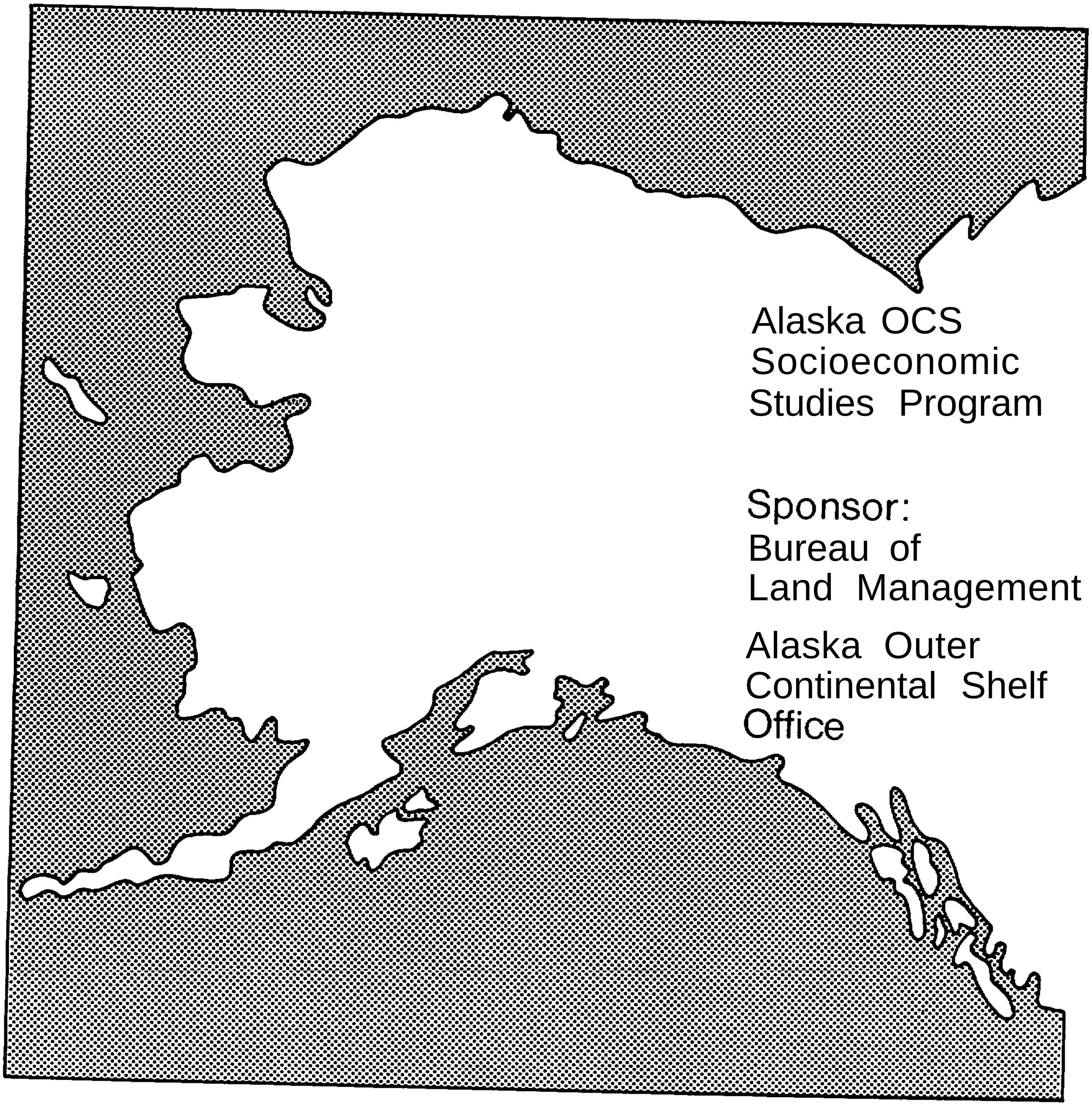
Technical Report Number 43



Alaska OCS
Socioeconomic
Studies Program

Sponsor:
Bureau of
Land Management

Alaska Outer
Continental Shelf
Office

Lower Cook Inlet and Shelikof Strait Petroleum Development Scenarios

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

The Alaska OCS Socioeconomic Studies Program is a multi-year research effort which attempts to predict and evaluate the effects of Alaska OCS Petroleum Development upon the physical, social, and economic environments within the state. The overall methodology is divided into three broad research components. The first component identifies an alternative set of assumptions regarding the location, the nature, and the timing of future petroleum events and related activities. In this component, the program takes into account the particular needs of the petroleum industry and projects the human, technological, economic, and environmental offshore and onshore development requirements of the regional petroleum industry.

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

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

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

Technical Report No. 43

ALASKA OCS SOCIOECONOMIC STUDIES PROGRAM
LOWER COOK INLET AND SHELIKOF STRAIT
OCS LEASE SALE NO. 60
PETROLEUM DEVELOPMENT SCENARIOS

FINAL REPORT

Prepared for

BUREAU OF LAND MANAGEMENT
ALASKA OUTER CONTINENTAL SHELF OFFICE

Prepared by

DAMES & MOORE

July 1979

Contract No. AA550-CT6-61,
Task 9BB

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NOTICES

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

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

3. The units presented in this report are metric with American equivalents except 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).

ALASKA OCS SOCIOECONOMIC STUDIES PROGRAM
Lower Cook Inlet and Shelikof Strait
OCS Lease Sale No. 60
Petroleum Development Scenarios
Final Report

Technical Report

Prepared by

DAMES & MOORE

July 1979

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1.0 INTRODUCTION

1.1 Purpose

In order to analyze the socioeconomic and environmental impacts of Lower Cook Inlet and Shelikof Strait petroleum exploration, development, and production, it is necessary to make reasonable and representative predictions of the nature of that development. The petroleum development scenarios in this report serve that purpose; they provide a "project description" for subsequent impact analysis. The socioeconomic impact analysis of the Lower Cook Inlet and Shelikof Strait petroleum development postulated in this report will be contained in a subsequent report of this study program.

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

It should be emphasized that this petroleum scenarios report is specifically designed to provide petroleum development data for the Alaska OCS socioeconomic studies program. The analytical approach is structured to that end and the assumptions used to generate scenarios may be subject to revision as new data becomes available. Within the study programs that are an integral part of the step-by-step process leading to OCS lease sales, the formulation of petroleum development scenarios is a first step in the study program coming before socioeconomic and environmental impact analyses.

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

1.2 Scope

The petroleum development scenarios formulated in this report are for the proposed Lower Cook Inlet and Shelikof Strait OCS lease sale no. 60[1] currently scheduled for August 1981. This is a second generation lease sale following and earlier lower Cook Inlet lease sale CI[1] held on October 27, 1977. In that sale a total of 87 tracts were leased of the 135 that were offered; the leased tracts comprise 200,448 hectares (495,307 acres) which is approximately 22% of the total federal acreage in lower Cook Inlet.

The study area considered in this investigation (Figure l-l) is the area of the call for nominations for Sale 60 which consists of all the unleased federal tracts of lower Cook Inlet and all of the federal waters of Shelikof Strait extending from Cape Douglas in the northeast southwest about a line drawn between Middle Cape (Kodiak Island) and Cape Igvak (Alaska Peninsula) at the southwestern entrance of the strait. The lower Cook Inlet tracts are located in water depths ranging from less than 30 meters (100 feet) in the northern part of the sale area south of Kalgin Island to 183 meters (600 feet) at Kennedy Entrance; over 50% of this area lies in water depths between 46 and 76 meters (150 and 250 feet). Water depths in Shelikof Strait range from 91 meters (300 feet) in the northeast to over 303 meters (1 ,000 feet) at the southwestern entrance.

The scope of work for this study did not include an evaluation of the natural environment (oceanography, geology, geologic hazards, biology), land status and environmental regulations with which to assess the

(1) Henceforth in this report for the purpose of brevity, these lease sales are referred to as "Sale 60" and "Sale Cl" respectively.

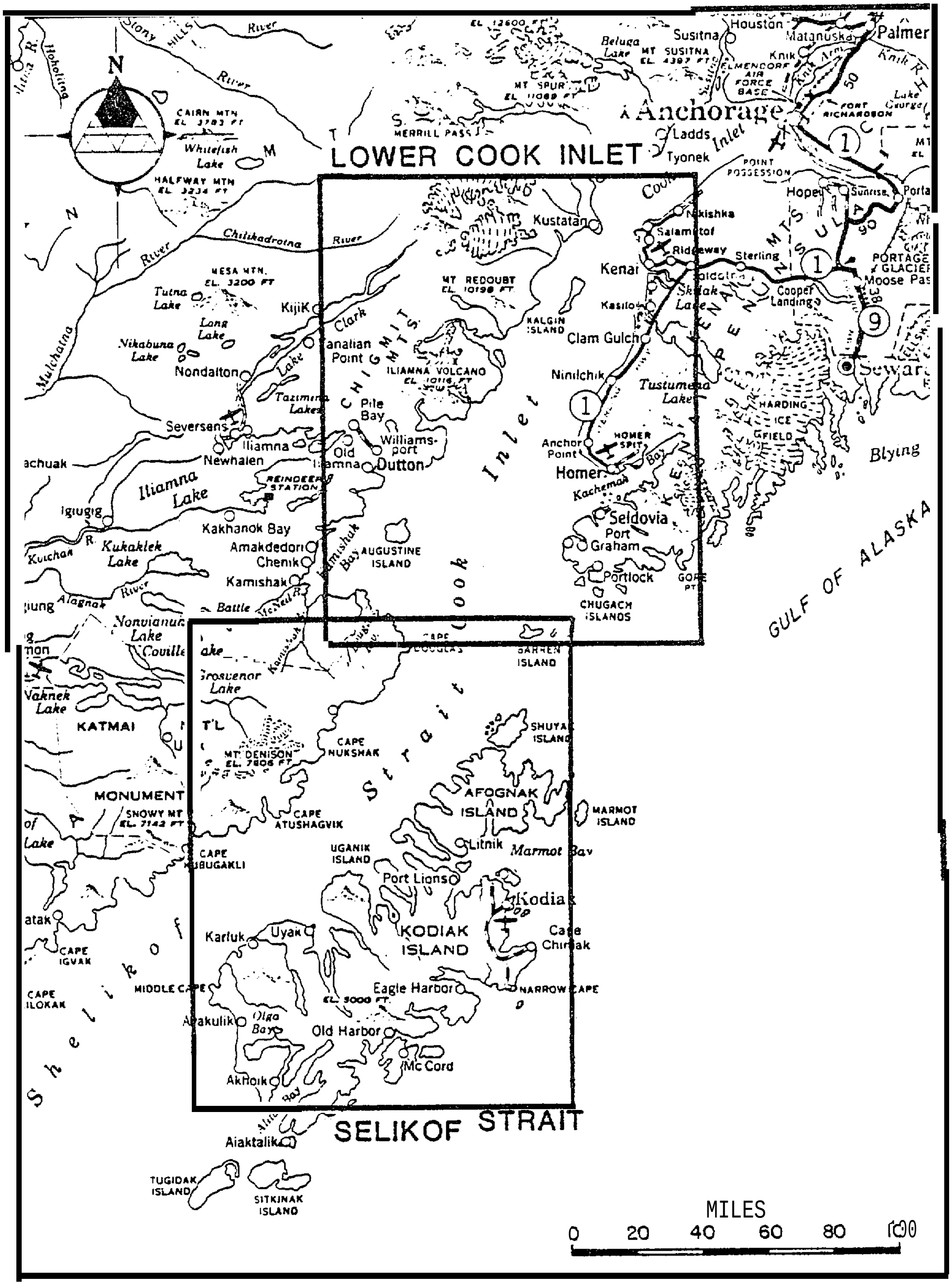

FIGURE 1-1

LOCATION OF THE **STUDY** AREA

environmental constraints on petroleum engineering (winds, waves, bottom sediments, geologic hazards etc.). Subsequent to completion of a draft version of this report but prior to publication of the final report, a shore facilities siting study was conducted to identify suitable sites for terminals and support bases in the northern portion of Shelikof Strait. The results of this siting study are presented in Appendix E.

This study is intended to detail scenarios describing the incremental facilities, employment etc. resulting from Sale 60 so that incremental socio-economic and environmental impacts of Sale 60 can be analyzed. As such care is taken in this study to make some basic assumptions on the treatment of Sale CI in the analysis (see Section 3.2).

The U.S. Geological Survey resource estimates, which are conditional on hydrocarbons being present, used in this study are as follows (Magoon et.al., 1978):

Lower Cook Inlet

	95 Percent Probability	5 Percent Probability	Statistical Mean
Oil (billions of barrels)	0.25	1.2	0.6
Gas (trillions of cubic feet)	0.25	1.1	0.6

Shelikof Strait

	Low	High
Oil (billions of barrels)	0.05	1.0
Gas (trillions of cubic feet)	0.05	1.0

This study details scenarios for high find and medium find resource levels derived from the U.S.G.S. estimates. In addition, a scenario specifying exploration only is detailed.

1.3 Report Content and Format

This report commences with a summary of findings under the headings of Resource Estimates, Selected Petroleum Development Scenarios, Employment, Technology and Resource Economics.

The basic analytical steps in the construction of the scenarios are described in Chapter 3.0, Methodology, which links the various geologic, technical and economic components of the study.

Each scenario is described in a separate chapter (4.0 - Exploration Only; 5.0 - High Find; 6.0 - Medium Find).

The analytical assumptions and research results of this study are presented in the appendices commencing with the economic analysis (Appendix A) which is the central component of this study.[(1)] The subsequent appendices detail the cost estimates used in the economic analysis (Appendix B), petroleum technology (Appendix C), manpower findings (Appendix D), and the results of a petroleum facilities siting study for northern Shelikof Strait (Appendix E).

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(1) The economic analysis was conducted prior to the late June (1979) OPEC meeting at which oil prices were raised to an average of about $20.00 per barrel and the preceding enactment of surcharges following the decrease in Iranian production.

2.0 SUMMARY OF FINDINGS

2.1 Petroleum Geology and Resource Estimates

The resource estimates that form the basis of this study are the U.S. Geological Survey estimates of undiscovered oil and gas resources (Magoon, et al., 1978). These estimates, which are conditional on hydrocarbons being present, are:

Lower Cook Inlet

	95 Percent Probability	5 Percent Probability	Statistical Mean
Oil (billions of barrels)	0.25	1.2	0.6
Gas (trillions of cubic feet)	0.25	1.1	0.6

Shelikof Strait

	Low	High
Oil (billions of barrels)	0.05	1.0
Gas (trillions of cubic feet)	0.05	1.0

Allocation of the Lower Cook estimates to the Sale 60 portion of the Inlet was based on the assumption that one-third of the total resource would be located there. A mid-range resource estimate of 500 million barrels of oil and 500 billion cubic feet of gas was assumed for Shelikof Strait. High, medium, and low estimates were thus defined for Sale 60 as follows:

Lower Cook Inlet

	Low Find	Medium Find	High Find
Oil (millions of barrels)	83	198	400
Gas (billions of cubic feet)	83	198	363

Shelikof Strait

	LoW Find	Medium Find	High Find
Oil (millions of barrels)	50	500	1,000
Gas (billions of cubic feet)	50	500	1,000

A set of reservoir and hydrocarbon assumptions were formulated for the economic analysis based on available geologic data and the need to explore the economic impact of geologic diversity. While Upper Cook Inlet serves as a producing analog for the Tertiary prospects of Lower Cook Inlet/Shelikof Strait, there is insufficient data to establish with any certainty reservoir characteristics for the Mesozoic prospects. However, as described in Chapter 3.0 and Appendix A, the following reservoir and production assumptions have been defined for the economic analysis:

- Average reservoir depths (gas and oil) -- 1,524 and 3,048 meters (5,000 and 10,000 feet).
- Recoverable reserves per acre -- 20,000 and 50,000 bbl.
- Well spacing -- variable, consistent with ranges in known producing fields.
- Initial well productivity -- oil -- 1,000, 2,000, and 5,000 barrels per day; gas -- 15 and 25 million cubic feet per day.
- Gas resource allocation between associated and non-associated -- -For scenario detailing and analytical simplification, all the gas resources are assumed to be non-associated (i.e. scenarios are detailed which include gas field(s) totaling the U.S.G.S. gas resource estimate);(1) oil fields are implicitly

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

assumed, therefore, to have a low gas-oil ratio (GOR) and that associated gas is uneconomic and is used to fuel platforms with the remainder reinfected.

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

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

2.2 Selected Petroleum Development Scenarios

Three scenarios are detailed describing exploration only (no commercial resources discovered), a high find case assuming significant commercial discoveries and a medium find case assuming modest commercial discoveries. The oil and gas resources developed in these scenarios correspond to the allocated U.S.G.S. estimates as described above. No scenario is detailed for the low find resource estimate because the resources in most discovery locations are uneconomic under the assumptions of this analysis. Similarly, the gas resources at both the low find and medium find resource levels are uneconomic.

2.2.1 Exploration Only Scenario

The exploration only scenario postulates that 19 exploratory wells are drilled over a three-year period following the lease sale with only non-commercial finds. Exploration is centered in the Shelikof Strait which has a total of 11 wells drilled. With the considerable variation in water depths in the sale area, a mixture of jack-up rigs, semi-submersibles and drillships are employed in the exploration program.

2.2.2 High Find Scenario

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

	Oil (MMbbl)	Non-Associated Gas (BCF)
Lower Cook	400	363
Shelikof	1,000	1,000

The major portion of the oil and gas resources are discovered in the Shelikof Strait area west of Afognak Island while the Lower Cook Inlet discoveries aremade immediately to the north of Sale CI. The Shelikof discoveries consist of two oil fields with reserves 550 million barrels and 450 million barrels, and a single non-associated gas field with reserves of one trillion cubic feet. All these discoveries are made in the northern Shelikof Strait west of Afognak Island in water depths between 152 and 183 meters (500 and 600 feet). The Shelikof oil fields share a short pipeline to a new shore terminal located of the west coast of Afognak Island. During the exploration phase, Nikiski, Seward, Kodiak, and Homer serve as support bases. A temporary construction base and permanent operations base are established adjacent to the terminal on Afognak Island.

The LowerCook oil fields are located in shallow water approximately80 kilometers (50 miles) south of Drift River. As such, they are well situated to use the Drift River terminal to handle their crude production. By the late 1980's, Drift River may have sufficient spare capacity to handle the incremental production from these fields, which would peak at about 150,000 bpd, although total Cook Inlet production may exceed existing capacity requiring expansion of Upper Cook refineries and/or terminals (see Appendix A, Section IV). A partial processing facility may have to be constructed onshore between the pipeline landfall and Drift River terminal. Although there are several production options for Lower Cook Inlet oil, this scenario assumes that the Sale 60 fields in Lower Cook Inlet do not share infrastructure with Sale CI fields, in particular pipelines, but rather support their own pipeline.

2.2.3 Medium Find Scenario

The medium find scenario assumes modest commercial discoveries of oil.

The total reserves discovered and developed are:

	Oil (MMBBL)
Lower Cook	198
Shelikof	500

The Lower Cook reserves are discovered in a single field located in about 76 meters (250 feet) of water 16 kilometers (10 miles) northwest of English Bay. The field produces through a short spur pipeline which connects with a trunk pipeline that takes production from a field located in Sale CI. The pipeline makes a landfall on the Kenai Peninsula near Anchor Point, where an intermediate pump station is located, and continues north to Nikiski where the crude is either shipped to the lower 48 via tanker or used in the Nikiski refineries. Nikiski is the principal support base for both the exploration and construction phases of development. Homer is utilized as a forward support base.

The single Shelikof field is located in the northern Shelikof Strait in about 183 meters (600 feet) of water west of Afognak Island (the island is currently a national forest). The field is developed using a single steel platform which produces to a short pipeline that connects with a new terminal constructed on the west coast of Afognak Island. During the exploration phase, Nikiski, Seward, and Homer serve as support bases. A temporary construction base and permanent operations base are established adjacent to the terminal on Afognak Island.

2.3 Employment

Offshore employment exceeds onshore employment in every year of all three scenarios. In the high find scenario, peak employment occurs in year 8 with an average of 2,740 workers per month (2,740 man-years); in the medium find scenario, peak employment occurs in year 7 with an average of 1104 workers per month (1104 man-years); in the exploration only scenario, maximum employment occurs in year 2 with an average of 699 workers per month. Manpower estimates in Tables 2-1 through 2-3 and

TABLE 2-1

SUMMARY OF MANPOWER REQUIREMENTS - HIGH FIND SCENARIO
TOTAL LABOR FORCE[1]

'tear After Lease Sale[4]	Monthly Average Nu ber of People[2]		Total[3]
	Offshore	Onshore	
1[5]	470	56	525
2	785	93	877
3	780	92	872
4	785	93	877
5[6]	623	334	957
6	634	111	745
7	1,298	573	1,871
8[7]	2,011	730	2,740
9	1,981	372	2,353
10	1,669	306	1,975
11	1,329	295	1,624
12	965	276	1,240
13	861	281	1,142
14	883	302	1,185
15	929	310	1,239
16	929	310	1,239
17	854	294	1,148
18	794	286	1,080
19	749	275	1,023
20	660	263	922
21	660	263	922
22	660	263	922
23	554	247	801
34	389	223	612
25	254	204	458
26	165	192	357
27	90	180	269

[1] Includes onsite and offsite workers.
[2] Yearly peak employment may exceed these averages (see manpower tables in Chapter 5.0); the figures in this column are equivalent to the number of man years of employment.
[3] Discrepancies due to rounding.
[4] Year after lease sale = 1982.
[5] Exploration starts.
[6] Field construction starts.
[7] Production commences.

Source: Dames & Moore Estimates

TABLE 2-2

SUMMARY OF MANPOWER REQUIREMENTS - MEDIUM FIND SCENARIO
TOTAL LABOR FORCE[1]

Year After Lease Sale[4]	Monthly Average Number of People[2]		Total[3]
	Offshore	Onshore	
1[5]	472	56	528
2	629	74	703
3	632	75	706
4	315	236	550
5[6]	0	62	62
6	634	149	783
7	769	335	1,104
8[7]	538	100	637
9	686	120	805
10	686	120	805
11	294	99	392
12	238	96	333
13	330	112	441
14	330	112	441
15	330	112	441
16	330	112	441
17	330	112	441
18	330	112	441
19	330	112	441
20	330	112	441
21	330	112	441
22	241	104	344
23	181	96	277
24	181	96	277
25	181	96	277
26	106	20	125

[1] Includes onsite and offsite workers.
[2] Yearly peak employment may exceed these averages (see manpower tables in Chapter 6.0); the figures in this column are equivalent to the number of man years of employment.
[3] Discrepancies due to rounding.
[4] Year after lease sale = 1982.
[5] Exploration starts.
[6] Field construction starts.
[7] Production commences.

Source: Dames & Moore Estimates

TABLE 2-3

SUMMARY OF MANPOWER REQUIREMENTS - EXPLORATION ONLY SCENARIO
TOTAL LABOR FORCE[1]

Year After Lease Sale[4]	Monthly Average Number of People[2]		Total[3]
	Offshore	Onshore	
1	468	56	523
2	625	74	699
3	130	16	146

[1] Includes onsite and offsite workers.
[2] Yearly peak employment may exceed these averages (see manpower tables in Chapter 4.0); the figures in this column are equivalent to the number of man" years of employment.
[3] Discrepancies due to rounding.
[4] Year after lease sale = 1982.

Source: Dames & Moore Estimates

in the tables presented in Chapters 4.0, 5.0, and 6.0 reflect assumptions made in this report regarding the shared use of existing and anticipated facilities in Upper Cook Inlet. Shared use of facilities -- pipelines, marine terminals, LNG plants, compressor stations and processing plants -- means that construction and operational manpower requirements, especially onshore manpower requirements, are significantly lower than would have been the case if new facilities were constructed. Only incremental manpower requirements associated with this lease sale area are estimated in the report.

2.4 Technology and Production Systems

While not as severe as the Gulf of Alaska, the operating environment in Lower Cook Inlet and Shelikof Strait nevertheless presents significant engineering constraints to offshore petroleum development. The Lower Cook Inlet tracts are located in water depths ranging from less than 30 meters (100 feet) in the northern part of the sale area south of Kalgin Island to 183 meters (600 feet) at Kennedy Entrance; over 50 percent of this area lies in water depths between 46 and 76 meters (150 and 250 feet). Water depths in Shelikof Strait range from 91 meters (300 feet) in the northeast to over 303 meters (1,000 feet) at the southwestern entrance. The design wave for the northern part of Lower Cook Inlet can be considered to be essentially the same as that considered for Upper Cook Inlet, i.e. about 8.5 meters (28 feet) while in the southern portion of Lower Cook Inlet the design wave is considerably greater, probably in excess of 20 meters (65 feet). The technology review of the Gulf of Alaska conducted for a companion study (Dames & Moore, 1979a and b) was utilized as the basis for selection of production systems to be evaluated in the economic analysis of Lower Cook Inlet and Shelikof Strait. These systems included conventional steel jacket platforms, concrete gravity platforms and floating platforms (e.g. converted semi-submersibles) which can either produce to pipelines or directly to tankers offshore via single point mooring buoys; the offshore loading systems could have storage capability using internal storage (which is a design feature of concrete platforms), storage buoys or permanently moored tankers. All of these systems could have application in Lower Cook Inlet and Shelikof Strait.

The production systems to be screened in the economic analysis were selected in consultation with the petroleum engineering departments of the major lease holders in Lower Cook Inlet. These consultations included discussion of the results of our technology review conducted for the Gulf of Alaska studies and our evaluation of oceanographic conditions of Lower Cook Inlet/Shelikof Strait that would affect production system selection, platform design, etc. The consensus of opinion was that. steel jacket platforms with a pipeline to shore terminal(s) or existing terminals/refineries in 'Upper Cook Inlet would be the production system generally adopted. Only minor interest was expressed in the use of gravity platforms, offshore loading systems and subsea completions. The relatively short distances to suitable shore landfalls and the petroleum facilities in Upper Cook Inlet were factors in the preference for platform pipeline systems. In Lower Cook Inlet, water depths of generally less than 91 meters (300 feet) favor fixed platforms over floating systems. In some parts of Lower Cook Inlet and Shelikof Strait, platforms may have to be designed for sea ice, in particular, location of wells within platform legs.

It is the deeper waters (200 to over 305 meters or 650 to over 1,000 feet) comprising the southern half of Shelikof Strait that present the most significant engineering challenges of lease Sale 60. While conventional steel jacket platforms may still have a role in this area, the development of marginal or deep water fields in areas such as Shelikof Strait in the late 1980's may involve the use of hybrid, compliant and floating platform designs. No attempt, however, was made in this study to predict the technologies and their costs for production systems in water depths greater than 200 meters (650 feet) because: (1) production systems other than the conventional steel jacket platform such as the guyed tower or tension leg platform have not been utilized beyond the prototype stage and no firm cost data or experience is available to evaluate such systems; and (2) conventional steel jacket platforms have not been installed in such water depths with comparable oceanographic conditions to provide a historic cost data base. Rather than predict the petroleum technologies and their development costs for the deeper Shelikof waters, it was decided to use the results of the economic analysis for the 183 meters (600 feet) production systems to establish the threshold of various economic sensitivities for petroleum development in greater water depths.

The production systems that were considered in this analysis are:

- Single steel jacket platform. Pipeline to a new shore terminal. Water depths: 30.5 to 183 meters (100 to 600 feet).
- Single steel jacket platform. Pipeline (offshore and onshore) to existing shore terminal/refinery in Upper Cook Inlet. Water depths: 30.5 to 183 meters (100 to 600 feet).
- Single steel jacket platform. Pipeline shared with other producing fields to shore terminal. Water depths: 30.5 to 183 meters (100 to 600 feet).
- Multiple steel jacket platforms. Pipeline to a new shore terminal. Water depths: 30.5 to 183 meters (100 to 600 feet).
- Multiple steel jacket platforms. Pipeline (offshore and onshore) to existing shore terminal/refinery in Upper Cook Inlet. Water depths: 30.5 to 183 meters (100 to 600 feet).
- Single or multiple steel platforms. Gas pipeline to shore, gas converted to LNG at new plant. Water depths: 30.5 to 183 meters (100 to 600 feet).
- Single or multiple steel platforms. Gas pipeline (offshore and onshore) to existing LNG plant or petrochemical plant in Upper Cook Inlet. Water depths: 30.5 to 183 meters (100 to 600 feet).

In Lower Cook Inlet (Sale 60) in the case of significant discoveries of oil, an operator has two principal options:

- A long pipeline (approximately 200 kilometers or 120 miles -- assuming a discovery in the central portion of Lower Cook Inlet) to existing or expanded Upper Cook Inlet petroleum facilities; a portion of this pipeline may be shared with other fields located in Lower Cook Inlet Sale CI or Sale 60, or Shelikof Strait Sale 60.

- A short to medium length pipeline (less than 80 kilometers or 50 miles) to a new oil terminal located on the lower Kenai Peninsula or west shore of Lower Cook Inlet.

In the case of significant discoveries of oil in the Shelikof Strait, an operator has three principal production options:

- A long pipeline (approximately 322 kilometers or 200 miles) to existing Upper Cook Inlet petroleum facilities; a portion of this pipeline may be shared with other fields located in Lower Cook Inlet Sale CI or Sale 60.

- A short pipeline (less than 32 kilometers or 200 miles) to a new oil terminal located on the east or west coast of Shelikof Strait.

- A medium length pipeline (approximately 160 kilometers or 100 miles) to a new shore terminal located in Lower Cook Inlet shared with Lower Cook Inlet fields.

Gas production options from offshore Lower Cook Inlet or Shelikof fields are limited to pipelines to either existing Upper Cook Inlet LNG plant(s), petrochemical plants or local markets, or to new LNG or petrochemical plants located along the shores of Shelikof Strait or Lower Cook Inlet.

2.5 Resource Economics

The economic characteristics of several likely oil and gas production systems suitable for the harsh conditions of Lower Cook Inlet and Shelikof Strait are analyzed in this report with the model described in Appendix A. The model is a standard discount cash flow algorithm designed to handle uncertainty among the variables and driven by the investment and revenue streams associated with a selected production technology.

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

Two vital pieces of information are estimated in this analysis:

- The minimum economic field size to justify development of a known field with a selected technology in Lower Cook Inlet.

- The minimum required price to justify development of a field in Lower Cook Inlet.

Both are very sensitive to water depth, and to the value of money used to discount cash flows. At water depths of 30.5 meters (100 feet), 91 meters (300 feet), and 183 meters (600 feet), the calculated minimum prices and field sizes are bracketed between 10 percent and 15 percent discount rates. Table A-1 (Appendix A) shows the results. The minimum required price for the most economic oil production system is bracketed between 30.5 and 183 meters (100 and 600 feet) assuming a 15 percent discount rate on Figure A-1 (Appendix A). Figure A-2 (Appendix A) shows the gas price.

The essential findings of this report are summarized below. The single value calculations discussed are based on the mid-range parameter values. Monte Carlo distributions showing the range of values for the after tax return on investment are discussed in Section II.7 of Appendix A. The technology, financial, reservoir and production assumptions of the analysis are detailed in Section III of Appendix A.

- The economic decision to pipeline oil to an existing terminal in Upper Cook Inlet or build a new terminal will depend on the location of a discovered field and whether or not there are other fields that can share either the pipeline to the existing terminal or the construction cost of building a new terminal.

- The economic results are very sensitive to assumptions about shared infrastructure. A large gas production platform in deep water with an assumed pipeline distance of 225 kilometers (140 miles) of onshore and offshore pipeline will earn 10 percent with 1.0 tcf recoverable reserves if the pipeline is shared; but requires 1.5 tcf to support the entire pipeline.

- Long pipelines from Lower Cook to Upper Cook are either the single largest element of development cost or the second most costly element after platform fabrication and installation. The relative shares depend on water depth which dramatically affects platform cost and offshore pipeline distance. Even one--half shared, a 225 kilometer (140 mile) gas pipeline with 97 kilometers (60 miles) offshore can range between 25 percent and 36 percent of development cost depending on water depth.

- Even in shallow water, no oil productions systems are able to earn 15 percent return on investment with fields of any size in Lower Cook Inlet with a wellhead price of $12.50 and initial production rate assumed to be 1000 B/D. Only fields of 150 to 210 MMb with reservoirs deep enough to allow production with 40 deviated wells are able to earn 10 percent. This is significant if geological conditions in Lower Cook Inlet suggest that initial production rates in the 1000 B/D range are reasonable expectations.

Assuming initial productivity of 2000 B/D different production systems in shallow water are able to earn 10 percent with fields in the 90-130 million barrel range. Fields ranging in size from 175 to 235 million barrels are required to earn 15 percent. The range in size is a function of reservoir target depth and production system.

In deep water 183 meters **(600 feet) no oil production system is able** to earn 15 percent in Lower Cook Inlet or Shelikof Strait assuming 2000 B/D initial production rate (and other assumptions of the analysis).

- An initial well productivity higher than 2000 B/D is required to earn the 15 percent hurdle rate in 183 meters (600 feet) of water in Lower Cook. Assuming 5000 B/D initial well productivity the minimum field size for development for a deep reservoir target is in the range of 250-300 million barrels depending on field location and production system.

- Relatively large 24-well production systems and large gas fields are required to justify development in Lower Cook Inlet/Shelikof Strait at even shallow water depths, assuming $2.10 for the wellhead price and 15 MMcfd for the initial production rate.

- The minimum sized gas field for development ranges between 1.0 and 2.0 Tcf in 91 meters (300 feet) of water and 15 percent discount rate depending on reservoir target depth. In shallower water slightly smaller fields would earn 15 percent.

- In deep water 183 meters (600 feet) an initial production rate in excess of 15 MMcfd is required to earn 15 percent for a gas field only large enough to justify a single platform. Assuming 25 MMcfd wells a 1.5 Tcf field will earn 15 percent even supporting an entire pipeline. A giant field capable of supporting two gas platforms will earn 15 percent with recoverable reserves of 3.8 Tcf.

- The minimum required price in 1978 dollars to justify development varies principally with field size, water depth, production system, initial production rate, and value of money. The calculated minimum oil price is slightly lower under the assumptions of the analysis for an existing terminal system than for a new terminal system. In shallow water minimum price at 15 percent discount rate and 2000 B/D declines from nearly $17.50 BBl for 100 million barrels of recoverable reserves to about $10.00 for 300 million barrels or more. In deep water, the minimum price declines from nearly $22.00 to $15.00 bbl at 300 million barrels. Reserves larger than 300 million barrels are recovered beyond 25 years from start-up; their present value is nearly zero.

- The minimum required gas price declines from nearly $2.25 Mcf to $1.65 Mcf for recoverable reserves of 900 billion cubic feet to 2.0 Tcf in 91 meters (300 feet) water depth. In deep water, the price is nearly $3.00 for the 900 Bcf field and declines to about $2.25 for 2.0 Tcf.

3.0 METHODOLOGY

3.1 Introduction

The geologic, economic and technical assumptions and parameters are discussed in more detail in the Appendices. The purpose of this chapter is to link the various analytic tasks in the scenario development describing step-by-step the construction of the scenarios that are detailed in Chapters 4.0, 5.0 and 6.0.

3.2 Treatment of Sale CI in the Scenario Analysis

As described in the Introduction (Chapter 1.0), the purpose of this study is to detail petroleum development scenarios for a second generation Lower Cook Inlet and Shelikof Strait OCS lease sale (No. 60) scheduled for 1981. The scope of work excludes analysis of possible petroleum development in the existing sale area and requires identification of new facilities, infrastructure etc. resulting from Sale 60 from which the incremental impacts of Sale 60 petroleum development can be discerned. Construction of scenarios for Sale 60, therefore, requires definition of some assumptions concerning the treatment of Sale CI in the scenario analysis.

As background it should be noted that petroleum development scenarios have been compiled for Lower Cook Inlet Sale CI in Lower Cook Inlet, Final Environmental Impact Statement Proposed 1976 OCS Oil and Gas Lease Sale No. CI (U.S.D.I., 1976), which describes a high development case and in Proceedings of the Lower Cook Inlet Synthesis Meeting, January 1978 -Probable OCS Development and Hypothetical Case Studies of Environmental Considerations (NOAA, 1978) which describes an average development case. These scenarios are based on U.S. Geological Survey resource estimates contained in Open-File Report 76-449 which have subsequently been revised; the revised estimates (1978) are being used in our analysis. The usefulness of these scenarios to our analysis is reduced by the fact that the resources upon which they were based were revised and the exploratory drilling to date has been at a lower level than that hypothesized in the scenarios. In addition, the Sale CI scenarios do not specify the location of infrastructure beyond identifying broad pipeline corridors and several alternate shore sites for various petroleum facilities.

Since the Lower Cook Inlet sales are closely spaced chronologically it is reasonable to assume that some infrastructure must be shared if commercial discoveries are made in both sale areas. (Indeed, development of petroleum discoveries in Sale CI may only occur when additional reserves have been proven in adjacent areas of Sale 60). The magnitude of the incremental impacts of Sale 60, therefore, depends to some extent on the infrastructure that may be developed in response to Sale CI discoveries which in turn depend on the amount of resource. In the scenario formulation, the projection of incremental impacts requires assumptions on Sale CI infrastructure (platforms, pipelines, shore terminals, etc.) and their locations. Allocation of the total Lower Cook Inlet resource between the two sale areas is also critical to the results of the analysis.

The following assumptions have been made concerning the treatment of Sale CI, in the analysis:

- U.S. Geological Survey resource estimates for Lower Cook Inlet are allocated two-thirds to Sale CI and one-third to Sale 60 (see discussion in Section 3.3).

- The scenarios formulated for Sale CI in the Final EIS and synthesis meeting report will not be utilized in this analysis for the reasons stated above.

- To assess the impact of Sale 60 oil and gas production on the supply-demand balance of Upper Cook Inlet petroleum facilities (terminals, refineries, etc.) and related production option decisions, a generalized production profile has been assumed for Sale CI resouces which produces the aggregated oil and gas resources in 20 to 25 years (see Appendix A).

- To examine the possibility that some Sale CI and Sale 60 fields may be developed jointly, the economic analysis also considers field development cases in which investment costs (particularly pipelines) are shared between field(s) located in Sale CI and Sale 60.

- In the detailing of scenarios which involve sharing of facilities with Sale CI field(s), only the incremental facilities such as platforms and spur pipelines and their related construction and operation employment are specified. The Sale CI field(s) is assumed to account for shore base construction, trunk pipeline, pump station, etc.

3.3 U.S. Geologic Survey Resource Estimates and Resource Allocation

The petroleum development scenarios are based upon U.S. Geological Survey estimates of undiscovered recoverable oil and gas resources of Lower Cook Inlet and Shelikof Strait. The most recent estimates for Lower Cook Inlet are contained in an unpublished resource report by Magoon et al. (1978). These estimates, which are conditional on hydrocarbons being present, are:

	95 Percent Probability	5 Percent Probability	Statistical Mean
Oil (billions of barrels)	0.25	1.2	0.6
Gas (trillions of cubic feet)	0.25	1.1	0.6

These estimates are for an area of about 9,100 square kilometers (3,500 square miles) of federal waters in Lower Cook Inlet and include both the existing Sale CI area and the remaining unleased tracts in the call for nominations area. These estimates represent percentage allocations of 50 percent for oil and 25 percent for gas, of the total Cook Inlet province assessment, a considerable reduction over previous allocations for Lower Cook Inlet (see U.S.G.S. Open-File Report 76-449, Magoon et al., 1976).

The resource estimates for the Shelikof Strait are (Magoon et al., 1978):

Oil (billions of barrels)	0.05 to 1.0
Gas (trillions of cubic feet)	0.05 to 1.0

These estimates are best estimates, not formal assessments, and are based on limited geologic data. Hence, probability ranges are not given. It should be noted that if probability ranges had been derived for the Shelikof estimates, a marginal probability would have been applied as is usually done for frontier areas and the 95 percent probability would be "O". Thus, the low estimate does not correspond to the 95 percent probability estimate.

The Lower Cook estimates apply to an area where water depths are generally less than 200 meters (650 feet); in contrast, federal waters in Shelikof Strait range from 46 meters (150 feet) to over 340 meters (1 ,000 feet).

3.3.1 Allocation of U.S.G.S. Resource Estimates

The allocation of the Lower Cook Inlet resource estimate between Sale CI and Sale 60 (call for nominations area) is the first step in scenario construction. There is insufficient geologic data to make a firm assumption on such an allocation. In terms of area, the currently leased tracts in Sale CI comprise about 22 percent of the total Lower Cook Inlet OCS acreage. It is reasonable to assume that the leased tracts comprise a significant portion of high potential Lower Cook Inlet acreage although some high potential tracts may not have been offered for sale for environmental or other reasons. Thus an allocation probably should be weighted toward the existing sale area although it comprises less than a quarter of the acreage. In consultation with BLM staff the assumption was made that two-thirds of the resource are located in the existing leased tracts of Sale CI and one-third in the Sale 60 portion of Lower Cook Inlet. The resources allocated according to this assumption are shown in Table 3-1.

TABLE 3-1

ALLOCATION OF U.S. GEOLOGICAL SURVEY[1] OIL AND GAS RESOURCE ESTIMATES TO LOWER COOK INLET SALE CI LEASES AND PROPOSED SALE 60

	Lower Cook Inlet[2] Sale 60		Lower Cook Inlet[2] Sale CI		Totals	
	Oil (mmbbl)	Gas (bcf)	Oil (mmbbl)	Gas (bcf)	Oil (mmbbl)	Gas (bcf)
Low Find	83	83	167	167	250	250
Medium Find	198	198	402	402	600	600
High Find	400	363	800	737	1200	1100

[1] Magoon et al., 1978

[2] Based on BLM staff's recommendation that two-thirds of the resource are located in the existing leased tracts of Sale CI and one-third in the Sale 60 portion of Lower Cook Inlet.

Because the total Lower Cook Inlet resource estimate has not been probabilistically apportioned to two areas and the Shelikof Strait estimate is not expressed in probability ranges, the scenarios developed in this report cannot be expressed as probability cases. We have therefore designated the scenarios as: "High Find Case" (for estimates derived from allocation of the five percent probability estimate), "Medium Find Case" (for estimates derived from allocation of the statistical mean probability estimate) and "Low Find Case" (for estimates derived from allocation of the 95 percent probability estimate),

With respect to the Shelikof Strait estimate, we have added the high estimate (1.0 Bbbl oil, 1.0 tcf gas} to the Lower Cook Inlet estimate derived from allocation of the five percent probability estimate and the low estimate (0.05 Bbbl oil, 0.05 tcf gas) to the Lower Cook Inlet estimate derived from allocation of the 95 percent probability estimate. In consultation with the BLM staff, a mid-range value of 500 mmbbl oil and 500 bcf gas has been assumed for Shelikof Strait and added to the medium Lower Cook Inlet estimate derived from allocation of the statistical mean probability estimate. The resource estimates for Sale 60 according to these assumptions and locations are shown in Table 3-2.

The allocation of the U.S. Geological Survey resource estimates to "high find", "medium find" and "low find" cases establishes the overall development potential, the general location of the resources and the largest field size that can be discovered under the umbrella of the U.S. Geological Survey estimates (assuming the total resource was found in one field) for scenario development.

3.4 Reservoir and Production Characteristics Assumed for the Economic Analysis

Reservoir and production characteristics that are required for the economic analysis are discussed in detail in Appendix A. The purpose of this section is to briefly explain their role in the scenario formulation process and their influence on petroleum economics.

TABLE 3-2

ALLOCATION OF U.S. GEOLOGICAL SURVEY[1] OIL AND GAS RESOURCE ESTIMATES
LOWER COOK INLET SALE 60[2] AND SHELIKOF STRAIT

	Lower Cook Inlet Sale 60[3]		Shelikof Strait		Totals	
	Oil (mmbbl)	Gas (bcf)	Oil (mmbbl)	Gas (bcf)	Oil (mmbbl)	Gas (bcf)
Low Find	83	83	50	50	133	133
Medium Find	198	198	500	500	698	698
High Find	400	363	1000	1000	1400	1363

[1] Magoon et al., 1978
[2] Sale No. 60 area only - excludes existing leased tracts of Sale CI.
[3] Based on BLM's recommended assumption that two-thirds of the resource are located in the existing leased tracts (Sale CI) and one-third in Sale 60 portion of Lower Cook Inlet.

