U.S. ARCTIC OIL & GAS

NATIONAL PETROLEUM COUNCIL · DEC. 1981

U.S. ARCTIC OIL & GAS

NATIONAL PETROLEUM COUNCIL - DEC. 1981

ROBERT O. ANDERSON, CHAIRMAN, COMMITTEE ON ARCTIC OIL AND GAS RESOURCES
HOWARD A. SLACK, CHAIRMAN, COORDINATING SUBCOMMITTEE

NATIONAL PETROLEUM COUNCIL

John F. Bookout, *Chairman*
Robert Mosbacher, *Vice Chairman*
Marshall W. Nichols, *Executive Director*

U.S. DEPARTMENT OF ENERGY

James B. Edwards, *Secretary*

The National Petroleum Council is a federal advisory committee to the Secretary of Energy.

The sole purpose of the National Petroleum Council is to advise, inform, and make recommendations to the Secretary of Energy on any matter requested by the Secretary relating to petroleum or the petroleum industry.

Library of Congress Catalog Card Number: 81-86072

Printed in the United States of America

NATIONAL PETROLEUM COUNCIL
1625 K Street, N.W., Washington, D.C. 20006 (202) 393-6100

December 3, 1981

My dear Mr. Secretary:

On behalf of the members of the National Petroleum Council, I am pleased to transmit to you herewith the report *U.S. Arctic Oil and Gas* as approved by the Council at its meeting on December 3, 1981. This report was prepared in response to an April 9, 1980, request from the Secretary of Energy. It is gratifying to be able to advise you that we have reached the broad conclusion that oil and gas production from undeveloped areas in the U.S. Arctic could make a significant contribution to the nation's energy supply. As an industry, we look forward with great optimism to the challenge of developing these resources, the benefits of which will play a key role in shaping the nation's future.

The report shows that substantial undiscovered oil and gas resources are believed to exist in the U.S. Arctic, and that the industry has demonstrated its capability to develop and adopt the basic technology to safely explore for, produce, and transport oil and gas in most of this area. The economics of oil and gas production should be attractive if sufficiently large resources are discovered.

The realities of the harsh climate and remote location require long lead times in developing these resources, so they could not have a significant effect on the nation's energy supply before the 1990s. It is not anticipated that international boundary disputes will hamper development, nor will relations with the State of Alaska and its communities pose significant problems as long as appropriate attention is given to planning and communication by all concerned parties. The Council is also confident that impacts on the environment from oil and gas development can be minimized or avoided so as to allow other activities dependent on biological resources to co-exist harmoniously. Optimization of all of the factors related to energy development will, of course, require continuing research and data gathering. The report suggests guidelines and directions for future governmental and industry research efforts.

Aside from the natural forces of climate and isolation inherent in the Arctic, the most significant deterrent to timely development of the Arctic oil and gas resources appears to be the complicated regulatory system created by the federal, state, and local governments to control oil and gas activities. It is the unanimous opinion of all parties involved in the regulatory program, both private and public, that the system needs to be redesigned to streamline procedures while providing appropriate operating safeguards. Specific recommendations for such reforms are included in this report.

Governmental reforms in the leasing of federal lands, both onshore and offshore, could also assist development. Modifications of the leasing system to make it more responsive to the factors encountered in the Arctic would do much to expedite development. We are pleased to note some constructive steps have already been taken in this direction by the Administration; additional recommendations are included in this report. Overall, the federal government should direct its actions towards accelerated leasing, allowing the oil and gas industry to proceed with a comprehensive exploratory drilling effort that will define the presently undiscovered resources as rapidly as possible. This would allow optimum development of the nation's Arctic resources. It is also recommended that funding, which recognizes the direct contributions of oil and gas operations, be provided to the governmental agencies with legislated support functions so that they may be prepared and staffed to meet the needs of oil and gas development.

The study has been made on what is believed to be a realistic basis; however, a note of caution should be sounded in regard to the economic analyses. They are necessarily based on resource assessments and equipment estimates developed from extremely limited data, and should be interpreted as directional in nature, rather than exact. They have been developed using constant 1981 dollars, and do not reflect the unpredictable effects of inflation. Further, they do not reflect the use of either existing or proposed transportation systems such as the Trans-Alaska Pipeline System or the Alaska Natural Gas Transportation System. These systems were assumed to be unavailable for undiscovered resources since allocation of their capacity was beyond the scope of this study. Favorable changes in any of these factors would improve the economics of development. Because this report presents estimates of what could happen under certain assumed technical and economic circumstances and is not intended to represent a forecast of what will occur, any significant oil and gas discoveries that are made will receive detailed, site-specific economic evaluation.

