewer wells have been drilled (McLean, 1975).

In the absence of subsurface well data within the Navarin province, the seismic lines provide important clues about the stratigraphy of this province. A visual feature common to all lines is the division of the basin fill into two different reflective sequences: 1) an upper strongly-reflective sequence of probable Miocene to recent age in which there appear to be reflections with rather long lateral continuity, and 2) a lower, weakly-reflective sequence of probable Eocene and Oligocene age in which the seismic reflections are mainly discontinous and short.

Based on regional paleogeologic evidence, porous clastic units should be common within the upper strongly-reflective sequence. The outer Bering Shelf was perodically swept by marine transgressions and regressions. These factors favor the deposition of coarse neritic clastic and deltaic sequences and, therefore, the likely presence of reservoir sands in the Miocene and Pliocene section.

It also seems likely that some course conglomerate beds would be present in the Eocene-Oligocene sequence within the deeper parts of the basins, where locally derived coarse debris from the upthrown basin margins are being eroded and deposited in the early depocenter of the Navarin Basin (Marlow et al., 1976).

Dredge data indicate that the upper 3 to 4 kilometers (10,000 to 13,000 feet) of the beds in the province are younger than early Eocene in age. Deeper strata are poorly reflective, diverge in dip from the overlying strata, and near the base of the section may be Cretaceous age or older.

II.2.4 Reservoir Rocks

The rocks considered to have reservoir potential for oil and gas in the Navarin Basin province are those correlative to the sandstone units of the middle to late Miocene Bear Lake Formation. Sand percentages within the Bear Lake, in the eight subsurface penetrations to the Alaska Peninsula, range from 33 to 67. The greatest amount of net sand is 1,330 meters (4,362 feet; 67 percent), which was encountered in the Pan Am Hoodoo Lake #1 (Sec. 21-T50S-R76W). Bear Lake sands exhibit very good reservoir quantities in most of the Alaska Peninsula test wells. In the deepest penetration, Gulf Sandy River #1 (Sec. 10-T46S-R70W), sonic and density log derived porosities of 25 to 27 percent were calculated from sands at a depth of 3,200 to 3,231 meters (10,500 to 10,600 feet). Sidewall core permeabilities as high as 1,165 millidarcys (mdcys) were recorded at 1,995 meters (6,545 feet) in the Gulf Port Heiden #1 (Sec. 20-T37S-R59W). The Bear Lake sands are both marine and non-marine, and age equivalent sands could be present in the Navarin province.

Shows of oil and gas were recorded on the mud log in the basal Bear Lake sands in the Gulf Sandy River #1.

Sandstones in the older Tertiary formations on the Alaska Peninsula, namely the Oligocene Stepovak and Eocene Tolstoi, contain a very low percentage of good reservoir quality sands. The low porosity and permeability are a function of a combination of factors, principally the abundance of volcanic detritus including matrix clay, and the relatively dense nature and high degree of induration. Higher quality reservoir rocks are expected in the Navarin province because early Tertiary rocks are expected to contain less volcanic derived matrix clays and are believed to contain sections of coarse clastics derived from the rapid erosion of fault scarps and basin margins. Coarse clastics could also originate as fluvial fans or deltiac deposits.

A series of samples were dredged by the U.S. Geological Survey from the Bering Sea continental shelf. Many of the dredged Miocene and Pliocene rocks consist of highly porous diatomaceous siltstone and sandstone and, if the textures and lithologies of these outcrops are partly representative of age-equivalent units within the Navarin Basin, adequate reservoir rocks may be anticipated.

Eocene to Pliocene diatomaceous mudstones exposed on the continental shelf have porosities ranging from 14 to 68 percent (average 48 percent). Neogene reservoir beds may be present in the adjacent Navarin province because sedimentation has matched subsidence, which averaged 100 to 200 m/10^6 year during Cenozoic time. Also, during Neogene time, the Navarin Basin were fed by major Alaska and Siberian rivers, e.g., the Yukon, Kuskokwim and Anadyr Rivers.

In the eastern Siberian Khatyrka Basin which lies a relatively close 325 kilometers (200 miles) from the Navarin province, a flow of up to 1.06 MMCF/day of gas from three intervals in Oligocene sandstone beds was recently reported (Marlow, 1981).

In the Anadyr Basin of eastern Siberia, which lies 370 kilometers (200 nautical miles) northwest of the Navarin province, significant oil shows have occurred in the Eocene and Oligocene strata. One well produced 0.3 tons of oil/day (approximately 2 barrels/day) from fractured strata. In another well, oil shows were noted in upper Eocene and Oligocene strata between 1,400 and 2,130 meters (4,600 and 7,000 feet).

An oil "strike" was recently reported (Oil & Gas Journal, March 22, 1982) by the USSR in the west central portion of the Anadyr Basin. No volumes were reported but oil was recovered from a depth of 1,650 meters (3,400 feet).

In the Anadyr Basin values as high as 26 percent effective porosity and 560 mdcys permeability have been reported for some Miocene sandstone beds. The net thickness of porous sandstone reported is as much as 80 meters (260 feet).

Wells drilled in the Anadyr basin have produced up to 10,000 MCF/day of gas but continued testing led to sharp drops in pressure and volume (Meyerhoff, 1972). The Miocene producing sections were relatively shallow (1,470 meters (4,800 feet)).

II.2.5 Source Rocks

Source rock analysis of the Alaska Peninsula wells indicates that, in general, the Miocene Bear Lake has abundant organic carbon but is immature and the kerogen is predominantly woody with a minor amount of amorphous sapropel. Bear Lake has a high extractable bitumen content with a correspondingly low hydrocarbon fraction, which is interpreted to reflect the coal-rich and/or woody character of the organic material in the formation. The Bear Lake, therefore, would most likely be gas prone on the Alaska Peninsula.

The most favorable source rocks examined were the Eocene Tolstoi in the Pan Am Hoodoo Lake #2 (Sec. 35-T50S-R76W). This unit was high in total organic carbon content, was within the oil generating range, and exhibited a modest vitrinite reflectance.

In the Navarin province, it is believed that Pliocene and Miocene shales will probably be light-colored with a poor source rock potential due to their open marine depositional environment. However, the Oliogene and Eocene shales within the deep Navarin Basin should be darker-colored, contain a higher percentage of organic matter, and serve as adequate source rocks. The deeper portion of the Navarin province was a closed, silled basin during early Tertiary time and ocean circulation was restricted. Thus, organic matter could have been preserved in a manner favorable for hydrocarbon generation.