The economic analysis requires assumptions about:

- Product on timing
- Initial production rate
- Reservo r depth
- Well spacing and recoverable reserves per acre
- Field sizes

In addition scenario formulation and detailing requires assumptions relating to:

- Allocation of the U.S. Geological Survey gas resource estimate between associated, and non-associated

- Gas-oil ratio (GOR)

- Oil properties

It should be emphasized that reservoir and production assumptions should not be construed as an attempt to construct a reservoir model for site specific prospects. Rather they are formulated to evaluate the overall resource economics of a large portion of a sedimentary basin comprising numerous petroleum prospects which may exhibit considerable variation in reservoir characteristics and production potential. The reservoir and production assumptions are designed to evaluate the economic sensitivities of geologic diversity. Nevertheless, the reservoir and production assumptions should fall within expectations indicated by the available geologic data and/or extrapolation from reasonable analogs.

3.4.1 Production Timing

The timing of production start-up, which varies with the construction delays associated with different production systems, numbers of platforms and wells, number of drilling rigs per platform, reservoir target depth and water depth, is required in the economic analysis to estimate the schedule of return on investment. The step-up to full production is determined by the rate of development well completion (dependent on the reservoir target depth and number of rigs operating on a platform) and total number of production wells required to efficiently drain the reservoir.

Production start-up for the production systems evaluated in the economic analysis generally commences in the sixth or seventh year of the field development schedule and two or three years more elapse to peak production as additional wells are brought on line.

3.4.2 Initial Production Rate

Initial well production rate is a parameter use in the economic analysis and scenario formulation as an index of reservoir performance in the absence of specific data on reservoir characteristics such as pay thickness, porosity, permeability, drive mechanism, etc. The initial productivity per well influences the numbers of wells which have to be drilled to efficiently drain a given reservoir.

As explained in Appendix A, the initial productivity rates assumed for the economic analysis and scenario formulation are:

Oil - 1,000, 2,000 and 5,000 bpd
Gas - 15 and 25 mmcfd

3.4.3 Reservoir Depth

Reservoir depth in this analysis is a parameter which defines the number of platforms required to efficiently produce a given field size. All other factors being equal, a shallow field with a thin pay reservoir covering many square kilometers and requiring several platforms to produce is less economic than a field of equal reserves, with a deep thick pay zone, which can be reached from a single platform.

In the economic analysis and scenario detailing, reservoir depth dictates the rate of development well completion which 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.

Two reservoir depths are evaluated in this analysis (see discussion in Appendix A):

Oil - 1,524 and 3,048 meters (5,000 and 10,000 feet)
Gas - 1,524 and 3,048 meters (5,000 and 10,000 feet)

3.4.4 Well Spacing

Well spacings consistent with industry practice and varying as a function of initial well productivity and recoverable reserves per acre are implicit in the scenarios (see Appendix A). For shallow reservoirs, industry well spacing practices can restrict the number of wells drilled from a platform and this has economic impact on the field development decision.

3.4.5 Recoverable Reserves

In the scenario analysis recoverable reserves per acre is a parameter which is used in place of more technical functional relationships for determining the number of wells required to produce a given field, given its initial production rate. Recoverable reserves per acre are determined by reservoir characteristics -- porosity, permeability, connate water, driving mechanism, etc.

Recoverable reserves per acre of 20,000 and 50,000 barrels are assumed for this study.

3.4.6 Field Sizes to be Evaluated in the Economic Analysis

There is insufficient geologic data to make reasonable predictions of the field sizes that may be discovered in Lower Cook Inlet. The field sizes selected for economic screening, therefore, have been selected to be consistent with the following factors:

- U.S. Geological Survey resource estimate (Magoon et al., 1978)
- Anticipated economic conditions (based on economic studies of other offshore areas)
- Geology (only gross structural geology and stratigraphic data are available)
- Requirement to examine a reasonable range of economic sensitivities

The field sizes evaluated in this study, therefore, range from 50 million barrels to one billion barrels for oil and 500 billion cubic feet to one trillion cubic feet for non-associated gas. The maximum field size is determined by the total resource estimate assuming that the total resource is contained in a single field.

3.4.7 Allocation of the U.S. Geological Survey Gas Resource Estimate Between Associated and Non-Associated

In the northern Gulf of Alaska petroleum development scenarios study (Dames & Moore, 1979a) the assumption was made that 20 percent of the gas resource is associated and 80 percent is non-associated following an assumption made in a report by Kalter, Tyner and Hughes (1975) based on U.S. historic production data. For scenario detailing and analytical simplification of this study, the assumption has been made that all the gas resource is non-associated, i.e. scenarios are formulated which include gas field(s) totaling the U.S. Geological Survey gas resource estimate. In reality, however, some portion of the gas resource will be associated; this study implicitly assumes that the oil fields are characterized by a low gas-oil ratio (GOR) and that the gas is used to fuel the platforms with the remainder reinfected.[1]

3.4.8 Gas-Oil Ratio

As explained in Section 3.4.7 and Appendix A, the assumption has been made of a low GOR for Lower Cook Inlet and Shelikof Strait reservoirs. Essentially this assumption stems from treatment of associated/non-associated gas in the analysis (Section 3.4.7). (It should be noted that reinfection equipment for associated gas is a significant cost component of platform equipment; also there is a loss of revenue stemming from the non-production of some natural gas liquids.)

3.4.9 Oil Properties

No assumption is made in this study on the quality of oil that may be found in Lower Cook Inlet. Qualitative differences in crudes and their accommodation in the economic analysis will be discussed in Appendix A.

3.5 Technology and Production System Selection

Having defined the reservoir and production parameters for input in the economic analysis, the next step in the scenario development process and economic analysis is the selection of production systems to be screened in the economic analysis. This selection involves:

- Identification of systems suitable for the oceanographic conditions of Lower Cook Inlet and Shelikof Strait;

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(1) The treatment of the associated/non-associated gas problem in the analysis is complicated by the fact that the gas resources, if non-associated, in many locations are marginally economic (under the assumptions of this analysis) at the high find level and generally uneconomic at the medium find and low find levels. If a major portion of the gas resource was associated, however, unlike Upper Cook Inlet, then a significant portion may be commercial since the incremental investment to produce associated gas would be less than the total development costs for a non-associated gas field with the same recoverable reserves.

- Selection of the systems most likely to be adopted by industry for this region;

- Estimation of costs for the various components of the systems (platforms, pipelines, terminals, etc.); and

- Scheduling of field development investment flows.

The production systems that were considered in this analysis are:

- Single steel jacket platform. Pipeline to a new shore terminal. Water depths: 30.5 to 183 meters (100 to 600 feet).

- Single steel jacket platform. Pipeline (offshore and onshore) to existing shore terminal/refinery in Upper Cook Inlet. Water depths: 30.5 to 183 meters (100 to 600 feet).

- Single steel jacket platform. Pipeline shared with other producing fields to shore terminal. Water depths: 30.5 to 183 meters (100 to 600 feet).

- Multiple steel jacket platforms. Pipeline to a new shore terminal. Mater depths: 30.5 to 183 meters (100 to 600 feet).

- Multiple steel jacket platforms. Pipeline (offshore and onshore) to existing shore terminal/refinery in Upper Cook Inlet. Water depths: 30.5 to 183 meters (100 to 600 feet).

- Single or multiple steel platforms. Gas pipeline to shore, gas converted to LNG at new plant. Water depths: 30.5 to 183 meters (100 to 600 feet).

- Single or multiple steel platforms. Gas pipeline (offshore and onshore) to existing LNG plant or petrochemical plant in

Upper Cook Inlet. Water depths: 30.5 to 183 meters (100 to 600 feet).

In Lower Cook Inlet Sale 60) in the case of significant discoveries of oil, an operator has two principal options:

- A long pipeline {approximately 200 kilometers or 120 miles -- assuming a discovery in the central portion of Lower Cook Inlet) to existing or expanded Upper Cook Inlet petroleum facilities; a portion of this pipeline may be shared with other fields located in Lower Cook Inlet Sale CI or Sale 60, or Shelikof Strait Sale 60.

- A short to medium length pipeline (less than 80 kilometers or 50 miles) to a new oil terminal located on the lower Kenai Peninsula or west shore of Lower Cook Inlet.

In the case of significant discoveries of oil in the Shelikof Strait, an operator has three principal production options:

- A long pipeline (approximately 322 kilometers or 200 miles) to existing Upper Cook Inlet petroleum facilities; a portion of this pipeline may be shared with other fields located in Lower Cook Inlet Sale CI or Sale 60.

- A short pipeline (less than 32 kilometers or 20 miles) to a new oil terminal located on the east or west coast of Shelikof Strait.

- A medium length pipeline (approximately 160 kilometers or 100 miles) to a new shore terminal located in Lower Cook Inlet shared with Lower Cook Inlet fields.

Gas production options from offshore Lower Cook Inlet or Shelikof fields are limited to pipelines to either existing Upper Cook Inlet LNG plant(s), petrochemical plants or local markets, or to new LNG or petrochemical plants located along the shores of Shelikof Strait or Lower Cook Inlet.

In addition to economics, it has to be recognized that there are many factors that will influence selection of the production system option such as the infrastructure that may be developed in response to Sale CI in Lower Cook Inlet, the available capacity of Upper Cook Inlet terminals, refineries or LNG plants, and the technical, environmental and socioeconomic feasibility of potential sites for shore facilities.

These options are accommodated in the economic analysis by evaluating cases with short and long pipelines, cases with and without investment in major new shore facilities, and cases involving investments shared with other fields. Table 3-3 indicates representative pipeline distances from potential discovery sites in Lower Cook Inlet and Shelikof Strait to existing or new facility sites.

3.6 Economic Analysis

In the scenario formulation process the economic analysis identifies those production systems which are economic and the minimum field sizes required to justify development for various discovery locations and production systems. The logic and data flow for field development and for discount cash flow analysis are illustrated in Figure 3-1. The results of the economic analysis also indicate the impact of various reservoir characteristics (depth, productivity potential, etc.) upon the economics of field development. As noted above, for example, other factors being equal, a shallow field with a thin pay reservoir covering many square kilometers and requiring several platforms to produce is less economic in Lower Cook Inlet than a field of equal reserves, with a deep and thick payzone, which can be reached from a single platform.

In some adverse discovery locations (e.g. deep water or isolated from facility sites) the economic analysis implies that excellent reservoir conditions may have to be postulated to infer development of a given field size.

TABLE 3-3

REPRESENTATIVE PIPELINE DISTANCES, LOWER COOK INLET AND SHELIKOF STRAIT DISCOVERY SITES TO EXISTING OR NEW SHORE PROCESSING FACILITIES

Discovery Site	Onshore Facility	Pipeline Distance				Total		Comments
		Offshore		Onsho				
		Kilometers	(Miles)	Kilometers	(Miles)	Kilometers	(Miles)	
Central portion of Sale CI due east of Augustine	Nikiski Complex	64	(40)	128	(80)	192	(120)	Landfall near Anchor Point
Lower Cook Inlet Sale CI or Sale 60 between Cape Douglas and Barren Islands	Nikiski Complex	96	(60)	12B	(80)	224	(140)	Landfall near Anchor Point
Northernmost tracts of Sale 60	Drift River	32	(20)	3	(2)	35	(22)	
northernmost tracts of Sale 60	Nikiski Complex	48	(30)	56	(35)	104	(65)	Landfall near Cape Kasilof
Sale 60 tracts west of English Bay	Nikiski Complex	48	(30)	128	(80)	176	(110)	Landfall near Anchor Point
Northern tracts of Sale CI	Nikiski Complex	32	(20)	80	(50)	112	(70)	Landfall near Ninilchik
Central Shelikof Strait	New terminal west coast of Kodiak Island	32	(20)	3	(2)	34	(22)	
Central Shelikof Strait	Nikiski Complex	193	(120)	128	(80)	321	(200)	Landfall near Anchor Point

Source: Dames & Moore Estimates

The role of the economic analysis in the scenario development process is to:

- Identify a minimum field size for development in relation to various physical characteristics that may be associated with different discovery locations.
- Identify the relationship between water depth and field development for a given field size.
- Identify the most economic production system option for a given field size and discovery location.
- Specify the general reservoir characteristics that would have to be encountered for a given field size in a specified location to justify development.
- Identify the minimum required price for development of a field with specified characteristics.

3.7 Identification of Skeletal Scenarios and Selection of Detailed Scenarios

The cases that were screened in the economic analysis were selected as reasonably representative of (a) current production technologies in deep water storm-stressed environments, (b) field sizes likely to justify development within the resource levels defined by the U.S. Geological Survey, (c) probable reservoir characteristics (well productivity, depth, etc.), and (d) anticipated ranges of water depths and distances to shore of possible oil and gas discoveries in Lower Cook Inlet and Shelikof Strait.

The economic analysis as discussed in the previous section (3.6) defines those field sizes, discovery locations, production systems and reservoir conditions that are economically viable under the assumptions of the analysis.

Since there is still a considerable number of permutations of field size, production technologies and discovery situations (water depth, distance to shore, geographic location) which have been demonstrated to be economically viable, it is necessary to limit the number of possible developmental options at each level of resource discovery (high find, medium find, low find, no commercial resources) through application of some basic assumptions and determination of the key parameters governing potential impacts on the Alaskan economy and environment.

A three phased approach in the scenario development is conducted at this point in the study:

- A number of skeletal petroleum development scenarios are defined with various combinations of discovery location (water depth, distance to shore etc.), production systems, field sizes and reservoir characteristics (depth, initial well productivity) which have been shown to be economic.

- The staff of the Bureau of Land Management, Alaska OCS Office selected from among the suggested skeletal scenarios one scenario to be detailed for each resource level.

- The equipment, materials, facilities, manpower and siting requirements and scheduling of each selected scenario (high find, medium find, low find, no commercial resources found) were detailed to show the magnitude of impacts.

The skeletal scenario options presented in Tables 3-4 through 3-15 demonstrate various production system options and infrastructure sharing arrangements between the three discovery areas -- Lower Cook Inlet Sale CI, Lower Cook Inlet Sale 60 and Shelikof Strait Sale 60. Variation in the onshore impact potential (i.e. the amount of new shore facility construction resulting from Sale 60 development) is also provided in skeletal scenario options through variation in the amount of infrastructure shared with Sale CI fields and the amount of production trans-

TABLE 3-4

HIGH FIND OIL - LOWER COOK SALE 60 FIELD SHARES PIPELINE WITH EXISTING LOWER COOK INLET SALE CI FIELD(S)
TO EXISTING UPPER COOK INLET TERMINAL OR REFINERY

Basin	Field Size Oil (MMBBL)	Production System	Platforms No./Type[1]	Number of Production Wells	Initial Well Productivity (B/D)	Peak Production Oil (MB/D)	Water Depth		Pipeline Distance to Shore Terminal		Trunk Pipeline Diameter (inches) Oil
							Meters	(Feet)	Kilometers	(Miles)	
Lower Cook	400	Steel platform with shared trunkline to shore	1 S	40	5,000	192	152-183	(500-600)	224	(140)	20

[1]S = Steel

Note: This skeletal scenario option specifies reservoir conditions and technical characteristics that are the most economic for the water depth specified.

Source: Dames & Moore

TABLE 3-5

HIGH FIND OIL - LOWER COOK SALE 60 FIELD SHARES PIPELINE WITH FIELD LOCATED IN SHELIKOF
TO EXISTING UPPER COOK INLET TERMINAL OR REFINERY

Basin	Field Size Oil (MMBBL)	Production System	Platforms No./Type[1]	Number of Production Wells	Initial Well Productivity (B/D)	Peak Production Oil (MB/D)	Water Depth		Pipeline Distance to Shore Terminal[2]		Trunk Pipeline Diameter (inches) Oil
							Meters	(Feet)	Kilometers	(Miles)	
Lower Cook	400	Steel platform with shared trunkline to shore	1S	40	5,000	192	152-183	(500-600)	224	(140)	20

[1] S = Steel
[2] Shared portion of pipeline, i.e., distance from Lower Cook Inlet to Nikiski or Drift River.

Note: As with Table 3-4, this skeletal scenario option specifies reservoir conditions and technical characteristics that are the most economic for the water depth specified. The only difference between Tables 3-4 and 3-5 is the infrastructure sharing arrangements.

Source: Dames & Moore

TABLE 3-6

HIGH FIND OIL - LOWER COOK FIELDS (BOTH FIELDS IN SALE 60) SHARE PIPELINE TO EXISTING UPPER COOK INLET TERMINAL OR REFINERY

Basin	Field Size Oil (MMBBL)	Production System	Platforms No. /Type[1]	Number of Production Wells	Initial Well Productivity (B/D)	Peak Production Oil (MB/D)	Water Depth Meters	Water Depth (Feet)	Pipeline Distance to Shore Terminal Kilometers	Pipeline Distance to Shore Terminal (Miles)	Trunk Pipeline Diameter (inches) Oil
Lower Cook	200	Steel platform with shared trunkline to existing shore terminal	1 s	40	2,000	76.8	30-60	(100-200)	48-80	(30-50)	16
	200	Steel platform with shared trunkline to existing shore terminal	1 s	40	2,000	76.8	30-60	(100-200)	48-80	(30-50)	16

[1]S = Steel

Source: Dames & Moore

TABLE 3-7

HIGH FIND OIL - SHELIKOF FIELDS SHARE PIPELINE TO LOWER COOK FIELDS -THEN SHARE PIPELINE
WITH LOWER COOK FIELDS TO EXISTING UPPER COOK TERMINAL OR REFINERY

Basin	Field Size Oil (MMBBL)	Production System	Platforms No. /Type[1]	Number of Production Wells	Initial Well Productivity (B/D)	Peak Production Oil (MB/D)	Water Depth		Pipeline Distance to Shore Terminal		Trunk Pipeline Diameter (inches) Oil
							Meters	(Feet)	Kilometers	(Miles)	
Shelikof	550	Steel platform with shared trunkline to shore	1S	40	5,000	192	152-183	(500-600)	322	(200)	20
	450	Steel platform with shared trunkline to shore	1S	40	5,000	192	152-183	(500-600)	322	(200)	20

[1]S = Steel

Source: Dames & Moore

TABLE 3-8

HIGH FIND OIL - SHELIKOF FIELDS SHARE PIPELINE TO NEW SHORE TERMINAL LOCATED ON WEST COAST OF KODIAK OR AFOGNAK ISLAND

Basin	Field Size Oil (MMBBL)	Production System	Platforms No./Type[1]	Number of Production Wells	Initial Well Productivity (B/D)	Peak Production Oil (MB/D)	Water Depth Meters	Water Depth (Feet)	Pipeline Distance to Shore Terminal[2] Kilometers	Pipeline Distance to Shore Terminal[2] (Miles)	Trunk Pipeline Diameter (inches) Oil
Shelikof	550	Steel platform with shared trunkline to shore	1 S	40	5,000	192	152-183	(500-600)	24-40	(15-25)	20
	450	Steel platform with shared trunkline to shore	1 S	40	5,000	192	152-183	(500-600)	24-40	(15-25)	20

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5

[1] S = Steel

[2] No more than 8 kilometers (5 miles) of pipeline are assumed to be onshore.

Source: Dames & Moore

TABLE 3-9

HIGH FIND NON-ASSOCIATED GAS - LOWER COOK SALE 60 FIELD SHARES PIPELINE WITH SALE CI FIELDS TO LNG PLANT IN UPPER COOK INLET

Basin	Field Size Gas (BCF)	Production System	Platforms No. /Type[1]	Number of Production Wells	Initial Well Productivity (MCF/D)	Peak Production Gas (MMCF/D)	Water Depth		Pipeline Distance to Shore Terminal		Trunk Pipeline Diameter (inches) Gas
							Meters	(Feet)	Kilometers	(Miles)	
Lower Cook	363	Steel platform with shared trunkline to LNG plant	1 s	8	25	192	30-60	(100-200)	48-80	(30-50)	20-26

[1] S = Steel

Source: Dames & Moore

TABLE 3-10

HIGH FIND NON-ASSOCIATED GAS - SHELIKOF FIELD WITH PIPELINE TO LOWER COOK FIELD(S) THEN SHARED PIPELINE TO UPPER COOK LNG PLANT

Basin	Field Size Gas (BCF)	Production System	Platforms No./Type[1]	Number of Production Wells	Initial Well Productivity (MCF/D)	Peak Production Gas (MMCF/D)	Water Oepth Meters	Water Oepth (Feet)	Pipeline Distance to Shore Terminal Kilometers	Pipeline Distance to Shore Terminal (Miles)	Trunk Pipeline Diameter (inches) Gas
Shelikof	1000	Steel platform with shared trunkline to LNG plant	1 s	24	25	576	152-183	(500-600)	321	(200)	24-28

[1]S = Steel

Source: Dames & Moore

TABLE 3-11

MEDIUM FIND OIL - SHELIKOF FIELD WITH PIPELINE TO SHORE TERMINAL ON WEST COAST OF KODIAK OR AFOGNAK ISLAND

Basin	Field Size Oil (MMBBL)	Production System	Platforms No. /Type[1]	Number of Production Wells	Initial Well Productivity (B/D)	Peak Production Oil (MB/D)	Water Depth Meters	Water Depth (Feet)	Pipeline Distance to Shore Terminal[2] Kilometers	Pipeline Distance to Shore Terminal[2] (Miles)	Trunk Pipeline Diameter (inches) Oil
Shelikof	500	Steel platform with shared trunkline to shore	1 s	40	5,000	192	152-183	(500-600)	24-40	(15-25)	16

[1] S = Steel

[2] Single field, pipeline not shared; maximum of 8 kilometers (5 miles) of onshore pipeline.

Source: Oames & Moore

TABLE 3-12

MEDIUM FIND OIL - LOWER COOK SALE 60 FIELD WITH UNSHARED PIPELINE TO EXISTING UPPER COOK INLET TERMINAL OR REFINERY

Basin	Field Size Oil (MMBBL)	Production System	Platforms No./Type[1]	Number of Production Wells	Initial Well Productivity (B/D)	Peak Production Oil (MB/D)	Water Depth		Pipeline Distance to Shore Terminal[2]		Trunk Pipeline Diameter (inches) Oil
							Meters	(Feet)	Kilometers	(Miles)	
Lower Cook	198	Steel platform with unshared pipeline to shore	1 s	40	2,000	76.8	61-91	(200-300)	32-56	(20-35)	10

[1] S = Steel

[2] Single field, pipeline not shared.

Source: Dames & Moore

TABLE 3-13

MEDIUM FIND OIL - LOWER COOK SALE 60 FIELD SHARES PIPELINE WITH COOK INLET SALE CI FIELD(S) TO EXISTING TERMINAL OR REFINERY IN UPPER COOK INLET

Basin	Field Size Oil (MMBBL)	Production System	Platforms No./Type[1]	Number of Production Wells	Initial Well Productivity (B/D)	Peak Production Oil (MB/D)	Water Depth		Pipeline Distance to Shore Terminal		Pipeline Diameter (inches) Oil
							Meters	(Feet)	Kilometers	(Miles)	
Lower Cook	198	Steel platform with shared trunkline to shore	1 S	40	2,000	76.8	61-91	(200-300)	160	(100)	12-16

[1]S = Steel

Source: Dames & Moore

TABLE 3-14

HIGH INTEREST LEASE SALE

Basin	YEAR AFTER LEASE SALE					
	1		2		3	
	No. of Rigs	No. of Wells	No. of Rigs	No. of Wells	No. of Rigs	No. of Wells
Lower Cook Sale 60	1	2	2	5	1	1
Shelikof	2	5	2	5	1	1
TOTALS	3	7	4	10	2	2
					TOTAL WELLS = 19	

Assumptions:

1. An average well completion rate of approximately 5 months
2. An average total well depth of 3,692 to 4,572 meters (13,000 to 15,000 feet)
3. Exploratory interest is centered in the Shelikof strait area (reflecting resource estimates)
4. Year after lease sale = 1982.

Source: Dames & Moore

TABLE 3-15

LOW INTEREST LEASE SALE

Basin	YEAR AFTER LEASE SALE					
	1		2		3	
	No. of Rigs	No. of Wells	No. of Rigs	No. of Wells	No. of Rigs	No. of Wells
Lower Cook Sale 60	--	--	--	--	--	--
Shelikof	2	5	1	2	1	1
TOTALS	2	5	1	2	1	1
					TOTAL WELLS = 8	

Assumptions:

1. An average well completion rate of approximately 5 months
2. An average total well depth of 3,692 to 4,572 meters (13,000 to 15,000 feet)
3. Exploratory interest is centered in the Shelikof strait area (reflecting resource estimates)
4. Year after lease sale = 1982

Source: Dames & Moore

ported to existing Upper Cook Inlet petroleum facilities (see discussion in Section 3.6).

It is important to point out that the location, production and reservoir characteristics, field size, and infrastructure sharing arrangements associated with each of the scenarios are essential combinations to generate a rate of return sufficiently large to induce development. In other words, we recognize that the conditional probability of all of the characteristics that define the skeletal scenarios is somewhat low - lower, without doubt, than the U.S. Geological Survey probability estimates of aggregate "economically recoverable resources". However, if any of the characteristics are much changed from those described in the skeletal scenarios, the reserves quickly become uneconomic and undevelopable regardless of their geologic probability of occurrence.

The resource assumptions on which these skeletal scenarios are based are explained in Appendix A and Sections 3.3 and 3.4.

Each skeletal scenario comprises one or more fields which in aggregate comprise the total U.S. Geological Survey resource estimate allocated between Lower Cook Inlet Sale 60 and Shelikof Strait (call for nomination area) and Lower Cook Inlet Sale CI as shown in Tables 3-1 and 3-2.

Tables 3-4 through 3-15 present skeletal scenario options for the high find, medium find, and no commercial resource estimates. The economic analysis indicates that the low find oil resources in most discovery locations are uneconomic. The low find resource has therefore been dropped from the scenario analysis. Since the resources are allocated to separate areas, Lower Cook Inlet and Shelikof Strait, separate cases are specified for each. Thus, for the high find and medium find resource cases, options have to be selected for both Lower Cook Inlet and Shelikof, together comprising a single scenario.

Table 3-4 shows that if the "high find" resource estimate -- 400 MB -- for Lower Cook Inlet shares existing infrastructure and pipelines from ported to existing Upper Cook Inlet petroleum facilities (see discussion in Section 3.6).

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Table 3-4 shows that if the "high find" resource estimate -- 400 MB -- for Lower Cook Inlet shares existing infrastructure and pipelines from the previous CI sale, the entire 400 MB must be in one field with a high initial production rate because: (1) the water depths where it could be located are 152 to 183 meters (500 to 600 feet) and (2) the pipeline distance to the existing terminal is approximately 225 kilometers (140 miles).

For one of the alternatives at the high find resource level, the Lower Cook Inlet option on Table 3-5 can only be selected with Table 3-7 since the options are interdependent in infrastructure sharing arrangements. Table 3-5 ties the Lower Cook Inlet field in with a pipeline coming from a newly discovered field in the Shelikof Strait. Table 3-7 shows that Shelikof oil production is piped to Lower Cook Inlet where it then shares a pipeline with fields located in Lower Cook Inlet (either Sale 60, Sale CI, or both) to a terminal and/or refinery in Upper Cook Inlet.

Table 3-6 shows that two fields comprise the high find resource estimate in Lower Cook Inlet Sale 60; these fields share a pipeline to an Upper Cook Inlet terminal or refinery. They do not share any infrastructure with fields in Lower Cook Inlet Sale CI area.

Table 3-8 provides an alternative to Table 3-7. Shelikof oil is brought to a new shore terminal on the west coast of Kodiak Island or Afognak Island.

The non-associated gas resources (high find) of Lower Cook Inlet and Shelikof Strait cannot support construction of a new LNG plant. To be economic, they have to share a pipeline with other Lower Cook Inlet gas fields (Sale CI) to existing LNG plants in Upper Cook Inlet. Furthermore, all the gas has to be located in a single field in each area (Lower Cook Inlet and Shelikof) and reservoir conditions have to permit high productivity wells. Because of these economic considerations, no skeletal scenario options can be realistically provided for the high find non-associated gas resources of Sale 60. Tables 3-9 and 3-10 together comprise the only scenario for the high find non-associated gas; Table 3-9 shows the Lower Cook Inlet gas resources in a single field which produces to a pipeline shared with Lower Cook Inlet Sale CI field(s) to an existing LNG plant in Upper Cook Inlet. Similarly, Table 3-10 shows Shelikof non-associated gas sharing a pipeline with Lower Cook Inlet field(s) to an existing LNG plant in Upper Cook Inlet.

At the medium find resource level, Shelikof oil can only be produced economically through a short pipeline to a new terminal located on the west coast of Kodiak Island or Afognak Island (Table 3-11).

The Lower Cook Inlet Sale 60 medium find oil resources have to comprise a single field to be economic. They can support an unshared pipeline to an existing Upper Cook Inlet shore terminal, provided the pipeline is short (Table 3-12); this means that the field would have to be located in the upper portion of Lower Cook Inlet. Alternatively, the single field could share a pipeline with field(s) in Sale CI (Table 3-13).

Two exploration scenario options are provided reflecting high industry interest (Table 3-14) and low industry interest (Table 3-15) in Sale 60. The low interest exploration scenario (Table 3-15) indicates interest in the Shelikof Straits area only; implicitly, this could indicate diminished prospects in Lower Cook Inlet perhaps resulting from unsuccessful results in Sale CI.

The following skeletal scenarios were selected by BLM staff for detailing:

High Find Oil and Non-Associated Gas

Table 3-6	High FindOil - Lower Cook Fields (Both Fields in Sale 60) Share Pipeline to Existing Upper Cook Inlet Terminal or Refinery
Table 3-8	High Find Oil - Shelikof Fields Share Pipeline to New Shore Terminal Located on West Coast of Kodiak or Afognak Island

Table 3-9	High Find Non-Associated Gas - Lower Cook Sale 60 Fields Shares Pipeline with Sale CI Fields to LNG Plant in Upper Cook Inlet
Table 3-10	High Find Non-Associated Gas - Shelikof Field with Pipeline to Lower Cook Field(s) then Shared Pipeline to Upper Cook LNG Plant

Medium Find Oil

Table 3-11	Medium Find Oil - Shelikof Field with Pipeline to Shore Terminal on West Coast of Kodiak or Afognak Island
Table 3-13	Medium Find Oil - Lower Cook Sale 60 Field Shares Pipeline with Cook Inlet Sale CI Field(s) to Existing Terminal or Refinery in Upper Cook Inlet

No Commercial Resources (Exploration Only)

Table 3-14	High Interest Lease Sale

3.8 Detailing of Scenarios

3.8.1 Introduction

The basic characteristics of the selected scenarios have already been defined in the skeletal scenarios (platform, pipeline and shore facility requirements, and general location). Detailing of the scenarios involves the following basic steps:

- Location of fields
- Identification of an exploration and field discovery schedule
- Specification of major facilities requirements and their siting

- Formulation of field development (construction) and operation schedules

- Translation of field development and operation schedules into employment estimates

3.8.2 The Location of Fields

The first step in scenario detailing is the location of fields identified in the selection of the skeletal scenario (the general location of the field has already been defined by distance to terminal site, water depth, etc.). Where possible the field is located on a known geologic structure of sufficient (apparent) size to accommodate the reserves within the range of recoverable reserves per acre assumed in the analysis. In the absence of sufficient geologic data, location of the field is arbitrary.

3.8.3 Exploration and Field Discovery Schedules

The exploration and field discovery schedules forming the basis of the scenario descriptions were formulated to be consistent with the following considerations:

- An exploratory effort consistent with the postulated resources at an assumed rate of discovery which has been sustained historically in some other offshore areas (a high discovery ratio is assumed for the high find scenario and more modest success ratio for the medium find scenario).

- An exploration pattern that builds up to a peak and then declines as prospects become fewer and more difficult to find and as petroleum company resources shift from exploration to field development investment.

- The larger fields are in general discovered and developed first.

- Most of the discoveries are made within five years of the lease sale (i.e. the initial tenure of the leases).

- Although availability of exploration rigs at the time of the lease sale cannot be predicted, the number of drill rigs and exploration well scheduling has been tailored to discover most, if not all, of the postulated resources within the five year tenure of the leases.

As explained in Appendix B, once a discovery has been made two or three delineation wells are assumed to be drilled and the decision to develop is assumed to be made 18 to 24 months after discovery. Significant investment in field development is assumed to commence the year following the decision to develop. Implicit in this schedule is some delay related environmental regulation. The first year of significant investment in field development is the year in which contracts are placed for platforms, process equipment, etc.; this is year 1 of the investment schedule as used in the economic analysis (see Appendix B).

3.8.4 Major Facilities and Their Siting

The major shore facility requirements of Sale 60 petroleum development to a large degree will depend upon the production options discussed in Section 3.7. In particular, the facility requirements will depend upon (i) the amount of production transported to existing Upper Cook Inlet facilities (terminals, refineries, LNG plants, etc.), (ii) the infrastructure developed in response to Sale CI discoveries, and (iii) the degree to which Sale 60 fields share infrastructure with Sale CI fields. Specifications on existing and planned Upper Cook Inlet petroleum facilities including their capacities and sources of oil and gas are presented in Table 3-16.

The results of a facilities siting analysis for the northern portion of Shelikof Strait are presented in Appendix E. Potential sites for various shore facilities in Cook Inlet, based on previous studies, are identified in Table 3-17.

TABLE 3-16

UPPER COOK INLET PETROLEUM FACILITIES

Facility/Owner	Location	Functions	Source of Supply	Products	Maximum Capacity	Average 1978/1979 Throughput	Comments
Tesoro	Nikiski	Oil refinery	Upper Cook State Royalty Oil (85%), Prudhoe Bay Oil (15%), Indonesian Oil (10%)	White gas, gas blend, jet fuel, arctic diesel, gas/oil/residuals	48,500 bpd	46,000 bpd	The proportions of the products will vary according to consumer demand.
Phillips	Nikiski	LNG plant	North Cook Inlet gas field	LNG	174 mmcfd	--	
Collier Carbon & Chemical Corp.	Nikiski	Ammonia/urea plant	Kenai gas field	3,100 tons ammonia per day (50% used for urea production) 2,700 tons urea per day	--	--	
Standard Oil	Nikiski	Oi 1 refinery	Upper Cook Inlet and Swanson River	--	22,000 bpd	13,200 bpd	
Cook Inlet Pipeline Co.	Drift River	Crude export	McArthur River, Trading Bay and Granite Point oil fields	.-	250,000 bpd	110,000 bpd	Handles 75% of Upper Cook Inlet oil pro-duction; treatment of crude is conducted at Trading Bay and Granite Point partial pro-cessing facilities.
Pacific Alaska LNG Company	Nikiski	LNG plant	Existing Upper Cook producing fields, shut-in fields and new reserves	LNG	200 mmcfd (Phase 1) 400 mmcfd (Phase 11)	-- --	

Source: Personal communications with Upper Cook Inlet operators.

TABLE 3-17

COOK INLET PETROLEUM FACILITY SITES

Facility	Site(s)	Comments	Source
Exploration Support Base	Nikiski Homer	Bases for current Sale CI exploration	CH2M Hill, 1978; U.S.D.I, 1976
Field Construction Support Base	Nikiski Seldovia Homer Stariski		CH2M Hill, 1978; U.S.D.I. , 1976
Oil Terminal	Drift River Nikiski Stariski-Anchor Point Cape Douglas	Partial treatment of crude not done at Drift River but at Trading Bay and Granite Point facilities	CH2M Hill, 1978; U.S.D.I. , 1976; NOAA, 1978
LNG Plant	Nikiski Stariski-Anchor Point	Phillips LNG Plant 170 MMCFD currently operating; Pacific Alaska LNG Co. plans 400 MMCFD plant	CH2M Hill, 1978; U.S.D.I., 1976; NOAA, 1978
Treatment Plant	Stariski-Anchor Point Redoubt Point		CH2M Hill, 1978; U.S.D.I. , 1976; NOAA, 1978

3.8.5 Field Development and Operation Scheduling

Once discovery and decision to develop dates have been established, field develop schedules are defined -for each scenario based on the assumptions explained in Appendix B which are consistent with schedules in other offshore areas such as the North Sea. Schedules for each scenario are shown on a series of tables showing the timing of platform installation and commissioning, development well drilling, major facilities construction, pipelaying, etc. For each field a production schedule is identified based on the production timing and production decline rates defined in Appendix A. These provide information on production start-up and field life necessary to determine the timing of facilities construction (marine terminals, pipelines, etc.) and the operational life of the field.

3.8.6 Translation of Field Development and Operation Schedules Into Employment Estimates

The field development and operation tables developed for scenario detailing, supplemented by information on the size of facilities (e.g. marine terminal capacity in barrels per day) or location of construction work (e.g. water depth of pipelaying), form the basis for estimating scenario employment.

The components of the construction and operation schedule are broken down into a number of employment tasks (development drilling, platform installation and commissioning, terminal and pipeline operations, etc.) of specified durations. Using a computer program specifically developed for this series of scenario studies, the scenario employment calculations are made. The methodology and assumptions of this OCS manpower model are explained in Appendix D. The reader is also referred to a worked example of these computations in a companion report of the Alaska OCS Socioeconomic Studies Program (Northern Gulf of Alaska Petroleum Development Scenarios, Appendix D, Dames & Moore, 1979a).

4.0 EXPLORATION ONLY SCENARIO

4.1 General Description

The exploration only scenario assumes that no commercial oil and/or gas resources are discovered. Industry interest is high and is principally centered in the Shelikof Strait (Table 4-l). A high level of exploratory activity characterizes the exploration program due to a number of promising "shows". However, the promise is never realized and only small non-commercial hydrocarbon deposits are found. Exploration terminates in the third year after the lease sale with a total of 19 wells drilled.

4.2 Tracts and Location

No tracts are specified in this scenario. The total of wells drilled (19) indicates that 19 of the leased tracts are drilled (the assumption has been made that no more than one well is drilled per tract), 11 in Shelikof Strait, and 8 in Lower Cook Inlet. Several of the larger structures are explored with more than one well, thus the total number of prospects examined is somewhat less than the total number of wells drilled.

4.3 Exploration Schedule

The exploration schedule, presented in Table 4-1, shows that exploration commences in the first year after the lease sale, peaks in the second year, and terminates in the third year after discouraging results.

4.4 Facility Requirements and Locations

Exploration in Lower Cook Inlet and Shelikof Strait will be conducted by a combination of semi-submersible drill rigs, drillships, and jack-ups. This variation in rig type is a result of the great range of water depths encountered in Sale 60 which range from less than 30 meters (100

TABLE 4-1

HIGH INTEREST LEASE SALE

Basin	YEAR AFTER EASE SALE					
	1				3	
	No. of Rigs	No. of Wells	No. of Rigs	No. of Wells	No. of Rigs	No. of Wells
Lower Cook Sale 60	1	2	2	5	1	1
Shelikof	2	5	2	5	1	1
TOTALS	3	7	4	10	2	2
						TOTAL WELLS = 19

Assumptions:

1. An average well completion rate of approximately 5 months
2. An average total well depth of 3,692 to 4,572 meters (13,000 to 15,000 feet)
3. Exploratory interest is centered in the Shelikof strait area (reflecting resource estimates)
4. Year after lease sale = 1982

Source: Dames & Moore

feet) in the upper portion of Lower Cook Inlet and in Kamishak Bay to over 305 meters (1,000 feet) at the southwestern end of Shelikof Strait. Jack-ups will be used in water depths of less than 61 meters (200 feet) while semi-submersibles and drillships will generally be used in water depths greater than 61 meters (200 feet). The number of rigs involved in the exploration program is given in Table 4-I.

The principal exploration support base for Lower Cook Inlet Sale 60 will be Nikiski, which will be used for the storage and transshipment of tubular goods, bulk materials (e.g. mud, cement), drilling tools, and fuel . Homer will serve as a terminal for air transportation of personnel, light supplies and water. (For discussion of facility sites including support bases, the reader is referred to a report by CH_2M Hill, 1978.) The Shelikof Strait exploration will also be supported by Nikiski facilities although Seward and Kodiak become more viable alternatives as distance from Nikiski increases.

4.5 Manpower Requirements

The manpower requirements associated with the exploration program are presented in Tables 4-2, 4-3, 4-4, and 4-5.

EXPLORATION ONLY SCENARIO
0.3/06/79

TABLE 4-2

ONSITE MANPOWER REQUIREMENTS BY INDUSTRY
(ONSITE MAN-MONTHS)

YEAR AFTER	PETROLEUM		CONSTRUCTION		TRANSPORTATION		MFG	ALL INDUSTRIES		
LEASE SALE	OFFSHORE	ONSHORE	OFFSHORE	ONSHORE	OFFSHORE	ONSHORE	ONSHORE	OFFSHORE	ONSHORE	TOTAL
1	2191.	230.	0.	0.	936.	252.	0.	3127.	482.	3609.
2	2938.	306.	0.	0.	1248.	336.	0.	4186.	644.	4830.
3	610.	64.	0.	0.	260.	70.	0.	870.	134.	1004.

EXPLORATION ONL% SCENARIO
03/08/79

TABLE 4-3

JANUARY, JULY AND PEAK MANPOWER REQUIREMENTS
(NUMBER OF PEOPLE)

YEAR AFTER LEASE SALE	JANUARY OFFSHORE ONSITE	JANUARY OFFSHORE OFFSITE	JANUARY ONSHORE ONSITE	JANUARY ONSHORE OFFSITE	JANUARY TOTAL	JULY OFFSHORE ONSITE	JULY OFFSHORE OFFSITE	JULY ONSHORE ONSITE	JULY ONSHORE OFFSITE	JULY TOTAL	PEAK MONTH	PEAK TOTAL
1	246.	207.	39.	15.	507.	271.	207.	41*	15.	534.	5	561.
2	328.	276.	52.	20.	676.	378.	276.	56.	20.	730.	5	730.
3	164.	138.	26.	10.	338.	0.	00	0*	0*	0.	5	365.

EXPLORATION 0NL% SCENARIO
03/08/79

TABLE 4-4

YEARLY MANPOWER REQUIREMENTS BY ACTIVITY
(MAN-MONTHS)

YEAR/ACTIVITY		1	2	3	4	5	b	7	8	9	10	11	12	13	14	15	16 **
1	ONSITE	302.	180.	(J.	o*	o*	o*	o.	0.	o*	o.	175.	2016.	0.	0.	o.	936.
	OFFSITE	o*	180.	0.	0.	0.	0.	0.	0.	o*	0.	o.	2016.	0.	0.	0.	468.
2	ONSITE	404.	240.	0.	0.	0.	0.	0.	0.	0.	o*	250.	2688.	0.	o*	0.	1248.
	OFF-SITE	0.	240.	0.	0.	0.	o*	o.	o*	o.	o*	o.	2688.	0.	o*	o*	624.
3	ONSITE	84.	50.	0.	0.	0.	0.	0.	0.	o*	o.	50.	560.	o.	0.	0.	260.
	OFFSITE	o*	50.	0.	0.	0.	0.	0.	0.	0.	0.	o*	560.	0.	0.	0.	130.