The National Petroleum Council is pleased to see the Administration has already moved in some of the directions that this report suggests. We sincerely hope this study and its associated reports benefit you and the government in your further efforts to expedite development of the oil and gas resources in the U.S. Arctic regions.

Respectfully submitted,

John F. Bookout

John F. Bookout
Chairman

The Honorable James B. Edwards
Secretary of Energy
Washington, D.C.

Table of Contents

Page

Preface 1

Findings and Recommendations 5

Summary 9

Chapter One: Resource Assessment

Definition of the U.S. Arctic Regions 13
International Jurisdiction 13
Discovered Resources 13
Undiscovered Resources 16
Arctic Resources as a Part of Total U.S. Resources 20
Future Resource Assessment 20

Chapter Two: Description of the Environment

Physical 21
Biological 27

Chapter Three: Exploration

History 33
Status 35
Current Exploration Technology 36
Future Exploration Technology 38
Cost Factors 39
Exploration Scenarios 41
Findings and Recommendations 43

Chapter Four: Production

History 47
Status 47
Current Production Technology 47
Future Production Technology 53
Cost Factors 54
Production Scenarios 57
Findings 57

Chapter Five: Transportation

History 63
Status 64
Current Transportation Technology 64
Future Transportation Technology 72
Cost Factors 73
Transportation Scenarios 74
Findings 78

Chapter Six: Economic Assessment

Economic Analysis 79
Economic Findings 95

Page

Chapter Seven: Community Impacts

Introduction 97
Native Lifestyle 98
Fisheries 99
Native Organizations 101
Local Government and Community Issues 101
Coastal Management Programs 102
Factors Affecting Social and Economic Impacts 103
Recommendations 104

Chapter Eight: Environmental Protection

History 107
Environmental Risks 107
Risk Avoidance 112
Data Needs 113
Waste Disposal 114
Fate and Effects of Oil in the Marine Environment 116
Oil Spill Countermeasures 116

Chapter Nine: Regulatory Considerations

Introduction 121
Leasing 121
Permitting 124
Regulatory Reform Recommendations 125

Appendices

Appendix A: Request Letter, Description of the National Petroleum Council, and National Petroleum Council Membership Roster A-1
Appendix B: Study Group Rosters B-1
Appendix C: Resource Assessment C-1
Appendix D: Operating Scenarios D-1
Appendix E: Costs E-1
Appendix F: Economic Assessment F-1
Appendix G: Working Papers G-1

Acronyms and Abbreviations

PREFACE

On April 9, 1980, the National Petroleum Council (NPC), a federal advisory committee to the Secretary of Energy, was requested by the Secretary to undertake a comprehensive study of Arctic area oil and gas development.

In requesting the study, the Secretary of Energy specified that:

> . . .the study should include: resource assessment information; an engineering economic analysis for exploration, development, and production activities; a state-of-the-art presentation on the adequacy of available recovery technology and prospects for innovative technology required by the harsh Arctic climate: an assessment of the environmental impact of Arctic oil and gas operations and of the available mitigating measures; a comprehensive review of the adequacy of the existing oil and gas transportation infrastructure and proposals for improving this situation; and a discussion of any international jurisdictional questions that may affect Arctic area development.