The Tertiary Khatyrka and Anadyr Basin of eastern Siberia are very similar in age, structural style, and stratigraphy to the offshore Bering Sea basins. Source rock data from the Russian basins compares quite closely with that derived from the Alaska Peninsula.

Eocene, Oligocene, and lower Miocene shales in the Khatyrka Basin all have sufficient organic matter and thermal maturity to qualify as adequate source rocks.

II.2.6 Comparison to Other Pacific Margin Basins

The Navarin province is the most geologically remote sedimentary basin in Alaska with an interesting oil and gas potential. There are no islands or upland areas in Alaska from which to draw outcrop and subsurface geological information with reasonable certainty. The eastern Siberia sedimentary basins are much nearer than any onshore Alaskan basins. For example, the Katyrka Basin is only 325 kilometers (200 miles) distant compared to a distance of 1,500 kilometers (1,000 miles) to the Cook Inlet oil producing area of south-central Alaska; the nearest sedimentary basin to have a well developed oil and gas production history. However, comments about possible common features and differences are appropriate. The Navarin province covers an area of about 1-1/2 times as large as the Cook Inlet Basin and contains about twice the thickness of Tertiary rocks. The increased thickness of the Tertiary section in the Navarin province should provide a more favorable thermal gradient for hydrocarbon maturation than exists in the Tertiary section of Cook Inlet.

There may be a similarity between the Eocene-Oligocene Hemlock conglomerate in Cook Inlet and some of the early Tertiary rocks of the Navarin province because both may have been produced by erosion products from high relief sources areas following the tectonically active close of the Mesozoic era.

A significant criterion that must be considered in the tectonic evolution of the Navarin province is the timing of the structural growth as it relates to time of deposition of the host reservoir beds. Generally, in the productive Pacific Tertiary basins, early structural growth, or development of synchronous "highs," is essential for entrapment of large hydrocarbon accumulations. Early structural growth can be demonstrated seismically in the Navarin province.

Based on our analysis of seismic data, Navarin province traps are very large and in some instances, overlapping. However, considering the very large area of the basin, the number of traps is low compared to more deformed Tertiary basins. Low trap density does tend to increase chances for very large fill-up and thus, very large oil and gas fields, assuming the presence of favorable source and reservoir rocks. Unfortunately, there is no reliable means to rationally estimate the percent fill-up of Navarin Basin structures. However, based on data from other Pacific margin basins, fill-up in excess of 50 percent would be the exception in the Navarin province with 30 percent being more probable.

II.2.7 Traps

Seismic data obtained from the U.S. Geological Survey and from proprietary sources indicate that structural, stratigraphic and combination structural and stratigraphic traps exist in the Navarin province. It also appears that several different types of traps may be superimposed giving rise to the possibility of multiple pool completions if the traps prove capable of oil or gas production. In addition to conventional types of traps there is a possibilty that gas hydrates or an impermeable boundary between overlying silica-rich diatomaceous deposits and an underlying crystalline indurated mudstone (silica-diagenetic boundary) could form seals resulting in the entrapment of hydrocarbons which would otherwise migrate to the ocean floor. Both of these potential hydrocarbon barriers have been noted to exist in water deeper than 500 meters (1,650 feet) in the Navarin province by the U.S. Geological Survey and have been termed Bottom Simulating Reflectors (BSR) because they mimic the bathymetric relief of the sea floor and often cross other layered acoustic reflectors.

The northern basin in the Navarin province contains closed anticlinal structures 10 to 15 kilometers (6 to 9 miles) across formed either by lateral compression or by diapirism. The anticlines are cut by an unconformity that is overlain by a few tens of meters of flat-lying strata. Shallow acoustic anomalies sometimes called "bright spots" are observed within the strata above the balded folds in all basins of the Navarin province.

Beds in the two southern basins are cut by normal growth faults showing very high relief.

Other types of potential traps exist where lower beds thin toward the flanks of the basins and dip toward the axis of each basin, possibly trapping hydrocarbons migrating up dip against less permeable basement rocks.

Discordant overlap of the older permeable stratigraphic sequences by younger impermeable beds may give rise to traps in all basins of the Navarin province.

Some basement highs show several thousands of meters of relief and the draping of younger sediments over these highs could result in traps. Some of these basement highs are 5 to 10 kilometers (3 to 6 miles) in length.

II.3 Assumptions

II.3.1 Initial Production Rate

II.3.1.1 Oil

Initial well production rate is used in the economic analysis as an index of reservoir performance in the absence of specific data about reservoir characteristics (pay thickness, porosity, permeability, drive mechanism, etc.). Initial production rate refers to the sustained average productivity of a well over the first 45 percent of its total production, after which exponential decline occurs. The initial productivity per well influences the number of wells that have to be drilled to efficiently drain a reservoir. Assuming standard well spacing (80 to 160 acres) and the maximum number of wells that can be drilled from a single platform or drilling vessel (dictated by the reservoir depth and well spacing limitations), the peak throughput of a producing system can be estimated using the initial well productivity assumption.

Initial production rate for wells on anticlines in the Navarin province is assumed to average 2,500 barrels per day. This value is higher than assumed for the St. George study because thicker producing sections are predicted and multiple completions are possible for Navarin. The estimated depth of wells in the north basin should range between 2.5 and 3.5 kilometers (6,500 to 11,500 feet) and 1 and 4-1/2 kilometers (3,300 to 13,000 feet) in the southern basins. An overall average of 10,000 feet is used as a base case as it seems to fit the typical anticline more closely. At this depth, the most favorable ratio of porosity, permeability, and pressure is anticipated to occur. It is noted that a single zone completion in the Hemlock formation in the McArthur River oil field of Cook Inlet, Alaska produced 3,772 barrels of oil per day of 113,168 barrels for the month of August, 1981 (Alaska Oil & Gas Convervation Commission). This well has been in production for over 5 years and produces from an anticlinal trap.

The initial productivity assumed for wells producing from the stratigraphic traps will vary widely as depths of these traps range from very shallow to very deep. Considering that some of the productive potential may orginate from coarse clastics formed at the bases of high relief basin walls on fault scarps and also that an overlaping of producing areas might exist, an average initial productivity of 2,500 barrels of oil per day is also assumed for wells on stratigraphic and combination structural and stratigraphic traps.