** SEE ATTACHED KEY OF ACTIVITIES

TABLE 4-4 (Attachment)

LIST OF TASKS BY ACTIVITY

ONSHORE

Activity	
1	Service Bases (Onshore Employment - which would include all onshore administration, service base operations, rig and platform service)
	Task 1 - Exploration Well Drilling
	Task 2 - Geophysical Exploration
	Task 5 - Supply/Anchor Boats for Rigs
	Task 6 - Development Drilling
	Task 7 - Steel Jacket Installations and Commissioning
	Task 8 - Concrete Installations and Commissioning
	Task 11 - Single-Leg Mooring System
	Task 12 - pipeline-Offshore, Gathering, Oil and Gas
	Task 13 - Pipeline-Offshore, Trunk, Oil and Gas
	Task 23 - Supply/Anchor Boats for Platform
	Task 24 - Supply/Anchor Boats for Lay Barge
	Task 27 - Longshoring for Platform
	Task 28 - Longshoring for Lay Barge
	Task 33 - Maintenance and Repairs for Platform and Supply Boats
	Task 37 - Longshoring for Platform (Production)
	Task 31 - Platform Operation
2	Helicopter Service
	Task 4 - Helicopter for Rigs
	Task 21 - Helicopter Support for Platform
	Task 22 - Helicopter Support for Lay Barge
	Task 34 - Helicopter for Platform
	Construction
3	Service Base
	Task 3 - Shore Base Construction
	Task 10 - Shore Base Construction
4	Pipe Coating
	Task 15 - Pipe Coating
5	Onshore Pipelines
	Task 14 - Pipeline, Onshore, Trunk, Oil and Gas
6	Terminal
	Task 16 - Marine Terminal (assumed to be oil terminal)
	Task 18 - Crude Oil Pump Station Onshore
7	LNG Plant
	Task 17 - LNG Plant
8	Concrete Platform Construction
	Task 19 - Concrete Platform Site Preparation
	Task 20 - Concrete Platform Construction
9	Oil Terminal Operations
	Task 36 - Terminal and Pipeline Operations
10	LNG Plant Operations
	Task 38 - LNG Operations

OFFSHORE

Activity	
11	Survey
	Task 2 - Geophysical and Geological Survey
12	Rigs
	Task 1 - Exploration Well
13	Platforms
	Task 6 - Development Drilling
	Task 31 - Operations
	Task 32 - Workover and Well Stimulation
14	Platform Installation
	Task 7 - Steel Jacket Installation and Commissioning
	Task 8 - Concrete Installation and Commissioning
	Task 11 - Single-Leg Mooring System
15	Offshore Pipeline Construction
	Task 12 - Pipeline Offshore, Gathering, Oil and Gas
	Task 13 - Pipeline Offshore, Trunk, Oil and Gas
16	Supply/Anchor/Tug Boat
	Task 5 - Supply/Anchor Boats for Rigs
	Task 23 - Supply/Anchor Boats for Platform
	Task 24 - Supply/Anchor Boats for Lay Barge
	Task 25 - Tugboats for Installation and Towout
	Task 26 - Tugboats for Lay Barge Spread
	Task 29 - Tugboats for SLMS
	Task 30 - Supply Boat for SLMS
	Task 35 - Supply Boat for Platform

NOTES TO TABLE 4-4

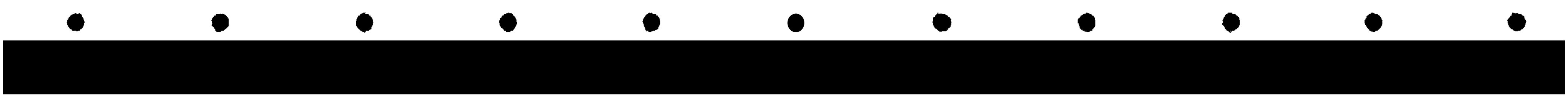
Task	
1	Average 28-man crew per shift on drilling vessel and six shore-based positions (clerks, expediters, administrators); shift on drilling vessel includes catering and oil field service personnel and vessel operating crew
2	Approximately one month of geophysical work per well based on 200 miles of seismic lines per well at approximately 15 miles/day x 2 (weather factor); 25-man crew and two onshore positions; crew can work from May through September
3	Requirements for temporary shore base construction varies with lease area
4	One helicopter per drilling vessel; two pilots and three mechanics per helicopter; considered onshore employment
5	Two supply anchor boats per rig; each with 13-man crew
6	Offshore crew includes approximate 15-man drilling crew, catering, platform, operating crew, and special drilling crews
8, 9	Includes all aspects of towout, placement, pile driving, module installation, and hook-up of deck equipment; also includes crew support (catering personnel) and diving
10	See Table D-7
12	Rate of progress assumed to be average of .75 per day for all gathering line; scale factors not applied to gathering line
13	Rate of progress averages ,5 mile per day of medium-size trunk line in water of medium depth; scale factors applied in shallow or deeper water and for pipe size; rate of progress makes allowance for weather down-time, tie-ins, and mobilization and de-mobilization
14	Rate of progress averages .3 mile per day of buried medium-size onshore trunk line in moderate terrain; scale factors applied for elevated pipe or rocky terrain and for field size
15	Rate of progress for pipe coating is one mile/day for 20-36" pipe; 1.5 mile/day for 10-19" pipe
16	See Table D-7
17	See Table D-7
20	See Table D-7
21	One helicopter per platform
22	One helicopter per lay barge spread
23	Three supply/anchor boats per platform
24	Five supply/anchor boats per lay barge spread
25	Four tugs for towout per platform; 10-man crew per boat
26	Two tugs per lay barge spread; 10-man crew
29	One tug boat perSLMS
30	One supply boat per SLMS
32	Assumed to begin five years after oil production begins; 2 crews kept busy for every 2 platforms, therefore, 1 crew per platform used in model; actually, 2 crews would be present on a platform at one time. This work over schedule does not apply to gas well platforms
33	Assumed to begin five years after production begins
36	Includes shore processing plant personnel

EXPLORATION ONLY SCENARIO
03/08/75

TABLE 4-5

SUMMARY OF MANPOWER REQUIREMENTS FOR ALL INDUSTRIES
ONSITE AND TOTAL

YEAR AFTER LEASE SALE	ONSITE (MAN-MONTHS)			TOTAL (MAN-MONTHS)			TOTAL LABOR FORCE (MONTHLY AVERAGE)		
	OFFSHORE	ONSHORE	TOTAL	OFFSHORE	ONSHORE	TOTAL	OFFSHORE	ONSHORE”	TOTAL
1	3127.	482.	3609.	5611.	662.	6273.	468.	56.	523.
2	4186.	644.	4830.	7498.	884.	8382.	625.	74.	699.
3	870.	134.	1OI-J4.	1560.	184.	1744.	1300	16.	146.



5.0 HIGH FIND SCENARIO

5.1 General Description

The high find scenario assumes significant commercial discoveries of oil and gas. The basic characteristics of the high find scenario are summarized in Tables 5-1 through 5-4. The total reserves discovered and developed are:

	Oil (MMbbl)	Non-Associated Gas (BCF)
Lower Cook	400	363
Shelikof	1,000	1,000

The major portion of the oil and gas resources are discovered in the Shelikof Strait area west of Afognak Island (Figure 5-1) while the Lower Cook Inlet discoveries are made immediately to the north of Sale CI (Figure 5-2).

The Lower Cook Inlet oil fields are located in shallow water approximately 80 kilometers (50 miles) south of Drift River. As such they are well situated to use the Drift River terminal to handle their crude production. By the late 1980's Drift River may have sufficient spare capacity to handle the incremental production from these fields which would peak at about 150,000 bpd although total Cook Inlet production may exceed existing capacity requiring expansion of Upper Cook refineries and/or terminals (see Appendix A, Section IV). A partial processing facility may have to be constructed onshore between the pipeline landfall and Drift River terminal. As discussed in Section 3.5, there are several production options for Lower Cook Inlet oil; this scenario assumes that the Sale 60 fields in Lower Cook Inlet do not share infrastructure, in particular pipelines, with Sale CI fields but rather support their own pipeline.

Of the production options for Shelikof Strait oil fields discussed in Section 3.5, a short pipeline to a new terminal constructed on the

TABLE 5-1

HIGH FIND OIL - LOWER COOK FIELDS (BOTH FIELDS IN SALE 60) SHARE PIPELINE TO EXISTING UPPER COOK INLET TERMINAL OR REFINERY

Basin	Field Size Oil MMBBL)	Production System	Platforms No./Type[1]	Number of Production Wells	Initial Well Productivity (B/D)	Peak Production Oil (MB/D)	Water Depth Meters	Water Depth (Feet)	Pipeline Distance to Shore Terminal Kilometers	Pipeline Distance to Shore Terminal (Miles)	Trunk Pipeline Diameter (inches) Oil
Lower Cook	200	Steel platform with shared trunkline to existing shore terminal .	1 S	40	2,000	76.8	30-60	[100-200)	48-80	(30-50)	16
	200	Steel platform with shared trunkline to existing shore terminal	1 s	40	2,000	76.8	30-60	(100-200)	48-60	(30-50)	16

[1] S = Steel

Source: Dames & Moore

TABLE 5-2

HIGH FIND OIL - SHELIKOF FIELDS SHARE PIPELINE TO NEW SHORE TERMINAL LOCATEDON WEST COAST OF KODIAK OR AFOGNAK ISLAND

Basin	Field Size Oil (MMBBL)	Production System	Platforms No./Type[1]	Number of Production Wells	Initial Well Productivity (B/D)	Peak Production Oil (MB/D)	Water Oepth		Pipeline Distance to Shore Terminal[2]		Trunk Pipeline Diameter (inches) Oil
							Meters	(Feet)	Kilometers	(Miles)	
Shelikof	550	Steel platform with shared trunkline to shore	1 s	40	5,000	192	152-183	(500-600)	24-40	(15-25)	20
	450	Steel platform with shared trunkline to shore	1 s	40	5 * 000	192	152-183	(500-600)	24-40	(15-25)	20

[1] S = Steel

[2] No more than 8 kilometers (5 miles) of pipeline are assumed to be onshore.

Source: Dames & Moore

TABLE 5-3

HIGH FIND NON-ASSOCIATED GAS - LOWER COOK SALE 60 FIELD SHARES PIPELINE WITH SALE CI FIELDS TO LNG PLANT IN UPPER COOK INLET

Basin	Field Size Gas (BCF)	Production System	Platforms No./Type[1]	Number of Production Wells	Initial Well Productivity (MCF/D)	Peak Production Gas (MMCF/D)	Water Depth Meters	Water Depth (Feet)	Pipeline Distance to "Shore Terminal" Kilometers	Pipeline Distance to "Shore Terminal" (Miles)	Trunk Pipeline Diameter (inches) Gas
Lower Cook	363	Steel platform with shared trunkline to LNG plant	1S	8	25	192	30-60	(100-200)	48-80	(30-50)	20-26

[1] S = Steel

Source: Dames & Moore

TABLE 5-4

HIGH FIND NON-ASSOCIATED GAS - SHELIKOF FIELD WITH PIPELINE TO LOWER COOK FIELD(S) THEN SHARED PIPELINE TO UPPER COOK LNG PLANT

Basin	Field Size Gas (BCF)	Production System	Platforms No./Type[1]	Number of Production Wells	Initial Well Productivity (MCF/D)	Peak Production Gas (MMCF/D)	Water Depth		Pipeline Distance to Shore Terminal		Trunk Pipeline Diameter (inches) Gas
							Meters	(Feet)	Kilometers	(Miles)	
Shelikof	1000	Steel platform with shared trunkline to LNG plant	1 s	24	25	576	152,-183	(500-600)	321	(200)	24-28

[1] S = Steel

Source: Dames & Moore

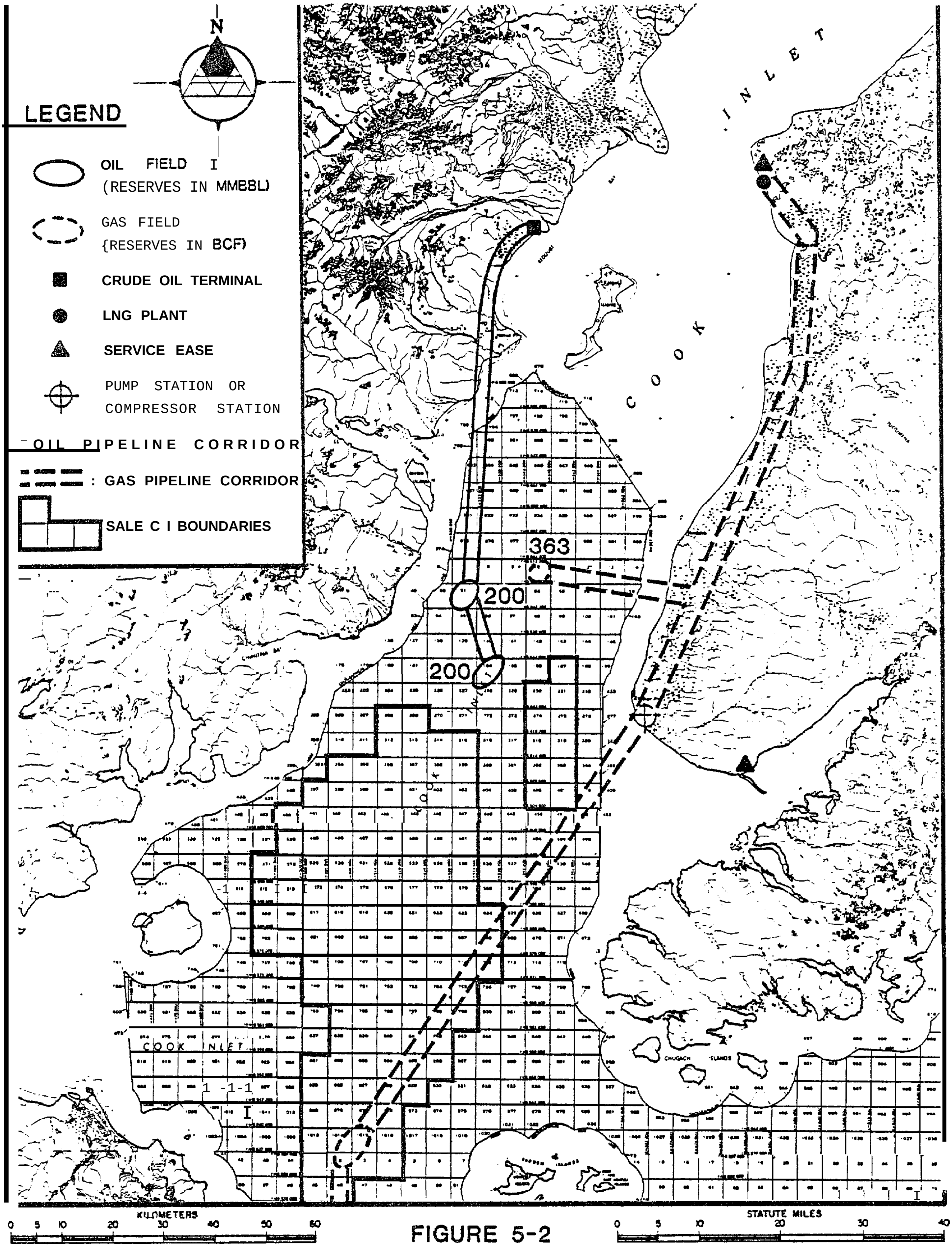
TABLE 5-7

TIMING OF DISCOVERIES - HIGH FIND SCENARIO

Year After Lease Sale	Type	Reserve Size		Location (Shelf)	Water Depth	
		Oil (mmbbl)	Gas (bcf)		meters	(feet)
1	Oil	550	--[1]	Shelikof	152-183	(500-600)
2	Oil	200	--[1]	Lower Cook	30- 61	(100-200)
2	Gas	--	1000	Shelikof	152-183	(500-600)
3	Oil	450	--[1]	Shelikof	152-183	(500-600)
3	Oil	200	--[1]	Lower Cook	30- 61	(100-200)
4	Gas	--	363	Lower Cook	30- 61	(100-200)

[1] Assumes field has low GOR and associated gas is used to power platform and reinjecte

Source: Dames & Moore



SOURCE: DAMES & MOORE

FIGURE 5-2

LOWER COOK INLET
HIGH FIND SCENARIO
FIELD AND SHORE FACILITY LOCATIONS

shores of Shelikof Strait was selected for the high find scenario in preference to a long pipeline connecting with Lower Cook Inlet fields to either Upper Cook Inlet facilities or a new terminal somewhere on the Kens'1 Peninsula. The basic characteristics of the Shelikof oil fields summarized in Table 5-2 indicate some important developmental considerations with respect to the resource economics in the deep waters of Shelikof:

- Favorable reservoir characteristics as indicated by a high individual well productivity are required for economic development.

- That the field can be developed with a single steel platform implies a fairly deep reservoir (about 3,048 meters or 10,000 feet) and reservoir characteristics that result in high recoverable reserves per acre (investment in a second platform necessitated, for example, by a shallow reservoir would make the economics significantly less favorable).

Similar considerations apply to the economics of non-associated gas. In addition, development of Shelikof gas can only be justified if it can share infrastructure (pipelines, etc.) with other fields; a one trillion cubic feet field in Shelikof cannot support development of an LNG or petrochemical plant alone -- the only markets available to gas production in an isolated location. Non-associated gas from Shelikof in the high find scenario is postulated to be piped to Lower Cook Inlet where it feeds into a trunk pipeline from Lower Cook Inlet gas fields. The pipeline landfalls on the Kenai Peninsula near Anchor Point and continues the Nikiski where the gas is converted to LNG and used as petrochemical feedstock.

5.2 Tracts and Location

The discovery tracts and their locations (designated by OCS protraction diagram numbers) are given in Table 5-5. The productive acreages cited

TABLE 5-5

HIGH FIND SCENARIO - FIELDS AND TRACTS

Location	Field Size		Acres[1]	Hectares	No. of Tracts[2]	OCS Tract Numbers[3]
	Oil (mmbbl)	Gas (bcf)				
Lower Cook	200		6,667	2,698	1.2	140, 183, 184, 226, 227
Lower Cook	200		6,667	2,698	1.2	51, 52, 7, 8
Lower Cook		363	1,820	737	0.3	10
Shelikof	550		11,000	4,452	1.9	566, 567, 568, 523, 524, 610, 611
Shelikof	450		9,000	3,642	1.6	742, 743, 698, 699
Shelikof		1,000	5,000	2,024	0.9	438, 439, 392, 482

[1] Recoverable reserves in the scenarios are assumed to range from 20,000 to 50,000 barrels per acre for oil and 120 to 300 mmcf for non-associated gas.

[2] A tract is 2,304 hectares (5,693 acres).

[3] Tracts listed include all tracts that are involved in the surface expression of an oil or gas field. In some cases only portions (a corner, etc.) of a tract are involved. However, the entire tract is listed above. (See Figure 5-1 for exact tract location and portion involved in surface expression of fields.)

Source: Dames & Moore

in Table 5-5 relate to the recoverable reserves per acre assumed for the scenario analysis.

5.3 Exploration, Development and Production Schedules

Exploration, development and production schedules are shown on Tables 5-6 through 5-14. The assumptions on which these schedules are based are given in Appendix B.

Exploration commences in the first year after the lease sale, peaks in the second and fourth years (each with 14 wells drilled) and terminates in the seventh year with a total of 57 wells drilled (Table 5-6). Four commercial oil discoveries and two gas discoveries are made in a four year period (Table 5-7). Field development commences in Year 4 following the decision to develop the first discovery (a 550 mmbbl oil field in Shelikof Strait). The first two production platforms are installed in Year 6 and the last two in Year 8 (Table 5-10). Construction schedules of the major onshore facilities are shown in Table 5-11.

Oil production from Lower Cook Inlet commences in Year 8 after the lease sale at the same time as oil production from Shelikof Strait (Table 5-8). Gas production from both Lower Cook Inlet and Shelikof Strait starts in Year 4.

5.4 Facility Requirements and Locations

Facility requirements (platforms, pipelines, terminals, etc.) and related construction scheduling are summarized in Tables 5-6 through 5-14.

The major facility constructed is a crude oil terminal located on the west coast of Afognak Island. The terminal is designed to process the estimated peak production of nearly 400,000 bpd from the two Shelikof oil fields. The terminal completes crude stabilization, recovers LPG, treats tanker ballast water and provides storage for about four million barrels of crude. There are two loading jetties for tankers destined for the U.S. West Coast. Due to the distance from Upper Cook Inlet

TABLE 5-6

EXPLORATION SCHEDULE FOR EXPLORATION AND DELINEATION WELLS - HIGH FIND SCENARIO

Shelf	Well Type	Year After Lease Sale 1		2		3		4		5		6		7		8		9		10		Well Totals
		Rigs	Wells[3]	Rigs	Wells	Rigs	Wells	Rigs	Wells	Rigs	Wells	Rigs	Wells	Rigs	Wells	Rigs	Wells	Rigs	Wells	Rigs	Wells	
Lower Cook	Exp.[1]	1	3	2	6	2	3	2	4	2	4											20
	Del.[2]						2		2		2											6
Shelikof	Exp.	2	5	3	5	3	5	3	6	2	3											24
	Del.				3		2		2													7
Total		3	8	5	14	5	12	5	14	4	9											57

[1] In this high find scenario a success rate of one significant discovery for approximately every 10 exploration wells is assumed. This is consistent with a 10 percent success rate in U.S. offshore areas in the past 10 years although higher than the average of the past five years (Tucker, 1978).

[2] The number of delineation wells assumed per discovery is two for field sizes of less than 500 mmbbl oil or 2,000 bcf gas, and three for fields of 500 mmbbl oil and 2,000 bcf gas and larger.

[3] An average completion time of four to five months per exploration/delineation well is assumed or 2.4 to 3 wells per rig per year.

Source: Dames & Moore

TABLE 5-8

FIELD PRODUCTION SCHEDULE - HIGH FIND SCENARIO

	Field Peak Production				Year After Lease Sale			
Location	Oil (MMBBL)	Gas (BCF)	Oil (MBD)	Gas (MMCFD)	Production Start Up	Production Shut Down	Peak Production	Years of Production
Lower Cook	200	--	76.8	--	8	22	10-11	15
	200	--	76.8	--	9	23	11-12	15
	---	363	--	192	9	16	9-11	8
Shelikof	550	--	192	--	8	26	10-11	19
	450	--	192	--	10	24	12-13	15
	--	1000	--	572	9	18	10-11	10

[1] Years of production relates to the date of start up from first installed platform (multi-platform fields); production shut down occurs at same time for all platforms.

Source: Dames & Moore

TABLE 5-9A

HIGH FIND SCENARIO OIL PRODUCTION BY YEAR
(IN MILLIONS OF BARRELS)

al endar Year	Year After Lease Sale	Oil Fie Is				1
		Lower Cook 200 MMBBL	Lower Cook 200 MMBBL	Shelikof 550 MMBBL	Shelikof 450 MMBBL	Total
1982	1	--	--	--	--	--
1983	2	--	--	--	--	--
1984	3	--	--	--	--	--
1985	4	--	--	--	--	--
1986	5	--	--	--	--	. .
1987	6	--	--	--	--	--
1988	7	--	--	--	--	--
1989	8	11.2	--	28.0	--	39.2
1990	9	21.0	11.2	52.6	--	84.8
1991	10	28.0	21.0	70.1	28.0	147.1
1992	11	28.0	28.0	70.1	52.6	178.7
1993	12	25.3	28.0	65.7	70.1	189.1
1994	13	19.9	25.3	52.6	70.1	167.9
1995	14	15.8	19.9	43.2	60.7	139.6
1996	15	12.6	15.8	34.8	45.3	108.5
1997	16	10.0	12.6	28.0	33.8	84.4
1998	17	8.0	10.0	22.2	25.2	65.4
1999	18	6.3	8.0	18.4	18.8	51.5
2000	19	5.0	6.3	14.9	14.0	40.2
2001	20	4.0	5.0	12.1	10.4	31.5
2002	21	3.2	4.0	8.9	7.8	23.9
2003	22	1.7	3.2	8.1	5.8	18.8
2004	23	--	1.7	6.7	4.3	12.7
2005	24	--	--	5.6	3.2	8.8
2006	25	--	--	4.6	--	4.6
2007	26	--	--	2.9	--	2.9
2008	27	--	--	--	--	--
2009	28	--	--	--	--	--
2010	29	--	--	--	--	--
2011	30	--	--	--	--	--

TABLE 5-9B

HIGH FIND SCENARIO GAS PRODUCTION BY YEAR
(IN BILLIONS OF CUBIC FEET)

		Gas F -ids		
l endar (ear	Year After Lease Sale	Lower Cook 363 BCF	Shelikof 1000 BCF	Total
1982	1	--	--	--
1983	2	--	--	--
1984	3	--	--	--
1985	4	--	--	--
1986	5	--	--	--
1987	6	--	--	--
1988	7	--	--	--
1989	8	--	--	--
1990	9	70.1	105.1	175.2
1991	10	70.1	210.2	280.3
1992	11	70.1	210.2	280.3
1993	12	59.1	172.6	231.7
1994	13	41.7	114.8	156.5
1995	14	29.4	76.4	105.8
1996	15-	20.7	50.8	71.5
1997	16	1.8	33.8	35.6
1998	17	--	22.5	22.5
1999	18	--	3.6	3.6
2000	19	--	--	--
2001	20	--	--	--
2002	21	--	--	--
2003	22	--	--	--
2004	23	--	--	--
2005	24	--	--	--
2006	25	--	--	--
2007	26	--	--	--
2008	27	--	--	--
2009	28	--	--	--
2010	29	--	--	--
2011	30	--	--	--

TABLE 5-10

PLATFORM INSTALLATION SCHEDULE - HIGH FIND SCENARIO

Location	Field		Year After Lease Sale											
	Oil (MMBBL)	Gas (BCF)	1	2	3	4	5	6	7	8	9	10	11	12
Cook Inlet	200	.-		*		D		As						
	200	--			*		D		As					
	--	363				*		D		As				
Shelikof	550	--	*		D			As						
	450	--			*		D			As				
	--	1000		*		D			As					
Totals								2	2	2				

* = Discovery; D = Decision to Develop; As = Steel Platform

Notes:

1. platform installation is assumed to begin in June in each case.
2. Platform "installation" includes module lifting, hook-up and commissioning.
3. Steel platforms in water depths <91.5 meters (<300 feet) are fabricated and installed within 48 months of construction start up; steel platforms in water depths 91.5 meters plus (300 feet plus) are fabricated and installed within 36 months of construction start up.

Source: Dames & Moore

TABLE 5-11

MAJOR FACILITIES CONSTRUCTION SCHEDULE - HIGH FIND SCENARIO

Facility[1]/Location	Peak Throughput		Year After Lease Sale											
	Oil (MBD)	Gas (MMCFD)	1	2	3	4	5	6	7	8	9	10	11	12
Afognak Oil Terminal	384	--												
Afognak Support Base														
Expansion of Nikiski & Homer Support Facilities														

[1] Assume construction starts in spring of year indicated.

Source: Dames & Moore

TABLE 5-12

MAJOR SHORE FACILITIES START UP DATE - HIGH FIND SCENARIO

Facility	Year After Lease Sale	
	Start Up Date[1]	Shut Down Date[2]
Afognak Oil Terminal	8	26

[1] For the purposes of manpower estimation start up is assumed to be January 1.

[2] For the purposes of manpower estimation shut down is assumed to be December 31.

Source: Dames & Moore

TABLE 5-13

DEVELOPMENT WELL DRILLING SCHEOULE - HIGH FIND SCENARIO

Location	Field Oil (MMBBL)	Field Gas (BCF)	Platforms Nos.	Platforms Type[1]	No.[2] of Drill Rigs Per Platform	Total No. of Production Wells	Other Wells[4]	Start of Drilling Month	Year After Lease Sale - No. of Wells Drilled[3] 1	2	3	4	5	6	7	8	9	10	11	12	13	14	15	16	17	18
Lower Cook	200	--	1	s	2	40	8	Jan.						Δ	12	12P	12	12			W					
	200	--	1	s	2	40	8	Jan.							A	12	12P	12	12			W				
	--	363	1	s	1	8	--	Jan.								A	6P	2								
Shelikof	550	--	1	s	2	40	8	April						A	9	12P	12	12	3		W					
	450	--	1	s	2	40	8	April								Δ	9	12P	12	12	3		W			
	--	1000	1	s	1	24	--	April							A	4	6P	6	6	2						

[1] S = Steel

[2] Platforms sized for 40 or more well slots are assumed to have two drill rigs operating during development drilling. Platforms sized for less than 40 well slots are assumed to have one drill rig operating during development drilling.

[3] Drilling progress is assumed to be 60 days per development well per drill rig, i.e. six wells per year for a 3,048 meter (10,000 feet) reservoir.

[4] Gas or water injection wells etc., well allowances assumed to one well for every five oil production wells.

W = Work over commences -- assumed to be five years after beginning of production from platform.

P = Production starts; assumed to occur when first 18 oil wells are completed.

A = Platform arrives on-site -- assumed to be June; platform installation and commissioning assumed to take seven months in Lower Cook and 10 months in Shelikof; development drilling commences when installation/commissioning complete.

Source: Dames & Moore

TABLE 5- 4

PIPELINE TRUCTION SCHEDULE HIGH FIND KILOMETERS (MILES) CONSTRUCTED BY YEAR

	(Inches)		Water Depth												
	Oil	Gas	Meters	(Feet)	1	2	3	4	5	6	7	8	9	0	11
Offshore	16		0- 61	(0-200)								64 (40)			
	20		0-183	(0-600)								32 (20)			
		16	0- 30	(0-100)									26 (5		
		24-28	91-183	(300-600)									80 (50.		
	Subtota											1 6	06 (65)		
Onshore	16		--	--								6 10)			
	20		--	--								3.2 (2)			
	Subtotal											19.2 (12)			
	Tota											130.2 (72)	65)		

Source: Dames & Moore

support facilities a forward service base supporting construction and operation of the Shelikof fields is constructed adjacent to the Afognak terminal. Exploration in the Shelikof Straits is supported principally out of Nikiski with aerial support and light supply transshipment provided by Homer. Field and terminal construction support bases are located at Nikiski and the forward support base.

The single commercial gas field discovered in Shelikof Strait produces to a spur pipeline that connects with a trunk line from a field in Lower Cook Inlet (Sale CI). The trunk line makes its landfall on the Kenai Peninsula and continues to LNG and petrochemical plants at Nikiski. An intermediate compressor station is required near the landfall of the pipel inc. (The pipeline construction shown in Table 5-14 only relates to spur line from the Shelikof gas field to the Lower Cook Inlet Sale CI field with which it shares the trunk line.)

The two Lower Cook Inlet oil fields discovered north of Sale CI share a pipeline to the Drift River terminal; a partial processing/treatment facility may be required near the pipeline landfall at Harriet Point. The plant would complete stabilization of the crude, remove impurities in the crude stream and recover LPG.

The small Lower Cook Inlet gas field (363 bcf reserves) produces to a short spur pipeline that connects with an onshore trunk line transporting gas from other Lower Cook Inlet and Shelikof fields to Nikiski via the Kenai Peninsula. (Only the spur pipeline construction is indicated in Table 5-14.)

5.5 Manpower Requirements

The manpower requirements for this scenario are given in Tables 5-15 through 5-18.

HIGH FIND SCENARIO
03/08/79

TABLE 5-15

ONSITE MANPOWER REQUIREMENTS BY INDUSTRY
(ONSITE MAN-MONTHS)

YEAR AFTER	PETROLEUM		CONSTRUCTION		TRANSPORTATION		MFG	ALL INDUSTRIES		
LEASE SALE	OFFSHORE	ONSHORE	OFFSHORE	ONSHORE	OFFSHORE	ONSHORE	ONSHORE	OFFSHORE	ONSHORE	TOTAL
1	2216.	232.	0.	0.	936.	252.	0.	3152.	484.	3636.
2	3710.	388.	0.	0.	1560.	420.	0.	5270.	808.	6078.
3	3660,	384.	0.	0.	1560.	420.	0.	5220.	804.	6024.
&	3710*	388.	o*	0.	1560.	420.	00	5270.	808.	6078.
5	2913.	306.	o.	2812.	1248.	336.	0.	4161.	3454.	7615.
b	0.	o*	2975.	699.	1106.	476.	0.	4081.	1176.	5256.
7	2352.	252.	4250.	5261.	1580.	680.	0.	8182.	6193.	14375.
8	4990.	511.	5550.	6443.	2028.	922.	o*	12568.	7876.	20444.
9	8350.	793.	2575.	649.	1282.	1688.	0.	12207.	3131.	15338.
10	9447.	848.	0.	0.	756.	1499.	o*	10203.	2348.	12551.
11	7325.	598.	0.	0.	864.	1570.	0.	8189.	2167.	10356.
12	5141.	364.	0.	0.	864.	1570.	0.	6005.	1933.	7938.
13	4325.	238.	192.	192.	864.	1570.	0.	5381.	1999.	7380.
14	4169.	202.	480.	480.	864.	1570.	0.	5513.	2251.	7764.
15	4349.	202.	576.	576.	864.	1570.	0.	5789.	2347.	8136.
16	4349.	202.	576.	576.	864.	1570.	0.	5789.	2347.	8136.
17	4046.	185.	480.	480.	792.	1523.	0.	5318.	2188.	7506.
18	3744*	168.	480.	480.	720.	1476.	0.	4944*	2124.	7068.
19	3593.	160.	384.	384.	684.	1453.	0.	4661.	1996.	6657.
20	3139*	134.	384.	384.	576.	1382.	0.	4099.	1901.	6000.
21	3139.	134.	384.	384.	576.	1382.	0.	4099.	1901.	6000.
22	3139.	134.	384.	384.	576.	1382.	0.	4099.	1901.	6000.
23	2657.	118.	288.	288.	504.	1336.	0.	3449.	1741.	5190.
24	1872.	84.	192.	'192.	360.	1242.	0.	2424.	1518.	3942.
25	1238.	59.	96.	96.	252.	1172.	0.	1586.	1327.	2913.
.26	785*	34*	96.	96.	144.	1102.	00	1025.	1231.	2256.
27	454.	25.	0.	0.	108.	1078.	0.	562.	1103.	1665.

HIGH FIND SCENARIO
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TABLE 5-16

JANUARY, JULY AND PEAK MANPOWER REQUIREMENTS
(NUMBER OF PEOPLE)

YEAR AFTER	JANUARY					JULY					PEAK	
	OFFSHORE		ONSHORE		JANUARY	OFFSHORE		ONSHORE		JULY		
LEASE SALE	ONSITE	OFFSITE	ONSITE	OFFSITE	TOTAL	ONSITE	OFFSITE	ONSITE	OFFSITE.	TOTAL	MONTH	TOTAL
1	246.	207.	39.	15.	507.	296.	207.	43.	15.	561.	5	561.
2	410.	345.	65.	25.	845.	485.	‘345.	71.	25.	926.	5	92b.
3	41(I.	345*	65.	25.	845.	460.	345*	69.	25.	899.	5	926.
4	410.	345.	65.	25.	845.	485.	345.	71.	25.	926.	5	926.
5	328.	276.	52.	20.	676.	378.	276.	424.	60.	1138.	9	1205.
6	0.	0.	201.	22.	223.	583.	504.	1119	15.	1212.	6	1212.
7	695.	616.	185.	21.	1517.	807.	728.	5b9.	62.	2166.	12	2510.
8	919.	840.	890.	97.	2746.	1447.	1320.	624.	71.	3462.	6	3729.
9	1156.	1065.	264.	109.	2593.	1220.	1153.	275.	114.	2762.	7	.?762.
10	872.	842.	197.	109.	2020.	816.	786.	191.	109.	1902.	10	2036.
11	766.	‘730.	190.	114.	1800.	654.	618.	178.	114*	1564.	1	1800.
12	542.	506.	166.	114.	1328.	486.	450.	160.	114.	1210.	1	1328.
13	532.	496.	176.	114.	1318.	420.	3n4.	164.	114.	1082.	1	1318.
14	459.	423.	188.	114.	1184.	459.	423.	188.	114.	1184.	1	1184.
15	482.	446.	196.	114.	1238.	482.	446.	196.	114.	1238.	1	1238.
16	482.	446.	196.	114.	1238.	482.	446.	196.	114*	1238.	1	1238.
17	474.	438.	188.	114.	1214.	412.	382.	177.	109.	1080.	1	1214.
18	412.	382.	177.	109.	1080.	412.	382.	177.	109.	1080.	1	10I3O.
19	404.	374.	169.	109*	1056.	404.	374.	169.	1090	1056.	1	1056.
20	34.? *	318.	158.	104.	922.	34%.	318.	158.	104.	922.	1	922.
21	342.	318.	158.	104.	922.	342.	318.	158.	104.	922.	1	922.
22	342.	318.	158.	104.	922.	342.	318.	158.	104.	922.	1	922.
23	319.	295.	150.	104.	868.	256.	238.	140.	99.	733.	1	868.
24	233.	215.	132.	99.	679.	171.	159.	121.	94.	545.	1	679.
25	148.	136.	113.	94.	491.	148.	136.	113.	94.	491.	1	491.
26	85.	79.	103.	89.	356.	85.	79.	103.	89.	356.	1	356.
27	62.	56.	95.	89.	302.	62.	56.	95.	89.	302.	1	302.

HIGH FIND SCENARIO
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TABLE 5-17

YEARLY MANPOWER REQUIREMENTS BY ACTIVITY
(MAN-MONTHS)

YEAR/ACTIVITY		1	2	3	4	5	b	7	8	9	10	11	12	13	14	15	16 **
1	ONSITE	304.	180.	0.	0.	0.	u.	00	0*	0.	o*	200.	2016.	0.	0.	0.	936.
	OFFSITE	0.	180.	0.	0.	0.	0.	0.	0.	0.	o.	0.	2016.	0.	0.	0.	468.
2	ONSITE	508.	300.	o*	o*	0.	0.	0.	0.	0.	0.	350.	3360.	0.	0.	0.	1560.
	OFFSITE	00	300.	o.	o.	0.	0.	0.	0.	0.	0.	o*	3360.	0.	0.	0.	780.
3	ONSITE	504.	300.	0.	0.	00	0.	0.	0.	0.	0.	300.	3360.	0.	0.	0.	1560.
	OFFSITE	0.	300.	O*	0.	0.	0.	0.	o*	0.	0.	0.	3360.	o*	0.	0.	780.
4	ONSITE	508.	300.	0.	0.	0.	0.	0.	0.	0.	o*	350.	3360 .	0.	0.	0.	1560.
	OFFSITE	0.	300.	0.	0.	0.	0.	0.	0.	0.	o.	0.	3360.	o*	0.	0.	780.
5	ONSITE	402.	240.	2812.	0.	0.	0.	0.	0.	0.	0.	2?5.	2688.	o.	0.	0.	1248.
	OFFSITE	0.	240.	309.	0.	0.	0.	0.	0.	0.	0.	o.	2688 .	0.	0.	0.	624.
b	ONSITE	703.	70.	402.	00	0.	0.	0.	0.	0.	0.	0.	o*	0.	2975.	0.	1106.
	OFFSITE	33. -	70.	44.	0.	0.	0.	0.	0.	0.	0.	0.	0.	o*	2975.	0.	553.
7	ONSITE	1257.	100.	0.	o*	0.	4836.	0.	0.	00	0.	0.	0.	2352.	4250.	0.	1580.
	OFFSITE	47.	100*	0.	0.	0.	532.	0.	0*	0.	0.	0.	o*	2352.	4250.	0.	790.
8	ONSITE	1875.	165.	0.	700.	300.	4836.	0.	0.	0.	0.	0.	o.	4990.	4250.	1300.	2028.
	OFFSITE	67.	165.	0.	77.	33.	532.	0.	0.	0.	0.	0.	0.	4990.	4250.	1300.	1014.
9	ONSITE	1538.	245.	0.	340.	0.	0.	0.	0.	1008.	0.	0.	0.	8350.	1275.	1300.	1282.
	OFFSITE	34.	245.	0.	37.	0.	0.	0.	0.	1008.	0.	0.	0.	8350.	1275.	1300.	641.
10	ONSITE	102s.	315.	0.	0.	0.	0.	0.	0.	1008.	0.	o*	0 0	9447.	0.	0.	756.
	OFFSITE	0.	315.	00	0.	0.	0.	0.	0.	1008.	0.	o*	0.	9447 .	0.	0.	378.
11	ONSITE	799.	360.	0.	0.	0.	0.	0.	0.	10080	0.	o.	0.	7325.	0.	0.	864.
	OFFSITE	0.	360.	0.	0.	0.	0.	0.	0.	1008.	0.	0.	0.	7325.	0.	0.	432.
12	ONSITE	565.	360.	0.	0.	0.	0.	0.	0.	1008.	0.	0.	0*	5141.	0.	0.	8b4.
	OFFSITE	0.	360.	0.	0.	0.	0.	0.	0.	1008.	0.	0.	0.	5141.	0.	0.	432.
13	ONSITE	631.	360.	0.	0.	0*	0.	0.	0.	1008.	0.	0.	0.	4325.	0.	0.	864.
	OFFSITE	0.	360.	0.	o.	0*	0.	0.	0.	1008.	0.	0.	0.	4325.	0.	0.	43%.
14	ONSITE	883.	360.	o*	o*	0.	00	0.	0.	1008.	o*	0.	0*	4169.	0.	0.	864.
	OFFSITE	0.	360.	0.	0.	0.	0.	0.	0*	100M.	o*	0.	0.	4169.	0.	0.	432.
15	ONSITE	979.	360.	0.	0.	0.	0.	0.	0.	1008.	o.	0.	0.	4349.	0.	0.	864.
	OFFSITE	o.	360.	0.	0.	0.	0.	0.	0.	1008.	0.	0.	0.	4349.	0.	0.	432.

** SEE ATTACHELJ KEY OF ACTIVITIES

HIGH FIND SCENARIO
03/08/79

TABLE 5-17 (Cont.)

YEARLY MANPOWER REQUIREMENTS BY ACTIVITY
(MAN-MONTHS)

YEAR/ACT V TY			2	3	4	5	6	7	8	9	1°		2	3	4	15	16 **
16	ONSITE	979.	360.	0.	0.	0.	0.	0.	0.	1008.	0.	0.	0.	4349.	0.	0.	864.
	OFFSITE	0.	360.	0.	0.	0.	0.	0.	0.	1008.	0.	0.	0.	4349.	0.	0.	432.
17	ONSITE	850.	330.	0.	0.	0.	0.	0.	0.	1008.	0.	0.	0.	4046.	0.	0.	792.
	OFFSITE	0.	330.	0.	0.	0.	0.	0.	0.	1008.	0.	0.	0.	4046.	0.	0.	396.
8	ONSITE	8 6.	300.	0.	0.	0.	0.	0.	0.	1°08.	0.	0.	0.	374[illegible].	0.	0.	720.
	°FFSITE	0.	300 *	0.	0.	0.	0.	0.	0.	1008.	0.	0.	0.	374[illegible].	0.	0.	360.
19	ONS TE	703.	285.	0.	0.	0.	0.	0.	0.	10°8.	0.	0.	0.	3593.	0.	0.	684.
	OFFS. TE	0.	285.	0.	0.	0.	0.	0.	0.	1008.	0.	0.	0.	3593.	0.	0.	342.
20	ONS TE	653.	24°.	0.	0.	0.	0.	0.	0.	10°8.	0.	0.	0.	3139.	0.	0.	576.
	OFFS. TE	0.	240.	0.	0.	0.	0.	0.	0.	1008.	0.	0.	0.	3139.	0.	0.	288.
21	ONSITE	653.	240.	0.	0.	0.	0.	0.	0.	1008.	0.	0.	0.	3139.	0.	0.	576.
	OFFSITE	0.	240.	0.	0.	0.	0.	0.	0.	1008.	0.	0.	0.	3139.	0.	0.	288.
22	ONSITE	653.	240.	0.	0.	0.	0.	0.	0.	1008.	0.	0.	0.	3139.	0.	0.	576.
	OFFSITE	0.	240.	0.	0.	0.	0.	0.	0.	1008.	0.	0.	0.	3139.	0.	0.	288.
23	ONS TE	523.	210.	0.	0.	0.	0.	0.	0.	°08.	0.	0.	0.	2657.	0.	0.	504.
	OFFS. TE	0.	210.	0.	0.	0.	0.	0.	0.	.008.	0.	0.	0.	2657.	0.	00	252.
24	ONSITE	360.	150.	0.	0.	0.	0.	0.	0.	1008.	0.	0.	0.	1872.	0.	0.	360.
	OFFSITE	0.	150.	0.	0.	0.	0.	0.	0.	1008.	0.	0.	0.	1872.	0.	0.	180.
25	ONS TE	2 4.	°5.	0.	0.	0.	0.	0.	0.	°°8.	0.	0.	0.	238.	0.	0.	252.
	OFFS. TE	0.	.0[illegible].	0.	0.	0.	0.	0.	0.	.008.	0.	0.	0.	.238.	0.	0.	126.
26	ONSITE	163.	60.	0.	0.	0.	0.	0.	0.	1008.	0.	0.	0.	785.	0.	0.	144.
	OFFSITE	0.	60.	0.	0.	0.	0.	0.	0.	1008.	0.	0.	0.	785.	0.	0.	72.
27	ONSITE	50.	45.	0.	0.	0.	0.	0.	0.	1008.	0.	0.	0.	454.	0.	0.	108.
	OFFSITE	0.	45.	0.	0.	0.	0.	0.	0.	1008.	0.	0.	0.	454.	0.	0.	54.