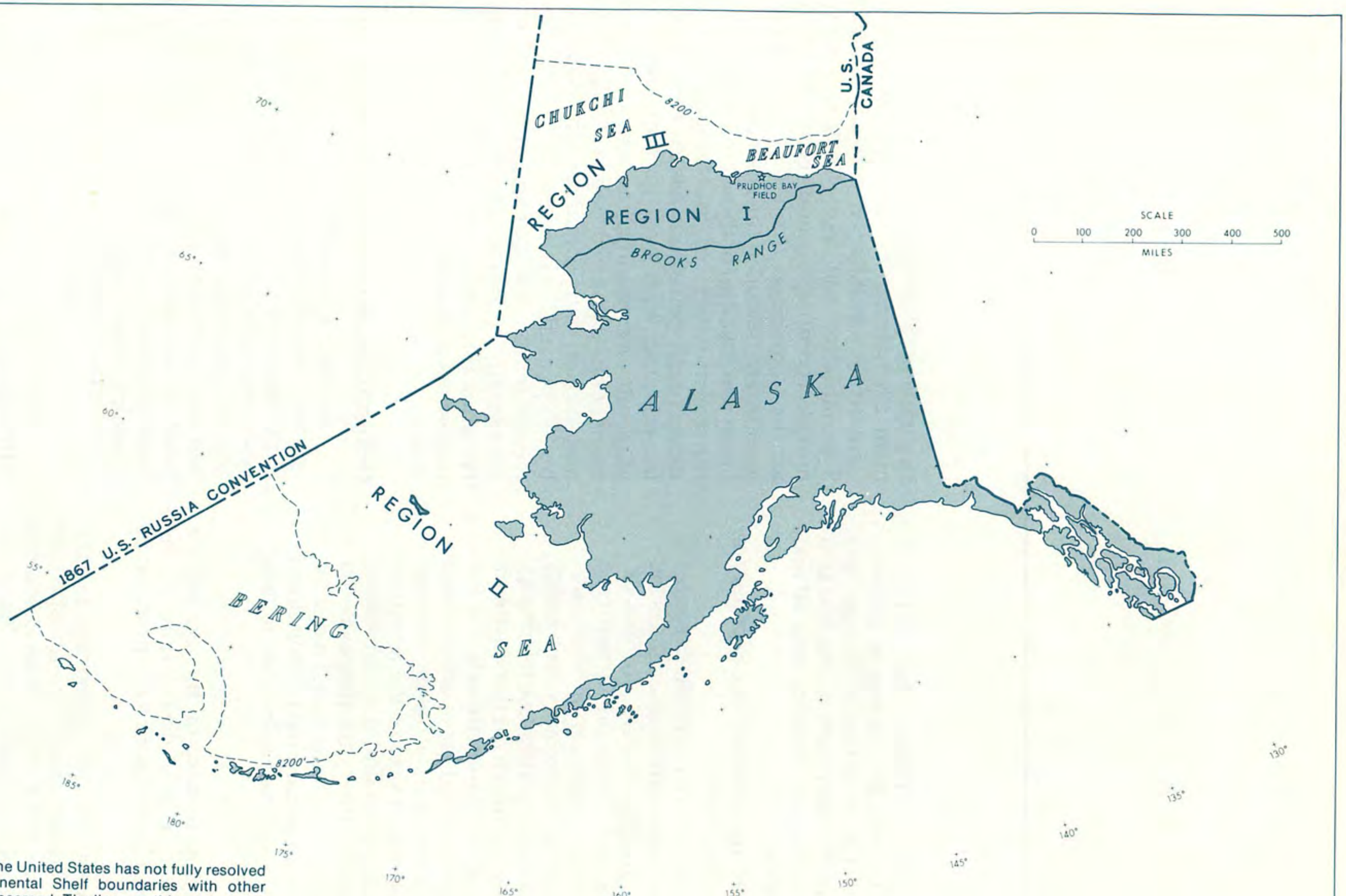
The complete text of the Secretary's request letter and a description of the National Petroleum Council are provided in Appendix A.

To assist in its response to the Secretary's request, the NPC established the Committee on Arctic Oil and Gas Resources under the chairmanship of Robert O. Anderson, Chairman of the Board, Atlantic Richfield Company. Hon. Jan W. Mares, Assistant Secretary for Fossil Energy, U.S. Department of Energy, served as Government Cochairman of the Committee. The Committee established a Coordinating Subcommittee and seven Task Groups to provide coordination and technical advice for the Committee. Rosters of these study groups are included in Appendix B. The broad membership of these groups includes representatives of both major and independent petroleum-related companies; federal, state, and local governments; the academic community; the environmental movement; organized labor; consultants; and Alaskan native organizations. As might be expected with such a diverse membership, all participants do not necessarily endorse each finding and recommendation; however, this report represents a consensus of the participants' views.

Geographic Area of the U.S. Arctic

In discussions with representatives of the U.S. Department of Energy during the early stages of this study, the Arctic area referenced in the Secretary's request letter was defined as seabed and subsoil under the resource jurisdiction of the United States north of the Aleutian Islands offshore and land territory north of the Brooks Range onshore. Accordingly, the terms "U.S. Arctic" and "Alaskan Arctic" as used in this report include the Bering Sea, a sub-Arctic region.

Due to differences in physical environment, operational requirements, and industry's expertise in the Arctic, three geographic regions, as shown in Figure 1, were defined for the purposes of this study.



NOTE: The United States has not fully resolved its Continental Shelf boundaries with other states concerned. The lines on this map are for purposes of illustration only and do not necessarily reflect the positions or views of the United States with respect to the boundaries involved.