Within certain technical and economic constraints, the number of wells and their spacing can be varied, depending upon the initial well productivity, to optimize the recovery or take-off rate. These are trade-offs between the investment in additional wells, and the increased revenue streams from a higher offtake rate. (Increasing the number of wells will decrease the well spacing.) In general, the deeper the reservoir the more expensive are the development wells and the longer the drilling time. Thus, it is more advantageous to increase the number of wells in shallow reservoirs (1,500 meters (4,500 feet) or less) to overcome low initial well productivities than it is for deeper reservoirs.

In this study, we have fixed the number of wells producing 2500 B/D to obtain a recovery rate that produces about 10 percent of total assumed reserves in the peak years of production. Our production profile, which assumes secondary recovery, produces approximately 45 percent of reserves during peak production prior to the onset of decline. (See also discussion of recoverable reserves, Section II.3.3, and production profile, Section II.3.4.).

II.3.1.2 Non-Associated Gas

Initial productivity per well for non-associated gas is essentially unknown at this time. Geochemical data on shale well cuttings are needed to determine the ability of a given potential source rock unit to generate oil and/or gas. This critical information is not available to us at this time. For economic analysis, we will assume a gas well productivity of 15 million cubic feet per day.

II.3.2 Reservoir Depth

The geophysical records indicate reservoir depths may range from very shallow (1,000 to 1,500 meters (3,300 to 5,000 feet)), to medium to deep (1,500 to 3,050 meters (5,000 to 10,000 feet)), and to very deep (4,000 to 6,000 meters (13,000 to 19,500 feet)). We therefore assumed reservoir depths of 1,000 meters (3,300 feet), 1,500 meters (5,000 feet), and 3,000 meters (10,000 feet). Analysis of the USGS seismic data covering the Navarin province provides the control for the reservoir depth assumptions. However, the economic analysis reflected only one target depth -- 3,000 meters (10,000 feet).

The most common reservoir depths should be shallow and medium where prospective sediments are draped over the "basement" highs located at the margins of the basin. Deep reservoir depths can be expected within possible fault closures that may exist along the walls of the basin margin and to drapes over basement highs and early Tertiary deposits of coarse clastics formed at the bases of high relief ridges or plateaus.

Reservoir depth in this analysis defines the number of producing systems required to efficiently produce a given field size and, in combination with optimal well spacing, the maximum number of production wells that can be housed in a single producing system whether it be a platform, gravity structure or sub-sea system. All other factors being equal, a shallow field with a thin pay reservoir covering many square kilometers and requiring several systems to produce is less economic than a field of equal reserves with a deep, thick pay zone that can be reached from a single producing system. In the economic and manpower analyses, reservoir depth dictates the rate of development well completion that, in turn, affects the timing of production start-up and peak production (and the schedule of investment return). The well completion rate also affects the development drilling employment.

II.3.3 Recoverable Reserves

II.3.3.1 Technical Introduction

An assessment of recoverable reserves in the virgin basins, such as these, is very speculative. A brief technical review of estimation methods for recoverable reserves demonstrates the complexity of the problem and the requirements for detailed reservoir data.

Recoverable oil from a reservoir is controlled by a combination of the following parameters:

- Oil gravity
- Oil viscosity
- Gas solubility in the oil
- Relative permeability
- Reservoir pressure
- Connate water saturation
- Presence of gas cap, its size, and method of expansion
- Fluid production rate
- Pressure drop in the reservoir
- Structural configuration of the reservoir

Many studies have been made of the relationship between these parameters, most of which are statistical in nature.

II.3.3.2 Estimate for Navarin

As stated earlier, the Miocene Bear Lake equivalent sands offer reservoir objectives in the Navarin province, if these sands are present. The porosity and permeability of these sands, as encountered in wells and outcrop on the Alaska Peninsula, compare closely with porosities and permeabilities of similar Tertiary sands in productive Pacific Margin basins that have recovery factors averaging 200 barrels per acre foot.

Assuming a recovery factor of 200 barrels per acre foot and net pay thicknesses of 200 feet, recoverable reserves per acre approximate 40,000 barrels for primary recovery.

Higher recovery factors such as those found in the Jurassic of the North Sea, the Permo-Triassic of the North Slope of Alaska, and Cretaceous sand reservoirs of the Middle East cannot be used as a basis for comparison. The reservoirs in these basins are generally mineralogically different than those in Pacific Margin Tertiary basins. The Tertiary sand reservoirs are typically arkosic with significant percentages of unstable feldspar minerals that diagenetically alter the clay minerals, thus reducing porosity and permeability. Sand reservoirs in the North Sea and North Slope, in contrast, consist of high percentages of stable minerals such as quartz, have high porosities and permeabilities, and correspondingly high productivities.

There is a possibility that diatomaceous sediments, such as have been dredged from the continental slope of the Bering Sea, will maintain their porosity at greater depths than ordinary sediments.

In this study, we assume primary recovery of 40,000 barrels per acre and primary plus secondary recovery, for a total of 60,000 barrels per acre. Table A-1 shows maximum recovery per producing system for various reservoir depths for these recoverable reserves. We emphasized 60,000 barrels per acre in the economic analysis. To optimize recovery, we have also assumed that a secondary recovery program (e.g., water injection) is initiated early in the development schedule. The field development plan would incorporate secondary recovery in the producing system and process equipment design since retrofitting for a secondary recovery program could be exceedingly expensive. Our idealized 365 million barrels fields, therefore, cover 6,080 acres. Well spacing, therefore, works out to a little under 160 acres per well.

TABLE A-1

MAXIMUM AREA REACHED WITH DIRECTIONAL WELLS FROM A PLATFORM

DEPTH OF RESERVOIR		MAXIMUM AREA PRODUCED[1,2]			MAXIMUM RECOVERY PER PLATFORM (million barrels)[3]		
METERS	FEET	SQUARE MILES	ACRES	HECTARES	30,000 bbl/acre	60,000 bbl/acre	90,000 bbl/acre
763[4]	2,500	0.25	162	66	4.9	9.7	14.6
1,525	5,000	3.9	2,510	1,016	75.3	150.6	225.9
2,286	7,500	11.7	7,503	3,036	225.1	450.2	675.3
3,000	10,000*	20	13,000	5,000	390	730	1,190

Notes:

1. Maximum angle of deviation assumed to be 60 degrees with a kick-off point at a depth of 150 meters (500 feet); this point is not likely to be more shallow than this.
2. See directional drilling chart Figure 3-8 for geometry below kick-off point.
3. Assumes secondary recovery.
4. For shallow reservoirs, the area of coverage is very sensitive to the depth of the kick-off point.