** SEE ATTACHED KEY OF ACT VIT ES

TABLE 5-17 **(Attachment)**

LIST OF TASKS BY ACTIVITY

ONSHORE

Activity

1 Service Bases (Onshore Employment - which would include all onshore administration, service base operations, rig and platform service)

Task 1 - Exploration Well Drilling
Task 2 - Geophysical Exploration
Task 5 - Supply/Anchor Boats for Rigs
Task 6 - Development Drilling
Task 7 - Steel Jacket Installations and Commissioning
Task 8 - Concrete Installations and Commissioning
Task 11 - Single-Leg Mooring System
Task 12 - Pipeline-Offshore, Gathering, Oil and Gas
Task 13 - Pipeline-Offshore, Trunk, Oil and Gas
Task 23 - Supply/Anchor Boats for Platform
Task 24 - Supply/Anchor Boats for Lay Barge
Task 27 - Longshoring for Platform
Task 28 - Longshoring for Lay Barge
Task 33 - Maintenance and Repairs for Platform and Supply Boats
Task 37 - Longshoring for Platform (Production)
Task 31 - Platform Operation

2 Helicopter Service

Task 4 - Helicopter for Rigs
Task 21 - Helicopter Support for Platform
Task 22 - Helicopter Support for Lay Barge
Task 34 - Helicopter for Platform

Construction

3 Service Base

Task 3 - Shore Base Construction.
Task 10 - Shore 8ase Construction

4 Pipe Coating

Task 15 - Pipe Coating

5 Onshore Pipelines

Task 14 - Pipeline, Onshore, Trunk, Oil and Gas

6 Terminal

Task 16 - Marine Terminal (assumed to be oil terminal)
Task 18 - Crude Oil Pump Station Onshore

7 LNG Plant

Task 17 - LNG Plant

8 Concrete Platform Construction

Task 19 - Concrete Platform Site Preparation
Task 20 - Concrete Platform Construction

9 Oil Terminal Operations

Task 36 - Terminal and Pipeline Operations

10 LNG Plant Operations

Task 38 - LNG Operations

OFFSHORE

Activity

11 Survey

Task 2 - Geophysical and Geological Survey

12 Rigs

Task 1 - Exploration Well

13 Platforms

Task 6 - Development Drilling
Task 31 - Operations
Task 32 - Workover and Well Stimulation

14 Platform Installation

Task 7 -- Steel Jacket Installation and Commissioning
Task 8 - Concrete Installation and Commissioning
Task 11 - Single-Leg Mooring System

15 Offshore Pipeline Construction

Task 12 - Pipeline Offshore, Gathering, Oil and Gas
Task 13 - Pipeline Offshore, Trunk, Oil and Gas

16 Supply/Anchor/Tug Boat

Task 5 - Supply/Anchor Boats for Rigs
Task 23 - Supply/Anchor Boats for Platform
Task 24 - Supply/Anchor Boats for Lay Barge
Task 25 - Tugboats for Installation and Towout
Task 26 - Tugboats for Lay Barge Spread
Task 29 - Tugboats for SLMS
Task 30 - Supply Boat for SLMS
Task 35 - Supply Boat for Platform

HIGH FIND SCENARIO
03/08/79

TABLE 5-18

SUMMARY OF MANPOWER REQUIREMENTS FOR ALL INDUSTRIES
ONSITE AND TOTAL

YEAR AFTER LEASE SALE	ONSITE (MAN-MONTHS) OFFSHORE	ONSHORE	TOTAL	TOTAL (MAN-MONTHS) OFFSHORE	ONSHORE	TOTAL	TOTAL LABOR FORCE (MONTHLY AVERAGE) OFFSHORE	ONSHORE	TOTAL
1	3152.	484.	3636.	5636.	664.	63110.	470.	56.	525.
2	5270.	808.	6078.	9410.	1108.	10518.	785.	93.	877.
3	5220.	804.	6024.	9360.	1104.	10464.	780.	92.	872.
4	5270.	808.	6078.	9410.	1108.	10518.	785.	93.	877.
5	4161.	3454.	7615.	7473.	4003.	11476.	623.	334.	957*
6	4081.	1176.	5256.	7609.	1322.	8931.	b34.	111.	745.
7	8182.	6193.	14375.	15574.	6872.	22446.	1298.	573.	1871.
8	12568.	7876.	2'0444.	24121.	8750.	32871.	2011.	730.	2740.
9	1.?207.	3131.	15338.	23772.	4455.	28228.	1981.	372.	2353.
10	10203.	2348.	12551.	20028.	3671 .	23699.	1669.	306.	1975.
11	8189.	2167.	10356.	15946.	3535.	19481.	13.29.	295.	1624.
12	6005.	1933.	7938.	11578.	3301.	14879.	965.	276.	1240.
13	5381.	1999.	7380.	1033IJ.	3367.	13697.	861.	281.	1142.
14	5513.	2251.	7764.	10s94.	3619.	14213.	883.	302.	11850
15	5789.	2347.	8136.	11146.	3715.	14861.	929.	310.	1239.
16	5789.	2347.	8136.	11146.	3715*	14861.	929.	310.	1239.
17	5318.	2188.	7506.	10241.	3526.	13766.	854*	294.	1148.
18	4944.	2124.	7068.	9528 .	3432.	12960.	794.	286.	1080.
19	4661.	1996.	6657.	8980.	3289.	12269.	749.	275.	1023.
20	4099.	1901.	6000.	-/91(,).	3149.	11059.	660.	2b3.	922.
21	4099.	1501.	6000.	7910.	3149.	11059.	660.	263.	922.
22	4099.	1901.	6000.	7Y10.	3149.	11059.	660.	2b3.	922.
23	3449.	1741.	5190.	6646.	2959.	9605.	554*	247.	801.
24	2424.	1518.	3942.	4668.	2676.	7344.	389.	223.	612.
25	1586.	1327.	2913.	3047.	2440.	5486.	254.	204.	458.
26	1025.	1231.	2256.	1978.	2299.	4277.	165.	192.	357.
27	562.	1103.	1665.	1069.	2156.	3226.	90.	180.	269.

6.0 MEDIUM FIND SCENARIO

6.1 General Description

The medium find scenario assumes modest commercial discoveries of oil. The basic characteristics of this scenario are summarized in Tables 6-1 and 6-2. The total reserves discovered and developed are:[1]

	Oil (MMBBL)
Lower Cook	198
Shelikof	500

A single oil field comprises the total resources of each area (Lower Cook and Shelikof). The Shelikof Strait field is located in the northern Shelikof Strait in about 183 meters (600 feet) of water and produces through a short pipeline to a new terminal constructed on the west coast of Afognak Island (Figure 6-1).[2] The Lower Cook Inlet oil field is located in approximately 76 meters (250 feet) of water 16 kilometers (1 O miles) northwest of English Bay (Figure 6-2). The field produces through a short spur pipeline which connects with a trunk pipeline that takes production from a field located in Sale CI. The pipeline makes landfall on the Kenai Peninsula near Anchor Point and continues north to Nikiski where the crude is either shipped to the lower 48 via tanker or used in the Nikiski refineries.

6.2 Tracts and Locations

The discovery tracts and their locations (designated by OCS protraction

(1) The non-associated gas resources assumed for the Sale 60 medium find case -- 198 BCF in Lower Cook Inlet and 500 BCF in Shelikof Strait -- are uneconomic under the assumptions of this analysis even postulating infrastructure sharing arrangements with Sale CI fields which themselves are marginally economic or uneconomic.

(2) The comments regarding production options, resource economics and reservoir characteristics for Shelikof discoveries made in Section 5.1 are also applicable to this case.

TABLE 6-1

MEDIUM FIND OIL - LOWER COOK SALE 60 FIELD SHARES PIPELINE WITH COOK INLET SALE CI FIELD(S) TO EXISTING TERMINAL OR REFINERY IN UPPER COOK INLET

Basin	Field Size Oil (MMBBL)	Production System	Platforms No./Type[1]	Number of Production Wells	Initial Well Productivity (B/D)	Peak Production Oil (MB/D)	Water Depth		Pipeline Distance to Shore Terminal		Trunk Pipeline Diameter (inches) Oil
							Meters	(Feet)	Kilometers	(Miles)	
Lower Cook	198	Steel platform with shared trunkline to shore	1 S	40	2,000	76.8	61-91	(200-300)	160	(100)	12-16

[1] S = Steel

Source: Dames & Moore

TABLE 6-2

MEDIUM FIND OIL - SHELIKOF FIELD WITH PIPELINE TO SHORE TERMINAL ON WEST COAST OF KODIAK OR AFOGNAK ISLAND

Basin	Field Size Oil (MMBBL)	Production System	Platforms No./Type[1]	Number of Production Wells	Initial Well Productivity (B/D)	Peak Production Oil (MB/D)	Water Depth		Pipeline Distance to Shore Terminal[2]		Trunk Pipeline Diameter (inches) Oil
							Meters	(Feet)	Kilometers	(Miles)	
Shelikof	500	Steel platform with pipeline to new shore terminal	1S	40	5,000	192	152-183	(500-600)	24-40	(15-25)	16

[1] S = Steel

[2] Single field, pipeline not shared; maximum of 8 kilometers (5 miles) of onshore pipeline.

Source: Dames & Moore

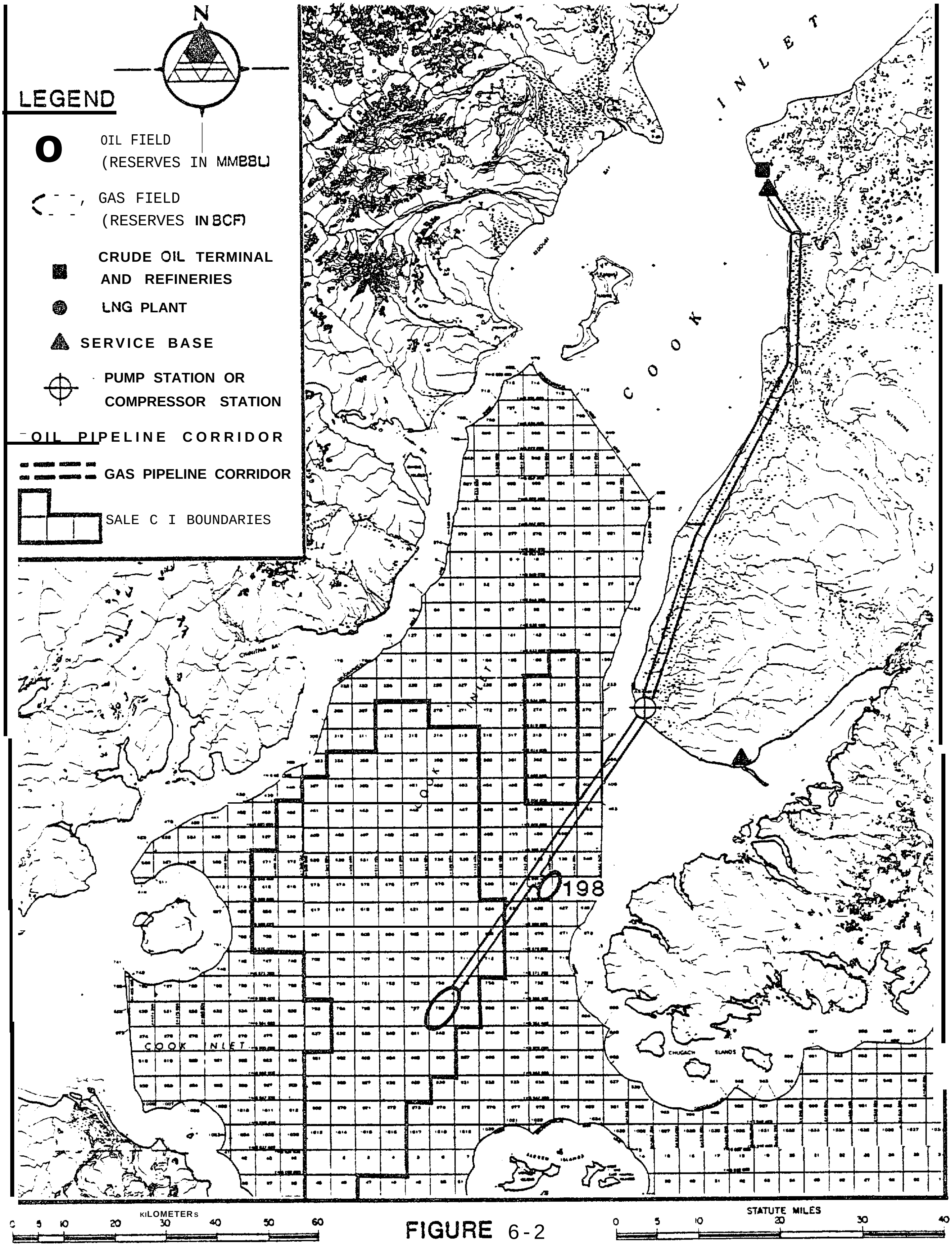

FIGURE 6-2

SOURCE : DAMES & MOORE

LOWER COOK INLET
MEDIUM FIND SCENARIO
FIELD AND SHORE FACILITY LOCATIONS

diagram numbers) are given in Table 6-3. The productive acreages cited relate to the recoverable reserves per acre assumed for analysis.

6.3 Exploration, Development, and Production Schedules

Exploration, development, and production schedules are shown in Tables 6-4 through 6-12. The assumptions on which these schedules are based are given in Appendix B.

Exploration commences in the first year after the lease sale peaks in Year 3 (with a total of 13 wells) and terminates in Year 4 with a total of 40 wells drilled (Table 6-4). Two commercial oil discoveries are made (Table 6-5). Field development commences in Year 4 -following the decision to develop the first discovery (a 500 mmbbl oil field in Shelikof Strait) and the production platforms for both fields are installed in Year 6 (Table 6-8). Oil production from both fields commences in Year 8 after the lease sale (Table 6-6).

6.4 Facility Requirements

Facility requirements (platforms, pipelines, terminals, etc.) and related construction scheduling are summarized in Tables 6-4 through 6-12.

The major facility constructed is a crude terminal located on the west coast of Afognak Island. The terminal is designed to process the estimated peak production of nearly 200,000 bpd, completes crude stabilization, recovers LPG, treats tanker ballast water, and provides storage for approximately 2 million barrels of crude (as such, the terminal combines the functions of a partial treatment/processing plant and crude storage and storage/transshipment which may sometimes be conducted at two separate facilities). Due to distance from Upper Cook Inlet support facilities, a temporary construction base and permanent operation base are constructed adjacent to the terminal site on Afognak Island. Some additional construction support is provided by Nikiski and Seward.

The Lower Cook Inlet field discovered west of English Bay shares a

TABLE 6-3

MEDIUM FIND SCENARIO - FIELDS AND TRACTS

Location	Field Size Oil (MMBBL)	Acres[1]	Hectares	No. of[2] Tracts	OCS Tract Nos.[3]
Lower Cook	198	6,600	2,671	1.1	582, 583, 538, 539
Shelikof	500	10,000	4,047	1.8	567, 568, 523, 524

[1] Recoverable reserves per acre in the scenarios are assumed to range from 20,000 to 500,000 barrels per acre for oil and 120 to 300 mcf for non-associated gas,

[2] A tract is 2,304 hectares (5,693 acres),

[3] Tracts listed include all tracts that are involved in the, surface 'expression of an oil or gas field. In some areas, only portions (a corner, etc.) of a tract are involved. However, the entire tract is listed above. (See Figure 5-1 for exact tract location and portion involved in surface expression of fields.)

Source: Dames & Moore

TABLE 6-4

EXPLORATION SCHEDULE FOR EXPLORATION AND DELINEATION WELLS-MEDIUM FIND SCENARIO

Shelf	Well Type	Year After Lease Sale 1		2		3		4		5				7		8		9				Well Totals
		Rigs	Wells[3]	Rigs	Wells	Rigs	Wells	Rigs	Wells	Rigs	Wells	Rigs	Wells	Rigs	Wells	Rigs	Wells	Rigs	Wells	Rigs	Wells	
Lower Cook	Exp.[1]	1	3	2	6	2	5	1	2													16
	Del.[2]						2		-													2
Shelikof	Exp.	2	6	2	4	2	6	2	4													20
	Del.				2		-		-													2
Total		3	9	4	12	4	13	3	6													40

[1] In this medium find scenario a success rate of one significant discovery for approximately every 20 exploration wells is assumed. This compares with a 10 percent success rate in U.S. offshore areas in the past 10 years-and a five percent success rate in the past five years (Tucker, 1978).

[2] The number of delineation wells assumed per discovery is two for field sizes of less than 500 mmbbl oil or 2,000 bcf gas, and three for fields of 500 mmbbl oil and 2,000 bcf gas and larger.

[3] An average completion time of four to five months per exploration/delineation well is assumed or 2.4 to 3 wells per rig per year.

Source: Dames & Moore

TABLE 6-5

TIMING OF DISCOVERIES - MEDIUM FIND SCENARIO

Year After Lease Sale	Type	Reserve Size		Location (Shelf)	Water Depth	
		Oil (mmbbl)	Gas (bcf)		meters	(feet)
1	Oil	500	--[1]	Shelikof	152-183	(500-600)
2	Oil	198	--[1]	Lower Cook	61- 91	(200-300)

[1] Assumes field has low GOR and associated gas is used to power platform and rejected.

Source: Dames & Moore

TABLE 6-6

FIELD PRODUCTION SCHEDULE - MEDIUM FIND SCENARIO

Location	Field		Peak Production		Year After Lease Sale			
	Oil (MMBBL)	Gas (BCF)	Oil (MBD)	Gas (MMCFD)	Production Start Up	Production Shut Down	Peak Production	Years of Production[1]
Lower Cook	198	--	76.8	--	8	21	10-11	14
Shelikof	500	--	192	--	8	25	10-11	18

[1] Years of production relates to the date of start up from first installed platform (multi-platform fields); production shut down occurs at same time for all platforms.

Source: Dames & Moore

TABLE 6-7

MEDIUM FIND SCENARIO OIL PRODUCTION BY YEAR
(IN MILLIONS OF BARRELS)

Calendar Year	Year After Lease Sale	Oil Fields		Total
		Lower Cook 198 MMBBL	Shelikof 500 MMBBL	
1982	1	--	--	--
1983	2	--	--	--
1984	3	--	--	--
1985	4	--	--	--
1986	5	--	--	--
1987	6	--	--	--
1988	7	--	--	--
1989	8	11.2	28.0	39.2
1990	9	21.0	52.6	73.6
1991	10	28.0	70.1	98.1
1992	11	28.0	70.1	98.1
1993	12	25.3	63.0	88.3
1994	13	19.9	49.8	69.7
1995	14	15.8	38.1	53.9
1996	15	12.6	29.8	42.4
1997	16	10.0	23.4	33.4
1998	17	8.0	18.3	26.3
1999	18	6.3	14.3	20.6
2000	19	5.0	11.2	16.2
2001	20	4.0	8.8	12.8
2002	21	3.2	6.9	10.1
2003	22	--	5.4	5.4
2004	23	--	4.2	4.2
2005	24	--	3.4	3.4
2006	25	--	2.6	2.6

Source: Dames & Moore

TABLE 6-8

PLATFORM INSTALLATION SCHEDULE - MEDIUM FIND SCENARIO

Field		Year After Lease Sale.											
Oil (MMBBL)	Gas (BCF)	1	2	3	4	5	6	7	8	9	10	11	12
198	-- --		*		D		As						
500	--- -	*		D			As						
Totals							- 2						

* = Discovery; D = Decision to Develop; Δs = Steel Platform

Notes:
1. Platform installation is assumed to begin in June in each case.
2. Platform "installation" includes module lifting, hook-up, and commissioning.
3. Steel platforms in water depths <300 feet are fabricated and installed within 48 months of construction start-up; steel and concrete platforms in water depths-300 feet plus are fabricated and installed within 36 months of construction start up.

Source: Dames & Moore

TABLE 6-9

MAJOR FACILITIES CONSTRUCTION SCHEDULE - MEDIUM FIND SCENARIO

Facility/Location	Peak Throughput Oil (MBD)	Peak Throughput Gas (MMCFD)	Year After Lease Sale 1	2	3	4	5	6	7	8	9	10	11	12
Afognak Oil Terminal	192	--												
Afognak Support Base														

Source: Dames & Moore

TABLE 6-10

MAJOR SHORE FACILITIES STARTUP DATE - MEDIUM FIND SCENARIO

Facility	Year After Lease Sale	
	Start Up Date[1]	Shut Down Date[2]
Afognak Oil Terminal	8	25

[1] For the purposes of manpower estimation start up is assumed to be January 1.

[2] For the purposes of manpower estimation shut down is assumed to be December 31.

Source: Dames & Moore

TABLE 6-11

DEVELOPMENT WELL DRILLING SCHEDULE - MEDIUM FIND SCENARIO

Field	Oil (MMBBL)	Gas (BCF)	Platforms Nos.	Platforms Type[1]	No. of Drill Rigs Per Platform[2]	Total No. of Production Wells	Other Wells[4]	Start of Drilling Month	Year After Lease Sale - No. of Wells Drilled[3]: 1	2	3	4	5	6	7	8	9	10	11	12	13	14	15	16	17	18	19	20
Lower Cook	198	--	1	S	2	40	8	January						Δ	12	12P	12	12			W							
Shelikof	500	--	1	S	2	40	8	April						Δ	9	12P	12	12	3									

[1]S = Steel

[2]Platforms sized for 40 or more well slots are assumed to have two drill rigs operating during development drilling. Platforms sized for less than 40 well slots are assumed to have one drill rig operating during development drilling.

[3]Drilling progress is assumed to be 60 days per development well per drill rig, i.e., six wells per year for a 3048 meter (10,000 feet) reservoir.

[4] Gas or water injection wells etc., well allowances assumed to one well for every five oil production wells.

W = Work over commences -- assumed to be five years after beginning of production from platform.

P = Production starts; assumed to occur when first 18 oil wells are completed.

Δ = Platform arrives on site -- assumed to be June; platform installation and commissioning assumed to take seven months in Lower Cook and 10 months in Shelikof; development drilling commences when installation/commissioning complete.

Source: Dames & Moore

TABLE 6-12

PIPELINE CONSTRUCTION SCHEDULE - MEDIUM FIND - Kilometers (MILES) CONSTRUCTED BY YEAR

	Pipeline Diameter (Inches)		Water Depth		Year After Lease Sale										
	Oil	Gas	Meters	(Feet)	1	2	3	4	5	6	7	8	9	10	11
Offshore	16		0-183	(0-600)							32 (20)				
	10-12		76	(250)							3 (2)				
Subtotal											35 (22)				
Onshore	16		--	--							3.2 (2)				
Subtotal											3.2 (2)				
Total											38.2 (24)				

Source: Dames & Moore

pipeline with a larger field(s) located in Sale CI. The pipeline landfalls near Anchor Point and continues to existing Upper Cook facilities. Construction support for this field is provided by Nikiski and a forward support base in Homer which is used for the ferrying of workers and light supplies.

Exploration activities in both Shelikof and Lower Cook Inlet are supported by a main base at Nikiski and a forward base at Homer. Additional support may be provided by Kodiak.

6.5 Manpower

The manpower requirements for this scenario are given in Tables 6-13 through 6-16.

MEDIUM FIND SCENARIO
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TABLE 6-13

ONSITE MANPOWER REQUIREMENTS BY INDUSTRY
(ONSITE MAN-MONTHS)

YEAR AFTER LEASE SALE	PETROLEUM OFFSHORE	PETROLEUM ONSHORE	CONSTRUCTION OFFSHORE	CONSTRUCTION ONSHORE	TRANSPORTATION OFFSHORE	TRANSPORTATION ONSHORE	MFG ONSHORE	ALL INDUSTRIES OFFSHORE	ALL INDUSTRIES ONSHORE	ALL INDUSTRIES TOTAL
1	2241.	234.	o.	o.	936.	252.	0.	3177.	486.	3663.
2	2988.	312.	0.	0.	1248.	336.	0*	4236.	648.	4884.
3	3013.	314.	0.	o*	1248.	336.	0*	4261.	650.	4911.
4	1494.	156.	0.	2144.	624.	168.	0.	2118.	2468.	4586.
5	0.	o*	o*	670.	0.	o.	0.	0.	b70.	670.
6	0.	o.	2975.	1117*	1106.	476.	0.	4081.	1593*	5673.
7	2352.	252.	1775.	3109.	644.	278.	0.	4771.	3639.	8409,
8	3142.	313.	o.	0.	108.	454.	0.	3250.	767.	4017.
9	3898.	355.	o*	0.	288.	571.	0.	4186.	926.	5112.
10	3898.	355*	o.	0.	288.	571.	0.	4186.	926.	5112.
11	1546.	103.	0.	0.	288.	571.	0.	1834.	674.	2508.
12	1210.	67.	o*	0.	288.	571.	0.	1498.	638.	2136.
13	1570.	67.	192.	192.	288.	571.	0.	2050.	830.	2880.
14	1570.	67.	192.	192.	288.	571.	0.	2050.	830.	2880.
15	1570.	67.	192.	192.	288.	571.	0.	2050.	830.	2880.
16	1570.	67.	192.	192.	288.	571.	0.	2050.	83(J.	2800.
17	1570.	67.	192.	192.	288.	571.	0.	2050.	830.	2880.
18	1570.	67.	192.	192.	288.	571.	0.	2050.	830.	2880.
19	1570.	67.	192.	192.	288.	571.	0.	2050.	83o.	2880.
20	1570.	67,	192.	192.	288.	571.	0.	2050.	830.	2880.
21	1570.	67.	192.	192.	288.	571.	00	2050.	830.	2880.
22	1087.	50*	192.'	192.	216.	524.	0.	1495.	767.	2262.
23	785.	34.	192.	192.	144.	478.	0.	1121.	703.	1824.
24	785.	34.	192.	192.	144.	478.	0*	1121.	703.	1824.
25	785.	34.	192.	192.	144.	478.	0.	1121.	703.	1824.
26	454.	25.	96.	96.	108.	70.	00	658.	191.	849.
27	0.	o*	96.	96.	0.	0.	0.	96.	96.	192.
28	o.	o.	96.	96.	0.	0.	0*	96.	96.	192.
29	0.	0.	96.	96.	o*	0.	0.	96.	96.	192.
30	0.	0.	96.	96.	o.	0.	0.	96.	96.	192.

MEDIUM FIND SCENARIO
03/08/79

TABLE 6-14

JANUARY, JULY AND PEAK MANPOWER REQUIREMENTS
(NUMBER OF PEOPLE)

YEAR AFTER LEASE SALE	JANUARY OFFSHORE ONSITE	JANUARY OFFSHORE OFFSITE	JANUARY ONSHORE ONSITE	JANUARY ONSHORE OFFSITE	JANUARY TOTAL	JULY OFFSHORE ONSITE	JULY OFFSHORE OFFSITE	JULY ONSHORE ONSITE	JULY ONSHORE OFFSITE	JULY TOTAL	PEAK MONTH	PEAK TOTAL
1	246.	207.	39.	15.	507.	296.	207.	43.	15.	561.	5	561.
2	328.	276.	52.	20.	676.	378.	276.	56.	20.	730.	5	757.
3	328.	276.	52.	20.	676.	403.	276.	58.	20.	75-f.	5	757.
4	164.	138.	26.	10.	338.	189.	138.	229.	32.	588.	10	784.
5	0.	0.	268.	29.	297.	0.	o*	0.	00	0.	1	297.
b	0.	o*	0.	0.	0.	583.	504.	150.	19.	1255.	12	1472.
7	695.	616.	396.	45.	1751.	559.	517.	330.	35.	1440.	3	1838.
b	224.	224.	56.	32.	536.	286.	280.	67.	37.	670.	10	805.
9	349.	337.	77.	42.	805.	349.	337*	77.	42.	805.	1	805.
1()	349.	337.	77.	42.	805.	349.	337.	77.	42.	805.	1	805.
11	237.	225.	65.	42.	569.	125.	113.	53.	42.	333.	1	569.
12	125.	113.	53.	42.	333*	125.	113.	53.	42.	333.	1	333.
13	171.	159.	69.	42.	441.	171.	1590	69.	42.	441.	1	441.
14	171.	159.	69.	42.	441*	171.	159.	69.	42.	441.	I	441.
15	171.	159.	69.	42.	441.	171.	159.	69.	42.	441.	1	441.
Ib	171.	159.	69.	42.	441.	171.	159.	69.	42.	441.	1	441.
17	171.	159.	69.	42.	441.	171.	159.	69.	4.2*	441.	1	441.
18	171.	159*	69.	42.	441.	171.	159.	69.	42.	441.	1	441.
19	171.	159.	69.	4.2*	441.	171.	159.	69.	42.	441.	1	441.
20	171.	159.	69.	42.	441.	171,	159.	69.	42.	441.	1	441.
21	171.	159.	69.	42.	441.	171.	159.	69.	42.	441.	1	441.
22	156.	144.	69.	42.	411.	93.	87.	59.	37.	276.	1	411.
23	93.	87.	59.	37.	276.	?3.	87.	59.	37.	276.	1	276.
24	93.	87.	59.	.31.	276.	93.	87.	59.	37.	276.	1	276.
25	93.	87.	59.	37.	276.	93.	87.	59.	37.	276.	1	276.
26	70.	64.	19.	5.	158.	70.	64.	19.	5.	158.	1	158.
27	8.	8.	8.	0.	24.	8.	8.	8.	0.	24.	1	24.
28	8.	8.	8.	0.	24.	8.	8.	8.	0.	24.	1	24.
29	b.	8.	8.	0.	24.	8.	8.	8.	0.	24.	1	24.
30	b.	8.	u.	0.	24.	8.	8.	8.	0.	24.	1	24.

TABLE 6-15

YEARLY MANPOWER REQUIREMENTS BY ACTIVITY
(MAN-MONTHS)

YEAR/ACTIVITY		1	2	3	4	5	6	7	8	9	10	11	12	13	14	15	16 **
1	ONSITE	306.	180.	0.	0.	0.	0.	0.	0.	0.	0.	225.	2016.	0.	0.	0.	934.
	OFFSITE	0.	180.	0.	0.	0.	0.	0.	0.	0.	0.	0.	2016.	0.	0.	0.	469.
2	ONSITE	408.	240.	0.	0.	0.	0.	0.	0.	0.	0.	300.	2688.	0.	0.	0.	1248.
	OFFSITE	0.	240.	0.	0.	0.	0.	0.	0.	0.	0.	0.	2688.	0.	0.	0.	624.
3	ONSITE	410.	240.	0.	0.	0.	0.	0.	0.	0.	0.	325.	2688.	0.	0.	0.	1248.
	OFFSITE	0.	240.	0.	0.	0.	0.	0.	0.	0.	0.	0.	2688.	0.	0.	0.	624.
4	ONSITE	204.	120.	2144.	0.	0.	0.	0.	0.	0.	0.	150.	1344.	0.	0.	0.	624.
	OFFSITE	0.	120.	236.	0.	0.	0.	0.	0.	0.	0.	0.	1344.	0.	0.	0.	312.
5	ONSITE	0.	11.	670.	0.	0.	0.	0.	0.	0.	0.	0.	0.	0.	0.	0.	0.
	OFFSITE	0.	0.	74.	0.	0.	0.	0.	0.	0.	0.	0.	0.	0.	0.	0.	0.
6	ONSITE	703.	70.	0.	0.	0.	819.	0.	0.	0.	0.	0.	0.	0.	2975.	0.	1106.
	OFFSITE	33.	70.	0.	0.	0.	90.	0.	0.	0.	0.	0.	0.	0.	2975.	0.	553.
7	ONSITE	688.	40.	0.	170.	50.	2691.	0.	0.	0.	0.	0.	0.	2352.	1275.	500.	644.
	OFFSITE	22.	40.	0.	19.	6.	296.	0.	0.	0.	0.	0.	0.	2352.	1275.	500.	322.
8	ONSITE	338.	45.	0.	0.	0.	0.	0.	0.	384.	0.	0.	0.	3142.	0.	0.	108.
	OFFSITE	0.	45.	0.	0.	0.	0.	0.	0.	384.	0.	0.	0.	3142.	0.	0.	54.
9	ONSITE	422.	120.	0.	0.	0.	0.	0.	0.	384.	0.	0.	0.	3898.	0.	0.	288.
	OFFSITE	0.	120.	0.	0.	0.	0.	0.	0.	384.	0.	0.	0.	3898.	0.	0.	144.
10	ONSITE	422.	120.	0.	0.	0.	0.	0.	0.	384.	0.	0.	0.	3898.	0.	0.	288.
	OFFSITE	0.	120.	0.	0.	0.	0.	0.	0.	384.	0.	0.	0.	3898.	0.	0.	144.
11	ONSITE	170.	120.	0.	0.	0.	0.	0.	0.	384.	0.	0.	0.	1546.	0.	0.	288.
	OFFSITE	0.	120.	0.	0.	0.	0.	0.	0.	384.	0.	0.	0.	1546.	0.	0.	144.
12	ONSITE	134.	120.	0.	0.	0.	0.	0.	0.	384.	0.	0.	0.	1210.	0.	0.	288.
	OFFSITE	0.	120.	0.	0.	0.	0.	0.	0.	384.	0.	0.	0.	1210.	0.	0.	144.
13	ONSITE	326.	120.	0.	0.	0.	0.	0.	0.	384.	0.	0.	0.	1570.	0.	0.	288.
	OFFSITE	0.	120.	0.	0.	0.	0.	0.	0.	384.	0.	0.	0.	1570.	0.	0.	144.
14	ONSITE	326.	120.	0.	0.	0.	0.	0.	0.	384.	0.	0.	0.	1570.	0.	0.	288.
	OFFSITE	0.	120.	0.	0.	0.	0.	0.	0.	384.	0.	0.	0.	1570.	0.	0.	144.
15	ONSITE	326.	120.	0.	0.	0.	0.	0.	0.	384.	0.	0.	0.	1570.	0.	0.	288.
	OFFSITE	0.	120.	0.	0.	0.	0.	0.	0.	384.	0.	0.	0.	1570.	0.	0.	144.

** SEE ATTACHED KEY OF ACTIVITIES

MEDIUM FIND SCENARIO
03/08/79

TABLE 6-15 (Cont.)

YEARLY MANPOWER REQUIREMENTS BY ACTIVITY
(MAN-MONTHS)

YEAR/ACTIVITY		1	2	3	4	5	6	7	8	9	10	11	12	13	14	15	16 **
16	ONSITE	326.	120.	o*	0.	o.	0.	0.	0.	384.	0.	0.	0.	1570.	0.	0.	288.
	OFFSITE	0.	120.	0.	o.	0.	0.	o*	0.	384.	0.	0.	0.	1570.	0.	o*	144.
17	ONSITE	326.	120.	o*	0.	00	0.	o.	0.	384.	0.	o.	o*	1570.	0.	o.	288.
	OFFSITE	o.	120.	0.	0.	0.	0.	0.	0.	384.	0.	0.	o.	1570.	0.	o*	144*
18	ONSITE	326.	120.	0.	o.	0.	u.	0.	u*	384.	0.	0.	0.	1570.	0.	o.	288.
	OFFSITE	0.	120.	0.	0.	(J.	0.	0.	u.	384.	o*	0.	0.	1570.	0.	0.	144.
19	ONSITE	326.	120.	o*	o.	0.	0.	().	0.	384.	00	0.	0.	1570.	0.	0.	288.
	OFFSITE	o.	120.	(J.	0.	0.	0.	0.	0.	384.	0.	0.	0.	1570.	0.	r).	144.
20	ONSITE	326.	120.	o.	0.	0.	0.	0.	0.	3d4 .	0.	o*	0.	1570.	0.	0.	288.
	OFFSITE	0.	120.	0.	0.	0.	u.	0.	o*	384.	0.	o.	0.	1570.	0.	0.	144.
21	ONSITE	326.	120.	o*	0.	0.	0.	0.	00	384.	0.	0.	0.	1570.	0.	0.	288.
	OFFSITE	0.	120*	o.	().	0.	0.	o*	0.	384.	0.	0.	0.	1570.	0.	0.	144.
22	ONSITE	293.	90.	0.	0.	0.	u*	o*	0.	384.	o*	0.	0.	1087.	o*	0.	216.
	OFFSITE	0.	9(J.	o*	0.	00	o.	o*	0.	384.	o.	o*	0.	1087.	o.	0.	led.
23	ONSITE	259.	60.	o.	0.	o*	0.	o.	0.	384.	0.	o.	0.	785.	0.	0.	144.
	OFFSITE	o*	60.	0.	0.	0.	o*	0.	0.	384.	0.	0.	0.	785.	0.	0.	72.
24	ONSITE	259.	600	0.	0.	o.	o.	o*	0.	384.	0.	0.	0.	785.	0.	o.	144.
	OFFSITE	o.	60.	0.	0.	o*	0.	o.	0.	384.	0.	0.	0.	785.	0.	0.	72.
25	ONSITE	259.	'60.	0.	0.	o*	0.	0.	0.	384.	0.	0.	0.	785.	0.	0.	144.
	OFFSITE	0.	60.	0.	0.	o.	u.	0.	0.	384.	0.	0.	0.	785.	o*	0.	72.
26	ONSITE	146.	45.	0.	0.	0.	0.	o.	0.	0.	0.	0.	o*	454 .	o.	0.	108.
	OFFSITE	0.	45.	0.	0.	0.	0.	0.	0.	0.	0.	0.	o.	454.	o*	0.	54 .
27	ONSITE	96.	0.	o*	0.	0.	u.	0.	0.	0.	0.	0.	0.	o*	0.	0.	0.
	OFFSITE	0.	0.	o.	0.	0.	0.	0.	0.	0.	0.	0.	0.	00	0.	o*	0.
28	ONSITE	96.	0.	0.	0.	f).	u.	0.	0.	o*	0.	0.	0.	0.	0.	o.	0.
	OFFSITE	o.	0.	o*	o*	o.	0.	0.	o*	o.	0.	o*	0.	0.	0.	0.	0.
29	ONSITE	96.	o*	o*	o*	0.	o*	0.	o.	0.	0.	o.	0.	0.	0.	0.	0.
	OFFSITE	o*	o.	O*	o.	0.	o*	0.	0.	0.	0.	0.	0.	0.	0.	0.	0.
30	ONSITE	96.	0.	o*	0.	0.	u.	0.	0.	0.	0.	0.	0.	o.	0.	0.	0.
	OFFSITE	0.	u.	0.	0.	o*	0.	0.	0.	0.	0.	0.	0.	0.	0.	0.	0.

** SEE ATTACHED KEY OF ACTIVITIES

TABLE 6-15 (Attachment)

LIST OF TASKS BY ACTIVITY

ONSHORE

Activity

1 Service Bases (Onshore Employment - which would include all onshore administration, service base operations, rig and platform service)

- Task 1 - Exploration Well Drilling
- Task 2 - Geophysical Exploration
- Task 5 - Supply/Anchor Boats for Rigs
- Task 6 - Development Drilling
- Task 7 - Steel Jacket Installations and Commissioning
- Task 8 - Concrete Installations and Commissioning
- Task 11 - Single-Leg Mooring System
- Task 12 - Pipeline-Offshore, Gathering, Oil and Gas
- Task 13 - Pipeline-Offshore, Trunk, Oil and Gas
- Task 23 - Supply/Anchor Boats for Platform
- Task 24 - Supply/Anchor Boats for Lay 8arge
- Task 27 - Longshoring for Platform
- Task 28 - Longshoring for Lay Barge
- Task 33 - Maintenance and Repairs for Platform and Supply Boats
- Task 37 - Longshoring for Platform (Production)
- Task 31 - Platform Operation

2 Helicopter Service "

- Task 4 - Helicopter for Rigs
- Task 21 - Helicopter Support for Platform
- Task 22 - Helicopter Support for Lay Barge
- Task 34 - Helicopter for Platform

Construction

3 Service Base

- Task 3 - Shore Base Construction
- Task 10 - Shore Base Construction

4 Pipe Coating

- Task 15 - Pipe Coating

5 Onshore Pipelines

- Task 14 - Pipeline, Onshore, Trunk, Oil and Gas

6 Terminal

- Task 16 - Marine Terminal (assumed to be oil terminal)
- Task 18 - Crude Oil Pump Station Onshore

7 LNG Plant

- Task 17 - LNG Plant

8 Concrete Platform Constriction

- Task 19 - Concrete Platform Site Preparation
- Task 20 - Concrete Platform Construction

9 Oil Terminal Operations

- Task 36 - Terminal and Pipeline Operations

10 LNG Plant Operations

- Task 38 - LNG Operations

OFFSHORE

Activity

11 Survey

- Task 2 - Geophysical and Geological Survey

12 Rigs

- Task 1 - Exploration Well

13 Platforms

- Task 6 - Development Drilling
- Task 31 - Operations
- Task 32 - Workover and Weil Stimulation

14 Platform Installation

- Task 7 - Steel Jacket Installation and Commissioning
- Task 8 - Concrete Installation and Commissioning
- Task 11 - Single-Leg Mooring Sys tern

15 Offshore Pipeline Construction

- Task 12 - Pipeline Offshore, Gathering, Oil and Gas
- Task 13 - Pipeline Offshore, Trunk, Oil and Gas

16 Supply/Anchor/Tug Boat

- Task 5' - Supply/Anchor Boats for Rigs
- Task 23 - Supply/Anchor Boats for Platform
- Task 24 - Supply/Anchor Boats for Lay Barge
- Task 25 - Tugboats for Installation and Towout
- Task 26 - Tugboats for Lay Barge Spread
- Task 29 - Tugboats for SLMS
- Task 30 - Supply Boat for SLMS
- Task 35 - Supply Boat for Platform

MEDIUM FIND SCENARIO
03/08/79

TABLE 6-16

SUMMARY OF MANPOWER REQUIREMENTS FOR ALL INDUSTRIES
ONSITE AND TOTAL

YEAR AFTER LEASE SALE	ONSITE (MAN-MONTHS)			TOTAL (MAN-MONTHS)			TOTAL LABOR FORCE (MONTHLY AVERAGE)		
	OFFSHORE	ONSHORE	TOTAL	OFFSHORE	ONSHORE	TOTAL	OFFSHORE	ONSHORE	TOTAL
1	3177.	486.	3663.	5661.	666.	6327.	472.	56.	528.
2	4236.	648.	4884.	7548.	888.	8436.	629.	74.	703.
3	4261.	650.	4911.	7573.	890.	8463.	632.	75.	706.
4	2118.	2468.	4586.	3774.	2824.	6598.	315.	236.	550.
5	0.	670.	670.	0.	744.	744.	0.	62.	62.
6	4081.	1593.	5673.	7609.	1785.	9394.	634.	149.	783.
7	4771.	3639.	8409.	9220.	4020.	13240.	769.	335.	1104.
8	3250.	767.	4017.	6445.	1196.	7642.	538.	100.	637.
9	4186.	926.	5112.	8227.	1430.	9658.	686.	120.	805.
10	4186.	926.	5112.	8227.	1430.	9658.	686.	120.	805.
11	1834.	674.	2508.	3523.	1178.	4702.	294.	99.	392.
12	1498.	638.	2136.	2851.	1142.	3994.	238*	96.	333*
13	2050.	830.	2880.	3955.	1334.	5290.	330.	112.	441.
14	2050.	830.	2880.	3955.	1334.	5290.	330.	112.	441.
15	2050.	830.	2880.	3955.	1334.	5290.	330.	112.	441.
16	2050.	830.	2880.	3955.	1334.	5290.	330.	112.	441.
17	2050.	830.	2880.	3955.	1334.	5290.	330.	112.	441.
18	2050.	830.	2880.	3955.	1334.	5290.	330.	112.	441.
19	2050.	830.	2880.	3955.	1334.	5290.	330.	112.	441.
20	2050.	830.	2880.	3955.	1334.	5290.	330.	112.	441.
21	2050.	830.	2880.	3955.	1334.	5290.	330.	112.	441.
22	1495.	767.	2262.	2882.	1241.	4123.	241.	104*	344*
23	1121.	703.	1824.	2170.	1147.	3317.	181.	96.	277.
24	1121.	703.	1824.	2170.	1147.	3317.	181.	96.	277.
25	1121.	703.	1824.	2170.	1147.	3317.	181.	96.	277.
26	658.	191.	849.	1261.	236.	1498.	106.	20.	125.

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APPENDIX A

APPENDIX A

THE ECONOMICS OF FIELD DEVELOPMENT IN THE LOWERCOOK INLET AND SHELIKOF STRAIT

1.1 The Objective of the Economic Analysis

I.1.1 Approach

The objective of the economic analysis is to evaluate the relationships among the likely oil and gas production technologies suitable for conditions in the Lower Cook Inlet and Shelikof Strait and the minimum field sizes required to justify each technology as a function of geologic conditions in different parts of the Inlet and Shelikof Strait, water depths and pipeline distances.

The analysis of this report focuses attention on the engineering technology required to produce discovered reserves under the difficult conditions of the Lower Cook Inlet and Shelikof Strait and emphasizes the risk due to the uncertainties in the cost of that technology. Sensitivity and Monte Carlo procedures are used in the analysis to allow for the uncertainty in the costs of technology and in the price of the oil and gas.

A model has been formulated that will allow determination of either: (a) the minimum field size to justify development under several oil and gas production technologies, or (b) the minimum required price to justify development given a field size and a selected production technology.

The model is a standard discount cash flow algorithm designed to handle uncertainty among key variables and driven by the investment and revenue streams associated with a selected production technology.

In general, the model calculates the discounted cash flows -- investment outflows and revenue inflows -- from production with different production systems at different water depths, reservoir target depths and distances to shore to examine how these different physical characteristics affect the decision to develop a discovered field.

The essential profitability criteria calculated by the model are: (a) the net present value (NPV) of the net after tax investment and revenue flows given a discount rate, or value of money (r) and, (b) the internal rate which equates the value of all cash inflows when discounted back to the initial time period.

1.1.2 Uncertainty of the Values of the Critical Parameters

Not one of the values of the economic and physical parameters that will affect the decision to develop some future discovered field in the Lower Cook Inlet and Shelikof Strait is known with certainty. Clearly, the quality of this future discovered oil is unknown. The exact water depths where a discovery will be made is not known. Neither is the field location, reservoir depth or a suitable shore' terminal site. Each of these is critical to the decision to develop.