Figure 1. Regions Studied.

Region I, onshore Alaska north of the Brooks Range, is composed of the coastal plains and the foothills of the Brooks Range. Region II, the Bering Sea, includes a broad continental shelf less than 650 feet (200 meters) in water depth; however, the southwest portion of the region falls off rapidly to extreme water depths. This region is characterized by seasonal ice and severe storms. Region III, the offshore area north of the Bering Strait, includes the Beaufort and Chukchi Seas. This region also has a continental shelf that falls off gradually to 650 feet in depth and more rapidly to greater depths. The majority of this region is characterized by multi-year ice with ice ridges that may reach a thickness of 150 feet (45 meters), although the area very near the coast may be ice free for as much as three months a year.

Task Groups

Seven Task Groups were established to provide specialized expertise for the development of this report. Experts in the areas of jurisdictional issues, resource assessment, exploration, production, transportation, environmental protection, and economics provided the data and support for this report.

The Jurisdictional Issues Task Group defined, for the purposes of this report, the territorial and seabed and subsoil limits of the United States in the Arctic area, applying principles embodied in international agreements and in the Draft Convention on the Law of the Sea. The Task Group also identified areas of state/federal dispute, native claims, and land withdrawal that may affect oil and gas operations in the Arctic.

The Resource Assessment Task Group made estimates of the conventionally recoverable undiscovered oil and gas resources in the Arctic, utilizing the expert opinions of 17 organizations or individuals that responded anonymously to the NPC Assessment of Arctic Oil and Gas Potential questionnaire. An independent public accounting firm aggregated the survey results for 20 geologic, geographic, or jurisdictional areas. Using Monte Carlo techniques, the Task Group provided resource assessments for the total Arctic area and the three regions previously described.

Petroleum operations in the Arctic were examined by three Task Groups: Exploration, Production, and Transportation. Each of these Task Groups developed a comprehensive review of all factors related to Arctic operations, especially the limitations of conventional methods and the opportunities for the development of innovative techniques to be used in the Arctic. These Task Groups also developed cost data on Arctic operations and examined the effect of the Arctic environment on the timely development of oil and gas resources.

The Economics Task Group utilized the output from the other Task Groups to determine the economic attractiveness of selected areas and to calculate their economically attainable resources. In addition, the sensitivity of these results to changes in key parameters such as timing were evaluated, and total capital requirements were estimated.

The Environmental Protection Task Group examined the physical and biological environment in which petroleum operations may occur, noted the effect these operations may have upon the environment, examined the risk avoidance and mitigation techniques that can be employed to protect the Arctic environment, and identified environmental data needs. In addition, the impact of operations upon Alaskan native populations as well as legislative and regulatory constraints to oil and gas development were studied.

The work of these seven Task Groups is the basis for this report and many of their findings have been incorporated into it. The working papers submitted by the individual Task Groups for the use of the Coordinating Subcommittee are available from the office of the National Petroleum Council. A listing and abstracts of these working papers are presented in Appendix G.

FINDINGS AND RECOMMENDATIONS

Findings

It is the Council's judgment that oil and gas production from undeveloped areas in the U.S. Arctic could make a significant contribution to the nation's future energy supply. This judgment is based on the analyses set forth in this report and on the expertise of the study participants, and is supported by the following findings:

- ***Substantial undiscovered oil and gas resources are believed to exist in the Arctic regions of the United States.*** The total potentially recoverable undiscovered oil and gas resources in the U.S. Arctic are estimated to be approximately 24 billion barrels of oil and 109 trillion cubic feet of total gas, or a total of 44 billion barrels of oil and oil-equivalent gas. It is also estimated that there is a 1 percent probability that the total undiscovered recoverable resources in this area could exceed 99 billion barrels of oil and oil-equivalent gas; there is an estimated 99 percent probability that the total undiscovered recoverable resources will exceed approximately 13 billion barrels of oil and oil-equivalent gas. These resources constitute a significant portion of total U.S. undiscovered oil and gas. It is felt that the Arctic Slope and the Bering, Beaufort, and Chukchi Seas all contain basins with significant promise.