*Reservoir depth evaluated in this study. This is near the limit of horizontal reach for directional drilling; the area and recovery maximums are therefore only approximate and will not change with further increases in depth.

Source: Dames & Moore

An assumption on a range of recoverable reserves per acre is required for this study as a general indication of the potential areal extent of a field for a given (assumed) reserve or field size, assuming simple reservoir geometry. This assumption, in combination with reservoir depth and well productivity, allows an estimate of the number of producing systems and wells required to drain a given field. A "best case" producing system (i.e., fewest producing systems) insofar as reservoir geometry would probably occur in the case of a simple anticline. Obviously, a complex faulted reservoir with the same reserves would necessitate a different producing system configuration, more systems, or even subsea wells. If the incremental recovery could not economically justify investment in an additional system, subsea wells may be required in a complex reservoir to drain isolated portions that could not be reached from directionally-drilled wells.

II.3.4 Production Profiles

II.3.4.1 Oil

The three basic production profile assumptions are: (1) about 40 to 45 percent of the reserves are captured during peak production prior to the onset of decline; (2) no more than 10 percent of total reserves are captured each year of peak production; and (3) decline is exponential at approximately 10 to 15 percent per year.

The timing of production start-up and build-up to peak is governed by the number of development wells, the reservoir depth (rate of well completion), and numbers of rigs (one or two) operating in the platform. For the Navarin analysis, production is assumed to commence in the sixth year after the decision to develop, and steps up to peak as a function of well completion rate, numbers of wells, and field size in the tenth year after decision to develop. Offshore loading platforms take an extra year to complete and delay production for one year.

II.3.4.2 Associated Gas

While recognizing the complex reservoir dynamics related to the production of associated gas, the economic model requires the analytical simplification of a constant ratio of associated gas to oil production at the assumed gas-oil ratio (GOR). Thus, an initial GOR of 500 standard cubic feet of gas per barrel of oil, for example, is maintained throughout the life of the field.

II.3.4.3 Non-Associated Gas

The principal production assumptions concerning non-associated gas production are: (1) about 75 percent of the reserves are captured during peak production*; and (2) decline is exponential and rapid thereafter. The factors affecting production time are essentially the same as those for oil; the main difference is that peak gas production generally occurs earlier because fewer wells are required. Typically, gas field production commences in the fifth year after the decision to develop and peak commences in the seventh or eighth year.

II.3.5 Field Size and Distribution

Three types of traps of economic importance may be present in Navarin province. These are:

1. Closed anticlines over basement highs;

2. Domes or closed folds with diapiric cores; and

3. Stratigraphic traps of either: (1) buttressing clastic units against normal growth fault scraps or basement highs; or (2) discordant overlap of older permeable stratigraphic sequences by younger impermeable beds.

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*Note this is essentially a plateau in the production profile where gas is produced at constant rate for a number of years (i.e., production at "peak" is essentially "flat").

All three potential traps are visible on the USGS seismic lines that cross the Navarin province.

At least one very large high angle fault exists in the south basin.

Potential stratigraphic traps of buttressing sands against pre-Tertiary basement highs are visible in all basins of the Navarin province.

Sufficient seismic data was not available to determine the closure, which is necessary to determine field size.

Assuming that Navarin province traps will be hydrocarbon bearing, and assuming seismic data were available to identify structures and estimate the areas of closure, etc., the all important economic problem would be the prediction of percent fill-up. The approach used to predict fill-up would be an analogy based on statistical comparisons with known productive Pacific Margin basins. It should be emphasized, however, that any analogical approach to prediction of petroleum resources is extremely hazardous. Each basin is unique. One critical difference in geologic parameters can completely negate the effect of many similarities.

Factors affecting percent fill-up are the richness of the source rock and quality of reservoir rock. In addition, trap density is also an important factor. Generally, the greater the trap density, the smaller the fill-up. As examples, the average percent fill-up of productive closures in the Pacific Margin Los Angeles and Ventura Basins are 40 and 15 percent full, respectively.

Unfortunately, there is no reliable way to estimate percent fill-up in the Navarin province. Based on data from around the Pacific Margin, we assume that fill-up in excess of 50 percent would be the exception in the Navarin basin. In estimating potential reserves of this basin, only those areas lying within the 50 percent fill contour should be considered, with 30 percent fill-up considered as average.

The field sizes selected for economic screening were consistent with, or reflect, the following factors:

- o U.S. Geological Survey resources estimates;
- o Geology (discussed above), which indicates that "giant" fields (billion barrels or more) are a possibility; and
- o Anticipated economic conditions and the requirement to examine a reasonable range of economic sensitivities.

The field sizes evaluated in this study, therefore, ranged from 365 million barrels to 1.8 billion barrels for oil and 1.4 trillion cubic feet for non-associated gas. It should be noted that once a number of field sizes (with a certain reservoir characteristic and matched engineering) have been evaluated, minimum economic field sizes can be calculated by the model. Therefore, a reasonable range of field sizes to be screened is important rather than the actual field size distribution.

II.3.6 Allocation of the U.S. Geological Survey Gas Resource Estimate Between Associated and Non-Associated and Gas-Oil Ratio (GOR)

To develop manpower and facility requirements corresponding to the U.S. Geological Survey mean gas estimates, we followed the USGS assumption about the allocation of the gas resource between associated and non-associated for the statistical mean resource estimate of 75 percent non-associated/25 percent associated (Marlow et al., 1979).

III. TECHNOLOGY AND TECHNICAL ASSUMPTIONS

III.1 Introduction

This section outlines the technical and technology assumptions behind the economic analysis, the principal aim of which was to evaluate the relationships among the engineering strategies that may be adopted to develop Navarin Basin oil and gas resources, and the minimum field sizes required to justify each technology as a function of geologic conditions in the sale area.

III.2 Production Systems Selected for Economic Evaluation

Based upon the results of the petroleum technology assessment (Chapter 3.0), the following production systems were selected for economic screening:

- Single steel platforms with shared or unshared pipelines to and terminals on St. Matthew Island -- -- and/or gas oil production.

- Concrete gravity platform with on-platform oil storage offshore loading to tankers shuttling to an Aleutian transshipment terminal -- oil production.