Development costs which are expected to be extremely large can only be estimated in a broad range under today's economic conditions and today's technology. Late 1980's technology and its costs can no more be pinned down with any certainty for this analysis than can future prices.

In view of the vast uncertainty attached to evaluating the economics of field development in the Lower Cook Inlet/Shelikof Strait, values for the variables that enter into the solution of the model have either been assumed to be a single value or entered as a range of values. Monte Carlo analytical techniques have been used to assess the effects on field development of the estimated range of values for investment and operating costs and oil and gas prices. Monte Carlo simulation has been used with selected oil development cases and a selected gas development case to develop a sampling distribution of the probability of achieving an assumed 15 percent hurdle rate in view of the vast uncertainty of prices and costs.

1.1.3 The Model

The model calculates the net present value of developing a certain field size with a given technology appropriate for a selected water depth and distance to shore. The data flow and analytical logic are illustrated in Figure 3-1 in Chapter 3.0. The following equation shows the relationships among the variables in the solution process of the model.

Equation No. 1:
$$NPV = \Big[[\text{Price} \times \text{Production} \times (1\text{-Royalty}) - \text{Operation Costs}](1 - \text{Tax}) + [\text{Tax Credits}] - [\text{Tangible Investments} + \text{Intangible Costs}]\Big] \times PV$$

Where:

NPV	=	net present value of producing a certain " field with specified technology over a given time period
Pv	=	present value operator to continuously discount all cash flows with value of money, r
Price	=	well head price
Production	=	annual production uniquely associated with a given field size, a selected production technology, and number of wells
Royal ty	=	royalty rate
Operating Cost	=	annual operation costs
Tax	=	tax rate
Tax Credits	=	the sum of investment tax credits (ITC) plus depreciation tax credits (DTC) plus intangible drilling costs tax credits (IDC)
Tangible Investments	=	development investments depreciated over life of production
Intangible Investments	=	development expenditures that can be expensed for tax purposes.

The model does not include exploration costs or an allowance for a bonus payment. The model assumes discovery costs are sunk and answers the question, "What is the minimum field size required to justify development from the time of discovery given a selected production technology?" "Sunk" exploration costs -- geophysical, dry hole expenditures, and lease bonuses -- must be covered by successful discoveries.

The analysis assumes that these costs are covered by the firm's earnings from its successful portfolio of exploration investments.(1)

Excluding exploration costs and bonus payments and the time for these activities leaves out a great deal of money and several years of discounting future revenues. The minimum field sizes to justify exploration and development with a specified technology is significantly larger than the minimum field size to justify development given a discovered and delineated field.

Since 1973 the industry has spent over $4.0 billion on lease bonuses in OCS areas, $560 million of which was spent in the April 1976 Gulf of Alaska lease sale. The results have been dismal and expensive: 18 dry holes in the Mafia Dome, no discoveries; 11 dry holes, one discovery off southern California; 11 dry holes, no discoveries in the Gulf of Alaska; about nine dry holes in the Baltimore Canyon and one Texaco well with some indication of petroleum. AAPG data show that, in fact, the industry has had a success rate of only 4.3 percent for offshore wildcats for the six years 1971 through 1976.

Dry holes in the Gulf of Alaska in 1977 and 1978 cost between $10 to $21 million each. Exploration clearly is an extremely costly adventure in the OCS area of Alaska. Excluding exploration costs from the analysis focuses attention on the problems related to production technology and its impacts on Alaska rather than exploration problems.

(1) Assuming that "sunk" costs are covered by the successful portfolio of exploration investments implies that the upstream operations of vertically integrated companies must account for their profit and loss without reliance on downstream earnings. For non-vertically integrated exploration and production companies there is no alternative.

The model does not include a term for salvage of equipment at the end of production. The assumption is made that the cost of removal of all equipment and of returning the producing area to its pre-development environmental conditions to meet state and federal regulations would be as much as the salvage value of the equipment. The model assumes that the cost of removal will be offset by the value of the salvage.

1.1.4 Solution to the Model

Equation No. 1 can be solved deterministically if values for the critical variables are known with reasonable certainty. But single values for the independent variables on the right-hand side of Equation No. 1 are not known. The technologies that have been developed for the North Sea (which has provided some petroleum development cost experience and data for this analysis) have not been tested in the Lower Cook Inlet/Shelikof Strait or cost-estimated in the United States (see Appendix B). Thus, upper, lower, and mid-range values have been estimated for the critical variables of Equation No. 1 and are used in the Monte Carlo solution process.

Monte Carlo simulation is designed to handle uncertainty among the input variables and give a measure of the spread of potential outcomes. Monte Carlo simulation yields a measure of the potential riskiness of the final outcome in the form of a sampling distribution of the probability of the outcome.

Equation No. 1 together with either sensitivity or Monte Carlo techniques allows several approaches to the solution process.

Equation No. 1 can be solved, given a field size and selected technology, to show the relationship between the NPV of production and different values for:

- The value of money;
- Prices;
- Operating costs;

- Tangible investment costs;
- Intangible drilling costs.

Alternatively, the model can be solved given field size, prices, and a selected technology for the rate of return that will drive the NPV of production to zero. Sensitivity analysis can be used to show how the previously calculated rate of return changes with different values for:

- Prices;
- Operating costs;
- Tangible investment costs;
- Intangible drilling costs.

Iterative solutions of Equation No. 1, given prices and a selected technology, can be used to determine the minimum size field to justify development at various values of money. Sensitivity analysis can be used to show how changes in the values for the four items above change minimum economic field size.

1.1.5 Organization of Remaining Sections

The analytical results are presented in Section II. This section first discusses the findings of the study in terms of the assumed mid-range single value results -- Sections 11.1 through 11.6 -- and then Section 11.7 deals with the uncertainty present in the analysis in terms of the range of values estimated for prices and costs.

The analytical results are critically dependent on many involved and often interrelated assumptions made about the technology of the production systems, reservoir characteristics and financial variables. Section III reviews the assumptions that affect the economic analysis. Section III.1 discusses technology assumptions, Section 111.2 states the financial assumptions and Section 111.3 discusses the assumed reservoir and production characteristics.

The financial assumptions were discussed in the previous Gulf of Alaska and Kodiak scenario reports (Dames & Moore, 1979a and b). Since those reports were written the only significant financial changes that impact on the financial assumptions have been:

- Passage of natural gas bill. (This was anticipated in the previous studies.)
- Change of income tax rate to 46 percent.
- Increase in the possibility of exporting Alaskan oil to Japan. (The possibility of Japanese exports was considered in the previous studies in the argument to support the assumed range for oil prices.)
- Increase in instability in the Middle East with, therefore, an increase in uncertainty about oil prices. (In the 1978 dollars used in this analysis Arab crudes are laying into the U.S. Gulf Coast at $15 to $16 per barrel. The range of Lower Cook Inlet wellhead oil prices assumed for this study has been adjusted up to $16.50 upper limit and $12.50 mid-range to account for the increase in world prices and increase in uncertainty.)

11. The Analytical Results

11.1 Summary of the Analysis: Minimum Field Sizes for Development

11.1.1 Explanation of Summary Table A-1

Table A-1 summarizes the results for the estimated minimum field size for development calculation. The minimum field size for 23 analytical cases are shown on Table A-1 for both 10 percent and 15 percent value of money. The mid-range values for costs, $12.50 barrel (bbl) oil and $2.10 thousand cubic feet (mcf) gas, are assumed in the minimum field calculation on Table A-1.

TABLE A-1

MINIMUM FIELD SIZES FOR DEVELOPMENT

	1 Mid-Range Investment ($ Million) 1978)	2 Water Depth (Meters)	3 Reservoir Target Depth (Meters)	4 Number of Producing Hells Per Platform	5 Initial Production Rate Per Well. (NED or MMCFD)[1]	6 Onshore & Offshore Pipeline Distance Km (Miles)	7 Minimum Size Field 10% 15%[4] (MMBLS or TCF)	8 R.O. R. A/T For Field Produced Within 20-25 Years (MMBLS or TCF)	9 Price Req'd To Earn 15% For 20-25 Year Producing Field ($/MCF or BBL)[2]
GAS PRODUCTION CASES									
Shallow & Intermediate Water Depths (30.5 & 91 Meters)									
Single Platform With Long Shared. Pipeline: Shallow Compared to Deep Reservoir									
1) Shallow Reservoir Target	$315.1	30.5	1525	12	15.0	97 off/129 on (60 Off/80 On)	0.9 NE[3]	1.0 /10.6%	$ 2.80
2) Deep Reservoir Target	$336.3	30.5	3050	12	15.0	'	1.25 NE	1.25/10.0%	$ 3.15 .
3) Shallow Reservoir Target	$378.0	91.0	1525	24	15.0	•	<0.754 1.0	2.0 /17.9%	$1.70
4) Deep Reservoir Target	$416.4	91.0	3050	24	15.0	.	0.75 2.0	2,0 /15.1%	$ 2.05
Single Platform With Short Shared Pipeline									
5) Shallow Target - Shallow Water	$227.7	30.5	1525	12	15.0	(20 Off/50 On)	<0.6 NE	1.25/14.9%	$2.15
Deep Water (183 Meters)									
Single Platform With Long Pipeline: Shared Compared to Unshared Pipeline									
6) Shallow Target - Shared Pipeline	$533.3	183.0	1525	24	15	97 off/129 On (60 Off/00 On)	1.0, NE	2.0 /14.2%	$ 2.25
7) Shallow Target - Unshared Pipeline	$678.3	183.0	1525	24	15	•	1.5 NE	2.0 /11.6%	$2.70

NE - Not economical

1 Initial production rates are assumed to be sustained until 45% of recoverable oil or 75% of recoverable gas has been captured and then decline exponentially.

2 The 20-25 year producing field size is that shown in column 8.

3 Production systems that are not economic do not yield the minimum 10% or 15% hurdle rate for an oil or gas field that can be recovered within 25 years. Either a faster recovery system or higher prices would be required to earn the hurdle rate and therefore justify recovery.

4 Where the minimum field size to earn 10% is shown to be less than (.) the size indicated, reservoir engineering principles imply that fewer producing wells than shown in column 4 could be used to develop such a smaller field.

TABLE A-1
(cont.)

	1 Mid-Range Investment ($ Million) (1978)	2 Water Depth (Meters)	3 Reservoir Target Depth (Meters)	4 Number of Producing Wells Per Platform	5 Initial Production Rate Per Wel I (MBD or MMCFD)	6 Onshore 6 Offshore Pipeline Distance Km (Miles	7 Mi nimum Size Fiel 10% 15% MMBBLS or TCF)	8 R.O. R. A/l For Field Produced Within 20-25 Years (MMBLS or TCF	9 Price Req'd To Earn 15% For 20-25 Year Producing Field $/MCF or BBL)
Deep Water (cont.)									
Two Platform System Sharing Long Pipeline									
8) Deep Water - Shal low Target	$1060.4	183.0	1525	24x2	15.0	97 Off/81 On (60 Off/50 On	:2.5 3.8	4.0/15.1%	$ 2.09
Single Platform with Long Unshared Pipeline									
9) Deep Mater - Shallow Target High Initial Productivity	$ 690.8	183.0	1525	24	25.0	97 Off/129 On (60 Off/80 On	:1.0 1.5	3.0/18.0%	$ 1.70
OIL PRODUCTION CASES									
Shallow Water (30.5 Meters)									
Low Initial Production Rate - 1000 B/O Well									
Single Platform with Short Shared Pipeline to New Shore Terminal									
10) Shallow Target	$293.4	30.5	1525	24	1.0	32 Off/8 On (20 Off/5 On)	NE NE	160/ 7.2%	$19.40
11) Deep Target	$431.9	30.5	3050	40	1.0	"	210 NE	210/10.0%	$17.40
Single Platform with Short Shared Pipeline to Existing Terminal									
12) Shallow Target	$238.3	30.5	1525	24	1.0	32 Off/8 On (20 Off/5 On)	NE NE	160/ 9.1%	$17.50
13) Deep ,arget	$361.0	30.5	3050	40	1.0	"	150 NE	200/ 11 .8%	$15.30
Moderate Initial Production Rate - 2000 B/D Well									
Single Platform with Short Shared Pipeline to New Terminal									
14) Shallow Target	S 306.0	30.5	1525	24	2.0	32 Off/8 On (20 Off/s On)	100 185	200/15.7%	$12.00
15) Oeep Target	$512.8	30.5	3050	40	2.0	.	130 235	300/16 . 9%	$11.25

NE - Not economi cal

TABLE A-1
(cont.)

	1 Mid-Range Investment ($ Million) [1978]	2 Water Depth (Meters)	3 Reservoir Target Depth (Meters)	4 Number of Producing Wells Per Platform	5 Initial Production Rate Per Well (MBD or MMCFD)	6 Onshore & Offshore Pipeline Distance Km (Miles)	7 Minimum Size Field (MMBBLS or TCF) 10%	7 15%	8 R.O.R. A/T For Field Produced Within 20-25 Years (MMBLS or TCF)	9 Price Req'd To Earn 15% For 20-25 Year Producing Field $/MCF or BBL
Moderate Initial Production Rate (cont.)										
Single Platform with Long Shared Pipeline to Existing Terminal										
16) Shallow Target	$276.2	30.5	1525	24	"2.0	97 off/129 on (60 Off/80 On)	90	175	200/16.0%	$12.00
17) Deep Target	$459.1	30.5	3050	40	2.0	.	125	210	300/17.5%	$10.50
Intermediate Water Depth (91.5 Meters)										
Single Platform With Shallow Reservoir Target and 2000 B/O Wells										
18) Long Shared Pipeline to Existing Terminal	$351.9	91.5	1525	24	2.0	97 Off/129 On (60 Off/80 On)	135	NE	200/12.8%	$14.20
19) Short Shared Pipeline to New Terminal	$399.8	91.5	1525	24	2.0	32 Off/8 On (20 off/5 on)	150	NE	200/12.3%	$14.90
Deep Water (183 Meters)										
High Initial Production Rate (5000 B/D) Compared to Moderate Rate (2000 B/O)										
Single Platform Sharing Long Pipeline To Existing Terminal										
20) Deep Reservoir- 2000 B/D Well	$637.2	183.0	3050	40	2.0	97 Off/129 On (60 Off/80 On)	210	NE	300/12.1%	$14.75
21) Deep Reservoir - 5000 B/O Well	$728.8	183.0	3050	40	5.0	.	150	.250	600/21.0%	$ 8.00
Single Platform Sharing Short Pipeline To New Terminal										
22) Deep Reservoir - 2000 B/O Well	$685.9	183.0	3050	40	2.0	32 Off/8 On (20 Off/5 On)	250	NE	300/11.1%	$16.00
23) Deep Reservoir - 5000 B/O Well	$841.0	183.0	3050	40	2.0	"	200	300	600/20.0%	$ 8.40

NE - Not economical

It is important to emphasize that there is no single valued solution for any calculation reported in this analysis. It also is important to emphasize that these calculations are sensitive to the relative relationships of prices and costs and these are assumed fixed at their 1978 levels.

Different rates of inflation for prices and costs could significantly change this relationship and affect the economic solutions. This analysis relies on a range of values for prices and costs to identify the plausible range of values for the calculated decision variables under 1978 economic conditions. While Table A-1 shows single-value minimum field sizes, Section I. emphasizes the actual range in economic field sizes with respect to upper and lower limit estimated costs and prices.

A considerable amount of information is summarized on Table A-1. The first column shows the mid-range total investment required for the specified production system for a given water depth and pipeline distance to shore. Costs range from $228 million for a single steel platform with a short pipeline to shore in 30.5 meters (100 feet) of water to $1.1 billion for two platforms in 183 meters (600 feet) of water 225 kilometers (140 miles) from shore facility. Columns 2 and 3 show the water depth and reservoir target depth assumed for each case. Water depth and reservoir depth are critical to the analytical results.

The fourth column shows the number of producing wells assumed to be housed on the platform. An additional service well is assumed for every five producing wells. Forty producing oil wells are assumed for oil platforms with a deep reservoir. Oil platforms with a shallow reservoir are limited to 24 wells by 32.4-hectare (80-acre) well spacing. Twelve to 24 wells are assumed for gas platforms. Column 5 shows the initial production range assumed for each case. Column 6 shows separately the offshore and onshore pipeline distances assumed in each case.

The seventh column shows the calculated minimum field size bracketed by 10 percent and 15 percent value of money for each production system at different water depths. The values shown refer to recoverable reserves.

Column 8 shows the internal rate of return on investment calculated for a field that can be recovered within 20 to 25 years. Production streams beyond 20 years from fields of any size add little to the economic payoff. Thus, the field sizes shown in Column 8 represent the upper economic limit for the production system assumed for each case. Column 9 shows the price required to earn 15 percent for the field size identified in Column 8.

II.1.2 Conclusions

Several important conclusions are suggested by the single value calculations based on mid-range values for prices and costs shown on Table A-1.

General to Oil and Gas Fields

- The economic results are sensitive to the value of money. Column 7 shows that minimum field sizes vary greatly at discount rates between 10 percent and 15 percent.

- The economic results are sensitive to water depth. Column 1 in all cases show that investment costs rise dramatically with water depth. The minimum field size increases with investment costs and longer platform installation time associated with increased water depth.

- The economic results are sensitive to reservoir target depth. Higher investment costs and longer development drilling time (which delays peak production) makes the minimum field size larger for reservoir targets at 3,050 meters (10,000 feet) than for reservoir targets at 1,525 meters (5,000 feet).

- A shallow reservoir together with reasonable well spacing limits the number of deviated wells that can be drilled from a platform. With fewer wells on a shallow reservoir platform less oil and gas can be recovered within 20 to 25 years than can be recovered with the same platform holding more wells installed for a deep reservoir. Case 10 shows that reservoir depth limits the platform to 24 wells at 1,525 meters [with 32-hectare (80-acre) well spacing]. Case 11, not limited by reservoir depth, assumes 40 wells [with 81-hectare (200-acre) spacing]. Over the 20 to 25 year field life the governing assumptions imply 50 MMB more reserves can be recovered from the deeper reservoir.

- The economic results are sensitive to the recovery rate of the reservoir. Increasing the recovery rate by either increasing the number of wells on a platform (compare cases 1 and 2 with 3 and 4) or by assuming higher initial production rates (compare cases 10 and 11 with 14 and 15) reduces the minimum field size.

- The economic results are sensitive to the assumption about a field sharing a pipeline to shore facilities with another field. (Compare Case 6 with Case 7.) The minimum field size for this gas field example is 50 percent larger if the pipeline cannot be shared. Pipeline distances from potential discovery sites to existing shore facilities in Upper Cook Inlet are likely to be a considerable distance from Lower Cook Inlet or Shelikof Strait. Pipeline costs are a large share of total costs.

Gas Fields

Relatively large 24-well production systems and large gas fields are required to justify development in the Lower Cook Inlet at even shallow 30.5-meter (100-foot) water depths, assuming $2.10 mcf for the wellhead price and 15 MMcfd for the initial production rate.

Cases 1 and 2 show that a 12-well platform is unable to recover sufficient gas within 20 to 25 years to earn 15 percent. A wellhead price in the range of $3.00 mcf with no change in costs would be required to earn 15 percent.

Cases 3 and 4 show that with a 24-well platform in 91 meters (300 feet) water depth a 1.0 tcf shallow reservoir field or a 2.0 tcf deep reservoir field will earn 15 percent. The same 24-well system installed in 30.5 meters (100 feet) water for $30.0 million less investment cost would require a slightly smaller minimum field size (not shown on Table A-l).

Case 5 considers the impact of pipeline distance on a small 12-well production system. (Compare Case 5 with Case 1.) The total pipeline distance in Case 5 is 113 kilometers (70 miles), half of that assumed in Case 1. The 12-well system in Case 6 still does not earn 15 percent. However, it comes sufficiently close that if the wellhead price is assumed to be $2.15 mcf or costs slightly less than mid-range, this small production system would earn 15. percent.

Case 6 shows that the 24-well system installed in 183 meters (600 feet) water with a shallow reservoir target is unable to earn 15 percent. A slightly higher price -- $2.15 mcf -- is required to earn 15 Percent. (It is important to remember that these conclusions are based on mid-range investment values. Actual investment costs are estimated to fall within 75 percent to 140 percent of the mid-range values. Thus, slightly lower investment costs would make this gas system earn 15 percent.)

Cases 8 and 9 illustrate field size and reservoir characteristics that will allow a gas field in 183 meters (600 feet) to earn a minimum 15 percent hurdle rate. Case 8 shows that a giant 3.8 tcf field, capable of supporting at least two platforms with 24 wells each, will allow recovery of the reserves fast enough to earn 15 percent. Case 9 shows that if the initial production rate is 25 MMcfd instead of 15 MMcfd, a 1.5 tcf field will earn 15 percent even if it has to support the entire costs of the pipeline. The minimum field size would be smaller if the pipeline were shared.

<u>Oil Fields</u>

- Cases 10, 11, 12 and 13 assume initial oil production rate is 1000 B/D per well and show that even in shallow water and with short pipeline distances no oil field is able to earn 15 percent with this assumption about initial productivity. Oil prices would have to range between $15.30 to $19.40 bbl with no change in the costs to earn the minimum 15 percent hurdle rate. With platforms limited to 24 wells by 1,525-meter (5,000-foot) reservoir depth and 32-hectare (80-acre) well spacing, no oil field is able to earn even 10 percent (Cases 10 and 12).

- With platforms limited to 24 wells the reservoir depth and well spacing, Cases 10 and 12 show that with 1000 B/D initial production rate no shallow reservoir oil field is able to earn even 10 percent. Cases 11 and 13 show that a deep reservoir oil field could earn 10 percent because the increased revenue stream associated with 40 wells more than offsets the increased investment cost.

- Cases 12 and 13 compared to 10 and 11 show that if pipeline distances were unchanged it would be more economic to pay a $0.50 bbl handling fee to use an existing terminal than to pay a proportionate share of a new terminal. A 200 mmbbl reserve deep reservoir field will earn 11.8 percent using the existing terminal but less than 10 percent sharing a new terminal (Cases 13 and 16).

- Cases 14, 15, 16 and 17 assume initial production rate per well at 2000 B/D for a field in shallow water and compare the economics of a long shared pipeline to an existing shore facility with a short pipeline to a shore location suitable for a new terminal. Again, the existing shore facility option offers a higher return than construction of a new terminal even though the pipeline distance is 225 kilometers (140 miles) combined onshore and offshore. The minimum field size to earn 15 percent is smaller for a shallow reservoir than for a deeper reservoir -- 175 mmbbl compared to 210 mmbbl for the existing terminal example (Cases 16 and 17).

- Cases 18 and 19 compare the economics of a long pipeline to an existing terminal, with a short pipeline to a new terminal, in 91.5 meters (300 feet) of water assuming a shallow reservoir target. Neither will earn the minimum 15 percent hurdle rate. The existing terminal option is shown again to earn a higher return than the new terminal. An oil price in the range of $14.20 to $14.90 with no change in costs is required to earn 15 percent for this system limited to 24 wells by reservoir depth and 32-hectare (80-acre) well spacing.

- Cases 20, 21, 22 and 23 compare initial productivities per well of 2,000 B/D and 5,000 B/D for a 40 well platform in 183 meters (600 feet) water with a deep reservoir target. The lower productivity rate will not earn the minimum 15 percent hurdle rate assuming either a long pipeline to an existing terminal or a short pipeline to a new terminal. With 2,000 B/D initial productivity 300 mmbbl fields earn only 11 to 12 percent. The minimum field size with 5,000 B/D Initial productivity is 250 mmbbl for the existing terminal (Case 21) and 300 mmbbl for the new terminal (Case 23).

II*2 Minimum Required Price to Justify Field Development

Given the estimated costs of various oil and gas production systems identified in this report, the minimum price to justify development has been calculated using the model for various field sizes. Different production systems with different investment costs yield different minimum prices for various field sizes. The minimum required price is sensitive to water depth, reservoir target depth and initial well production rate as well as, of course, the assumed value of money.

II.2.1 Oil

Figure A-1 shows the minimum required price to develop a known oil field with a single steel platform producing system in 30.5 meters (100 feet) and 183 meters (600 feet) of water sharing a long pipeline to an existing

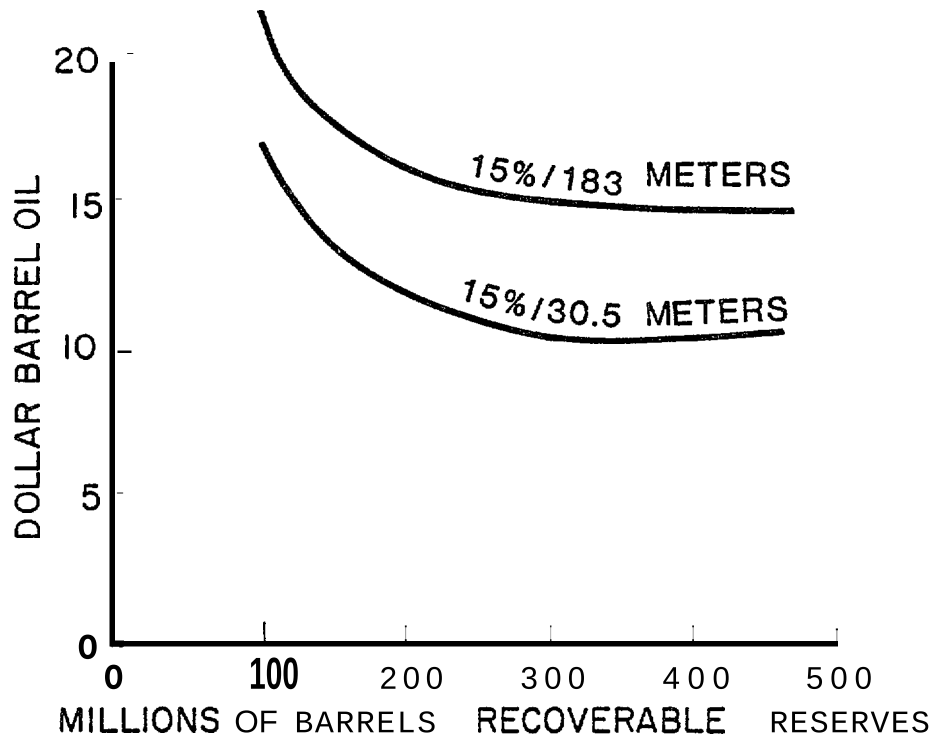


FIGURE A-1

MINIMUM REQUIRED PRICE TO JUSTIFY DEVELOPMENT
AS A FUNCTION OF FIELD SIZE & WATER DEPTH -OIL
SINGLE STEEL PLATFORM WITH LONG PIPELINE
TO EXISTING SHORE TERMINAL

(3050 METER RESERVOIR, 2000 B/D INITIAL WELL PRODUCTIVITY) shore terminal. Forty producing wells are assumed. Table A-1 previously showed that economics favor using an existing terminal over building a new terminal even if the pipeline distance to the existing terminal is in the range of six times the distance to a new terminal.

Figure A-1 brackets the minimum price at 15 percent for field sizes up to 450 MMbbl. Figure A-2 demonstrates two important conclusions of the analysis:

- The minimum price calculated with the model is little affected by production from fields larger than 300 MMbbl assuming initial well productivity of 2,000 B/D.

- The minimum price calculated with the model is very sensitive to the water depth of the field. A 150 MMbbl field in 30.5 meters (100 feet) breaks even with the development costs at $14.50 bbl at 15 percent value of money. A 150 MMbbl field in 183 meters (600 feet) breaks even at $16.80 bbl at 15 percent.

Under the various assumptions employed in the analysis, especially the initial production rate of 2,000 B/D, 300 MMbbl is the largest field size that can be produced from a 40 producing well platform in about 20 years. Adding five years to allow for the time from initial investment to initial production means that the last barrels of oil from fields larger than 300 MMbbl are captured beyond 25 years into the future. The present value of this oil has little impact on the calculation of the minimum price for field development. Thus, the minimum required price at 30.5 meters (100 feet} does not drop much lower than $10.50 bbl at 15 percent as fields increase beyond 300 MMbbl produced with this system. At 183 meters (600 feet), minimum price does not drop much below $14.75 bbl .

11.2.2 Non-Associated Gas

Figure A-2 shows the minimum required price for developing a known gas field with a single steel platform, sharing a long pipeline to shore.

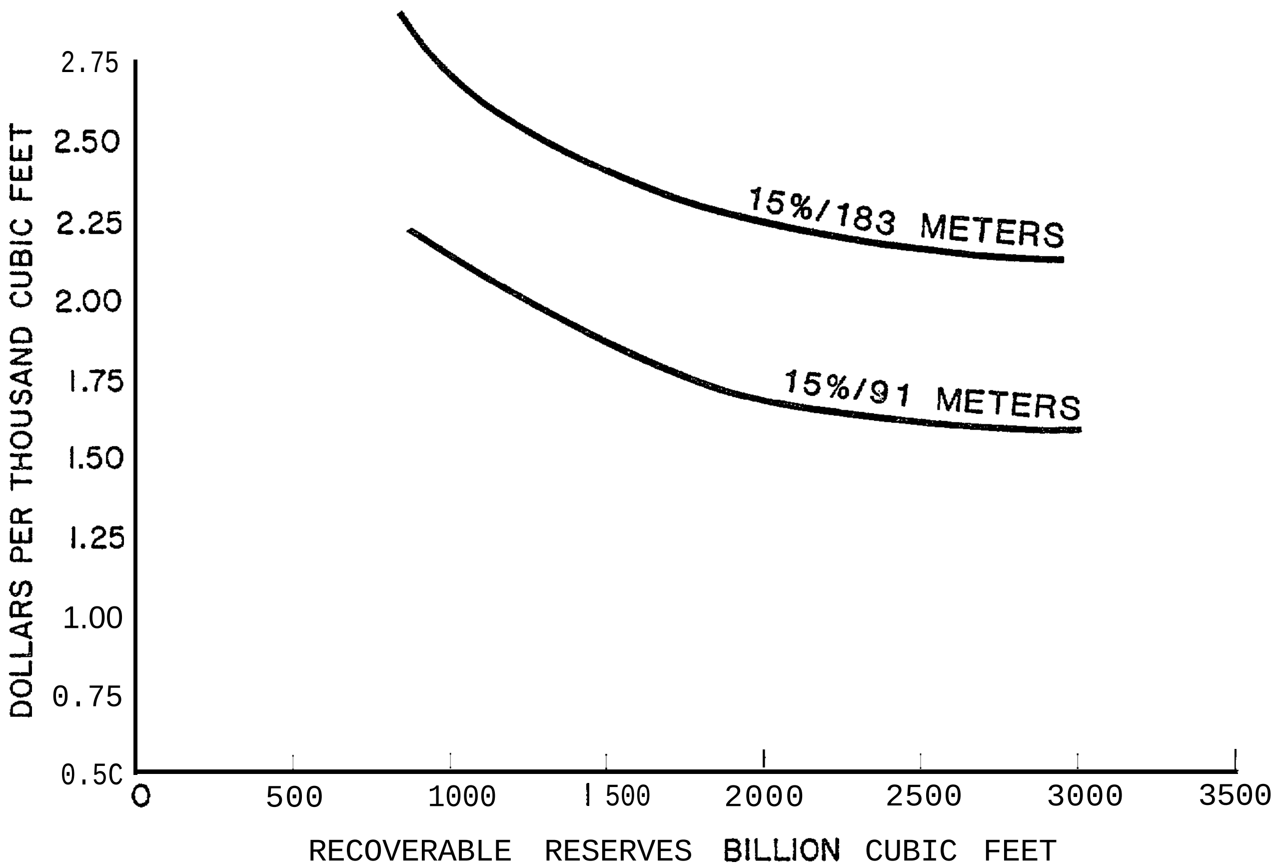


FIGURE A-2

MINIMUM REQUIRED PRICE FOR DEVELOPMENT
AS A FUNCTION OF FIELD SIZE & WATER DEPTH - GAS
SINGLE STEEL PLATFORM WITH PIPELINE TO SHORE
(1 525 METER RESERVOIR, 15 MMCFD INITIAL WELL PRODUCTIVITY)

Figure A-2 shows the minimum price in 91 and 183 meters (300 and 600 feet) of water for a shallow reservoir field. Twenty-four wells on the platform are assumed to produce 15 MMcfd each at peak production.

The curves for 30.5 meters (100 feet) water depth are only slightly lower than 91 meters (300 feet) curves and are not shown.

The minimum required price calculated with the model is sensitive to water depth, reservoir depth, the value of money and size of field. Under the assumptions of the analysis 2.0 tcf can be produced in about 22 years. Thus, production from fields larger than this will have little impact on the minimum required price calculation.

For a 1.0 tcf field at 15 percent value of money, the minimum price to justify development is $2.20 Mcf at 91 meters (300 feet) water depth and $2.70 Mcf at 183 meters (600 feet).

For a 2.0 tcf field, the minimum pr· ce at 15 percent value of money to justify development is $1.70 Mcf at 91 meters (300 feet) water depth and $2.25 Mcf at 183 meters (600 feet).

11.3 Critical Examination of New Shore Terminal Compared to Existing Shore Terminal Development Options

Cases 16 and 17 compared to Cases 14 and 15 on Table A-1 showed that running a long pipeline to an existing terminal cost less and earned a higher return on fields of the same size than building a new terminal. The relative pipeline distances to the new or existing terminal, whether or not the pipeline cost can be shared with another field operator, and the share of cost of the new terminal relative to the transshipment fee to use the old terminal are, of course, critical parameters to the solution. The assumptions for these variables used in the analysis are restated on Table A-2. An examination of the different assumptions on Table A-2 shows that, in fact, the comparative economic differences of the two alternatives for handling the crude oil are small and a change in any one of the assumptions could alter the outcome.

TABLE A-2

CRITICAL ASSUMPTIONS -- EXISTING VERSUS NEW SHORE TERMINAL

	Existing	New
Pipeline Distance To Shore Terminal {miles)	60 Off/80 On	20 Off/ 5 On
Shared Pipeline (?)	Yes - One-half	Yes - One-half
Pipeline Diameter (inches)	16	16
Shared Cost of Pipeline	$94.0	$30.5
Terminal Size and Share	NA	$109.2
Transshipment Fee	$0.50 bbl	NA
Total Mid-Range Investment Cost:		
Deep Reservoir Cases 15 and 17 ($ Million 1978)	$459.1	$512.8
Return on Investment -- 300 MB Field	17.5%	16.9%
Memo: Total Pipeline and Terminal Cost ($ Million 1978)	$94.0	$139.7

NA - Not applicable

Source: Dames & Moore Calculation Based on Costs in Appendix B.

A larger new terminal shared by more producers would allow economies of scale that could tip the scale in favor of building a new terminal. A longer offshore pipeline distance to the existing terminal, or a long unshared spur line to join with the assumed shared trunkline, would increase the costs and tip the scale to favor building a short line to a near shore location suitable for a new terminal.

It is also true that there may not be an option. It may not be feasible for any number of reasons including environmental constraints to run a long pipeline to an existing facility on the Kenai. Similarly, it may not be feasible to build a new terminal anywhere near discoveries in either the Lower Cook or Shelikof Straits.

II.4 The Effect of Water Depth and Pipeline Distances on the Distribution of Field Development Cost

Tables A-3 and A-4 show the percentage distribution of development costs for typical oil and gas steel platform production systems at various water depths in the Lower Cook Inlet. Both platforms assume a deep reservoir [3,050 meters (10,006 feet)] and a 225-kilometer (140-mile) shared pipeline to existing shore facilities.

No bonus payment or exploration costs are included either in Table A-3 or A-4. As discussed in Section 1.1.4 development costs are those incurred after discovery and delineation.

Tables A-3 and A-4 show the increasing relative share of platform structure costs at increasing water depths. From 30.5 to 183 meters (100 to 600 feet), platform costs increase nearly three times.

At 30.5 meters (100 feet) Table A-3 shows that oil development well costs are the largest share of investment; pipeline and platform costs are nearly equal. At 183 meters (600 feet), however, platform costs clearly dominate the investment total.

TABLE A-3

OIL: Percentage Distribution of Development Costs For A Single Steel Platform Over A 3050 Meter Reservoir With A Long Pipeline To An Existing Shore Terminal At Various Water Depths: Production -- 2000 B/D

	30.5 Meters	91 Meters	183 Meters
Platform Fabrication & Installation	20.5%	25.2%	40. 8%
Platform Equipment & Misc.	25.2	23.9	19.7
Development Wells (48)	34.1	31.9	24.8
Shared Pipeline - 96 kilometers (60 miles) Offshore/129 kilometers (80 miles) Onshore	20.2 100.0%	19.0 100.0%	14.7 100.0%
Total Mid-Range Investment: $ Million (1978)	464.5	496.0	677.8
Of which, Platform Cost: $ Million	95.0	125.0	260.0
Pipeline Cost: $ Million	94.0	94.0	94.(-)

TABLE A-4

GAS : Percentage Distribution of Development Costs For A Single Steel Platform Over A 3050 Meter Reservoir At Various Water Depths Sharing A Pipeline To Shore: Production -- [illegible]0 MMCf/d

	30.5 Meters	91 Meters	183 Meters
Platform Fabrication & Installation	23.8%	29.1%	45.5%
Platform Equipment & Misc.	16.8	15.9	13.2
Development Wells (28)	23.2	21.5	16.2
Shared Pipeline - 96 kilometers (60 miles) Offshore/129 kilometers (80 miles) Onshore	36.2 100.0%	33.5 100.0%	25.1 100.0%
Total Mid-Range Investment: $ Million (1978)	398.4	429.9	571.6
Of which, Platform Cost: $ Million	95.0	125.0	260.0
Pipeline Cost: $ Million	144.0	144.0	144.0

Source: Based on Estimated Costs in Appendix B.

Table A-4 shows that for gas platforms, pipeline costs dominate in shallow water but, although the second largest share of the investment total in 183 meters (600 feet) water depth, are clearly subordinate to platform costs.

Tables A-3 and A-4 indicate that gas field development in the Lower Cook Inlet will be more sensitive to field location relative to shore facility location and the connecting pipeline distance than oil field development. Shorter pipeline distances will improve the development economics; longer distances will worsen the payoff for development.

Figure A-3 shows the effect of the increase in water depth on field development economics. A 300 MMbbl, deep reservoir field produced from a single steel platform and pipeline to an existing shore terminal earns 17.5 percent in 30.5 meters (100 feet) of water and 12.1 percent in 183 meters (600 feet).

As shown in Figure A-3 this oil production system in 183 meters (600 feet) of water is unable to earn a 15 percent rate of return. Either higher prices, lower costs or peak production rates in excess of 2,000 bpd well are required to allow an oil field to earn 15 percent in 183 meters (600 feet) in the Lower Cook Inlet.

11.5 The Effect of Faster Initial Production Rates on Minimum Field Size for Development: Oil and Non-Associated Gas

Cases 20 and 22 from Table A-1 confirm a finding of the previous Gulf of Alaska studies. If initial productivity is assumed to be no more than 2,000 B/D, no field of any size in 183 meters (600 feet) water depth can be recovered fast enough to justify development if the developing firm's minimum hurdle rate of return is 15 percent. Explicitly, therefore, oil discovered in deep water in the Lower Cook Inlet and Shelikof Strait must have a higher initial productivity than 2,000 B/D or more wells per platform (which implies closer well spacing) or it is not economic at 15 percent value of money. The prior studies showed that additional plat-

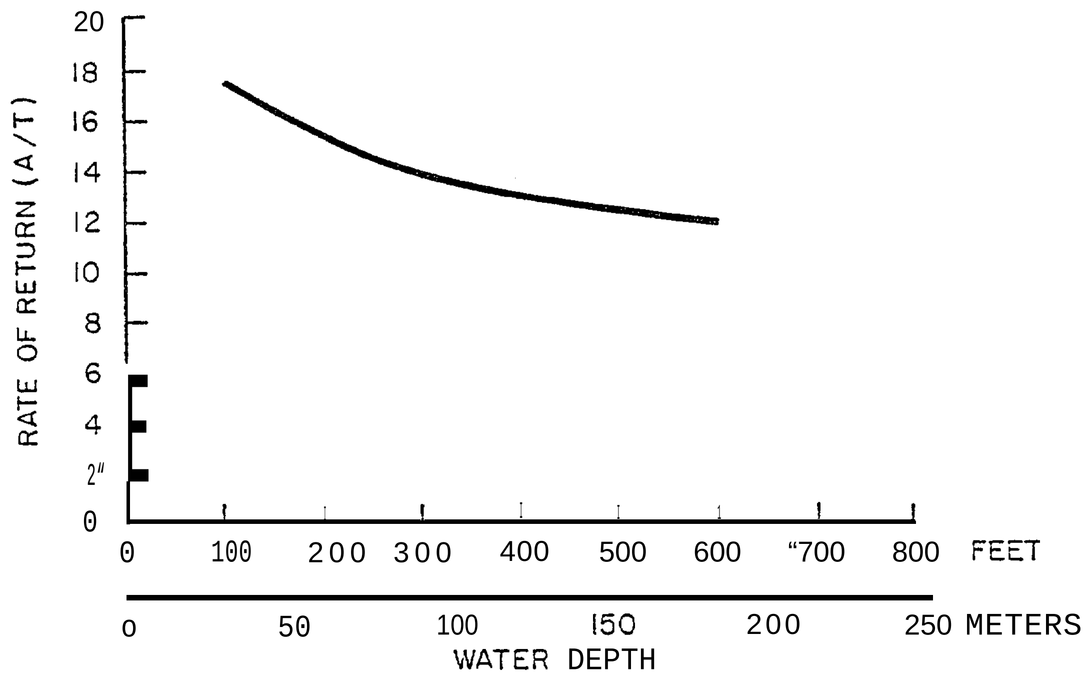


FIGURE A-3

INTERNAL RATE OF RETURN
FOR 300 MILLION BARREL DEEP RESERVOIR FIELD
AT DIFFERENT WATER DEPTHS

(SINGLE STEEL PLATFORM WITH LONG PIPELINE
TO EXISTING TERMINAL. - INITIAL PRODUCTION RATE 2000 B/D)

forms did not improve the oil recovery rate sufficiently to offset the additional cost.

Cases 5 and 6 show that gas fields in 183 meters (600 feet) water with 15 MMcfd wells are not able to earn 15 percent with 24 well platforms. Either larger platforms, more platforms (Case 8) or higher initial production rate (Case 9) are required to earn 15 percent.

Table A-5 compares shallow reservoir gas Cases 6 and 9 and deep reservoir oil Cases 20 and 21 to highlight the effect of increased production rate on minimum field size at 183 meters (600 feet).

11.6 Equivalent Amortized Total Per Barrel Cost of Development and Production of Oil

Table A-6 shows the equivalent amortized per barrel cost of developing and operating an oil field in the Lower Cook Inlet for Case 8 (Table A-1, p. A-10) compared with a case researched in an earlier report for the Northern Gulf of Alaska (Dames & Moore, 1979a -- Case 12, Table 7-1, p. 166). The notes to Table A-6 explain its calculation. Cost streams were taken from actual computer printouts and discounted to yield the present values.

Clearly, per barrel amortized development costs are sensitive to all of the assumptions of the analysis. Thus, as with the remainder of the analytical results, these may only be considered mid-range values for particular cases from which these costs streams were taken.

Both this report and the Gulf of Alaska report (Dames & Moore, 1979a) indicate that the preferred development strategy for most discovery locations given the physical and environmental conditions of these areas is to pipeline production to shore. Thus, in a sense, these equivalent amortized costs represent the major development alternatives implied in our scenarios.

Although per barrel costs shown for these two examples in 91.5 meter

TABLE A-5

EFFECT OF INCREASED PRODUCTION RATE ON
MINIMUM FIELD SIZE FOR DEVELOPMENT
AT 183 METER WATER DEPTH

Initial Production Rate (Per Well)	Mid-Range Investment cost ($ Million) (1978)	Case #	Reservoir Depth (Meters)	Minimum Field Size Trillion Cubic Feet/ Million Barrels 10%	15%
2000 B/D	637.2	20	3050	210	NE
5000 B/D	728.8	21	3050	150	250
15 MMcfd	533.3	6	1525	1.0	NE
25 MMcfd	690.8	9	1525	<1.0	1.5

NE - Not economic

Source: Dames & Moore Calculation.