- ***The basic technology is available to safely explore for, produce, and transport oil and gas in most of the U.S. Arctic.*** Industry experience in the North Slope area, Cook Inlet, Gulf of Alaska, Canadian Arctic, North Sea, and in other cold, hazardous, or deep-water areas provides the basis for the design, construction, and operation of systems in Arctic regions. Proven technology exists for onshore operations. Proven technology and sufficient information and technical expertise for advanced design work is available for the industry to proceed confidently with operations in water as deep as 650 feet in the southern Bering Sea and to about 200 feet in the more severely ice-covered areas of the northern Bering, Chukchi, and Beaufort Seas. These capabilities will allow development of prospective areas in all of the northern Bering Sea, most of the southern Bering Sea, and well out into the ice-covered areas of the Chukchi and Beaufort Seas.

- ***Long lead times are required prior to production in the Arctic because of its harsh climate, remote location, and the large scale of the projects.*** Depending on the location, at least 9 to 14 years will be required for planning, permitting, exploration, development drilling, design work, facility construction, and transportation system construction. These timing projections are felt to be near the minimums under improved business and regulatory conditions; even in an emergency, development could be accelerated by only a few years because of the unalterable physical obstacles.

- ***Economic analyses indicate that it will be attractive for industry to develop U.S. Arctic oil and gas if sufficiently large resources are found to support the costly development, production, and transportation systems that are***

required to operate in the region. Oil and gas operations in the hostile environment of the remote Arctic regions will be much more costly than those experienced in other climates. A significant cost associated with developing large resource volumes will be the major new transportation systems, either marine or pipeline, required to move the oil and gas to the market. Based on the assumptions used in these analyses, it appears that 18 to 21 billion barrels of the 24 billion barrels of potentially recoverable undiscovered oil will be economically recoverable. Of the 109 trillion cubic feet (TCF) of potentially recoverable natural gas and natural gas liquids, 68 TCF is non-associated and 41 TCF is associated, i.e., produced with oil from the same reservoir. Under the assumptions used in these analyses, 10 TCF of non-associated gas will be economically recoverable. At a 10 percent rate of return criterion, more than 22 billion barrels of oil and oil-equivalent gas are estimated to be economic. Certain key assumptions made and bases established in these economic analyses must be kept in mind in interpreting the economic findings since they have significant effects on the analyses and could yield low-side estimates. In this study, the more complex economics of associated gas were not evaluated, nor were the economics of the incremental use of the Trans-Alaska Pipeline System or the proposed Alaska Natural Gas Transportation System considered. The volume of economically recoverable gas would likely increase substantially if existing or planned production and/or transportation systems are in place and available at the time of development, since the analyses assume grass roots investments are required for all oil and gas production and transportation.

Some individual companies, utilizing their own internal assumptions and assessments, have considerably more optimistic estimates of economically recoverable gas. An optional portion of the NPC resource assessment survey requested participant estimates of the economically attainable resources. Limited responses suggest that 14 billion barrels of oil, 34 TCF of non-associated gas, and 20 TCF of associated gas, or a total of 24 billion barrels of oil and oil-equivalent gas, would be economically recoverable. This total is very similar to that obtained by the detailed analyses in this report.

- ***Pre-exploratory resource assessment or economic analysis, while useful, should not be given undue weight in the decision to open a basin for leasing.*** Until a considerable amount of exploratory drilling is conducted in each and every basin, any assessment of potential resources or economically recoverable resources and whether the resources will be oil and/or gas must be taken as a preliminary estimate.
- ***Several promising sedimentary basins extend across international boundaries both to the east and to the west.*** The boundary with the Soviet Union is defined by the Convention of 1867; no agreement exists as to the continental shelf boundary with Canada. No promising areas were identified beyond the seabed and subsoil under the resource jurisdiction of the United States as they are defined by the Draft Convention on the Law of the Sea.
- ***Year-round oil and liquefied natural gas tanker operations to ports south of the Bering Strait are feasible and practical.*** In severe ice areas north of the Bering Strait, year-round tanker operations can probably be established, but the ability to maintain a continuous uninterrupted schedule is uncertain. Significant interruptions of tanker arrivals would require additional facilities if continuous production from a field is to be maintained. The cost of these facilities or the loss of revenues resulting from production cutbacks would reduce the amount of economically recoverable oil and gas in marginal areas.
- ***Many benefits can accrue to Alaskans from the oil industry's activities in their state.*** Some of the income from lease sales, royalties, and taxes will provide additional support for government programs. Industry operations have provided employment, a source for emergency medical aid, and communications. Industry personnel and equipment have been used for rescue operations, and company personnel are usually active in their local communities.