- Single steel platform with on-platform gas liquification facilities offshore loading to LNG tankers bound for the West Coast -- gas production.

III.3 Pipeline Distances and Transportation Options

Distances from potential discovery sites to the potential shore terminal sites are described in Chapter 4.0. Based on these distances, the following pipeline distances were selected for economic evaluation: St. Matthew Terminal -- 240 kilometers (150 miles), and St. Paul Terminal -- 480 kilometers (300 miles).

III.4 Other Technical Assumptions

III.4.1 Well Spacing

III.4.1.1 General Considerations and Oil

Based on reservoir depths, initial well productivity, and recoverable reserves per acre, there will have to be enough wells to meet these production criteria:

- Produce about 10 percent of reserves each year for peak production at a spacing generally between 80 and 160 acres.

- Allow exhaustion of recoverable reserves within 20 - 25 years.

Well spacings consistent with industry practice, reflecting maximum efficiency rates, and varying as a function of initial well productivity, recoverable reserves per acre, reservoir depth and numbers of wells are implicit in Table A-1. Table A-1 indicates the maximum number of production wells that can be housed on platform for well spacings of 80 and 160 acres. Based on industry practices in the upper Cook Inlet, well spacing for the Navarin Basin oil fields could range between 40 - 160 acres per well. In shallow reservoirs with low IP, wells spacing may be as low as 40 acres. The oil wells in McArthur River field in upper Cook Inlet, for example, are now completed with 80-acre spacing. Although the original spacing was 160 acres, this was reduced by in-filling as field development proceeded.

At Prudhoe Bay, high production is currently coming from wells on moderate spacing in this unitized field. Ultimate well spacing at Prudhoe Bay may be less, although the actual reservoir management strategy will depend upon reservoir performance. A reasonable assumption, therefore, is that standard industry well spacing between 80 and 160 acre spacing will be adopted for Navarin Basin oil fields; oil fields may be developed initially on a 160-acre spacing but, subsequently, reduced by in-filling to 80-acre spacing.

III.4.1.2 Non-Associated Gas

As noted in previous scenario studies, well spacing in Alaska frontier areas is likely to be set by the market demand for gas, or frontier constraints on the ability to convert gas to LNG, rather than by industry desire to maximize recovery. Consistent with reservoir engineering and petroleum geology, well spacing up to 1,200 acres may allow sufficient gas production to run potential LNG capacity. Well spacing in the usual U.S. range of 160 - 320 acres may have little relevance to gas producers in the Navarin Basin if there is a limited market for gas.

III.4.1.3 Well Allowances

A certain number of wells in a field are non-producing wells. These wells may be (1) water injection wells required as part of a secondary recovery program, (2) abandoned wells, and (3) gas injection wells drilled either as part of a pressure maintenance program or because there was no market for associated gas. As in previous studies, we have assumed that well allowances will be one in five wells. This is consistent with experience in producing fields although the ratio may be as high as 1:3. In our analysis we have assumed early initiation of a secondary recovery program. However, it should be emphasized that the number of non-producing wells will vary considerably with reservoir characteristics and reservoir management program. Well allowances are factored into the economic and manpower analyses.

III.4.2 Well Completion Rates

III.4.2.1 Exploration Wells

As indicated in the petroleum geology review, the depth to basement varies considerably across the Navarin area from less than 1,500 meters (5,000 feet) on the flanks of the basin to well over 10,000 meters (33,000 feet) in the interior portions. Prospective reservoirs probably lie at depths ranging from less than 1,500 meters (5,000 feet) to about 7,500 meters (25,000 feet). Consequently, other factors apart, there will be considerable variation in the completion schedules of exploratory wells. Based upon drilling experience in the other OCS areas, medium to deep exploratory wells can be expected to take 3 to 5 months to drill. Actual schedules will vary according to geologic conditions, testing requirements and technical difficulties. For the purposes of manpower estimation and analytical simplification, we have assumed that exploratory and delineation drilling averages 4 months per well.

III.4.2.2 Development Wells

Potential reservoir depths range from 917 - 4,572 meters (3,000 - 15,000 feet). Since most of the development wells will be drilled directionally from platforms, their actual length (measured depth) will be greater. Directional wells drilled into the Sadlerochit reservoir (2,400 - 2,800 meters or 8,000 - 9,000 feet) at Prudhoe Bay take an average of 30 days to drill. We will assume 60 days for the 3,000-meter (10,000-foot) reservoirs assumed in the Navarin basin analysis. Wells drilled from offshore platforms may be drilled on the batch principle.

IV. ECONOMIC ANALYSIS

We have adopted the same economic assumptions made for our recently completed St. George Basin study as described in Appendix A, Section IV, of that final report. Except for changes in prices and costs, no factors have changed since completion of that study that would warrant any changes in our economic assumptions.

In keeping with our earlier analyses of St. George and North Aleutian Basins, the Navarin economic analysis does not reflect the significant cost inflation that could occur as a result of equipment bottlenecks resulting from the proliferation of OCS lease sale activity in the Bering Sea. Our studies have been mandated to evaluate each sale individually and in isolation; the combined or cumulative economic, socioeconomic, and infrastructure affects of several closely-spaced (chronologically) lease sales are not reflected.

Our economic assumptions for Navarin (more detailed background for these are discussed in Appendix A of the final St. George Basin report) are summarized below:

- Time Values of Money: We have assumed an 8 to 12 percent discount rate bracket after-tax real hurdle rates. Constant (1981) dollar prices and costs are used.

- Oil Prices: The value of oil F.O.B. in the Aleutian is \$32.00, which is \$4.50 higher than the prices used for earlier (1980) studies of Bering Sea leases. This assumes existing low 1982 crude oil prices will recover in real terms by the time the Navarin development begins.

- Natural Gas Prices: The value of gas is assumed to be \$6.15 per MCF laid-in at a California port. This price is based on an equivalent value per BTU of diesel oil (\$35 per barrel). Unlike earlier analyses, the California rather than the net-back Alaska value is used in this study. This was done because the gas is assumed to be liquified offshore in the Navarin and transported by dedicated tankers direct to market.

- Effective Income Tax Rate: We have assumed a ratio of 46 percent of taxable income after various deductions.

- Royalty: We have assumed 16-2/3 percent of the value of production.

- Tax Credits, Depreciation and Depletion: Investment tax credits of 10 percent apply to tangible investments. Depreciation of tangible investments are calculated by the units-of-production method. No depletion is allowed over the production life of the field. Bonus and lease expenses are treated as sunk costs and assumed away for the development decision analysis.