TABLE A-6

Equivalent Amortized Total Cost of Oil Development and Production

	Present Value of Annual Costs @ 15%[3] ($ Million 1978)	Equivalent Amortized Cost per Barrel[5] ($ 1978)	
LOWER COOK INLET[1]			
Capital Return	$96.83	$2.32	
Depreciation	37.28	0.89	
Intangible Drilling Costs	126.83	3.04	
Operating Costs	133.11	3.19	
Royalty	86.93	2.08	
Federal Taxes	82.98	1.99	
	$563.96	$13.52	
Present Barrel Equivalent at 15% of producing 200 million barrels with 24 producing well platform (2000 B/D initial productivity)			41.7194
GULF OF ALASKA[2]			
Capital Return	$167.45	$2.69	
Depreciation	71.14	1.14	
Intangible Drilling Costs	97.24	1.56	
Operating Costs	94,88	1.53	
Royalty	124.39	2.00	
Federal Taxes	182.70	2.94	
	$737.80	$11.86	
Present Barrel Equivalent to 15% of producing 300 million barrels with 40 producing well platform (2500 B/D initial productivity)			62.183[4]

Source: Dames & Moore Calculations.

Notes to TABLE A-6

1. Single steel platform sharing onshore and offshore pipeline to existing shore terminal in Upper Cook Inlet.

   91.5 meter water depth

   1525 meter reservoir target depth

   24 producing wells

   2000 B/D initial well production rate

   Mid-range cost of system: $351.9 million

   This is Case 8, Table A-1, p. A-10.

2. Single steel platform sharing pipeline to new shore terminal in Gulf of Alaska. "

   91.5 water depth

   3050 meter reservoir target depth

   40 producing wells

   2500 B/D initial well production rate

   Mid-range cost of system: $507.9 million

   This is Case 12, Table 7-1, p. 166, Dames &Moore (1979a), Northern Gulf of Alaska Petroleum Development Scenarios, Alaska OCS Socioeconomic Studies Program, Technical Report No. 29, February 1979.

3. This discounted present value of all future costs at 15% can be expressed as:

$$\text{Pv cost} = \sum_{t=1}^{T} \sum_{i=1}^{6} (C_{it}) e^{-.15t}$$

where:

C_{it} = the cost streams for the six cost items shown on the table and taxes are net of depreciation tax credits and other tax credits,

$e^{-.15t}$ = Continuous discounting factor at 15%

4. The present barrel equivalent of the production of oil is the present value of the oil discounted at 15%, the same rate employed to calculate the present value of costs.

$$P.B.E. = \sum_{t=1}^{T} (Q_t)e^{-.15t}$$

where:

P.B. E. = Present barrel equivalent

Q_t = annual oil production in year t

$e^{-.15t}$ = continuous discounting factor at 15%

The present barrel equivalent of production is clearly different from either average annual production or peak annual production and reflects the timing of the production flows. The concept is described in our Northern Gulf of Alaska report. It is generally used in utility rate calculations. See Electric Power Research Institute, Technical Assessment Guide, Special Report, June 1978, Page v-17-18.

5. The equivalent amortized cost (E.A.C.) per barrel is equal to the present value of annual costs divided by present barrel equivalent.

$$E.A.C. = \sum_{i=1}^{6} \left[\frac{\sum_{t=1}^{T} (C_{it})e^{-.15t}}{\sum_{t=1}^{T} (Q_t)e^{-.15t}} \right]$$

depth are higher for the Lower Cook Inlet than for the Gulf of Alaska, by no means can they be generalized. Per barrel equivalent costs are extremely sensitive to the timing of the production flows. The Lower Cook Inlet case assumes only 24 wells producing 2000 B/D each at maximum. The Gulf of Alaska case assumes 40 wells produce 2500 B/D each at maximum. The Lower Cook platform can only recover about 200 million barrels in 20 years. The Gulf of Alaska platform can recover 300 million barrels in about 17.5 years.

These cost calculations are useful to compare the relative shares of cost components within a production system and to get an order-of-magnitude idea of the per barrel cost of production for off-shore Alaska. However, comparisons between systems are not valid unless identical assumptions governed the calculations of both systems.

11.7 Monte Carlo Results for Selected Production Scenarios

11.7.1 Range of Values for After Tax Return on Investment

Previous sections have reported results based on the mid-range values for prices and costs. Repeatedly, however, this report has emphasized that costs for production technology that will be employed in the mid-1980's can only be estimated in 1978 dollars within a range of values. In this section, Monte Carlo distributions for the after-tax return on investment for selected production scenarios are reported to emphasize the uncertainty built into this economic analysis of field development in the Lower Cook Inlet and Shelikof Strait.

Just as there is a range of values estimated for prices and costs, there is a range of values for the profitability criteria calculated by the model. A Monte Carlo solution to the model is a way to estimate the range of outcomes by repeatedly solving the model with values selected at random in each solution pass for each of the variables whose values are entered as a range. With a few hundred solution passes the Monte Carlo distribution reveals a probabilistic estimation of the worst outcome, best outcome and intermediate results.

II.7.2 Oil Platforms

Tables A-7 and A-8 show the Monte Carlo results for the distribution of return on investment for two plausible oil development scenarios:

- A long shared pipeline to an existing terminal;
- A short shared pipeline to a new terminal.

The mid-range results for these scenarios are shown as Cases 14 and 16 on Table A-1. Both scenarios assume a 200 MMbbl shallow reservoir field [1 ,525 meters (5,000 feet)] in shallow water [30.5 meters (100 feet)]. The shallow target together with 32-hectare (80-acre) well spacing implies that the platforms are restricted to 24 producing wells. Wells are assumed to initially produce 2,000 B/D in these two cases.

Table A-7 shows that for the existing terminal scenario:

- There is only a 2.0 percent chance of earning less than 9.3 percent;

- There is a 41.0 percent chance of earning less than 15.3 percent;

- There is 100 percent chance of earning less than 21.6 percent;

- The expected value for rate of return is 15.7 percent.

Thus, if 15 percent is the hurdle rate the decision to develop a field known to have 200 MMbbl recoverable reserves must recognize that while the expected rate of return exceeds the hurdle rate, there is some chance greater than 31 percent and less than 41 percent of earning less than the hurdle rate. However, if 10 percent is the hurdle rate, Table A-7 shows that there is less than 3.0 percent of earning less than 10 percent.

TABLE A-7

SINGLE OIL PLATFORM SHARING LONG PIPELINE TO **EXISTING** TERMINAL (Case 16)
200 Million Barrel Field, 30.5 Meter Water Depth, 1525 Meter Reservoir Target
Initial Production Rate: 2000 B/D

Monte Carlo Results For Ater-Tax DCF Rate of Return

RESULT VALUE	PROBABILITY OF BEING LESS THAN RESULT
9.27	.02
9.97	.030
10.90	.035
11.53	.045
12.16	.070
12.79	.090
13.42	.170
14.04	.235
14.67	.310
15.30	.410
15.93	.540
16.56	.650
17.18	.725
17.81	.840
18.44	.890
19.07	.920
19.70	.950
20.33	.980
20.96	.995
21.59	1.000

Expected Value = 15.69
Standard Deviation = 2.3670

Source: Dames & Moore Calculation.

TABLE A-8

SINGLE OIL PLATFORM SHARING SHORT PIPELINE TO NEW TERMINAL (Case 14)
200 Million Barrel Field, 30.5 Meter Water Depth, 1525 Meter Reservoir Target
Initial Production Rate: 2000 B/D

Monte Carlo Results For After-Tax DCF Rate of Return

RESULT VALUE	PROBABILITY OF BEING LESS THAN RESULT
9.67	.020
10.27	.030
10.88	.035
11.48	.045
12.08	.070
12.69	.095
13.29	.170
13.89	.240
14.49	.315
15.10	.425
15.70	.550
16.31	.655
16.91	.745
17.51	.845
18.12	.890
18.72	.920
19.33	.950
19.93	.975
20.53	.995
21.14	1.000

Expected Value = 15.4186
Standard Deviation = 2.2797

Source: Dames & Moore Calculation.

Table A-8 shows that for the new terminal scenario:

- There is only a 2.0 percent chance of earning less than 9.7 percent;

- There is 42.5 percent of earning less than 15.1 percent;

- There is 100 percent chance of earning less than 21.1 percent;

- The expected value for rate of return is 15.4 percent.

Tables A-7 and A-8 reveal that the differences between these two development scenarios are less clear than suggested by the mid-range results presented on Table A-1. While the existing terminal case is still slightly preferred, the differences between the two cases are so small that it is an analytical fiction derived from the general nature of the assumptions to say that one alternative is less economic than the other. The clearest conclusion is that neither option is precluded by the analysis; actual conditions rather than general assumptions will be required to determine that one alternative is more economic than the other.

The rate of return distributions shown on Tables A-7 and A-8 confirm other conclusions indicated by the mid-range single value results on Table A-1. Any number of changes to the reservoir and technical assumptions that govern the Monte Carlo results of these two tables would lower the expected value of the rate of return and increase the chance of earning less than 15 percent; increased water depth, increased reservoir depth, lower initial productivity, shorter sustained plant production rate, smaller field, etc.

11.7.3 Gas Platforms

Table A-9 shows the Monte Carlo distribution for the rate of return for a two gas platform development scenario for a giant 4.0 tcf recoverable reserves gas field. The field, Case 8 on Table A-1, is assumed to have

TABLE A-9

NON-ASSOCIATED GAS, TWO PLATFORMS SHARING
LONG PIPELINE TO SHORE FACILITY (Case 8)
4.0 Trillion Gas Field, 183 Meter Water Depth, 1525 Meter Reservoir Target
Initial Production Rate: 15 MMcfd

Monte Carlo Results For After-Tax DCF Rate of Return	
RESULT VALUE	PROBABILITY OF BEING LESS THAN RESULT
11.86	.010
12.23	.025
12.61	.045
12.98	.080
13.35	.125
13.73	.155
14.11	.265
14.47	.305
14.85	.410
15.22	.545
15.59	.640
15.97	.735
16.34	.810
16.71	.870
17.09	.890
17.46	.920
17.83	.950
18.21	.970
18.58	.985
18.95	1.000
Expected Value =	15.1187
Standard Deviation =	1.4980

Source: Dames & Moore Calculation.

a shallow reservoir [1,525 meters (5,000 feet)] and occurs in deep water [183 meters (600 feet)]. The Monte Carlo distribution shows that:

- There is a 1.0 percent chance of earning less than 11.9 percent;
- There is a 54.5 percent chance of earning less than 15.2 percent;
- There is 100 percent chance of earning less than 19.0 percent;
- The expected value for rate of return is 15.1 percent.

This two platform gas development case in deep water demonstrates clearly that given the reservoir and technical assumptions that govern this analysis, notably initial productivity of 15 MMCFD per well and no production until the fifth year following initial platform investment, the costs of developing a gas field in the Lower Cook Inlet and Shelikof Strait will preclude a bonanza payoff even with a giant field.

III. Review of the Assumptions that Affect the Economic Analysis

III.1 Technology Assumptions

111.1.1 Production Systems to be Screened

As indicated in Section 1.1, the objective of the economic analysis is to evaluate the relationships among the likely oil and gas production technologies suitable in Lower Cook Inlet and the minimum field sizes required to justify each technology as a function of geologic conditions in different parts of the Inlet, water depths and pipeline distances.

The production systems to be screened in the economic analysis were selected in consultation with the petroleum engineering departments of the major lease holders in Lower Cook Inlet. These consultations included discussion of the results of our technology review conducted for the Gulf of Alaska studies and our evaluation of oceanographic conditions of Lower Cook Inlet/Shelikof Strait that would affect production system selection, platform design, etc.

The consensus of opinion was that steel jacket platforms with a pipeline to new shore terminal(s) or existing terminals/refineries in Upper Cook Inlet would be the production system generally adopted. Only minor interest was expressed in the use of gravity platforms, offshore-loading systems and subsea completions. The relatively short distances to suitable shore land-falls in Lower Cook Inlet and the accessibility of petroleum facilities in Upper Cook Inlet were factors in the preference for platform pipeline systems. In Lower Cook Inlet, water depths of generally less than 91.5 meters (300 feet) favor fixed platforms over floating systems. In some parts of Lower Cook Inlet and Shelikof Strait, platforms may have to be designed for sea ice, in particular location of wells within platform legs.

The basic oil production systems evaluated in this study are:

- Single steel jacket platform sharing a <u>short</u> pipeline to a new shore terminal in water depths of 100 to 600 feet.

- Single steel jacket platform sharing a <u>long</u> pipeline (offshore and onshore) to <u>existing</u> shore terminal/refinery in Upper Cook Inlet in water depths of 30.5 to 183 meters (100 to 600 feet).

Where a new oil terminal is assumed, the analysis includes a share of the new terminal capital cost in the investment flow. For an existing oil terminal, a transshipment per barrel handling fee is charged as part of operating costs. All gas is assumed shipped to planned LNG facilities on the Kenai Peninsula.

III.1.2 <u>Pipeline Distances</u>

Pipeline distances costed and screened in the economic analysis are consistent with distances from potential discovery sites to suitable shore terminal/plant sites (assuming new plants) and to existing terminals/ plants in Upper Cook Inlet (see Table 3-3).

Distances that represent upper and lower limit pipeline distances are screened in the analysis. Existing shore facilities -- oil terminals or refineries and LNG plants -- are assumed to be 87 kilometers (140 miles) from potential field locations that have the option of using existing facilities. Of this distance, 97 kilometers (60 miles) is offshore and 129 kilometers (80 miles) onshore on the Kenai Peninsula. New terminal facilities are assumed to be constructed within 40 kilometers (25 miles) of a discovered field -- 32 kilometers (20 miles) of offshore pipeline, and eight kilometers (5 miles) onshore. These distances are considered to bracket actual probable pipeline distances. In those cases which are sensitive to pipeline costs, a short pipeline -- 40 kilometers (25 miles) -- to an existing terminal is tested as an optimistic case.

111.1.3 Number of Wells

Drilling production platforms are assumed to accommodate a maximum of 48 wells. Well allowances (i.e. nonproduction wells such as water injection or gas reinfection) are assumed to be one well per five production wells. The number of production wells in the scenarios will be consistent with reservoir and production characteristics (reservoir depth, recoverable reserves per acre, etc.). For oil fields, under the assumptions of the economic analysis, the typical platform will accommodate either 24 or 40 production wells depending on reservoir depth' and well spacing described in Section 111.3.5. Gas platforms are assumed to house 12 to 24 producing wells.

111.1.4 Well Completion Rate

Based on discussions with petroleum industry engineers, development well completion rate is assumed to be 30 days for 1,525 meters (5,000 feet) reservoirs and 60 days for 3,048 meters (10,000 feet) reservoirs. On larger platforms with 36 or more well slots, two drilling rigs are assumed to be installed and operating until completion of the development wells (after completion one rig may be removed); for platforms with less than 36 well slots, development drilling is assumed to be completed with one rig. These assumptions are consistent with industry practice as discussed in Chapter 4.0 in the Gulf of Alaska reports (Dames & Moore, 1979a and 1979b).

III.2 Financial Assumptions

, 111.2.1 Assumed Values for Fixed Variables

- Prices and costs are held constant in 1978 dollars.
- The model uses continuous discounting. Discounting of cash flows begins with the first development investment
- Net present value calculations use 10 percent and ' 5 percent as the upper and lower limit value of money.
- Sensitivity analyses assume 15 percent value of money.
- Federal tax rate is assumed to be 46 percent.
- No state or local taxes are assumed.
- No depletion allowance is allowed.
- Royalty rate is assumed at 16-2/3 percent,
- Investment tax credit on tangible investments is assumed to be 10 percent.
- No bonus bid or exploration costs are included; again, it should be emphasized that this analysis investigates the economics of the production systems required to develop oil and gas fields in the Lower Cook Inlet/Shelikof Strait with certain assumed reservoir characteristics.

- Fifty percent of capital investment is assumed tangible and is depreciated over the production life of the field using the units-of-production method.

- Fifty percent of capital investment is assumed intangible drilling costs and is expensed against revenue from production.

- Investment schedules vary with the different production systems and with water depth. Time lags and costs incurred for permits, etc. from time of discovery to initial development investment are assumed to be expenses against corporate overhead. Typical investment schedules vary from four to five years for the non-associated gas system to six or seven years for a single platform oil system. Seven or eight year investment schedules are assumed for two platforms.

- Annual platform and pipeline operating costs are assumed to be constant per platform and not to vary with production. Thus, as production declines over time, the cost per barrel produced rises. The terminal handling fee for oil transshipment from an existing terminal is assumed to be $0.50 BBL.

III.2.2 Variables Entered as a Range of Values

- Oil prices are entered at $10.00, $12.50, and $16.50 BBL.

- Gas prices are entered at $1.75, $2.10, and $2.75 MCF.

- Annual operating costs are entered as follows:

	($ Million 1978)		
	Low	Mid	High
Single Platform Oil or Gas System	$25	$35	$50
Two Platform Oil Systems	$50	$70	$100

- Tangible and intangible mid-range costs are entered. For sensitivity and Monte Carlo analysis, lower limits are estimated to be 75 percent of tangible and intangible mid-range values; upper limits are estimated to be 140 percent of mid-range values.

III.3 Reservoir and Production Assumptions

III.3.1 Introduction

The economic analysis and detailing of scenarios for offshore petroleum development require that some basic assumptions on the characteristics and performance of prospective reservoir(s) be made. Because the economic analysis considers the total prospective acreage of the lease sale area and not a single site specific prospect, the assumptions that are made have to be generally representative of anticipated conditions. Where possible, a range of values are selected for some parameters but those cases are limited due to computational expenses. There is very little published data available to make assumptions on these parameters.

The reservoir and production assumptions selected result from a review of Lower and Upper Cook Inlet petroleum geology by a petroleum geologist and discussions with geologists and petroleum engineers of companies with interests in Lower Cook (Sale CI) leases.

Although the available data on reservoir and hydrocarbon characteristics does not permit specificity in the economic analysis, the economic methodology is flexible enough to accommodate a range of values. The economic model can explore the effects of variation in such parameters as well productivity and thus detect key economic sensitivities produced by contrasts in reservoir/hydrocarbon characteristics.

In a frontier area such as Lower Cook Inlet, resource evaluation has to rely to some extent on external productive analogs. The U.S.G.S. , for example, used the McAlister and Ventura basins as analogs for Lower Cook Inlet (Magoon et al., 1976). For more specific estimates in reservoir performance, there is the productive analog of Upper Cook Inlet for the Tertiary prospects of Lower Cook. Predicting possible reservoir and production characteristics for the Mesozoic prospects is very difficult since oil and gas has not been produced from rocks of this age in the Cook Inlet basin. Further, well data which is publically available, is limited, being restricted to onshore wells around the periphery of Lower Cook Inlet and one C.O.S.T. well. For a given formation or rock unit, important properties such as porosity and permeability may vary significantly over the lease area. The reservoir and production assumptions required by the economic analysis are:

- Production timing, initial productivity-and decline.
- Initial production rate.
- Platform capacity.
- Reservoir depth.
- Well spacing and recoverable reserves per acre.
- Oil properties.

111.3.2 Production Timing, Initial Productivity and Decline

The timing of production start-up varies with the construction delays associated with different production systems, for either oil or gas, numbers of platforms and wells, number of drilling rigs per platform, reservoir target depth, and water depth. In view of the high investment cost of production in the Lower Cook Inlet/Shelikof Strait, production is assumed to start as early as possible. Some delay is assumed in these production schedules due to environmental requirements and permit acquisition.

111.3.2.1 Oil

Timing

For the typical platform over a 3,048 meters (10,000 foot) deep reservoir with two drilling rigs and 40 producing wells (oil or oil and associated gas), plus 8 service wells, each rig completes a well in 60 days and producing wells come on-stream in four groups over a 4--year period beginning with the fifth year after development begins in water depths up to 91.5 meters (300 feet) and beginning with the sixth year at depths above 9?.5 meters (300 feet).[1] Production rises to peak in the eighth or nineth year, depending on water depth and is assumed to begin an exponential decline after 45 percent of the recoverable reserves are produced.[2] Between 65 and 70 percent of recoverable reserves are produced within the first 40 percent of the life of the field. Enhanced recovery procedures are assumed to be used over the last 60 percent of the life of the field to maintain a stable exponential decline.

For the typical platform over a 1,524 meters (5,000 foot) deep reservoir with 24 producing wells plus four service wells and one drilling rig, each rig completes a well in 30 days and producing wells come on-stream in two groups over a 2-year period. Production begins in the fifth or sixth year, depending on water depth[1] and rise to peak the next year. Decline beings as stated above.

Platform Capacity and Field Decline

Oil platforms are assumed to be sized to hold either 24 or 40 producing wells and 4 or 8 service wells, depending on reservoir depth and well spacing. Maximum production per platform depends on the assumed initial production rate. Full capacity systems are assumed to produce at 96 percent of capacity. All production is assumed to be pipelined to shore;

(1) Water depth and production schedule are related insofar as platform fabrication and installation for fields in water depths of up to 91.5 meters (300 feet} are assumed to take about two years, and about three years for fields in water depths of over 91.5 meters (300 feet). This is because platform size (and hence fabrication time) is in part related to water depth.

(2) This is a somewhat conservative assumption in that some industry analysts suggest as much as 50 percent of reserves would be produced before decline begins. However, all fields are different; assuming either 45 or 50 percent does not mean some yet-to-be discovered oil field in Lower Cook Inlet/Shelikof Strait will decline according to our assumption -- or any other.

no offshore loading is assumed. Production decline rates vary as a function of production system, reserves recovered per well, and the assumed initial productivity rate. Figure A-4 shows a typical oil production profile. Production is assumed to be sustained at the initial production rate until 45 percent of reserves are recovered, and then decline exponentially.

Initial Production Rate

Initial well productivities assumed for this study are 1,000 bpd, 2,000 bpd and 5,000 bpd. These have been selected in part on the basis of limited geologic/analog data and in part by the requirement to explore a range of economic sensitivities related to this parameter.

For the Mesozic prospects there was a consensus of opinion among the geologists consulted that reservoir performance would be mediocre (in the context of offshore petroleum economics) based on permeability/ porosity and potential pay thickness data from the C.O.S.T. well, out-crop data and regional geologic considerations. In the C.O.S.T. well, for example, all of the sandstones in the Mesozoic encountered below 2,088 meters (6,850 feet) were found to be impermeable due to changes caused by diagenesis.

For the Tertiary prospects, Upper Cook Inlet serves as a analog; initial well productivity there has averaged 1000 to 2000 bpd although there are some wells which have produced at significantly higher rates (see Diver, Hart and Graham, 1976). Currently, with production from Cook Inlet oil fields in decline, wells are averaging for individual fields from 159 bpd to 1530 bpd (State of Alaska, Department of Natural Resources, Division of Oil and Gas, 1977 Statistical Report).

111.3.2.2 Non-Associated Gas

Timing

The typical non-associated gas platform starts production in the fifth year after development begins in water depths up to 91.5 meters (300

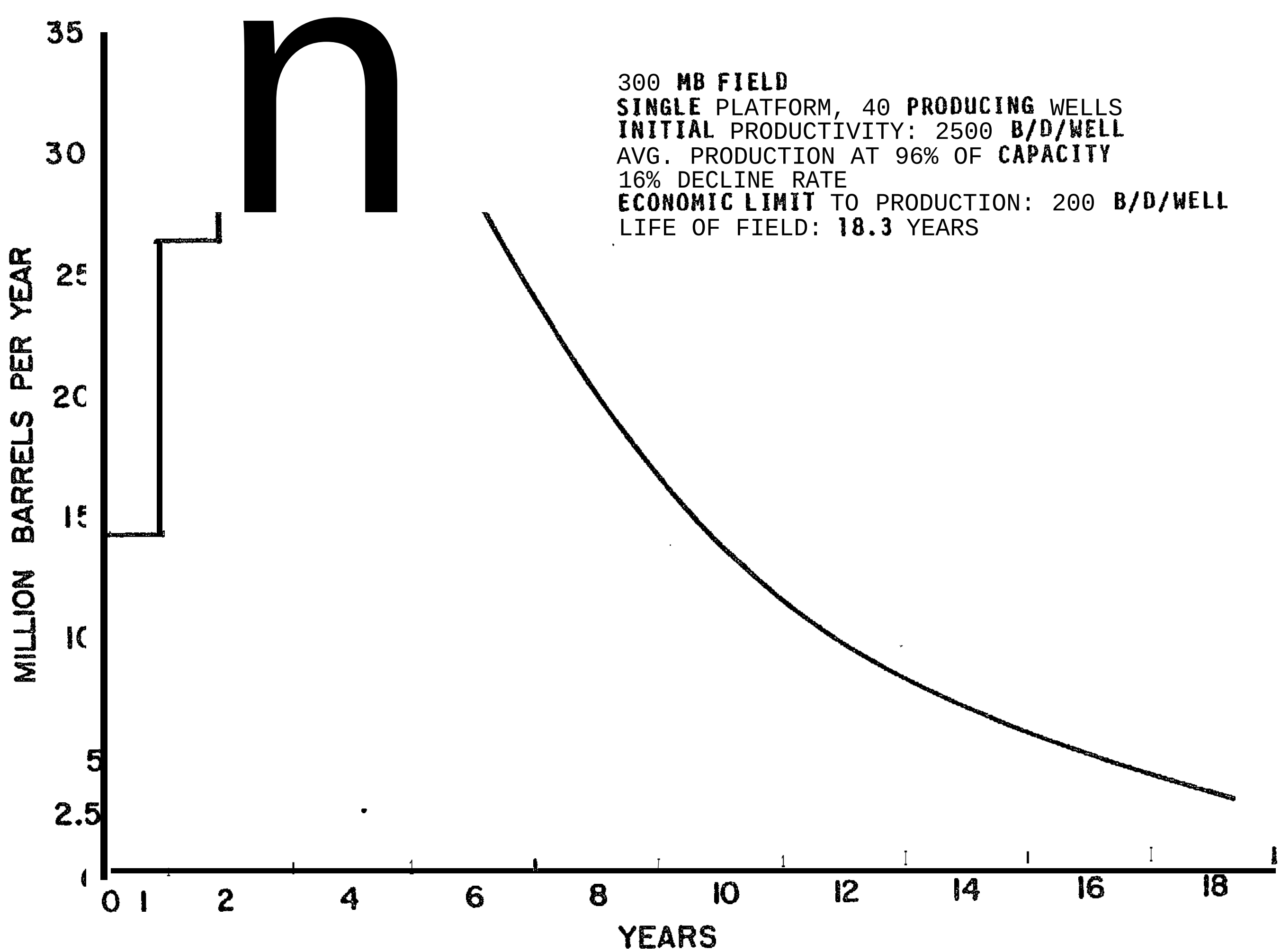


FIGURE A-4

TYPICAL PRODUCTION PROFILE

feet) and in the sixth year at water depths greater than 91.5 meters (300 feet). Gas production steps up to peak in the same way as oil production depending on depth of reservoir. Production continues flat at peak until 75 percent of recoverable reserves are produced and then begins an exponential decline.

Platform Capacity and Field Decline

Twelve or 24 gas wells per platform plus 2 or 4 service wells are assumed for the development scenarios. Maximum platform production depends on the assumed initial production rate. Platforms are assumed to produce 96 percent capacity. Production is assumed to be sustained at the initial production rate until 75 percent of reserves are recovered, and then decline exponentially.

Initial Production Rate

Initial productivity per well for non-associated gas is assumed to be 15 mmcfd based on the Teritary analog of Upper Cook Inlet. No analog or data is available for the Mesozoic prospects to make an assumption on gas well productivity; 15 mmcfd gas wells are also assumed for these prospects. Upper limit productivity is assumed to be 25 mmcfd for field size sensitivity testing.

111.3.3 Reservoir Depth

Two reservoir depths have been assumed for this study -- 1,524 and 3,048 meters (5,000 and 10,000 feet) -- for both Tertiary and Mesozoic prospects.

Review of the available data on structural geology, and formation thickness and depth reveals the base of the Tertiary varies from about 2,500 meters (8,200 feet) near Anchor Point to less than 750 meters (2,500 feet) in the vicinity of the Augustine - Seldovia Arch (Fisher, 1977; Magoon et al., 1976). The Tertiary strata thicken to the southeast of the arch where the base of the Tertiary increases in depth to over 2,000 meters (6,500 feet). The base of the Upper Jurassic strata lies at over 7,000 meters (23,000 feet) in the north of the lease sale area, becomes shallower over the Augustine - Seldovia Arch, where it is less than 4,000 meters (13,000 feet) deep and increases in depth to the south of the arch to over 5,000 meters (16,000 feet) near Cape Douglas.

Prospective formations, however, probably lie at depths less than 3,048 meters (10,000 feet) in Lower Cook Inlet with Mesozoic prospects probably restricted to the upper portion of the Mesozoic section. Table A-10 summarizes the estimated reservoir depths and possible producing formations from which these values were selected.

In view of the extreme cost of installing and maintaining platforms in the Lower Cook Inlet, it is necessary to minimize their number. All other factors being equal, a shallow field with a thin pay reservoir covering many square miles and requiring several platforms to produce is less economic in Lower Cook Inlet than a field of equal reserves, with a deep and thick payzone, which can be reached from a single platform. The reservoir depths of 1,524 meters and 3,048 meters (5,000 feet and 10,000 feet) assumed in this analysis, which on the limited data available are believed to probably be representative of ranges for Lower Cook Inlet, will dictate economic examination of variation in this parameter.

111.3.4 Recoverable Reserves Per Acre

It can be shown that reservoir characteristics -- porosity, permeability, connate water, driving mechanism, and depth as it relates to pressure, etc. -- together with thickness of payzone define the recoverable reserves per acre. Thus, recoverable reserves per acre is a good proxy in place of more technical functional relationships for determining the number of wells required to produce a field, given its initial production rate.

The Arthur D. Little report (1976) indicated that recoverable reserves per acre range from as high as 300,000 barrels per acre in the extremely productive fields of the North Sea and as low as 5,000 barrels per acre in the Gulf of Mexico. The Dames & Moore Beaufort Sea report (1978) in-

TABLE A-10

RESERVOIR DEPTHS AND PRODUCING FORMATIONS - LOWER COOK INLET

Reservoir Depths

Tertiary Area

Oil	2438 to 3048 meters (8,000 to 10",000 feet)
Dry Gas	1524 to 3048 meters (5,000 to 10,000 feet)

Mesozoic Area

Oil	2134 to 3048 meters (7,000 to 10,000 feet)
Dry Gas	1219 to 3048 meters (4,000 to 10,000 feet)

Possible Producing Formations

Tertiary Area

Oil - Lower and Basal Kenai Fm.
Dry Gas - Upper to Lower Kenai Fm.

Mesozoic Area

Oil - Upper Cretaceus Kaguyak Fm. (Best potential reservoir in C.O.S.T. well)
Lower Cretaceus - unnamed Fm.
Upper Jurassic Naknek Fm.
Basal Naknek - Possible potential reservoir, locally very deep
Dry Gas - Same as for oil

Source: J. Ganapole, report to Dames & Moore dated November 1978.

dicated that the recoverable reserves per acre for Prudhoe Bay is about 50,000 barrels and adopted as a reasonable range 20,000 to 50,000 recoverable barrels of oil per acre for the Beaufort Sea. As with the two Gulf of Alaska studies, we have assumed 20,000 to 50,000 recoverable barrels per acre in this study, which brackets the Upper Cook Inlet average of 30,000 barrels per acre (Ganapole, 1978).

111.3.5 Well Spacing

111.3.5.1 General Considerations and Oil

The number of wells that can be drilled from a platform depend on:

- Reservoir characteristics of the particular oil or gas field.
- The average depth of the reservoir.

The first item governs how the oil or gas flows. We have fixed initial production rates by assumption (see Section 111.3.2). Reservoir depth determines the maximum area which can be produced from a platform, assuming that a deviated well can be drilled to an angle of up to 50 degrees from the vertical; Table A-II shows that the maximum area that can be produced from a single platform ranges from 2.6 to 72.5 square kilometers (one to 28 square miles), assuming the depth ranges from 1,525 to 4,575 meters (5,000 to 15,000 feet). For the assumed reservoir depths of this study, a single platform will be able to reach a maximum area of either 7.8 square kilometers (3.0 square miles) for a 1,525 meter (5,000 feet) deep reservoir or 32.4 square kilometers (12.5 square miles) for a 3,050 meter (10,000 feet) deep reservoir.

Industry practices in the Upper Cook Inlet indicate that well spacing for the Lower Cook Inlet fields may range between 32 to 130 hectares (80 to 320 acres) per well as a function of initial well productivity and recoverable reserves per acre. Depending, therefore, on reservoir depth, initial productivity, and the number of wells per platform (24 or 40), sufficient platforms will be assumed to house enough wells to:

TABLE A-11

MAXIMUM AREA WHICH CAN BE REACHED WITH
DEVIATED WELLS DRILLED FROM A SINGLE PLATFORM

Depth of Reservoir		Maximum Area Produced			
Meters	(Feet)	Sq. Kilometers	(Sq. Miles)	Hectares	(Acres)
1,525	(5,000)	7.8	(1.0)	777	(1 ,920)
2,286	(7,500)	16.0	(7.0)	1,813	(4,480)
3,050	(10,000)	32.4	(12.5)	3,238	(8,000)
3,812	(12,500)	50.5	(19.5)	5,051	(12,480)
4,575	(15,000)	72.5	(28.0)	7,252	(17,920)

Notes:

1. Maximum angle of deviation assumed to be 50 degrees.

Source: Dames & Moore Estimate

- Allow spacing between 80 to 320 acres.

- Allow exhaustion of recoverable reserves in 20-25 years or less.

At 1,525 meters (5,000 feet), 80-acre spacing implies no more than 24 wells may be drilled into a reservoir from a single platform. Forty wells drilled into a reservoir at 3,050 meters (10,000 feet) implies 81 hectares (200-acre) spacing.

111.3.5.2 Non-Associated Gas

The 1976 A. D. Little report showed that non-associated gas recoverable reserves per acre in the Gulf of Mexico varied between 50-200 mmcf and between 50-500 mmcf in the North Sea (A. D. Little, 1976, p. III-26). We assume recoverable reserves in the Lower Cook Inlet will fall between 120 and 300 mmcf per acre as we assumed in the two Gulf of Alaska reports.

Well spacing in the Lower Cook Inlet is likely to be set by the market demand for gas, rather than by industry desire to maximize recovery. Consistent with reservoir engineering and petroleum geology constraints, well spacing up to 518 hectares (1,280 acres) may allow sufficient gas production to run expected LNG capacity. Final design well spacing in the usual U.S. range of 65 to 130 hectares (160 to 320 acres) may have little relevance to gas producers in the Cook Inlet if they have no market for their gas.

111.3.6 Oil Properties

No assumption is made in this study on the quality of oil that may be found in Lower Cook Inlet. Possible qualitative differences in crudes are accommodated in the economic analysis by the range of prices considered.

The gravity of oil in Upper Cook Inlet fields ranges from 27.7" API (Redoubt Shoal field shut-in) to 44° API (Granite Point Field) but generally falls within the range of 35-38° API. Upper Cook Inlet crude is "sweet" with a generally low sulphur content reaching a maximum of 0.22 percent in the Redoubt Shoal field (shut-in).

I.V. Projected Cook Inlet Oil Production and Facility Capacity

This section briefly discusses the projected Cook Inlet oil production and its relationship to the capacity and utilization of Upper Cook Inlet petroleum facilities. Future Cook Inlet oil production will come from (1) existing fields in Upper Cook Inlet which are currently in decline, (2) discoveries in Sale CI, and (3) discoveries in Sale 60.

IV.1 Upper Cook Inlet Production

Production from Upper Cook Inlet fields has peaked and is declining; production will probably cease in the mid 1990's (see Tables A-12 and A-13). In 1980, production from existing Upper Cook Inlet fields will average 114,795 barrels per day. By the time Lower Cook Inlet production (Sale CI and Sale 60) comes on line in the mid to late 1980's, Upper Cook Inlet production will have declined to between approximately 35,000 and 50,000 bpd.

IV.2 Sale CI Production

A hypothetical production schedule has been developed for the aggregated oil resources of Sale CI for the high find and medium find estimates (see Tables 3-1 and 3-2). The production schedule shown in Tables A-12 and A-13 for Sale CI were constructed using the same production, decline, timing, and field development schedule assumptions adopted for this analysis. For Sale CI, the assumptions have been made that:

- Oil is first discovered in 1980.

TABLE A-12

PROJECTED OIL PRODUCTION
HIGH FIND RESOURCE ESTIMATES COMPARED WITH
UPPER COOK INLET FORECASTED PRODUCTION

Year	Production in MMBBL Year — Lower Cook Only[2] Sale CI[1]	Sale 60	Upper Cook Inlet[3]	Totals
1980	--	--	41.9	41.9
1981	--	--	36.7	36.7
1982	--	--	32.0	32.0
1983	--	--	27.8	27.8
1984	--	--	24.3	24.3
1985	--	--	21.2	21.2
1986	14.0	--	18.5	32.5
1987	40.3	--	16.2	56.5
1988	75.3	--	14.2	89.5
1989	96.3	11.2	12.5	120.0
1990	102.0	32.2	10.9	145.1
1991	95.7	" 49.0	9.6	154.3
1992	80.2	56.0	8.5	144.7
1993	61.8	53.3	7.4	122.5
1994	49.4	45.2	6.5	101.1
1995	39.0	35.7	5.7	80.4
1996	31.1	28.4	--	59.5
1997	24.9	22.6	--	47.5
1998	20.3	18.0	--	38.3
1999	14.6	14.3	--	28.9
2000	10.1	11.3	--	21.4
2001	8.7	9.0	--	17.7
2002	7.5	7.2	--	14.7
2003	6.5	4.9	--	11.4
2004	5.6	1.7	--	7.3
2005	4.9	--	--	4.9
2006	4.2	--	--	4.2
2007	3.6	--	--	3.6
2008	3.1	--	--	3.1

[1] See Table 3-1

[2] See Table 5-14.

[3] Source: State of Alaska, Department of Revenue, 1979.

TABLE A-13

PROJECTED OIL PRODUCTION
MEDIUM FIND RESOURCE ESTIMATES COMPARED WITH
UPPER COOK INLET FORECASTED PRODUCTION

	Production in MMBBL Year			
	Lower Cook Only[2]			
Year	Sale CI[1]	Sale 60	Upper Cook Inlet[3]	Totals
1980	--	--	41.9	41.9
1981	--	--	36.7	36.7
1982	--	--	32.0	32.0
1983	--	--	27.8	27.8
1984	--	--	24.3	24.3
1985	--	--	21.2	21.2
1986	14.0	--	18.5	32.5
1987	40.3	--	16.2	56.5
1988	61.3	--	14.2	75.5
1989	67.0	11.2	12.5	90.7
1990	60.7	21.0	10.9	92.6
1991	47.6	28.0	9.6	85.2
1992	33.6	28.0	8.5	70.1
1993	25.1	25.3	7.4	57.8
1994	18.0	19.9	6.5	44.4
1995	12.9	15.8	5.7	34.4
1996	9.2	12.6	--	21.8
1997	6.8	10.0	--	16.8
1998	2.9	8.0	--	10.9
1999	--	6.3	--	6.3
2000	--	5.0	--	5.0
2001	--	4.0	--	4.0
2002	--	3.2	--	3.2
2003	--	--	--	--
2004	--	--	--	--
2005	--	--	--	--
2006	--	--	--	--
2007	--	--	--	--

[1] See Table 3-1

[2] See Table 6-12.

[3] Source: State of Alaska, Department of Revenue, 1979.

- The total resource is discovered over a three-year period for the high find estimates and a two-year period for the medium find estimate.

- Two fields with reserves of 200 mmbbl each comprise the medium find estimate of approximately 400 mmbbl.

- Two fields with reserves of 200 mmbbl each and one field with reserves of 400 mmbbl comprise the high find estimate.

- Oil production is brought on line during the period 1986-87 for the medium find estimate and 1986-88 for the high find estimate.

The medium find Sale CI production is assumed to commence in 1986, peaks in 1989, and ceases in 1998 (Table A-13). Peak production of 60.7 mmbbl in 1989 translates to an average daily production rate of 183,561 barrels. The high find Sa?e CI production is assumed to commence in 1986, peak in 1990, and cease in 2008 (Table A-12). Peak production of 102 mmbbl in 1990 translates to an average daily production rate of 279,452 barrels.

IV.3 Sale 60 Production

The production schedules for the high find and medium find scenarios, individual fields and totals, are given in Tables 5-14 and 6-12, respectively. These schedules are based upon the various production and field development assumptions discussed earlier in this Appendix and in Chapter 3.0.

In the scenarios selected for detail (Chapters 4.0, 5.0, and 6.0), oil production from Shelikof Strait field(s) is piped to a new marine terminal constructed on the west coast of Afognak Island while oil production from Lower Cook Inlet fields goes to existing Upper Cook facilities. Therefore, in the evaluation of the affects of Sale 60 incremental production on Upper Cook facilities only the production from Lower Cook Sale 60 fields is shown in Tables A-12 and A-13. At the medium find resource level, Lower Cook Sale 60 production commences in 1989, peaks in 1991-92, and ceases in 2002 (Table A-13). The annual peak production of 28 mmbbl translates to an average daily production rate of 76,712 barrels. At the high find resource level, Lower Cook Sale 60 production commences in 1989, peaks in 1992, and ceases 2008 (Table A-12). The annual peak production of 56 mmbbl corresponds to an average daily production of 153,425 barrels.

IV.4 Projected Cook Inlet Oil Production and the Capacity of Upper Cook Inlet Facilities

The total projected production for Cook Inlet adding the production for Sale CI, Sale 60 (Lower Cook only) and Upper Cook Inlet fields is shown in the last column of Table A-12 and A-13 for the high find and medium resource estimates respectively. This should be compared with the existing capacity of Upper Cook Inlet facilities shown on Table 3-16.

IV.4.1 High Find Resource Level

At the high find resource level, the decline of Cook Inlet production will be reversed in 1986 as new oil production commences from Lower Cook Inlet Sale CI fields (Table A-12). Production will increase from 1986 to 1991 when it will peak with an annual production of 154.3 mmbbl or an average daily production of nearly 423,000 barrels. Production will then decline and eventually cease in 2008. Shelikof Strait oil production (see Table 5-14) is not included in these figures; that production would commence in 1989, peak in 1993 with an average daily production of about 372,000 barrels, and cease in 2007.

Currently Upper Cook Inlet terminals and refineries have a handling capacity of about 320,000 bpd (see Table 3-16) approximately 100,000 barrels less than the projected peak Cook Inlet production. The development implications of this capacity shortfall are that either expansion of Upper Cook Inlet facilities would be required to handle the additional production or a new crude oil terminal would have to be constructed somewhere on the Kenai Peninsula or west shore of the Inlet. Other factors would, of course, influence such development decisions on the use of existing facilities or the construction of new ones such as the quality of Lower Cook crudes, unitization agreements, and the demand of local Alaska markets for refined products. If Shelikof oil production were to share infrastructure with Lower Cook fields, major new facilities construction would be required in Cook Inlet to export the crude and/or refine it in-state. Facility requirements are dictated by the production schedule; any departures from the hypothetical production profiles for Sale CI and Sale 60 oil, would significantly affect the facility handling or process capacity requirements. For example, a three year delay in production from Lower Cook Sale 60 fields from that identified in Table A-12 would mean that all Lower Cook production could be accommodated by the existing facilities.

The high find scenario detailed in this study (Chapter 5.0) assumes that Lower Cook oil goes to existing Upper Cook facilities; expansion of Upper Cook oil facilities that maybe required to handle Sale 60 and CI oil is assumed for the purposes of impact analysis to be induced by the Sale CI fields which are assumed to have two-thirds of the total Lower Cook reserves.

IV.4.2 Medium Find Resource Level

When oil production commences from Sale CI fields (medium find resource level) in 1986, the decline of Cook Inlet oil production will be reversed (Table A-13). Production will increase from 1986 to 1990 when it will peak with an annual production of 92.6 mmbbl or an average daily production of 253,000 barrels. Production will then decline and eventually cease in 2002.

The projected peak production of 253,000 barrels is significantly less than the handling and process capacity of the Upper Cook Inlet terminals and refineries; in fact, all this production could be handled by the Drift River terminal. If Shelikof Strait oil production at the medium find resource level (Table 6-12), which is hypothesized to peak at approximately 192,000 bpd in 1991-92, were to be pipelined to Lower Cook

Inlet to share infrastructure with Lower Cook fields, then new facilities or expansion of existing facilities would be required in Cook Inlet. The medium find scenario (Chapter 6.0) assumes that production from the single Sale 60 field is transported to Nikiski in a pipeline shared with Sale CI field(s).

APPENDIX B

APPENDIX B

PETROLEUM DEVELOPMENT COSTS AND FIELD DEVELOPMENT SCHEDULES

This appendix presents the field development and operating cost estimates used in the economic analysis. Exploration costs are not included in the economic analysis and are, therefore, not discussed here (see Appendix A).

Predictions on the costs of petroleum development in frontier areas such as Lower Cook Inlet (which has only experienced exploration to date) and Shelikof Strait (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.