- ***Native interests exert an important influence over oil and gas development in the Arctic.*** Through their native-owned corporations, Alaskan natives control more than 40 million acres of land throughout Alaska that they wish to see developed in a manner that will meet their social and financial goals. Subsistence activities, particularly hunting and fishing, are of vital importance in preserving their cultural heritage and integrity. The oil and gas industry must be responsive to these interests.
- ***Impacts from oil and gas development on the lifestyle of the Alaskan native population can be anticipated, managed, and made beneficial by improvements in communication among all parties involved and by careful long-term joint planning.*** It is in both the communities' and industry's best interests to develop good practical planning capabilities in order to prepare for future petroleum developments. Such planning is necessary to help alleviate citizen concern about their lifestyle and livelihood and to maximize opportunities for these citizens resulting from the development activities while avoiding adverse impacts.
- ***The Arctic environment is important and sensitive, but impacts from the development of oil and gas resources can be minimized or avoided.*** The ecology in this region, both onshore and offshore, is important. Although accelerated activities in undeveloped areas will require an extension of existing information and technology, no problems are perceived that are beyond the demonstrated capability of the industry to solve. Prudent designs and methods of operation will allow oil and gas development to co-exist with commercial fisheries, recreational activities, and subsistence needs that are dependent on biological resources.
- ***A complicated regulatory system created by federal, state, and local governments to control oil and gas activities has delayed and added to the cost of Arctic oil and gas development.*** This system is made more complex by overlapping jurisdictions, by limited coordination between agencies, and by the lack of a clear federal policy regarding Arctic development. There appears to be unanimous agreement by all affected parties that this regulatory system needs to be redesigned.

Recommendations

To assist the nation in realizing the oil and gas potential of the U.S. Arctic, the federal government should implement and maintain a clear, comprehensive policy for Arctic oil and gas development. This policy should be responsive to the national need for domestic resources, consistent with national energy policies. Expedited development of oil and gas resources and multiple use of Arctic lands, both onshore and offshore, should be an integral part of this policy, consistent with local needs and concerns. State and local governments should be encouraged to support this policy. Accordingly, the Council makes the following specific recommendations:

- ***A stable lease schedule offering federal Arctic lands for private exploration and development should be established, with all areas both onshore and offshore having oil and gas potential included in the schedule.*** Areas with the greatest potential should be scheduled for early leasing. Scheduled lease sales need not be delayed until comprehensive information on physical and biological environmental conditions is available, or until specific site information is available; such information can be developed well in advance of any significant onsite work. Adequate provisions exist under present law to allow withholdings of tracts with potentially significant environmental problems until mitigating measures are developed.
- ***The leasing system should be made responsive to the unique conditions encountered in the development of oil and gas in the U.S. Arctic.*** Each lease sale should include a sufficient amount of acreage to justify necessary operating systems. Acreage offered for the first sale in a frontier area should cover all major exploration prospect features in the entire basin or area of interest so as to expedite the evaluation of prospective areas. The primary lease term for Outer Continental

Shelf leases should be at least 10 years because remote operating areas combined with hostile climate require lengthy lead time preparations. An automatic "suspension of production" provision should become a part of leasing policy so that marginal discovered resources can be retained by the lease owner until economic transportation can be justified.

- ***A comprehensive exploratory drilling effort extending to all areas thought to have undiscovered resources should be undertaken by industry to define the true oil and gas potential of the U.S. Arctic.*** Several resource assessments of the type prepared for this report have been completed by others. Additional similar analyses will not enhance real knowledge of the region's resources until the promising areas have been leased and tested by drilling, and important new data have been obtained.

- ***A specific existing agency should be designated the responsibility for expediting permitting actions in the Arctic.*** A common procedure should be established to ensure that both its own permits and those of other involved agencies are expedited. The most important way to accelerate and improve efficiency is to streamline and simplify the laws and regulatory processes relating to leasing and permitting. Overlapping responsibilities of regulatory agencies should be eliminated. Such changes would allow government to be more pragmatic in its decision making. Statutes and procedures that unnecessarily delay operations or are not applicable to the Arctic should be modified or eliminated. Deadlines should be set for procedural requirements and for approvals. Such initiatives should be aimed at expediting energy development while fully responding to substantive environmental and socio-economic needs.

- ***Government agencies with legislated responsibilities for conducting operations in support of exploration, production, and transportation activities in the Arctic should be organized and staffed to meet in a timely manner those responsibilities.*** Some of these responsibilities include search and rescue, oil spill surveillance, weather and ice forecasting, structure accreditation, vessel inspection, preparation of environmental impact statements, and surface and air navigational aids.