- Fraction of Investment As Intangible Cost: Expenses are written off as intangible drilling costs to the maximum extent permissible by law. Expenses incurred before production are assumed to be expensed against other cash flows of the producer.

  The allocation of tangible investment costs varies with the component parts of offshore development. A 50/50 split between tangible and intangible offshore development costs is used in this analysis.

- Investment Schedule: Continuous discounting of cash flow is assumed to begin when the first development investment is made. This assumes that time lags and costs for permits, etc. from the time of field discovery to initial development investment are expensed against corporate overhead. This is a critical assumption that removes 12 to 36 months of discounting from the ultimate cash flow and makes minimum field sizes calculated smaller than if the lags were included. Investment schedules are further discussed in Appendix B of this report.

APPENDIX B

FIELD DEVELOPMENT COMPONENT COSTS AND SCHEDULES

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APPENDIX B

FIELD DEVELOPMENT COMPONENT COSTS AND SCHEDULES

I. DATA BASE

This appendix presents cost estimates for the field development and operating used in the economic analysis. Exploration costs are not included (see discussion in Appendix A). The cost estimates given in this appendix were developed by engineering staff of Santa Fe Engineering Services Co. and supplemented by Dames & Moore.

Several important qualifications need to be discussed with respect to estimating petroleum facility and equipment costs for frontier areas such as the Navarin Basin. Predictions about the costs of petroleum development in frontier areas (where no exploration has yet occurred) can be risky or even spurious. Such predictions rely on extrapolation of costs from known producing areas suitably modified for local geographic, economic, and environmental conditions. Further, cost predictions require identification of probable technologies to develop, produce, and transport OCS oil and gas. No offshore area developed to date has the particular combination of waves, sea-ice, water depths, seismicity, and remoteness that characterize the Navarin. As such, there is little or no engineering and direct cost experience upon which to make these cost estimates.

Petroleum development cost data are based on either direct cost experience of projects in current producing areas such as the Gulf of Mexico and North Sea, or projections based upon experience elsewhere modified for the technical and environmental constraints of the frontier area. For sub-arctic and arctic areas, facility cost projections may involve estimates for new technologies, construction techniques, etc. that have no base of previous experience (e.g., offshore LNG). It should be emphasized that in-depth research on production technologies and related costs for the Bering Sea basins has begun only in recent years.

The approach in this study involved cost estimating by petroleum, drilling, pipeline and marine engineers. In the course of earlier Alaska OCS studies on the Gulf of Alaska (Dames & Moore, 1979a and b), Lower Cook Inlet (Dames & Moore, 1979c) and Norton Sound (Dames & Moore, 1980), a considerable data base on petroleum facility costs for offshore areas was obtained that provided supplemental information for this study. Those data were based on published literature, interviews with oil companies, construction companies, and government agencies involved in OCS research.

In addition to the difficulties in obtaining relevant and comparable cost data (which applied as well to our earlier Bering Sea studies), lease sales, the extreme remoteness of the Navarin from shore facilities imposed even greater cost estimation uncertainties. As a result, Navarin cost estimates are even more speculative than the earlier studies. Where primary source data were unavailable (particularly in the case of gas production), cost estimates were obtained from a recent publication of the National Petroleum Council entitled U.S. Arctic Oil and Gas (December 1981).

II. COST AND FIELD DEVELOPMENT SCHEDULE UNCERTAINTIES

As explained in Chapters 1.0 and 6.0 of this report, the purpose of the economic analysis is not to evaluate a site-specific prospect with relatively well-known reservoir and hydrocarbon characteristics but to bracket the development economics of the lease area, which comprises a number of prospects that will have a range of reservoir and hydrocarbon characteristics. This requires a set of assumptions on reservoir and hydrocarbon characteristics and technology (see Appendix A). The facilities cost data, presented in Tables B-1 through B-9 present these assumptions.

It should be emphasized that field development costs actually vary considerably even for fields with similar recoverable reserves, production systems, and environmental setting. Some of the important factors in this variability are reservoir characteristics, quality of the hydrocarbon stream, distance to shore, proximity of other fields, and lead time (from discovery to first production). For example, platform processing equipment costs vary significantly with reservoir characteristics including drive mechanism, hydrocarbon properties, and anticipated production performance. Analytical simplification, however, requires that costs vary with throughput while the other parameters are fixed by assumption. In order to focus on the key development issues and keep the analysis manageable, not all these economic sensitivities can be accommodated.

Other factors, such as market conditions, also play a role in field development costs. The price an operator pays for a steel platform, for example, will be influenced by national or international demand for steel platforms at the time he places his order and whether he is in a buyer's or seller's market. Similarly, offshore construction costs will be influenced by lease rates for construction and support equipment (lay barges, derrick barges, tugs, etc.), which will vary according to the level of offshore activity nationally or internationally. There may also be significant differences in the cost of platforms fabricated in the United States versus other countries such as Japan; currently, on the U.S. west coast, the cost savings of platforms fabricated in Japan more than offset additional transportation costs.

The costs presented in Tables B-1 through B-9 reflect our estimates of the facility and equipment costs, based on the stated simplifying assumptions. All the cost figures are given in 1981 dollars.

Briefly discussed below are the principal uncertainties relating to the cost estimates for the various facility components. Important assumptions are noted in the tables.

II.1 Platform Fabrication and Installation (Table B-1)

Cost estimates are presented for two types of platforms -- a steel jacket and a concrete gravity structure -- in water depth representative of the high interest areas of Navarin Basin. These costs include design, manufacture, tow-out and installation.

In addition to the water depth for steel platforms, factors such as design deck load and number of well slots also affect cost. Fewer than 32 wells may be difficult to justify economically, while greater than 48 becomes a design constraint for these platforms. For this general estimate, we feel that the difference in cost estimates is not that great between platforms containing between 32 and 48 conductors. In estimating platform costs, process equipment specifications could have been considered as a more appropriate size/deck load index. This is true in many cases. However, for the platforms and various design criteria considered, the deck load does not appear to be a principal cost factor.

II.2 Platform Process Equipment (Tables B-2 and B-3)

As noted above, our platform processing equipment costs (Tables B-2 and B-3) vary with throughput and assume that other parameters are fixed as noted in the tables.

Although there is little difference in cost related to the decision to produce or reinject associated gas, for the range of figures and type of construction we have assumed, the major cost is equipment installation, not the cost of hardware.