Much of the cost data presented in this study was obtained in connection with a companion study of this program for the Gulf of Alaska (Dames & Moore, 1979a and b). That data, which was based on published literature, interviews with government agencies, oil companies and construction companies (including those involved in the North Sea development), was modified and refined in consultation with various industry sources to arrive at estimates of development costs that may be encountered in the somewhat less severe climatic and oceanographic conditions of Lower Cook Inlet and Shelikof Strait (see Appendix C for a brief description of Lower Cook Inlet and Shelikof Strait oceanography).

New cost data was also obtained directly from oil companies interested in the Lower Cook Inlet/Shelikof Strait area. In some facility categories there was considerable variation in cost estimates from the various industry sources; such variations were accommodated in this analysis by taking the average of the estimates and evaluating low and high cost cases, No attempt was made in this study to predict or estimate costs for production systems in water depths greater than 200 meters (650 feet) which occur in the southwestern half of Shelikof. This is because: (1) production systems other than the conventional steel jacket platform such as the guyed tower or tension leg platform may be utilized and no firm cost data or experience is available to evaluate such systems; and (2) conventional steel jacket platforms have not been installed in such water depths in areas with comparable oceanographic conditions to provide a historic cost data base. Rather than predict petroleum development costs for the deeper Shelikof waters, it was decided to use the results of the economic analysis for the 183 meters (600 feet) production systems to establish the threshold of various economic sensitivities for petroleum development in greater water depths.

I. Published Data Base

It is appropriate to briefly describe the published data base that is available on petroleum development costs for frontier areas (this discussion was also included in the Gulf of Alaska scenario studies, Dames & Moore, 1979a and b).

The North Sea cost data base includes the "North- Sea Service" of Wood, Mackenzie & Co. which monitors North Sea petroleum development and conducts economic and financial appraisals of North Sea fields. The Wood, Mackenzie & Co. reports provide a breakdown and scheduling of capital cost investments for each North Sea field. A. D. Little, Inc. (1976) have estimated petroleum development costs for the various U.S. OCS areas, including Alaskan frontier areas, and have identified the costs of different technologies and the various components (platforms, pipelines, etc.) of field development. The results of the A. D. Little study have also been produced in a text by Mansvelt Beck and Wiig (1977).

Gulf of Mexico data has provided the basis for several economic studies of offshore petroleum development (National Petroleum Council, 1975;

Kalter, Tyner and Hughes, 1975). Gulf of Mexico cost data has been extrapolated to provide cost estimates in more severe operating regions through the application of a cost factor multiplier. For example, Gulf of Alaska cost estimates for exploration and development have been developed using cost factor multipliers of 1.8 (exploration) and 2.8 (development) as defined by Kalter, Tyler and Hughes (1975). This approach has been used in this report to provide a comparison among estimates.

Other important cost data sources include occasional economic reports in the Oil and Gas Journal and American Petroleum Institute (API) statistics on drilling costs. A problem with some of the cost data, especially estimates contained in technology references, is that they do not precisely specify the component costed. Thus a reference to a platform quoted to cost $100 million may not specify whether the estimate refers to fabrication of the substructure, fabrication and installation of the substructure, or the completed structure including topside modules. Another problem is that the year's dollars (1975, 1976, etc.) to which the cost estimate is related is often not specified.

All the cost figures cited in Tables B-1 through B-8 are given in 1978 dollars. Cost figures from the various sources have been inflated to 1978 dollars using United Kingdom and United States petroleum industry indices. For North Sea cost data a modified U.K./U.S. index has been used. In addition to the data sources cited beneath the cost tables, a major source of these cost estimates was personal communications with various industry sources.

Estimation of steel platform fabrication costs (Table B-1) was assisted by plotting costs of North Sea platforms vs. water depth on log-log paper and conducting a regression analysis on the data. This was done because a geometric increase in platform fabrication costs with water depths has been reported (Bendiks, 1975; Lovegrove, 1976). A reasonable fit was obtained, and cost ranges for steel jacket platforms, at various water depths, were defined and compared with independent data.

TABLE B-1

PLATFORM FABRICATION COST ESTIMATES

Platform Type[2]	Water Depth	Cost $ Millions 1978 Mid-Range Value[1]
Steel Jacket	100	35
	300	65
	600	180

Sources: Wood, Mackenzie & Co., 1978, A.D. Little, Inc., 1976; Bendiks, 1975; Peat, Marwick, Mitchell & Co., 1975; Dames & Moore.

Notes:

[1] A mid-range value is given here. In the economic analysis a low estimate 25% less than this value and a high estimate of 40% greater than this value were investigated. Explanation of this range is presented in the text.

[2] These estimates do not reflect sensitivity for numbers of well slots or production throughput. The estimates presented here are based primarily on larger North Sea platforms with 20+ well slots and throughput of 70,000 to 200,000 bpd.

TABLE B-2

PLATFORM INSTALLATION COST ESTIMATES [1]

Platform Type	Cost $ Millions 1978 Mid-Range Value [2]
Steel Jacket	60

Sources: Wood MacKenzie & Co., 1978; A.D. Little, Inc., 1976; Dames & Moore.

Notes:

[1] Platform "installation" includes site preparation, tow out, setdown, pile driving, module lifting, facilities hookup, etc.

[2] See Note No. 1, Table B-1.

TABLE B-3A

PLATFORM EQUIPMENT AND FACILITIES
COST ESTIMATES OIL PRODUCTION

Platform Type[2,3]	Peak Capacity Oil (MBD)	Cost $ Millions 1978 Mid-Range Value [1]
Steel Jacket	25	48
	25-50	60
	50-100	95

Sources: Wood, Mackenzie & Co., 1978; A.D. Little, Inc., 1976.

Notes:

[1] See Note No. 3, Table B-1.

[2] It is assumed that the fields have a low GOR and that associated gas is used to fuel platforms and the remainder is reinfected.

[3] It is also assumed that a reservoir pressure maintenance program involving water injection will be required.

TABLE B-3B

PLATFORM EQUIPMENT AND FACILITIES COST ESTIMATES
NON-ASSOCIATED GAS PRODUCTION [1]

Platform Type	Peak Capacity Gas (MMCFD)	Cost $ Millions 1978 Mid-Range Value [1]
Steel Jacket	200-300	35
	300-400	48

Sources: Wood, Mackenzie & Co., 1978; A.D. Little, Inc., 1976; Dames & Moore.

Notes:

[1] See Note No. 3, Table B-1.

TABLE B-4

DEVELOPMENT WELL COST ESTIMATES

Well Type	Cost $ Millions 1978 Mid-Range Value[1]	
	5,000 Feet	10,000 Feet
Development Well (Each)	2.0	3.3

Sources: Wood, Mackenzie & Co., 1978; API, 1978; Gruy Federal, Inc., 1977; Bendiks, 1975; Dames & Moore

Notes:

[1] See Note No. 1, Table B-1.

TABLE B-5A

MARINE PIPELINE COST ESTIMATES

Diameter (Inches)	Average Cost Per Mile $ Million 1978 Mid-Range Value[1]	Burial Costs Per Mile $ Millions
20-29	3.8	0.20
10-19	2.5	0.13
<10	1.3	0.07

[1] See Note No. 1, Table B-1.

Sources: Wood, Mackenzie & Co., 1978; O'Donnell, 1976: Eaton. 1977; Oil and Gas Journal, August 14, 1978; Offshore, July, 1977; Dames & Moore.

TABLE B-56

ONSHORE PIPELINE COST ESTIMATES

Diameter (Inches)	Average Cost Per Mile $ Millions 1978 Mid-Range Value[1]
20-29	.750
10-19	.400
<10	.200

Source: Oil and Gas Journal, August 14, 1978.

Note:

[1] See Note No. 1, Table B-1.

TABLE B-6

OIL TERMINAL[1] COST ESTIMATES

Peak Throughput (MBD)[2]	Total Cost $ Millions 1978 Mid-Range Value[3]
< 100	180
100-200	270
200-300	420
300-500	540

Sources: Wood, Mackenzie & Co., 1978; Duggan, 1978; Cook InJet Pipeline Co., 1978; Shell Oil Co., 1978.

Notes:

[1] The terminals costed here are assumed to perform the following functions: pipeline terminal (for offshore lines), crude stablization, LPG recovery, tanker ballast treatment, crude storage (sufficient for about 10 days production), and tanker loading for crude trans-shipment to the lower '48.

[2] There is a cost index which equates facility cost with daily bbl capacity - the terminal costs cited here range from $1000 to $2000 per daily bbl capacity.

[3] See Note 1, Table B-1.

TABLE B-7

LNG SYSTEM FACILITY AND EQUIPMENT
COST ESTIMATES[1]

Facility/Equipment	Cost $ Millions 1978 Mid-Range Value[2]
Liquefaction Plant (200 MMCFD) and Marine Terminal	514
each additional 200 MMCFD	155
LNG Tankers (2)	435
Regasification Plant (Lower '48)	150
each additional 200 MMCFD	6

Sources: Pacific Alaska LNG, 1977; Oil and Gas Journal, August 18, 1975; Oil and Gas Journal, December 18, 1978.

Notes:

[1] Field development costs (platforms, wells, pipelines, etc.) are not included in this table.

[2] See Note 1, Table B-1.

TABLE B-8

ANNUAL FIELD OPERATING COST ESTIMATES

	$ Millions 1978 Mid-Range Value
1 Platform Field	35
2 Platform Field Pipeline-Terminal	70
3 Platform Field Pipeline-Terminal	100

Sources: Wood, Mackenzie & Co., 1978; A.D. Little, Inc., 1976; Gruy Federal, Inc., 1977.

It should be emphasized that in reality field development costs will 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). The available cost data is insufficient to provide all these economic sensitivities. Other factors also play a role in field development costs such as market conditions. 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, whether he is in a buyers or sellers 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.

Offshore field development costs are often quoted in terms of cost per barrel of daily peak production. These costs range from about $2,500 per barrel of maximum production to over $11,000 for North Sea fields currently under development (Lovegrove, 1976; Enright, 1978).

Because of considerable variation in both published and industry data low, medium, and high values for the various petroleum facilities and equipment were defined. A low estimate of 25 percent less than the mid-range (medium) value and a high estimate of 40 percent greater than this value were selected and used for economic screening.

II. Methodology

The cost tables presented in this appendix were the basic inputs in the economic analysis. Each case analyzed was essentially defined by reserve size, production technology and water depth. To cost a particular case the economist took the required cost components (field facility and equipment components) from Tables B-1 through B-8 using a building block approach; in some cases a facility or equipment item was deleted or substituted.

The cost components of each case are then scheduled as indicated in the examples presented in Table B-9. The schedules of capital cost expenditures are based upon typical North Sea development schedules. They are expressed as a percentage of the total expenditures for that item (platform fabrication, development well etc.) by year in the development schedule.

III. <u>Exploration and Field Development Schedules</u>

This appendix discusses the assumptions made in defining the exploration and field development schedules contained in the scenario descriptions in Chapters 4.0, 5.0 and 6.0. These schedules are basic inputs into the economic analysis (scheduling of investments) and manpower calculations (facilities construction schedule} as described in Chapter 3.0 and Appendix A.

To simplify these analyses a number of scheduling assumptions were made based upon review of petroleum technology and petroleum development in comparable environments.

Figure B-1 illustrates the field development schedule for a medium-sized oil field involving a single steel platform, pipeline to shore and shore terminal. The sequence of events in field development from time of discovery to start-up of production involves a number of steps commencing with field appraisal, development planning and construction. The appraisal process involves evaluation of the geologic data obtained (see Figure B-2) from the discovery well , followed by a decision to drill delineation (appraisal) wells to obtain additional geologic/reservoir information for reservoir engineering. There is a trade-off between additional delineation wells to obtain more reservoir data (to more closely predict reservoir behavior and production profiles) and the cost of the drilling investment. Using the results of the geological and reservoir engineering studies, a set of development proposals are formulated. These would also take into account locational and environmental factors such as meteorologic and oceanographic conditions. The develop-

TABLE B-9

EXAMPLE OF TABLES USED IN ECONOMIC ANALYSIS

A. SCHEDULE OF CAPITAL EXPENDITURES FOR FIELD DEVELOPMENT - SINGLE CONCRETE PLATFORM WITH STORAGE, OFFSHORE LOADING

Facility/Activity	Year After De sion to Deve p - Percent f Expenditur					
	1	2	3	a	5	6
Platform Fabrication	35	45	20			
Platform Equipment	45	45	10			
Platform Installation			100			
Development Wells[1] 36			5	44	44	11
48			4	33	33	30
SPM			50	50		
Miscellaneous			33	33	34	

Source: Based on analysis of expenditures of North Sea projects.

[1] Example presented is for 36 and 48 wells based on assumption of two rigs working at a completion rate of 45 days per well per rig; for different numbers of wells the expenditures are prorated approximately at the assumed completion rate. If fewer than 36 wells are required, then only one rig is assumed to be working.

B. SCHEDULE OF CAPITAL COST EXPENDITURES - SINGLE STEEL OR CONCRETE PLATFORM, PIPELINE TO SHORE, SHORE TERMINAL[1]

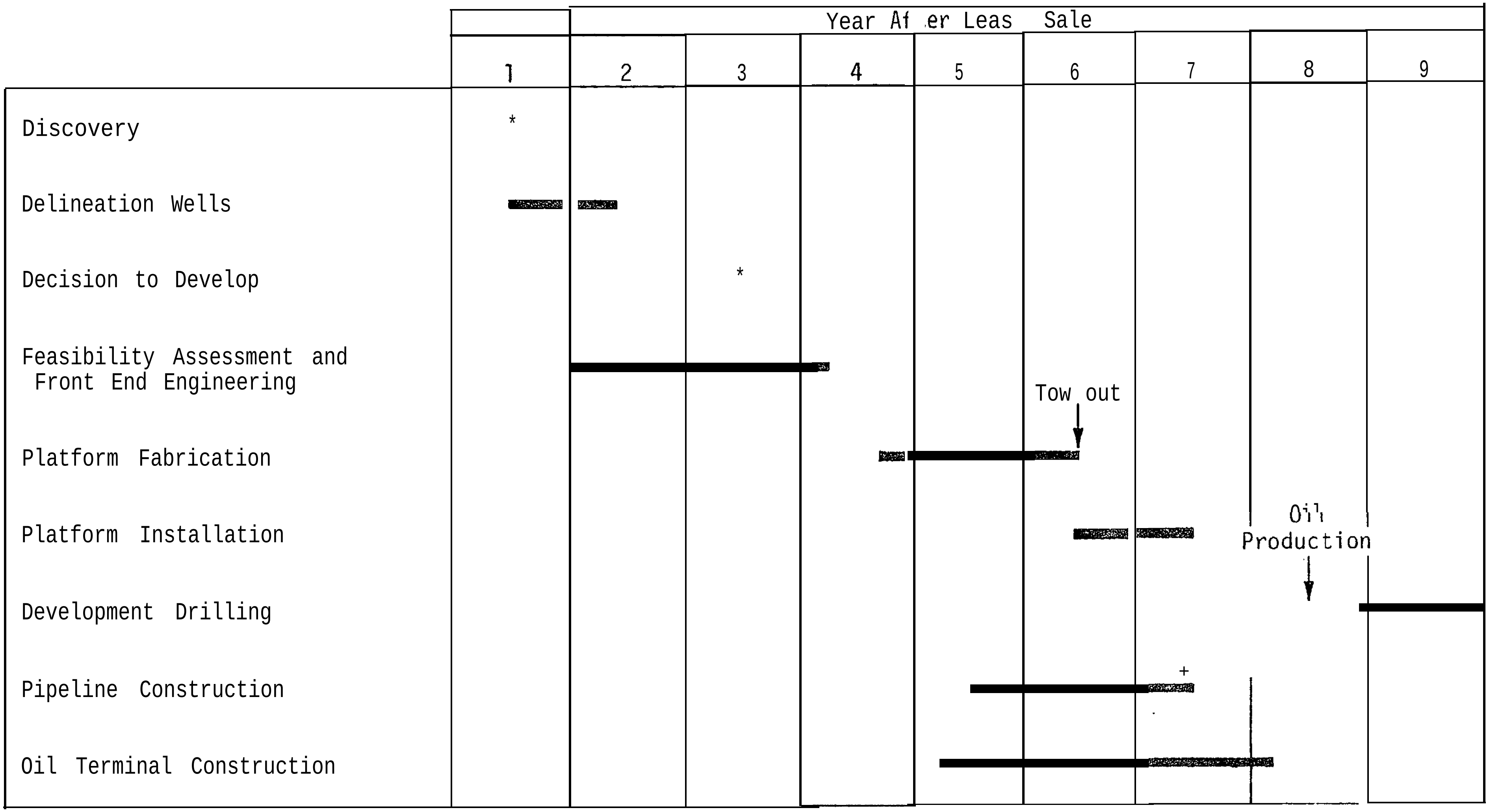
Facility/Activity	Year After Decision to Deve p-Percent of Expenditure					
	1	2	3	4	5	6
Oil Pipeline (10 miles) 16 Km	30	70				
(25 miles) 40 Km	30	70				
(50 miles) 80 Km	25	60	15			
(80 miles) 129 Km	25	60	15			
Terminal	5	40	40			

Source: Based on analysis of expenditures of North Sea projects.

[1] Instructions - this table added to a table such as Example A (above) with deletion of SPM provides schedule of cost flows for oil field produced by a single platform with pipeline to shore and shore terminal.

FIGURE B-1

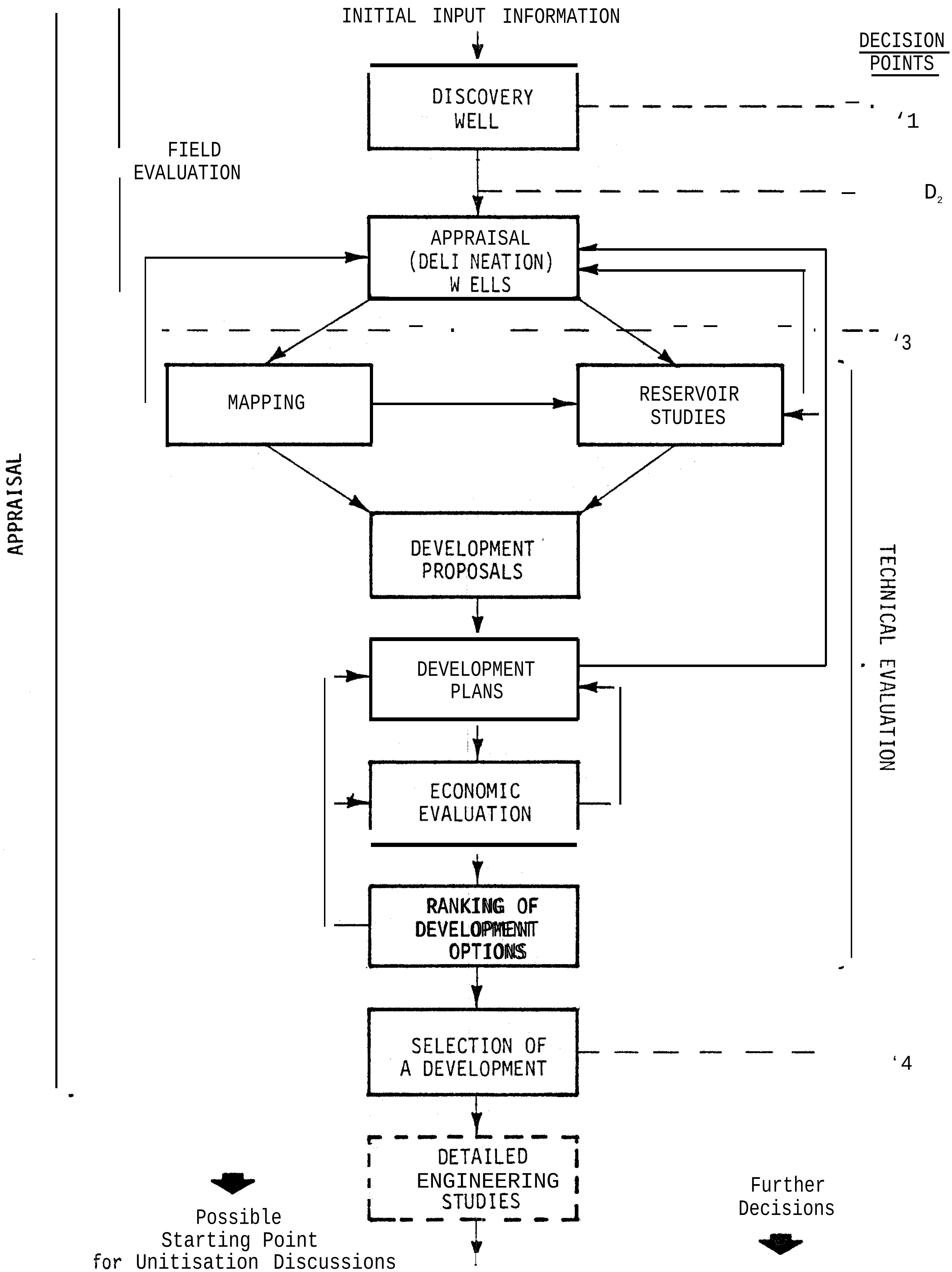
EXAMPLE OF MEDIUM-SIZED FIELD COMPLETION SCHEDULE
SINGLE STEEL PLATFORM, OIL PIPELINE TO SHORE, SHORE TERMINAL[2]



Source: Dames & Moore

[1]For illustrative purposes, discovery is assumed to occur in year following lease sale which is assumed to be first year of exploration.
[2]Seasonality of the level of some activities is not reflected in this figure.

FIGURE B-2



THE APPRAISAL PROCESS

Source: Birks (1978)

ment proposals involve preliminary engineering feasibility with consideration of the number and type of platforms, pipeline vs. offshore loading, processing requirements, etc.

As illustrated in Figure B-2, the development proposals are screened for technical feasibility and other sensitivities, reducing them to a small number to be examined as development plans. These are further screened for technical, environmental and political feasibility. An economic analysis of these plans is conducted similar to that conducted in this study. In the economic evaluation, facilities, equipment and operating expenditures are costed and expenditures and income scheduled. A ranking of development plans according to economic merit is then possible and weighed accordingly with technical, environmental and political factors to select a development plan for subsequent engineering design. The feasibility appraisal process is complete. At this time, the operator will make a preliminary go, no-go decision.

If the decision is made to proceed, the operator will conduct preliminary design studies which involve marine surveys, compilation of detailed design criteria, evaluation of major component alternatives and detailed economic and budget evaluation. Trade offs between technical feasibility and economic considerations will be an integral part of the design process. The preliminary design stage will be concluded when the operator selects the prefered alternatives for detailed design. The decision to develop will then be made.

The field development and production plan will then have to pass regulatory agency scrutiny and approval. In the United States the operator will have to submit an environmental report together with the proposed development and production plan to the U.S. Geological Survey in accordance with U.S. Geological Survey Regulation S250.34-3 Environmental Reports presented in the Federal Register, Vol. 43, No. 19, Friday, January 27, 1978.

In terms of the effect upon the development schedule, delays due to regulatory agency review, environmental requirements, etc. can not be predicted with accuracy for possible Lower Cook Inlet and Shelikof discoveries. The time that may elapse from discovery to decision to develop is field specific and also difficult to predict as is the number of delineation wells required to assess the reservoir. However, these factors are accommodated in this report by the schedule assumptions cited below.

With the decision to develop final design of facilities and equipment commences and contracts placed with manufacturers, suppliers, and construction companies. Significant investment expenditures commence at this time. Front-end engineering and design would take from one to two years following decision to develop, depending upon the facility/equipment. Design and fabrication of the major field component -- the drilling and production platform would take about three years for a large steel jacket such as Chevron's North Sea Ninian Southern Platform (Hancock, White and Hay, 1978). Onshore fabrication of a steel jacket platform will vary from about 12 to 24 months' depending upon size and complexity of the structure (Antonakis, 1975). An additional seven months of offshore construction will be required for pile driving, module placement and commissioning.

A critical part of offshore field development is scheduling as much offshore work in the summer "weather window" and timing of onshore construction to meet deadlines imposed by the weather window. In the Lower Cook Inlet and Shelikof Strait, platform tow-out and installation will occur in early summer, May or June, to permit maximum use of the weather window. If the weather window is missed or the platform is installed in late summer, costly delays up to 12 months in length could result. The "weatherw indow" is likely to be longer in Lower Cook Inlet and Shelikof Strait than in the more severe operating environment of the Gulf of Alaska.

Construction of offshore pipelines and shore terminal facilities are scheduled to meet production start-ups which is related to platform installation and commissioning, and development well drilling schedules. If shore terminal and pipeline hookup are not planned to occur until after production can feasibly commence, offshore loading facilities may be provided as an interim production system (and long-term backup). The operator has to weigh the investment costs of such facilities against the potential loss of production revenue from delayed production.

Development well drilling will commence as soon as is feasible after platform installation. If regulations permit, the operator may elect to commence drilling while offshore construction is still underway even though interruptions to construction activities on the platform occur during "yellow alerts" in the drilling process (Allcock, personal communication, 1978). The operator has to weigh the economic advantages of early production vs. delays and inefficiencies in platform commissioning. Development drilling will generally commence from 6 to 12 months after tow-out on steel jacket platforms. Development wells may be drilled using the "batch" approach whereby a group of wells are drilled in sequence to the surface casing depths, then drilled to the 13-3/8 inch setting depth, etc. (Kennedy, 1976). The batch approach not only improves drilling efficiency but also improves material-supply scheduling. 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 workover.

IV. Scheduling Assumptions

Based upon a review of technology data and industry experience, the following assumptions have been made on exploration and field development scheduling (see field development schedules in Chapters 5.0 and 6.0 and economic assumptions in Appendix A).

- Exploration commences the year following the lease sale (i.e. 1981); all schedules relate to 1981 as Year 1.

- An average completion rate of four to five months per exploration/delineation well is assumed or 2.4 to 3 wells per rig per year with an average total well depth of 3,962 to 4,572 meters (13,000 to 15,000 feet).

- The number of delineation wells assumed per discovery is two for field sizes of less than 500 MMbbl oil or 2,000 bcf gas, and three for fields of 500 MMbbl oil and 2,000 bcf gas and larger.

- The "decision to develop" is made 24 months after discovery.

- Significant capital expenditures commence the year following "decision to develop"; that year is Year 1 in the schedule of expenditures in the economic analysis.

- Steel platforms in water depths less than 91 meters (300 feet) are fabricated and installed within 24 months of construction start-up; and within 36 months in water depths 91 meters (300 feet) plus. Platform installation and commissioning has been assumed to be completed within seven months for the shallow and less stormy waters (less than 91 meters or 300 feet) of Lower Cook Inlet and 10 months for the deeper and stormier waters (greater than 91 meters or 300 feet) of the lower portion of Lower Cook Inlet and Shelikof Strait. Development well drilling is thus assumed to start about seven months after platform tow-out in the former areas and 10 months in the latter areas.

- Platform tow-out and emplacement is assumed to take place in June.

- Platforms sized for 36 or more well slots are assumed to have two drill rigs operating during development drilling. Platforms sized for less than 36 well slots are assumed to have one drill rig operating during development well drilling.

- Drilling progress is assumed to be 30 days per oil development well per drilling rig, i.e. 12 wells per year for 1,524 meters

(5,000 feet) reservoirs and 60 days per well, i.e. six wells per year for 3,048 meters (10,000 feet) reservoirs.

- Production is assumed to commence when about one-half of the development wells have been drilled.

- Well workover is assumed to commence five years after production start-up.

- Oil terminal and LNG plant construction takes between 24 and 36 months depending on design throughput.

APPENDIX C

APPENDIX C

PETROLEUM TECHNOLOGY AND PRODUCTION SYSTEM SELECTION

I. Introduction

As indicated in Chapter 3.0 and Appendix A, the objective of the economic analysis is to evaluate the relationships among the likely oil and gas production technologies suitable in lower Cook Inlet and the minimum field sizes required to justify each technology as a function of geologic conditions, water depths and pipeline distances in different parts of the Inlet.

A comprehensive description of offshore production systems with special reference to production platforms and a discussion of production system options and selection criteria has been provided in an earlier study of this program (Dames & Moore, 1979 a&b). Those findings are to a large extent relevant to lower Cook Inlet and Shelikof Strait but are not reiterated here. Some important contrasts between the Gulf of Alaska and Lower Cook Inlet/Shelikof Strait that would affect development decisions in Sale 60 should, however, be noted:

- Most potenial discovery locations in Lower Cook Inlet and Shelikof Strait are less than 40 kilometers (25 miles) from shore whereas in the Gulf of Alaska some locations are more distant.

- There is an existing petroleum infrastructure including terminals, refineries and petrochemical plants in Upper Cook Inlet which may be able to take new oil or gas production from Lower Cook/Shelikof Strait thus decreasing the requirement for new shore facilities construction. No such infrastructure is available within economic pipeline distances for Gulf of Alaska discoveries.

- Lower Cook Inlet is adjacent to the major population center of Alaska and markets for petroleum products; the Gulf of Alaska is distant from local markets.

- Water depth ranges in the areas that are planned to be leased in Lower Cook Inlet and the Gulf of Alaska are similar. However, in the southern Shelikof Strait water depths range from 200 to over 305 meters (650 to 1,000 feet).

This appendix briefly reviews the oceanographic conditions of Lower Cook Inlet as they pertain to offshore engineering, describes petroleum technology and development in Upper Cook Inlet and discusses the selection of production systems evaluated in the economic analysis.

II. Oceanography

The proposed lease area for the Lower Cook Inlet portion of Sale 60 extends over the lower half of Cook Inlet south, to approximately Shuyak Island, which lies at the northern tip of the Kodiak Archipelago. The sale area also encompasses all the federal waters of Shelikof Strait from Cape Douglas southwest to approximately a line drawn between Middle Cape and Cape Igvak. The area exhibits extreme variability both in climatology and in oceanography.

Climalogically, the northern portion of Lower Cook Inlet is in a transition climate between a maritime climate to the south and a continental climate to the north. Clearly, most of this area including all of the southern portion exhibit maritime weather. The transition climate characteristically has more extreme temperatures, both higher and lower than its maritime counterpart. Winds in the transition zone are generally light while maritime winds are persistenly strong. Oceanographic variations are in part a result of the climatic heterogeneity. But principally the oceanographic variability stems from the dominant estuarine character at the head of Cook Inlet and the oceanic quality at the lower portion. This difference is strongly manifest in the salinities over the entire region. Hydrological measurements during the month of July indicate that in the northern portion salinities can be as low as 22% and exceed 31% in the southern portion. July is the month of maximum fresh-water discharge into the Inlet; consequently, such large variations are probably not present during the remainder of the year.

Circulation within Cook Inlet is dominated by tidal forces. In the Inlet itself, the flood is to the north, ebb to the south. Generally, the tidal ranges and the associated currents increase from south to north. Maximum tidal currents are approximately two to three knots in the southern portion of the Inlet and may be as great as ‘seven or eight knots in the northern part of the Inlet (U.S. Department of Commerce, 1977a). In the northern part of the proposed lease areas, maximum currents are probably on the order of four to five knots, both during the ebb and the flood. Maximum currents are probably on the order of four or five knots in north and south direction. No direct measurements of currents have been made in Shelikof Strait, but ship reports have indicated that magnitudes may exceed one knot both north and south of the Strait.

The mean range of variation in diurnal tides along the eastern side of Cook Inlet vary from about 4.3 meters (14 feet) in the south, to 5.8 meters (19 feet) in the northeast corner of the proposed lease area (U.S. Department of Commerce, 1977 b). Along the western side of the Inlet tide data are much less abundant, but indications are that the diurnal tidal ranges vary from approximately 5.2 meters (17 feet) near Point Harriet to about 4.3 meters (14 feet) in Kamishak Bay.

The variability in meteorology and oceanography is also reflected in the extreme variability of design parameters over the area. The dominant design parameters include the water depth, the design waves, ice thicknesses and coverage, as well as wind speeds. The wind speed by itself is probably not a significant design parameter, that is, it does not contribute significantly to the environmental loading on any type of offshore drilling production platform. It is considered, however, because it does, in fact, generate the design waves and coupled with surface ice, may significatnly contribute to ice forces on structures.

Since the shoreward boundaries of the proposed lease area is the three-mile limit, the depths vary from approximately 30 meters (100 feet) to near, or in excess of 183 meters (600 feet) in lower Cook Inlet. Along the northern boundary, depths vary between 30 and 61 meters (100 and 200 feet), with some shallower water occurring just south of Kalgin Island. Two distinct channels cut through the northern boundary, one on each side of the Inlet, and merge near the cetner of the Inlet, directly west of the Kenai Peninsula community of Ninilchik. A single trough then continues, gradually deepening toward the south. This channel remains near the central axis of Cook Inlet. On a line roughly between St. Augustine Island and the mouth of English Bay, which is on the southern tip of the Kenai Peninsula, the channel again separates. The northern portion enters the Gulf of Alaska, as the Kennedy Straits, while the southern portion forms the Shelikof Strait. Maximum water depths in each of these straits exceeds 183 meters (600 feet).

In the northern portion of Lower Cook Inlet, the design parameters, specifically ice and waves, should be similar to their values for Upper Cook Inlet. These have been reported as 8.5 meters (28 feet) for the design wave, and 151 centimeters (42 inches) for the design ice thickness (Visser, 1969). This reference also states that the dominate design force in the northern Inlet is ice loading. Certainly the extent and characteristics of sea ice are better known for Upper Cook Inlet, where there has been a significant amount of petroleum development, than in the proposed sale area of the Lower Cook Inlet/Shelikof Strait. Little data exist in that area to delineate the extent of ice coverage. The winter of 1973-74 was considered a severe year for the Cook Inlet area when significant ice coverage as far south as the tip of Kalgin Island (Schula, 1977) was reported. During the winter of 1970-71, however, the ice extended as far south as Cape Douglas on the western side of the Inlet and Anchor Point on the eastern side. The Forecast Center of the National Weather Service in Anchorage has indicated that significant ice build-up occurs in the Kamishak Bay, probably as a result of repeated growth of ice that has been deposited on the beach during high tides. At times this ice can break free from the beach and pose a real hazard to shipping and present a definite design parameter for marine structures. The forecast office (Pat Poole, personal communication) indicated that this type of ice could be as large as 11 kilometers (7 miles) long and 5 to 7 kilometers (3-4 miles) wide. The thicknesses may be as great as a meter. It is not known whether this ice has the same strength as ice that is formed directly on the water surface, but regardless, it should be considered as an important design parameter for all portions of the Lower Cook Inlet.

As mentioned above, the design wave for the northern portion of the lease area can be considered to be essentially the same as that considered for Upper Cook Inlet, which was around 8.5 meters ('28 feet). However, in the southern portion, where the water body broadens markedly, the fetch becomes significant not only in the north-south direction, but also in the east-west direction. There is roughly a 113 kilometer (70 mile) fetch from the western shore of Kamishak Bay to the Barren Islands. Again, the Forecast Center has indicated that sustained winds of 50 or 60 knots coming from the northwest could exist in that area for possibly several days. In the absence of measured wave data for that area, the formula given by Neumann and Pierson (1966), gives a significant wave height for a 60 knots sustained wind as approximately 20 meters (65 feet). It is obvious, however, that this value is extremely high and applies to a region of unlimited fetch, unlike the lower Cook Inlet. Some compensation can be made on the basis of data from studies by Derbyshire (from Wiegel, 1964) in which he presents a ratio for a fetch limited wave height to the infinite fetch wave height as a function of fetch. This aid illustrates that for a 113 kilometers (70 mile) fetch, a 10.6 meter (35 foot) significant wave height is reasonable. When translated to a maximum wave, through Rayliegh statistics, this significant wave can Include a maximum 19.2 meter (63 feet) wave. Since the wind conditions cited above may be atypical for this area, this maximum wave cannot be considered a design wave. However, these calculations give an indication that the waves are considerably larger in the southern portion of Lower Cook Inlet than in the northern part of the lease area.

As in Upper Cook Inlet, ice loading may well be the dominant environmental design criterion in the northern portion of Lower Cook Inlet. Too little data are available to suggest whether sea ice or the design wave would become dominant, as a design parameter in the southern portion of the sale area.

111. Technology and Selected Production Systems

While not as severe as the Gulf of Alaska, the operating environment in Lower Cook Inlet and Shelikof Strait nevertheless presents significant engineering constraints to offshore petroleum development (see Section II, above). The Lower Cook Inlet tracts are located in water depths ranging from less than 30 meters (100 feet) in the northern part of the sale area south of Kalgin Island to 183 meters (600 feet) at Kennedy Entrance; over 50 percent of the area lies in water depths between 46 and 76 meters (150 and 250 feet). Water dephs in Shelikof Strait range from 91 meters (300 feet) in the northeast to over 303 meters (1,000 feet) at the southwestern entrance. The design wave for the northern part of Lower Cook Inlet can be considered to be essentially the same as that considered for Upper Cook Inlet, i.e. about 8.5 meters (28 feet) while in the southern portion of Lower cook Inlet the design wave is considerably greater, probably in excess of 20 meters (65 feet). The technology review of the Gulf of Alaska conducted for a companion study (Dames & Moore, 1979a and b) was utilized as the basis for selection of production systems to be evaluated in the economic analysis of Lower Cook Inlet and Shelikof Strait. These systems included conventional steel jacket platforms, concrete gravity platforms and floating platforms (e.g. converted semi-submersibles) which can either produce to pipelines or directly to tankers offshore via single point mooring buoys; the offshore loading systems could have storage capability using internal storage (which is a design feature of concrete platforms), storage buoys or permanently moored tankers. All of these systems could have application in Lower Cook Inlet and Shelikof Strait.

The production systems screened in the economic analysis were selected in consultation with the petroleum engineering departments of the major lease holders in Lower Cook Inlet. These consultations included discussion of the results of our technology review conducted for the Gulf of Alaska studies and our evaluation of oceanographic conditions of Lower Cook Inlet/Shelikof Strait that would affect production system selection, platform design, etc. The consensus of opinion was that steel jacket platforms with a pipeline to shore terminal(s) or existing terminals/refineries in Upper Cook Inlet would be the production system generally adopted. Only minor interest was expressed in the use of gravity platforms, offshore loading systems and subsea completions. The relatively short distances to suitable shore landfalls and the petroleum facilities in Upper Cook Inlet were factors in the preference for platform-pipeline systems. In Lower Cook Inlet, water depths of generally less than 91 meters (300 feet) favor fixed platforms over floating systems. In some parts of Lower Cook Inlet and Shelikof Strait, platforms may have to be designed for sea ice, in particular, location of wells with platform legs.

It is the deeper waters (200 to over 305 meters or 650 to over 1,000 feet) comprising the southern half of Shelikof Strait that present the most significant engineering challenges of lease Sale 60. While conventional steel jack platforms may still have a role in this area, the development of marginal or deep water fields in areas such as Shelikof Strait in the late 1980's may involve the use of hybrid, compliant and floating platform designs. No attempt, however, was made in this study to predict the technologies and their costs for production systems in water depths greater than 200 meters (600 feet) because: (1) no firm cost data or experience is available to evaluate such non-conventional systems such as the guyed tower and tension leg platform, the development of which has not progressed beyond the prototype stage; and (2) conventional steel jacket platforms have not been installed in such water depths with comparable oceanographic conditions to provide a historic cost data base. Rather than predict the petroleum technologies and their development costs for the deeper Shelikof waters, it was decided to use the results of the economic analysis for the 183 meters (600 feet) production systems to establish the threshold of various economic sensitivities for petroleum development in greater water depths.

The production systems that were considered in this analysis are:

- Single steel jack platform. Pipe' ine to a new shore terminal. Water depths: 30.5 to 183 meters (100 to 600 feet).
- Single steel jacket platform. Pipeline (offshore and onshore) to existing shore terminal/refinery in Upper Cook Inlet. Water depths: 30.5 to 183 meters (100 to 600 feet).
- Single steel jack platform. Pipeline shared with other producing fileds to shore terminal. Water depths: 30.5 to 183 meters (100 to 600 feet).
- Multiple steel jacket platforms. Pipeline to a new shore terminal. Water depths: 30.5 to 183 meters (100 to 600 feet).
- Multiple steel jacket platforms. Pipeline (offshore and onshore) to existing shore terminal/refinery in Upper Cook Inlet. Water depths: 30.5 to 783 meters (100 to 600 feet).
- Single or multiple steel platforms. Gas pipeline to shore, gas converted to LNG at new plant. Water depths: 30.5 to 183 meters (100 to 600 feet).
- Single or multiple steel platforms. Gas pipeline (offshore and onshore) to existing LNG plant or petrochemical plant in Upper Cook Inlet. Water depths: 30.5 to 183 meters (100 to 600 feet).

In Lower Cook Inlet (Sale 60) in the case of significant discoveries of oil, an operator has ''two principal options:

- A long pipeline (approximately 200 kilometers or 120 miles -- assuming a discovery in the central portion of Lower Cook

Inlet) to existing or expanded Upper Cook Inlet petroleum facilities; a portion of this pipeline may be shared with other fields located in Lower Cook Inlet Sale CI or Sale 60, or Shelikof Strait Sale 60.

- A short to medium length pipeline (less than 80 kilometers or 50 miles) to a new oil terminal located on the lower Kenai Peninsula or west shore of Lower Cook Inlet.

In the case of significant discoveries of oil in the Shelikof Strait, an operator has three principal production options:

- A long pipeline (approximately 322 kilometers or 200 miles) to existing Upper Cook Inlet petroleum facilities; a portion of this pipeline may be shared with other fields located in Lower Cook Inlet Sale CI or Sale 60.

- A short pipeline (less than 32 kilometers or 200 miles) to a new terminal located on the east or west coast of Shelikof Strait.

- A medium length pipeline (approximately 160 kilometers or 100 miles) to a new shore terminal located in Lower Cook Inlet shared with Lower Cook Inlet fields.

Gas production options from offshore Lower Cook Inlet or Shelikof fields are limited to pipelines to either existing Upper Cook Inlet LNG plant(s), petrochemical plants or local markets, or to new LNG or petrochemical plants located along the shores of Shelikof Strait or Lower Cook Inlet.

IV. Petroleum Development in Upper Cook Inlet

This section briefly reviews the history and problems of Upper Cook Inlet petroleum development and its relevance to Lower Cook Inlet development.

Offshore petroleum development in Upper Cook Inlet began in the early 1960's. At that time, this area probably presented the oil industry with the harshest set of environmental conditions offshore that it had encountered to date. Tidal variations are in excess of 9 meters (30 feet) and currents approach 8 knots. The design wave is 8.5 meters (28 feet) and the design ice thickness 2 meters (6 feet). Diving operations are extremely difficult due to the combination of extreme turbidity and vertical variability of currents. The highly turbid condition is created by glacial silt, most of which comes from the rivers emptying into the Inlet. The vertical variation in tidal currents is produced by the increased friction in the lower water layers; slack waters and subsequent current reversals occur earlier near the bottom than waters near the surface. The current can scour huge depressions on the upstream sides of marine structures and fill them in during the next half-tidal cycle.

Drilling Operations

The initial exploration drilling in Upper Cook Inlet was conducted from drill ships and jackup structures. According to Geopfert (1967), tidal currents forced the drill ships to use heavier anchoring gear than ever before. Special slip joints had to be designed for the riser to accommodate the large tidal variations. The currents caused the risers to strum as regular oscillating vortices were shed in their lees. "Spoilers" were installed to retard the creation of these "vortex streets" behind the risers.

All development drilling was done from bottom-founded structures. Most were four-legged structures, two had three legs, and Union installed a single-legged monopod platform (Visser, 1969). Visser states that during the field development phase several innovative techniques were successfully attempted to minimize the effects of the severe environment. To reduce the dependence on diver assistance in pipeline hook-up, special "pulltubes" were installed within structural members. This reduced the necessity of underwater welding by permitting pipelines to be pulled up to deck levels on the platforms. It also kept the pipelines protected from possible ice damage. Divers were assisted by the installation of special diver ports near the mud line so divers would not have to be confronted with the differences in current direction between near surface and near bottom zones. Special steels that retain strength and integrity at low temperatures were used. No structural cross bracing could be used in the ice zone and for protection from ice loading, production risers and drill strings were enclosed in the platform legs.

Pipeline Construction

Migrating sandwaves tens of feet high and hundreds of feet long have been observed in Upper Cook Inlet. Variable bottom geology including erratics, rock outcrops, as well as extensive areas of mud and silt make detailed route surveys necessary. Large sandwaves have also been identified in lower Cook Inlet.