- ***Continued private and public Arctic research is important to the national interest and should be encouraged and supported where necessary.*** Research and development in Arctic technology for operations in hostile environments will lead to evolutionary improvements in operating systems. Efforts to enhance knowledge of ice conditions, ice properties, and ice forces should be stressed. Biological research and monitoring should be continued. Federally funded research programs should focus on collection and characterization of fundamental data and testing programs of broad issue. Timely and rapid dissemination of information obtained by government agencies should be required.

- ***The federal and state governments should provide necessary assistance to local communities and governments in understanding and planning for the community development that will evolve with oil and gas development.*** Particular attention should be given to determining the most efficient means of funding comprehensive and continuous planning efforts.

- ***Sources of funding should be identified for government and community programs and activities related to development of oil and gas in the U.S. Arctic.*** Both lease sales and production royalties provide substantial sources of funds directly attributable to oil and gas industry activities. A portion of these direct revenues could be used to ensure that appropriate governmental support is provided. Stability of funding is required for effective execution of these programs.

More detailed findings and recommendations can be found in the chapters of this report.

SUMMARY

History

Arctic oil and gas exploration began in Alaska with the U.S. Geological Survey's (USGS) surface work in 1901. In 1904, oil seeps were found on what is now the National Petroleum Reserve-Alaska (NPRA). This 23.6-million-acre area was designated the Naval Petroleum Reserve Number 4 (NPR-4) by Executive Order in 1923, and some geological mapping occurred shortly thereafter. From 1944 until 1953, the Navy, in conjunction with civilian drilling contractors, conducted an extensive geological mapping and exploratory drilling program on the NPR-4. Renewed government exploration in the NPRA was undertaken in the 1970s. Commercial quantities of oil and gas were not found.

During 1949 and 1950, in an effort to develop a natural gas fuel supply for the Navy's Barrow Camp, several test wells were drilled in the vicinity. These South Barrow wells were the first development wells drilled and completed in the U.S. Arctic. They furnished proof that hydrocarbons could be produced in the Arctic region.

In 1968, the Prudhoe Bay oil field was discovered east of the NPRA. After this field was discovered, two alternate transportation options were considered: tanker movement through the Northwest Passage, and pipelining across Alaska to an ice-free port. The pipeline option was chosen on the basis of reliability, and pipe was ordered. The design called for a 48-inch-diameter line with a potential capacity of 2 million barrels per day, initially equipped to deliver 1.2 million barrels per day across an 800-mile route from Prudhoe Bay to an ice-free terminal in Valdez, Alaska.

Opposition to the pipeline by environmentalists and disputes over land ownership led to a series of legislative, environmental, and judicial hearings that delayed the start of construction for five years. Construction of the Trans-Alaska Pipeline System (TAPS) began in April 1974, and the pipeline was completed and went into service in mid-1977. Upon completion of TAPS, the field was placed on continuous production.

During the early 1970s an extensive research and development program was carried out by industry to solve the many problems associated with oil operations in the Arctic. The success of these programs is attested to by the fact that some 350 wells have been completed, and oil is being produced and transported at a rate of 1.5 million barrels per day. A total of approximately 2 billion barrels of oil have been moved to market as of the end of 1981. A second, smaller field, Kuparuk, is now being developed, and production is expected to commence in 1982.

Development of the Prudhoe Bay field and construction of TAPS and the Valdez terminal were conducted under the most rigorous design and quality control specifications ever imposed upon onshore petroleum operations. Successful operation of this system has been achieved and it represents a model for future land pipelines and terminals.

Resources

An evaluation of the potential oil and gas resources in the sedimentary basins of the U.S. Arctic was made based on a review of published information, USGS data, and a survey of the study participants. It was established that as of August 1980, 16.5 billion barrels of recoverable oil and oil-equivalent gas had been discovered on the North Slope of Alaska. Of this total, 10.2 billion barrels are oil and 35.4 trillion cubic feet (TCF) are gas. An additional 44 billion barrels of undiscovered recoverable oil and oil-equivalent gas resources are expected to be present in the Arctic. Of these total undiscovered resources, it was estimated that 24 billion barrels will occur as oil, and the remainder will consist of 109 TCF of gas and natural gas liquids. Of this gas total, 68 TCF are expected to occur as non-associated gas and 41 TCF should be associated with oil production.