As the gas-oil ratio increases, the size of the pressure or production vessels and pipelines increase. Larger, more sophisticated equipment is required to handle the gas. At some point, depending on the amount of gas handled, the amount of entrained liquids, and costs, it becomes economical to take the natural gas liquids, stabilize them, and inject this stream into the oil pipeline. Associated gas may be reinjected into the reservoir to maintain pressure and to prolong the flowing life of the well. If natural gas production is not economically feasible, reinjection of associated gas is the only viable solution to the flaring ban imposed upon producing fields.

On offshore platforms, space requirements for larger process vessels, pipelines and the increased equipment requirements for gas processing, usually will not dramatically affect the platform costs.

In the economic analysis, we have evaluated the economics of associated gas production assuming the field(s) have a high GOR (see Chapter 6.0).

The costs for platform process equipment for a secondary recovery program (e.g., water injection) are much reduced if planned from the beginning. When water is injected, some of the drilling slots must be used, thus reducing the number available for production and, in turn, reducing the production rate and revenue flow. Also, more space is required for equipment. However, given the platform designs considered, this would have little effect on overall installed platform costs.

II.3 Production Wells (Table B-4)

Production wells are assumed to be drilled from platform-mounted rigs. Two rigs would be used intially in developing the specified 365-million-barrel oil fields. These rigs are able to drill a well every 60 days for a total of 12 wells per platform per year during production step-up. Once the inital drilling period is over, one rig would be removed, while the second would remain on the platform for workovers.

Gas wells are similar in design and cost to oil wells. Since fewer wells are assumed drilled from each platform, only a single rig would be installed on each gas platform.

II.4 Marine Pipelines (Table B-5)

The costs of pipelines are presented for 150- and 300-mile lengths which are representative of the distance from the center of the Navarin Basin to St. Matthew and St. Paul Islands, respectively. The cost per mile is lower for a given diameter for the longer line, since the mobilization/demobilization cost are amortized over more miles. The cost per unit throughput will be greater for the longer (St. Paul) pipeline, however, since a larger diameter would be required, to minimize pressure losses (see discussion in Section 6.2). The costs in Table B-5 assume an average depth of 120 meters (400 feet). If the average depth were 90 or 150 meters (300 or 500 feet), the above costs would be affected by a factor of approximately 10 percent, plus or minus. No onshore pipelines are assumed to be required.

Natural gas pipelines are usually trunklines, as large quantities of gas reserves are required to produce sufficient revenue to pay back the capital investment.

II.5 Oil Terminal Costs (Table B-6)

Particular uncertainty exists regarding crude oil terminal costs in the more remote areas of Alaska. Oil terminal costs will vary as a function of throughput, quality of crude, upgrading requirements of crude for tanker transport, terrain and hydrographic characteristics of the site, type, size, and frequency of tankers, and many other factors. Rugged terrain and remote location will impose significantly greater costs on terminal construction than a similar project in the Cook Inlet area or Lower 48. There is little cost experience to project terminal costs in Alaska except Cook Inlet and Alyeska's Valdez terminal. Further afield, there is the North Sea experience of the relatively remote Flotta and Sullom Voe terminals located in the

Orkney and Shetland Islands, respectively. Consequently, these costs are more speculative than most presented in this report.

Two studies have addressed the economics of terminal siting and marine transportation options in the Bering Sea (Global Marine Engineering, 1977; and Engineering Computers Opteconomics, 1977). A third study addressing these problems was conducted for the Alaska Oil and Gas Association (AOGA) and is currently proprietary.

As indicated in Table B-6, it is assumed that the Bering Sea marine terminal combines the functions of a partial processing facility (to upgrade crude for tanker transport) and a storage and loading terminal. It is assumed that an Aleutian Island terminal would serve as: (1) a transshipment facility for fields that may employ offshore loading, and/or (2) a transshipment terminal where crude from the northern Bering Sea would be transferred from ice-reinforced tankers to conventional tankers bound for the Lower 48 states. The Aleutians terminal includes the cost of a deep water mooring for loading VLCC tankers.

II.6 Costs Estimates for Tankers and Workboats (Table B-7)

Production of Navarin's oil and gas resources requires ice-reinforced oil and LNG tankers and ice-breaking workboats. To reflect economics of scale inherent in oil tanker operation, cost for two sizes of tankers are estimated. The 100,000 DWT tanker is used for single field cases, while the costs for the larger (150,000 DWT) are used for the larger cases.

Ice-reinforced LNG tankers do not yet exist, although they are being designed. The design configuration and cost for those vessels is taken from the NPC Arctic Oil and Gas Study (Section E of the 1981 draft).

Workboats with ice-breaking capability would be required at a Bering Sea terminal and to serve the offshore platforms. Costs, on Table B-7 are based on a 290- foot 2,000-DWT vessel developing 18,000 horsepower. These estimates were provided by Santa Fe Engineering.

II.7 Annual Fuel Operating Costs (Table B-8)

The costs for owning and operating marine terminals and ships are shown on Tables B-6 and B-7, respectively. The cost of operating offshore platforms, pipelines and general and administrative support activities are shown on Table B-8. General and administrative operating costs for platform decline significantly as the number of platforms increase. A distinction is made between the high level of administrative support required during construction and the lower level of administrative activity needed once the production routine is established.

II.8 Miscellaneous Costs Estimate

In the economic analysis, 10 percent of the total field development costs (including pipelines and terminals) has been added to the total capital expenditures for costs that cannot be readily classified (e.g., flare booms). This cost is based on a review of the North Sea field development costs.

II.9 Scheduling of Capital Expenditures and Method of Analysis (Table B-9)

The cost tables presented in this appendix are the basic inputs in the economic analysis. Each case analyzed is essentially defined by recoverable reserves, reservoir characteristics, and production technology (type of platform, transportation option, distance from shore terminal). To cost a particular case, the economist matches the engineering to the assumed reservoir conditions, selects the production technology and takes the related required cost components from Tables B-1 through B-8 using a building block approach, in some cases this involves deletion or substitution of a facility or equipment item. The reservoir engineering of cases is further explained in Appendix A.

The cost components of each case are scheduled as indicated on Table B-9. The schedules of capital cost expenditures are based upon typical development schedules in other offshore areas modified for the environmental conditions of the Navarin Basin making certain assumptions on field construction schedules.