Most pipelines have been constructed using the conventional lay barge and stinger method. The pipe moves off the lower end of the stinger which is dragged along the sea bottom on a sled. Preceding but attached to the forward end of the sled is a jet plow which forms a trench into which the pipe is laid. The trench is not filled mechanically but probably does not remain open owing to the quantity of sediment being transported during each tide. Some portions of the pipeline may become repeatedly buried and exposed as the sandwaves migrate up and down the Inlet. Sand bags have been used to provide additional weight to the pipeline on hard bottoms. Approximately half of the pipe laid in Cook Inlet is cement coated (Nelson, 1967). In at least one case where an unstable bottom was encountered, the pipeline was supported on bottom-founded piling (personal communication, Duthweiler, 1979).

A common practice in Upper Cook Inlet has been to lay pipe in pairs. Since pipelaying in the Inlet is a seasonal operation, this provides the necessary redundancy to reduce the possibility of an extended shutin due to pipeline failure.

The length of gas and oil pipelines thus far laid in the Upper Cook Inlet exceeds 240 kilometers (150 miles). Lines go both east and west from the offshore fields to either the facilities at Nikiski on the eastern shore or to the Drift River terminal to the west.

Processing

Environmental conditions doe not greatly affect process facility technology. This is primarily dependant on reservoir conditions, distance from shore, etc. As a result, the Cook Inlet operations offer relatively little new in terms of process systems technology.

Comparison with Lower Cook Inlet Petroleum Development

Some of the adverse conditions encountered in the Upper Cook Inlet will not be as severe in the lower Cook. Tidal ranges will be less. Currents will not be as strong. Ice should not present the same level of concern and diving operations will be facilitated by reduced turbidity and currents. On the other hand, weather conditions will be very similar so the use of low temperature steels and enclosed decks may still be necessary. Water depths will be greater, distances to shore may exceed those in the Upper Cook Inlet, design wave heights will be much greater, and perhaps not be confined to such a narrow directional sector. Ice cannot be ruled out, so drilling and production strings will probably still have to be protected. Finally, winds will be stronger and more sustained in the Lower Cook Inlet, which will greatly affect the logistics of resupply in support of offshore operations in Lower Cook.

Shore Facilities

Information on the major Upper Cook Inlet shore facilities (terminals, refineries, etc.) is provided in Table 3-16.

APPENDIX D

APPENDIX D

EMPLOYMENT

I. Introduction

This section provides a general introduction to the subject of manpower requirements for offshore petroleum development as well as the definitions, assumptions, and methods used to generate the manpower estimates for each scenario described in Chapters 4.0, 5.0, and 6.0. Refer to these chapters for the results of the analysis described in this section.

II. Three Phases of Petroleum Exploitation

Exploitation of a petroleum reserve involves three distinct phases of activity -- exploration, development, and production. The exploration phase encompasses seismic and related geophysical reconnaissance, wildcat drilling, and "step out" or delineation drilling to assess the size and characteristics of a reservoir. The development phase involves drilling the optimum number of production wells for the field (many hundreds of wells are used to produce a large field) and construction of the equipment and pipelines necessary to process the crude oil and transport it to a refinery or to tidewater for export. The production phase involves the day-to-day operation and maintenance of the oil wells, production equipment, and pipelines, and the workover of wells later in their producing life.

The three phases of petroleum exploitation overlap and all three may occur simultaneously. Exploration for additional fields continues in the vicinity of a newly discovered field as that field is developed and put into production. On the North Slope, for example, where the Prudhoe Bay field is in production, exploratory and delineation drilling will continue for several more years. Development activity typically continues after the initial start-up of production. Operators need to start production as soon as possible to begin to recover expenses of field development (Milton, 1978). In the North Sea, for example, production from some fields was initiated with temporary offshore loading systems while development drilling continued and before underwater pipeline construction began.

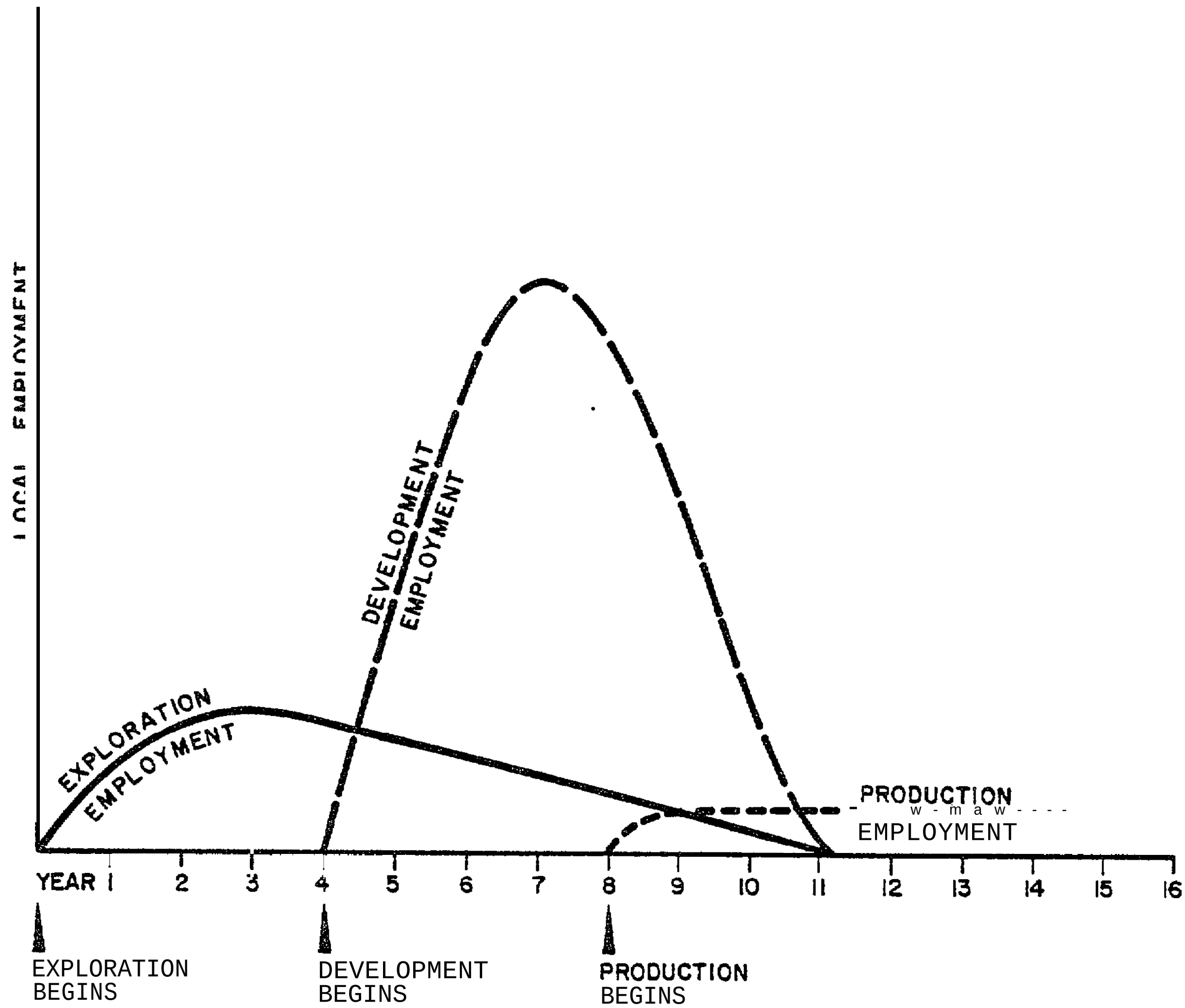
Local employment[1] created by each phase of the petroleum exploitation process tends to have a characteristic magnitude and attributes. For example, exploratory work is not particularly labor intensive, and wildcat crews come and go with drilling contractors. Local residents are most likely to benefit indirectly from expenditures made for exploration programs rather than from direct employment in the oil field. The development phase creates the highest levels of employment locally, and much of this employment is in the construction and transportation industries. Labor directly associated with drilling and installing crude processing equipment is highly skilled. Because of automation, the production phase does not require a substantial work force. This work force will include many experienced oil field operators recruited from outside the area or transferred from other fields by the owner companies.

Figure D-1 depicts a very general and hypothetical temporal relationship of the exploration, development, and production phases and the relative magnitude of local employment created by each. Particular oil fields differ in their own development schedule and requirements for production and transportation facilities.

III. Characteristics of Offshore Petroleum Development and Some Implications for Alaska

Offshore petroleum development has several important general characteristics that distinguish it from onshore development, and each of these

(1) Local employment refers to employment at or near the petroleum reservoir. It does not include the manufacturing and construction employment created away from the site, such as that involved with the building of process equipment and offshore platforms, nor does it include professional, administrative, and clerical work that occurs in regional headquarters (London and Aberdeen in the case of North Sea fields and Anchorage in the case of Alaska fields, for example).



SOURCE: DAMES & MOORE

FIGURE D-1

LOCAL EMPLOYMENT CREATED BY THE THREE PHASES OF PETROLEUM EXPLOITATION, A HYPOTHETICAL CASE has implications for the economic impacts that will be experienced in Alaska. The first of these general characteristics is the extreme specialization of the offshore petroleum industry. An offshore drilling and construction program typically requires a very large number of contractors who supply special services and high technology equipment. Deepwater marine construction for the petroleum industry involves engineering design, component fabrication, and installation techniques that are among the most sophisticated and expensive in the world. United States firms pioneered offshore petroleum engineering and technology in the Gulf of Mexico and major U.S. firms located in Texas and Louisiana such as Brown and Root, Inc. and J. Ray McDermott, Inc. still dominate the industry. Since the development of North Sea gas and oil reserves, Dutch, German, British, French, Norwegian, Swedish, and Finish firms have entered the industry. Italian and Spanish firms are now active in the Mediterranean Sea. As offshore petroleum fields are discovered in waters of the Outer Continental Shelf in Alaska, they will be developed by the large U.S. firms. Participation of Alaska-based contractors in an offshore petroleum development program will mainly be limited to onshore construction requirements, which may or may not be large.

Development of an an offshore oil field may occur without a great deal of onshore construction work. Wells and most of the processing equipment are located offshore. Typically there is little requirement for overland pipeline transportation. If oil comes ashore at all, it does so at the most convenient landfall and is stored for tanker transport.[1] Development of onshore fields on the North Slope, in contrast, created a large amount of civil construction work -- drill pads, roads and road maintenance, bridges, pump station sites, the pipeline construction pad, etc. -- for which local contractors were capable of bidding. An offshore development program would not necessarily involve much of this type of work. On the other hand, if large shore bases, marine terminals,

(1) Natural gas from offshore fields will create demand for considerable onshore pipeline capacity if a national market is at hand, as in Great Britain, Netherlands, or Germany. In Alaska no such market exists; offshore gas will be exported in liquified form, and require the construction of a liquefaction plant.

and gas treatment/liquefaction plants are required (they may not be), the construction of these facilities generate substantial onshore employment.

An aspect of the major firms active in offshore petroleum development is their international character. These firms have more or less regular, experienced crews who are dispatched to jobs around the world. Many of the firms provide specialty services that require only short visits to the oil field. Ordinarily, however, the drilling and construction crews work 12 hour per day shifts for 14, 21, or 28 days and then take an equal number of days off. They are provided round-trip airfare from their point of hire for these rotations.

The unfortunate implication of this aspect of the offshore development phase for Alaskan workers is that Alaskans face an international labor market which does not recognize the high cost of living here. Contractors are likely to have a seasoned work force on the payroll or a long "call up" list. Because there is not a local offshore construction industry, Alaska workers are not likely to have the skills and experience required by contractors who might need new hires. Furthermore, offshore contractors will doubtless pay wages at rates prevailing on the Gulf coast of the United States, where most of the firms are headquartered. In the Gulf of Alaska from 1975 to 1978, for example, workers on the offshore vessels were virtually all from out-of-state, many of these from Texas and Louisiana. Their wages were significantly less than those received by non-salaried onshore oil field workers in Alaska (Dames & Moore, 1978c).

Offshore petroleum activity that may occur in the waters of the Gulf of Alaska is not reached by state regulatory or taxing authority. Only onshore activity is within state jurisdiction. Alaska's so-called local hire (also known as Alaska hire) statute was declared unconstitutional by the U.S. Supreme Court.[1] Even if the state successfully fashions a new statute that gives local residents preferential treatment in hiring and also meets the Court's constitutional standards, it will not apply to employment on the offshore platforms.

Coastal municipalities (cities and boroughs) that are within the orbit of offshore activity and experience permanent population growth as a consequence will be eligible to receive additional state revenue sharing income through the percapita distribution formula used by the state for this revenue distribution. The municipalities and the state will be able to tax the real and personal property of the oil companies and contractors that are located within their boundaries, but they will not be able to extend their taxing power to the very valuable platforms and producing equipment located beyond the three-mile limit of state jurisdiction.

IV. Labor Productivity in Offshore Operations

The length of time and the crew size required to accomplish any task depend upon the productivity of the labor force. Experience of the crew, quality of project supervision, state of labor relations, and job conditions are conventional productivity factors. In Alaska and the North Sea, for example, where long days of hard work, isolation, and bad weather are typical, additional productivity factors become important considerations. These are the number of hours worked per day (efficiency

(1) On June 22, 1978, the Court held the Alaska Hire Statute unconstitutional because it violates the Privileges and Immunities Clause of Article IV Section 2. The Court ruled that the Alaska Hire Statute was too imprecise and ineffective to accomplish its ostensible objective of reducing unemployment in Alaska, which is largely the result of lack of training and skills among the jobless or remoteness from employment opportunities. Furthermore, the statute gave preference to all Alaska residents, unemployed or not. Also, the Court held that the state's ownership of oil and gas lands was not an adequate foundation for the statute which reached employers who have no connection with the state's oil and gas, perform no work on state land, have no contractual relationship with the state, and receive no payment from the state.

drops off sharply after eight hours), the number of days worked consecutively without a break (efficiency drops as the length of the rotation increases), the amount of daylight, and temperature.

In the case of offshore work, weather is also a critical determinant of much labor productivity. Winter gales can cause all activity to stop, or it can effectively stop all work if helicopters and supply boats cannot service drilling rigs, platforms, lay barges or derrick barges. Even if work is not suspended, weather can greatly reduce productive efficiency. An industry guide, Cost Estimating Manual for Pipelines and Marine Structures (Page, 1977), projects the productivity loses for certain tasks caused by wind, current, and waves. These are shown in Tables D-1 through D-3. Tasks affected by wind and currents are, for example, installing platform jackets, and setting piling.

It is evident that these productivity factors can profoundly affect the scheduled completion of a job. Offshore work in an area such as the Gulf of Alaska and the North Sea, where high wind and waves are commonplace, where it is very cold and there are long hours of darkness during the winter, and where crews work 12-hour shifts up to a month at a time without a day off, labor product"ivity may be a third or less of labor productivity in, say, Gulf of Mexice, where conditions are not as severe.

V. The OCS Employment Model

Estimated manpower requirements for each scenario presented in Chapters 4.0, 5.0, and 6.0 are the product of an employment model originally developed for projecting the manpower requirements of petroleum development in the Gulf of Alaska.[1] The model has been adapted for use in Lower Cook Inlet by scaling back the manpower requirements of several components. It is assumed that offshore labor requirements for several

(1) "Northern Gulf of Alaska Petroleum Development Scenarios", Alaska OCS Socioeconomic Studies Program Technical Report No. 29 (Dames & Moore, 1979a) and "Western Gulf of Alaska Petroleum Development Scenarios", Alaska OCS Socioeconomic Studies Program Technical Report No. 35 (Dames & Moore, 1979b).

tasks in Lower Cook Inlet will be greater than those experienced in Upper Cook Inlet[1], but not as large as those foreseen for petroleum development in the Gulf of Alaska (estimates based largely on the experience of the North Sea). Labor force estimates for construction of several onshore facilities have been lowered from those used in the Gulf of Alaska scenarios to make them close to the actual experience of development in Upper Cook Inlet.

It is important to recognize that manpower projections -- from any source -- of hypothetical petroleum development can only be, at best, "ball park" estimates. There are too many unknown and unpredictable factors to refine projections beyond a very modest measure of accuracy.

The crew size and length of time required to accomplish a task can vary enormously from one site, or one situation, to another. Requirements for building an oil terminal of a certain capacity, for example, will depend to a large extent upon the site available for the facility'. The massive labor requirements of the Valdez terminal built for the trans-Alaska pipeline, were due in large part, to the need to excavate and reinforce a rock mountainside. Offshore construction activity such as pipelining also depends upon the physical environment (subsea soil conditions, weather, etc). The uncertainty of these operations is reflected in the fact that construction contracts are typically executed on a reimbursable day rate plus fixed fee basis, since contractors dare not quote a per unit (mile, ton, etc.) basis. The manpower model used in this report is based upon very general assumptions about labor productivity, the physical environment, the range and relative scale of operations, and many other factors. While projections appear quite precise, the implied degree of accuracy is spurious. The estimates give only indications of the relative magnitude of labor force requirements.

(1) These activities have been chronicled, somewhat irregularly, in the local trade journal Alaska Construction and Oil (prior to 1967 Alaska Construction).

TABLE D-1

WIND PRODUCTIVITY FACTORS

Description	Wind Miles Per Hour	Percent Efficiency
Calm	0 - 1	100
Light Air	1 - 3	100
Slight Breeze	4 - 7	95
Gentle Breeze	8 - 12	90
Moderate Breeze	13 - 18	75
Fresh Breeze	19 - 24	50
Strong Breeze	25 - 31	30

Source: Cost Estimating Manual for Pipelines and Marine Structures (Page, 1977)

TABLE D-2

CURRENT PRODUCTIVITY FACTORS

Average Total Current in Feet Per Second	Percent Efficiency
0.0 to 0.5	100
0.5 to 1.0	97
1.0 to 2.0	95
2.0 to 2.5	90
2.5 to 3.0	85
3.0 to 3.5	78
3.5 to 4.0	70
4.0 to 5.0	65

Source: Cost Estimating Manual for Pipelines and Marine Structures (Page, 1977)

TABLE D-3

WAVE PRODUCTIVITY FACTORS

Equipment and Type of Operations	WAVE HEIGHT IN METERS (FEET) AND PERCENTAGE EFFICIENCY FOR:					
	Safe Efficient Operations		Marginal Operations		Dangerous and/or Inefficient Operations	
	Wave Height Meters (feet)	Percent Efficiency	Wave Height Meters (feet)	Percent Efficiency	Wave Height Meters (feet)	Percent Efficiency
Deep Sea Tug:						
Towing Derrick Barge	0-1.2 (o-4)	100-70	1.2-1.8 (4-6)	70-50	1.8+ (6+)	50-20
Towing Material Barge	0-1.2 (o-4)	100-70	1.2-1.8 (4-6)	70-50	1.8+ (6+)	50-20
Working Derrick Barge	0-0.6 (O-2)	100-70	0.6-0.9 (2-3)	70-40	0.9+ (3+)	40-10
Working Material Barge	0-0.6 (o-2)	100-70	0.6-0.9 (2-3)	70-40	0.9+ (3+)	40-10
Crew Boats [18 to 27 Meters (60 to '90 Feet) Long]:						
Underway	0-2.4 (O-8)	100-80	2.4-4.6 (8-15)	80-40	4.6+ (15+)	40-10
Loading or Unloading Crews	0-0.9 (o-3)	100-70	0.9-1.5 (3-5)	70-50	1.5+ (5+)	50-20
Derrick Barge:						
Small Barge-Underway	0-0.6 (o-2)	100-70	0.6-0.9 (2-3)	70-50	0.9+ (3+)	50-20
Large Barge-Underway	0-0.9 (o-3)	100-70	0.9-1.5 (3-5)	70-50	1.5+ (5+)	50-20
Small Barge-Platform Building	0-0.6 (O-2)	100-70	0.6-0.9 (2-3)	70-40	0.9+ (3+)	40-10
Large Barge-Platform Building	0-0.9 (0-3)	100-70	0.9-1.2 (3-4)	70-40	1.2+ (4+)	40-10
Small Barge-Buoy Laying	0-0.6 (0-2)	100-70	0.6-0.9 (2-3)	70-40	0.9+ (3+)	40-10
Ship-Mounted Derrick:						
Platform Building	0-1.2 (o-4)	100-70	1.2-1.8 (4-6)	70-50	1.8+ (6+)	50-20

Source: Cost Estimating Manual for Pipelines and Marine Structures, Page,(1977).

VI. Definitions

It is very important that terms are defined before beginning a discussion of the manpower requirements for the discovery, development, and production of a petroleum field. Although several studies of OCS petroleum impact have now been made which include manpower estimates, neither a uniform set of definitions nor an articulated methodology has emerged (see, for example, NERBC, 1976). Indeed, no attempt has been made in these to define such basic terms as jobs and employment, and the methods used by them to calculate manpower totals are opaque at best.[1] The following definitions are used in the present study:

Job

A job is a position, such as driller, roustabout, or diver, rather than a specific task or the person who performs the task or fills the position.

Crew

A crew is a group of individuals who fill a set of jobs; a drilling crew, for example, is a group of men who fill generally standardized jobs necessary to accomplish the task of drilling a well. The term crew is also used to refer to an estimated monthly shift labor force (below).

Estimated Shift Labor Force

This is the average number of people employed per shift per month over the life of the task. This estimate is made when several crews are combined into a composite estimate of work force size and/or when the task for which an estimate is being made has a fluctuating monthly labor force.

(1) Because terms are not clear, manpower estimates are not readily comparable. It is seldom evident, for example, if all crews are counted (most offshore work has more than one crew on site) and if off-site employment is counted.

Shift

Shift refers to the hours worked by each crew each day; a normal shift of offshore crews is 12 hours, and there are two shifts per day.

Rotation Factor

The rotation factor is defined as $(1 + \frac{\text{number of days off duty}}{\text{number of days on duty}})$; if a crew worked for 14 days and then took 14 days off, the rotation factor would be two $(1 + \frac{14}{14} = 2)$; if a crew worked 28 days and took 14 off, the rotation factor would be 1.5 $(1 + \frac{14}{28} = 1.5)$;

Total Employment

Total employment is the total number of men employed, and it is found by the formula: jobs (crew size) x number of shifts/day x rotation factor; for example, if a new task creates 10 positions, and two crews each work consecutive 12-hour shifts, and the men work 14 days and take 7 off, then total employment is 30 (10 x 2 x 1.5); thus, total employment includes on-site employment and off-site employment;

On-Site Employment

On-site employment is composed of the workmen who are not on leave rotation, or two complete crews if two shifts are worked per day;

Off-Site Employment

Off-site employment is the group of employees who are on leave rotation and not physically present at the work site.

Net Employment

Net employment refers to net additions to the work force. Total employment associated with a petroleum development program is probably not net employment because the major industry contractors have steady crews that move around the world as new fields are developed.

Man-Months

A man-month is the employment of one man for one month.[1] Thus, a man-month is a measure of work that incorporates the element of duration of work. This unit of measure is necessary to compare labor that varies in length. Suppose a project had three components: component A employed 100 men for two months; component B employed 50 men for three months; and component C employed 80 men for 12 months. To say the project resulted in employment of 230 is to say little about it because there is no indication of how long the employment lasted. Although component C employed only 80 men, it was responsible for over four times as much employment as component A, which employed 100 men for a shorter period (960 man-months vs. 200 man-months).

In this report a distinction is made between on-site man-months of employment and total man-months. On-site man-months represent the number of men physically present at the worksite and on the payroll (workers on leave rotation are not typically paid) during the project.

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(1) A month of employment (30 days) can involve very different amounts of work depending upon the hours worked during the week. Notice, for example, that 8,000 man-hours of work are accomplished by 50 men working 40 hours per week for four weeks, while 16,800 are accomplished by 50 men working 84 hours per week (equivalent of seven 12-hour days) for four weeks. Both cases might be said to represent 50 man-months of employment, since both involve 50 men for one month. However, one could argue that the first case represents 50 man-months and the second roughly twice that amount since men must have a reasonable amount of time to recuperate from their labor. In the case of OCS employment at hand, men normally work long shifts for long periods, and then have a long rest break. Thus, in the example used above, it would be likely that 50 men would work 12 hours per day for the first 15 days and then take the second 15 days off, while a second group would rest the first 15 days and work the second 15-day period. This would be the equivalent of 100 man-months (50 men x 1 shift x rotation factor of 2 x 1 month) based on a work week of some 40 hours.

Nevertheless, in the example above, there were no more than 50 men physically present on the worksite at one time, and there were no more than 50 men on the employer's payroll at one time. Therefore, on the basis of a definition of a man-month that involves soley the duration of a worker's paid presence at the site, there were only 50 man-months of employment.

This number represents actual labor expenditures for tasks (such as building an oil terminal, installing a platform, etc). Total man-months include on-site workers and off-site workers. This number indicates the overall laborforce requirements of the project. Monthly average total laborforce levels -- that is, the monthly average number of men engaged in all phases of work during the year -- can be derived by dividing the total number of man-months by 12.(1)

The scope of employment covered in this study is that which is generated in the field, that is direct employment on the platforms, on the supply boats, barges, and helicopters, at the shore bases, and at field construction sites if there are any. The clerical, administrative, engineering, and geological work that occurs off the site or away from the shore support bases is not included. Neither is indirect or induced labor included in this analysis.

VII. Description of Model and Assumptions

For maximum analytical utility, manpower estimates are needed for each month of each year; for onshore as well as offshore employment; for on-site as well as off-site employment; and for each important industrial sector.

Monthly estimates are required because it is necessary to know employment levels for the months of January and July. Per capita distributions of state revenue sharing programs are based on the populations of municipalities in these months. However, since offshore population cannot be counted for this purpose, nor can off-site population (that is, workers on leave rotation), it is also necessary to distinguish between these categories of employment. Also, for impact analysis generally it is necessary to distinguish between offshore and onshore

(1) If a crew of 50men worked 12 hours per day for the first half of each month for one year, and a second crew worked for the second half of each month for the year, on-site employment would be 600 man-months (50 men x 12 months); total employment would be 1,200 man-months (50 men + 50men x 12 months); and the average monthly laborforce would be 100 men.

labor force levels, because offshore workers have very little or no contact at all with the local economy.

To enhance the sophistication of the effort generally and to increase its usefulness for impact analysis, employment is categorized by the four main industries that are involved in petroleum development: petroleum, construction, transportation, and manufacturing. Probably over 98 percent of the field labor associated with the exploration, development, and production of petroleum fall within one of these four Standard Industrial Classification (SIC) sectors.(1)

It was necessary to identify the basic tasks of each phase that generate significant employment. A unit of analysis, such as a well, platform, or construction spread, was established for each of these labor-generating tasks, which are the basic "building blocks" of the system. Manpower requirements for each unit of analysis were estimated, as were the number of shifts worked each day, and the labor rotation factor for that task. This information is presented in Table D-4.

Crew size or the length of employment for some activities is not influenced by the size of the oil field or physical conditions such as water depth. Well drilling, for example, requires basically the same size crew in waters of 50 feet or 800 feet. This is not the case with other activities such as platform installation or pipelaying. Here, the size of the field (which determines the size and number of platforms used) and the depth of water are critical determinants of crew size and duration of employment. To account for these variations, a general set of scale factors was used to increase or decrease labor requirements when field size and other conditions required that adjustments be made. Scale factors are shown in Table D-5. Scale factors are applied to the crew size.

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(1) Environmental engineering consulting services, and contract communications work are sources of minor employment that come to mind that do not fall within these four industrial sectors.

TABLE D-4

OCS MANPOWER EMPLOYMENT MODEL

Phase	Industry		Task	Unit of Analysis	Duration of Employment/ Unit of Analysis[1] (in months)	Crew Size/ Unit of Analysis[2] (number of people) Offshore	Onshore	Number of Shifts/Day	Rotation Factor	Scale Factor
Exploration	A. Petroleum		Exploration We l	Well	5	28 0	0 6	2 1	2 1	Crew Size
		2	Geophysical and Geo-logic Survey	Crew	5	25 0	0 2	1 1	1 1	N.A.
	B. Construction	3	Shore Base Construc-tion	Base	Assigned	Ass gned		1	1	N.A.
	C. Transportation	4	He icopter for Rigs	Well	Same as Task	0	5		2	N A.
		5	Supply/Anchor Boats for Rigs	Well	Same as Task 1	26 0	0 2	1 1	1.5 1	N.A.
	o Manufacturing									
	A. Petroleum	6	Development Dril ing	P atform	Ass ened	28 if 1 rig 56 if 2 rigs	6 if 1 rig 2 if 2 rigs	2 1	2 1	N.A.
	B. Construction	7	Steel Jacket Instal-lation and Commission-ing	P atform	10	125 0	0 25	2 1	2 1.	Crew Size
		8	Concrete Installation and Commissioning	Platform	10	200 0	0 25	2 1	2 1.11	Crew Size
		9	Shore Treatment Plant	P ant	6	0	40	2	1.11	
		10	Shore Base Construc-tion	Base	Assigned	0	Assigned Monthly	0 1	0 1.11	Assigned
			Single-Leg Mooring System	System	6	100 0	0 25	2 1	2 .11 1.	Crew Size
		12	Pipeline Offshore, Gathering, Oil and Gas	Spread	Ass gne<	oo o	0 25	2 1	2 .11 1.	Assigned
		13	Pipeline Offshore, Trunk, Oil and Gas	Spread	Ass ene<	25 0	0 35	2 1	2 .11 1.	Assigned
		14	Pipeline Onshore, Trunk, Oil and Gas	Spread	Ass gned	0	300		1.11	Assigned

TABLE D-4 (Cont.)

Phase	Industry		Task	Unit of Analysis	Duration of Employment/ Unit of Analysis[1] (in months)	Crew Size Unit of Analysis[2] (number of people) Offshore	Onshore	Number of Shifts/Day	Rotation Factor	Scale Factor
		15	Pipe Coating	Pipe Coating Operation	Assigned	0	175	1	1.11	Crew Size
		16	Marine Terminal	Terminal	Assigned	0	Assigned Monthly	1	1.11	Assigned
		17	LNG Plant	Plant	Assigned	0	Assigned Monthly	1	1.11	Assigned
		18	Crude Oil Pump Station Onshore	Station	12	0	200	1	1.11	Crew Size
		19	Vacant							
		20	Vacant							
	C. Transportation	21	Helicopter Support for Platform	Platform; Same as Tasks 7 & 8	Same as Tasks 7 & 8	0	5	1	2	N.A.
		22	Helicopter Support for Lay Barge	Lay Barge Spread; Same as Tasks 12 & 13	Same as Tasks 12 & 13	0	5	1	2	N.A.
		23	Supply/Anchor Boats for Platform	Platform; Same as Tasks 7 & 8	Same as Tasks 7 & 8	39 0	0 12	1 1	1.5 1	N.A.
		24	Supply/Anchor Boats Lay Barge	Lay Barge Spread; Same as Tasks 12 & 13	Same as Tasks 12 & 13	65 0	0 12	1 1	1.5 1	N.A.
		25	Tugboats for Installation & Towout	Platform	Same as Tasks 7 & 8	40	0	1	1.5	N.A.
		26	Tugboats for Lay Barge Spread	Lay Barge Spread; Same as Tasks 12 & 13	Same as Tasks 12 & 13	20	0	1	1.5	N.A.
		27	Longshoring for Platform Construction	Platform; Same as Tasks 7 & 8	Same as Tasks 7 & 8	0	20	1	1	Crew Size

TABLE D-4 (Cont.)

Phase	Industry		Task	Unit of Analysis	Duration of Employment/ Unit of Analysis[1] (in months)	Crew Size Unit of Analysis[2] (number of people) Offshore	Onshore	Number of Shifts/Day	Rotation Factor	Scale Factor
		28	Longshoring for Lay Barge	Lay 8arge Spread; Same Tasks 12 & 13	Same as Tasks 12 & 13	0	20	1	1	Crew Size
		29	Tugboat for SLMS; (Task 11)	Same as Task 11	Same as Task 11	10	0	1	1.5	N.A.
		30	Supply Boat for SLMS; (Task 11)	Same as Task 11	Same as Task 11	13	0	1	1.5	N.A.
	D. Manufacturing									
Production	A. Petroleum	31	Operations and Maintenance (routine preventive)	Platform	Assigned	35	4	2 1	2 1	Crew Size
		32	Oil Well Workover and Stimulation	Platform	Assigned	15	0	1	2	N.A.
	B. Construction	33	Maintenance and Repair for Platform and Supply Boats (replacement of parts, rebuild, painting, etc.)	Platform	Assigned	8 0	0 B	1 1	2 1	Crew Size
	C. Transportation	34	Helicopters for Platform	Platform	Same as Task 31	0	5	1	2	N.A.
		35	Supply Boats for Platform	Platform	Same as Task 31	12	0	1	1.5	N.A.
		36	'Terminal and Pipeline Operations	Terminal	Assigned	0	Assigned	2	2	N.A.
		37	Longshoring for Platforms	Platform	Same as Task 31	0	4	1	1	Crew Size
	D. Manufacturing	38	LNG Operations	LNG Plant	Assigned	0	Assigned	2	2	N.A.

[1] Different labor force values may be substituted for these if deemed appropriate by site-specific characteristics.
[2] "Assigned" means that scenario-specific values are used, and that no constant values are appropriate.

Additional notes on next page.

Source: Dames & Moore

TABLE D-4a
(Attachment to Notes to Table D-4)

SPECIAL MANPOWER ASSUMPTIONS FOR LOWER COOK INLET SCENARIOS

Task	Special Assumptions
10 (shore base construction)	For high find scenario, assumed two sets of construction activity; one at Afognak Island at site of oil terminal with the following monthly manpower loading: 67, 134, 201, 268, 335, 402, 402, 335, 268, 201, 134, 67 (beginning year 5 month 4); one on Kenai Peninsula involving expansion of existing facilities at Nikiski and Homer with the following manpower loading: 50, 50, 100, 100, 50, 50 (beginning year 5 month 4). For medium find scenario, no manpower expenditure on Kenai Peninsula, same as high find scenario on Afognak (Shelikof Strait).
14 (onshore pipe construction)	For medium find scenario, assumed manpower expenditure of 50 men for 1 month (year 7 month 9) for short distance of onshore pipe; this construction would be part of terminal project.
15 (pipe coating)	Assumed for small pipeline, mileages crew size and production rate would be approximately half that shown in Table D-4, or 85 men producing 5 miles of pipe per day.

TABLE D-5

SCALE FACTORS USED TO ACCOUNT FOR INFLUENCE OF
FIELD SIZE AND OTHER CONDITIONS ON MANPOWER REQUIREMENTS

Scale Factor	Field Size	Water Depth	Pipelay Conditions Offshore and Onshore
0.7	Small	Shallow	Easy
(Base Case) 1.0	Moderate	Moderate	Moderate
1.3	Large	Deep	Difficult
1.7	Very Large	Very Deep	Very Difficult

Source: Dames & Moore

Scale factors are a necessary element of the manpower model to reduce to a manageable number the inputs required by it, and also to generate estimates for which specific references are not available in the literature. Scale factors in Table D-5 were derived by a process of trial and error from a wide variety of information about crew sizes and manpower requirements of petroleum activities of a different nature and scale. They represent a single set of factors that seem to best express the relationships that exist between manpower demands of disparate projects and activities. For example, in the case of platform operating personnel (task 31, Table D-4), the small offshore platform of Marathon Oil Company in Upper Cook Inlet (Dolly Varden) has an offshore crew of approximately 23 per shift (46 total, Marathon Oil Company, 7978), while the very large North Sea platforms have crews of approximately 60 per shift (120 total, Addison, G.D., 1978). Thus, these two crew sizes have a relationship that generally matches the scale factors in Table D-5. They also suggest a crew size for a platform of moderate and large size. The scale factor of 1.0 corresponds to a crew of 35 (derived), the scale factor of 1.3 corresponds to a crew of 47 (derived), a scale factor of .7 corresponds to a crew of 25 (contrasted to 23 of Marathon platform), and a scale factor of 1.7 corresponds to a crew size of 61.(1) While the use of a single general set of scale factors introduces a measure of distortion into the manpower estimating process, the distortion seems to be within an acceptable overall range of accuracy.

Occasional deviation from the scale factors in Tables D-5 is necessary, as for example in the construction and operation of major onshore facilities which do not appear to have a simple, linear relationship between project size and labor force requirements. Also, in the case of these

(1) An actual platform operating crew will depend upon the volume of gas and liquids produced, the extent of secondary recovery (water flood pumps, gas life compressors, etc.), and the extent of primary processing. Even a large near shore platform without secondary recovery could operate with a relatively small operating workforce. Also, a producing platform will have a larger day crew than a night crew (i.e. shifts are not the same size). However, total platform population is divided into two crews of equal size to simplify the modeling of this employment.

project size and labor force requirements. Also, in the case of these onshore facilities, monthly construction labor force levels vary greatly, so it was necessary to develop complete sets of monthly employment figures. These estimates are shown in Tables D-6a and D-6b. The numbers in Tables D-6a and D-6b are general estimates derived from available information about the length of construction, peak workforce, and operating crew size of similar facilities.(1) It was assumed that peak employment on a construction project of this type would reach a brief plateau at approximately midway through the project, and that it would steadily increase prior to the peak and steadily decrease after the peak had been reached. Thus, a graph of the manpower requirements for these projects would generally approximate an equilateral triangle with a blunt tip. This assumption allowed monthly manpower estimates to be calculated once the peak level and construction period were identified.

Identifying typical crew sizes and reasonable monthly average work force levels for the various labor-generating activities constituted the major research task. Information was obtained from many sources -- trade journals (advertisements as well as articles), industry equipment specifications, interviews with contractors experienced in offshore work, government studies including offshore petroleum impact assessments, professional papers, and cost estimating manuals.

A computer was utilized to calculate and sum the manpower requirements for each scenario. It used the following basic formula for each task, all of which were coded by industry:

> Number of units x crew size x duration of task x number of shifts x rotation factor x scale factor

(1) Among the more helpful references are: Sullom Voe Environmental Advisory Group (1976); El. Paso Alaska Co. (1974); Dames & Moore (1974); Crofts (1978); Akin (1978); Pipeline and Gas Journal (1978a); Larminie (1978); 'Addison (1978); Duggan (1978); Trainer et al. '(1976); Alaska Construction (1966); Alaska Construction (1967b); Bradner (1969). These sources provided information about peak workforce levels and/or construction periods for oil terminals or LNG plants. Shore base construction estimates in Tables 5-6A and 5-6B are by Dames & Moore.

TABLE D-6a

MANPOWER ESTIMATES FOR MAJOR ONSHORE FACILITIES, SUMMARY[1]

Facility	Size	Approximate Capacity	Duration Construction	Approximate Peak Construction Employment (number of People)	Operating Personnel (Crew Size)[2]
Oil Terminal (BD)	Small	200,000 minus	18	350	16
	Medium	200,000 - 500,000	24	750	42
	Large	500,000- 1,000,000	36	1,200	55
	Very Large	1,000,000 plus	36	3,500	70
LNG Plant (MMCFD)	Small	500 minus	24	400	20
	Medium	500- 1,000	24	800	30
	Large	1,000- 1,500	36	2,000	50
	Very Large	1,500 plus	36	4,000	125
Shore Base (field size in MMBD)	Medium	1.5 minus	12	400	--
	Large	1.5 plus	16	700	--

[1] Monthly manpower requirements presented in Table D-6b.

[2] Two shifts and a rotation factor of 2 are assumed.

Source: Dames & Moore (see text)

TABLE D-6b

MONTHLY MANPOWER LOADING ESTIMATES, MAJOR ONSHORE CONSTRUCTION PROJECTS

Facility: Oil Terminal
Size: Sma11
Duration of Construction: 18 Months
Approximate Peak Employment (number of people): 350

Month:	1	2		4	5	6	7	8	9	10	11	12	13	14	15	16	17	18
Workers:	39	78	1:?	156	1 95	234	273	312	351	351	312	273	234	195	156	117	78	39

Facility: Oi l Terminal
Size: Medium
Duration of Construction: 24 Months
Approximate Peak Employment (number of people): 750

Month:	1	2	3	4	5	6	7	8	9	10	11	12	13	14	15	16	17	18	19	20	21	22	23	24
Workers:	62	124	186	248	310	372	434	496	558	620	682	744	744	682	620	558	496	434	372	310	248	186	124	62

Facility: Oi 1 Terminal
Size: Large
Duration of Construction: 36 Months
Approximate Peak Employment (number of people): 1200

Month:	1	2	3	4	5	6	7	8	9	10	11	12	13	14	15	16	17	18	19	20	21	22	23	24
Workers:	67	134	201	268	335	402	469	536	603	670	737	804	871	938	1005	1072	1139	1206	1206	1139	1072	1005	938	871

Month:	25	26	27	28	29	30	31	32	33	34	35	36
Workers:	804	737	670	603	536	469	402	335	268	201	134	67

Facility: Oil Terminal
Size: Very Large
Duration of Construction: 36 Months
Approximate Peak Employment (number of people): 3500

Month:	1	2	3	4	5	6	7	8	9	10	11	12	13	14	15	16	17	18	19	20	21	22	23	24
Workers:	194	388	582	776	970	1164	1358	1552	1746	1940	2134	2329	2522	2716	2910	3104	3298	3500	3298	3298	3104	2910	2716	2522

Month:	25	26	27	28	29	30	31	32	33	34	35	'36
Workers:	2328	2134	1940	1746	1552	1358	1164	970	776	582	388	194

TABLE D-6b (Cont.)

Facility: **LNG Plant**
Size: Sma 11
Duration of Construction: 24 Months
Approximate Peak Employment (number of people): 400

Month:	1	2	3		5	6	7	8	9	10	11	12	13	14	15	16	17	18	19	20	21	22	23	24
Workers:	33	66	99	1:2	165	198	231	264	297	330	363	396	396	363	330	297	264	231	198	165	132	99	66	33

Facility: LNG Plant
Size: Medium
Duration of Construction: 24 Months
Approximate Peak Employment (number of people): 800

Month:	1	2	3	4	5	6	7	8	9	10	11	12	13	14	15	16	17	18	19	20	21	22	23	24
Workers:	67	134	201	268	335	402	469	536	603	670	737	804	804	737	670	603	536	469	402	335	268	201	134	67

Facility: LNG Plant
Size: **Large**
Duration of Construction: 36 Months
Approximate Peak Employment (number of people): 2000

Month:	1	2	3	4	5	6	7	8	9	10	11	12	13	14	15	16	17	18	19	213	21	22	23	24
Workers:	110	220	330	440	550	660	770	880	990	1100	1210	1320	1430	1540	1650	1760	1870	1980	1980	1870	1760	1650	1540	1430
Month:	25	26	27	28	29	30	31	32	33	34	35	36												
Workers:	1320	1210	1100	990	880	770	660	550	440	330	220	110												

Facility: LNG **Plant**
Size: Very Large
Duration of Construction: 36 Months
Approximate Peak Employment (number of people): 4000

Month:	1	2	3	4	5	6	7	8	9	10	11	12	13	14	15	16	17	18	19	20	21	22	23	24
Workers:	222	444	666	888	1100	1332	1554	1776	1998	2220	2442	2664	2886	3108	3330	3552	3774	4000	4000	3774	3552	3330	3108	2886
Month:	25	26	27	28	29	30	31	32	33	34	35	36												
Workers:	2664	2442	2220	1998	1776	1554	1332	1100	888	666	444	222												

TABLE D-6b (Cont.)

Facility: Shore Base
Size: Small-Medium
Duration of Construction: 12 Months
Approximate Peak Employment (number of people): 400

Month:	1	2	3	4	5	6	7	8	9	10	11	12
Workers:	67	134	201	268	335	402	402	335	268	201	134	67

Facility: Shore Base
Size: Large
Duration of Construction: 16 Months
Approximate Peak Employment (number of people): 700

Month:	1	2	3	4	5	6	7	8	9	10	11	12	13	14	15	16
Workers:	88	176	264	352	440	528	616	704	704	616	528	440	352	264	176	88

Source: Dames & Moore (see text)

The information in Table D-4 comprises the framework of the computer model. For each task, inputs were provided for the number of units, the starting year and month, and if necessary the duration of employment for the unit. Because most tasks involved units which started and ended at different times, a separate entry was usually required for each unit. For example, platforms are built and go into production at different times, so each platform was entered separately with approximate dates, lengths of operation, scale factors, etc.

Off-site employment is derived from the rotation factor. If the rotation factor is two, then one-half of the total manpower requirement for the task would be off-site each month; if 1.5, one-third would be off-site each month; and if 1.11, slightly more than one-tenth would be off-site each month.

Transportation requirements are triggered by petroleum and construction activity. Thus, the input for number of units, starting dates, and duration of work for the transportation tasks were tied to the same inputs for each petroleum and construction task. For example, each pipelaying spread requires tug and supply boat service for the same length of time the spread is working. Thus, for each pipelaying spread entered (tasks 12 and 13), its transportation requirements were automatically calculated and assigned to the same months.

Summary employment tables in Chapter 2.0 show total man-months of labor for each year. Employment for each month has been calculated separately and is available if needed.