In scheduling expenditures, a distinction is made between pipeline and offshore loading scenarios. The offshore loading scenarios utilize concrete gravity platform which take longer to build and bring into production. Expenditures are scheduled to reflect this difference.

TABLE B-1
COST ESTIMATES FOR INSTALLED PLATFORMS

PLATFORM TYPE	WATER DEPTH METERS	WATER DEPTH FEET	NUMBER OF WELL SLOTS	INSTALLED COST[2] ($ Millions) (1981)
Steel Jacketed (no storage)	125	410	48	160
Gravity Base With 1.5 MMBBL storage[1]	125	410	48	450

Notes: 1. Represents a 15-day storage capacity at a production of 100,000 BOPD.

2. In addition to fabrication of the gravity structure in a Lower 48 yard, and fabrication of the steel platform in a Japanese yard, these estimates include the cost of platform installation, which involves site preparation, tow-out, set-down and pile driving. The above estimates do not include any allowance for the installation or hook-up of topside facilities (see Table B-3).

Source: Santa Fe Engineering Services Co.

TABLE B-2
COST ESTIMATES FOR PLATFORM EQUIPMENT[1] AND FACILITIES FOR OIL PRODUCTION

PEAK CAPACITY OIL (Barrels Per Day)	COST[2] ($ Millions 1981)
100,000 to pipeline	165[3]
100,000 offshore loaded[4]	200

Notes:
1. The cost of topside facilities would be essentially the same for all the platform types being considered.
2. The above cost estimates include installation, hook-up, and commissioning. It is assumed that module installation would be concurrent with platform installation, thus avoiding a second mobilization and demobilization of the equipment.
3. Gas/oil ratio is assumed 500:1. If significantly lower ratios are encountered, these cost could be up to 20 percent lower.
4. The offshore loading equipment adds an estimated $35 million to the equipment cost.

Source: Santa Fe Engineering Services Co.

TABLE B-3

COST ESTIMATES FOR PLATFORM EQUIPMENT AND FACILITIES FOR GAS PRODUCTION

PEAK CAPACITY GAS (Thousand MCF Per Day)	COST ($ Millions 1981)
250 (production equipment)	250
1,000 (liquifaction and storage equipment--offshore)	2590[3]

Notes: 1. The cost of topside facilities would be essentially the same for all the platform types being considered.

2. See Notes 1 and 2 on Table B-3.

3. This cost only applies to offshore loading equipment. Onshore LNG equipment is discussed under terminals (Table B-7).

Source: National Petroleum Council, US Arctic Oil and Gas, August 1981.

TABLE B-4

COST ESTIMATES OF PRODUCTION WELLS (OIL OR GAS)

WELL TYPE	RESERVOIR DEPTH METERS	RESERVOIR DEPTH FEET	COST ($) MILLION (1981)
Production Well			
(Drilled in 125 meter Water depth from on-platform rig)	3,000	10,000	6.6

Source: Santa Fe Engineering

Notes:

1. Well is assumed to be directionally drill (below the mud line).
2. Includes rig cost for two rigs, one of which will remain on the platform for workovers.
3. Includes mobilization costs operating cost and consumables.

TABLE B-5

COST ESTIMATES FOR MARINE PIPELINE

DIAMETER (inches)	PIPELINE SPREAD $ MILLION, 1981 150-Mile (per mile)	PIPELINE SPREAD $ MILLION, 1981 300-Mile (per mile)	DAILY THROUGHPUT (MBOPD) 150-Mile	DAILY THROUGHPUT (MBOPD) 300-Mile
20	1.8	1.5	100	75
24	2.1	1.8	250	150
30	2.7	2.2	340	250
36	3.4	3.2	500	440
38	3.7	3.4	600	500
42	4.3	NA	1000	NA

Notes:

1. Maximum pumping pressures are 2,000 psi necessitating use of thick-walled pipe. No intermediate pumping stations are required, assuming crude properties are similar to Prudhoe Bay crudes.
2. No trenching or insulation is assumed.
3. Includes mobilization/demobilization of a third generation lay barge (two for the 300-mile pipeline to St. Paul).

Source: Santa Fe Engineering Services Co.

TABLE B-6
ESTIMATES OF OIL TERMINAL COSTS[1]

PEAK THROUGHPUT (Thousand Barrels Per Day)[2]	CAPITAL COST ($ Millions 1981)	OPERATING COST ($ Millions 1981)	
		Aleutian Islands	St. Matthew or St. Paul
100	250	23	27
200	380	25	29
300	470	27	31
400	560	29	33
500	650	31	35

Notes: 1. The shore terminals costed here are assumed to perform the following functions; pipeline terminal (for offshore lines), crude stabilization, LPG recovery, tanker ballast treatment, crude storage (sufficient for about 10 days' production), and tanker loading of crude.

2. Operating costs for terminals at St. Matthew or St. Paul include the cost of operating one 280-foot ice-breaking tug/work boat.

3. Capital costs for Aleutian Island terminal includes cost of a deepwater mooring for loading VLCC tankers.

Source: Dames & Moore estimates compiled and National Petroleum Council, 1981 and Santa Fe Engineering Services Co.

TABLE B-7

ESTIMATES OF COSTS AND ANNUAL OPERATING
EXPENSES FOR TANKERS AND WORK BOATS

VESSEL TYPE	CAPITAL COST ($ MILLION 1981)	ANNUAL OPERATING COST ($ MILLION 1981)
1. Ice Reinforced 150,000 DWT Oil Tanker	155	16
2. Ice Reinforced 100,000 DWT Oil Tanker	125	14
3. Ice Strengthened 140,000 cubic meters LNG Tanker	310	23
4. Ice Breaking Workboat - 140 feet	40	4

Sources: Santa Fe Engineering and National Petroleum Council.

TABLE B-8

ESTIMATES OF ANNUAL FIELD GENERAL AND ADMINISTRATIVE AND OPERATING COSTS ($ Million 1981)

SYSTEM	OPERATING COST PER PLATFORM	GENERAL AND ADMINISTRATIVE COST PER PLATFORM DURING: CONSTRUCTION	PRODUCTION
1 Platform Field*	50	20	10
2 Platform Field	40	18	8
3 Platform Field*	35	17	7
4 Platform Field	30	16	6
5 Platform Field*	30	15	5

* Only these values were required for the cases investigated in this study.

Source: Dames & Moore estimates compiled from various sources including Wood, MacKenzie & Co., 1978; Gruy Federal, Inc., 1977.