Although there are at least 10 highly prospective areas, the largest resources are estimated to occur in the Beaufort Shelf and the Navarin Basin Shelf. It was also concluded that there is a 1 percent chance that the total quantity of undiscovered recoverable oil and oil-equivalent gas could exceed 99 billion barrels, and a 99 percent chance that it could exceed 13 billion barrels. These undiscovered resources may constitute as much as 40 percent of the total undiscovered recoverable oil and gas resources remaining within U.S. jurisdiction.

Basins appearing to have a low potential should not be ignored. Additional basic geological information could cause significant revisions, either upward or downward, in the estimates. Confirmation of these estimates can be achieved only by extensive leasing and exploratory drilling.

Technology

Large-scale Alaskan North Slope operations and extensive experience in the Cook Inlet, the Canadian Arctic, and the North Sea have demonstrated that, with an economic incentive, the petroleum industry can rapidly develop sufficient technology to safely conduct exploration, design and operate production facilities, and provide transportation in cold, remote, and ice-covered regions, both onshore and offshore. The fundamental techniques of exploration, production, and transportation in Arctic regions are not significantly different than those used elsewhere. The novel problem is the design and operation of systems that can cope with severe sea ice. Continuing research, development, and engineering programs will provide basic information and technology for successful site-specific designs. Technological advances that have the greatest economic potential relate to improving the ability to operate exploration, drilling, production, and transportation systems efficiently during all seasons. This requires coping with low temperatures, poor visibility, storm waves in the Bering Sea, and particularly, the extreme sea ice conditions in the Chukchi and Beaufort Seas.

Exploration technology in the Arctic requires that the usual geological techniques be modified to accommodate weather and specific environmental concerns, but no unique methods are needed or employed. The same is true for geophysical work, although seasonal considerations more generally control the use of heavy geophysical equipment on the tundra and affect the accessibility of offshore areas containing sea ice. The drilling of an exploratory well in the Arctic differs from drilling in other climates in that special techniques have been developed for drilling safely in permafrost areas. Offshore drilling sites must be located in areas free of sea ice or must have a platform or island as a drilling base able to withstand the moving pack ice. Remote locations make logistical support of operations very difficult. These considerations lead to substantially higher costs than those encountered in less hostile regions. Most of the future geological and geophysical technology that will improve exploration will not be Arctic-specific but will be applicable in all areas.

Production technology for Arctic regions requires similar considerations of weather and climate, especially in the design, construction, and installation of production facilities under adverse conditions. Installations and operations must be designed for permafrost, both onshore and in some offshore locations. Offshore structures for drilling, production, storage, and loading that will successfully resist sea ice are a major requirement. It should be possible to develop safe designs for offshore production islands or platforms within the time period required to lease, explore, and delineate a major oil or gas find.

Additional information on sea ice and its associated problems is being obtained through research programs. These research programs should be continued, as they are needed to complete novel designs and will lead to more cost-efficient operations. Modular construction in temperate climates with transportation of large modules to the site is a proven method of reducing construction costs.

Transportation technology for oil in Arctic regions has been successfully developed for onshore pipelines, as demonstrated by TAPS. Marine transportation has not reached the same level of development. Appropriate tankers and icebreakers can be designed to provide year-round reliable operations to ports south of the Bering Strait handling either crude oil or liquefied natural gas (LNG). Marine vessel operations north of the Bering Strait appear less reliable, and there is a need for more icebreaker experience in this area before tankers are considered an attractive transportation system. Marine pipeline operations in the Arctic should be similar to operations in the North Sea and Cook Inlet, but will be more difficult and demanding because weather and logistics are more severe. As in the case of exploration and production, extended knowledge of the characteristics, conditions, and dynamics of sea ice is needed to optimize and ensure reliability in Arctic marine operations.

Economics

Limited economic evaluations of the Arctic oil and gas resources were made based on assessments of potential resources, costs, and schedules for operations developed in this study. These evaluations demonstrate that large reserves are required to support the high cost of oil and gas field development and associated transportation systems. When transportation systems can be shared by producing areas, significantly improved economics are obtained.

The economic resource base was calculated by combining the reserve evaluations with the resource assessments. Estimates of the capital investment required for exploration, production, and transportation facilities were developed and the sensitivity of the economics to various factors was evaluated.

In evaluation of the oil resources, the economic resource base analysis showed that when applying a 10 percent return as an investment criterion and deleting presently infeasible areas, the total risked mean assessment was reduced from 24 billion barrels to 21 billion barrels. At a 15 percent return it was reduced to 18 billion barrels of economically recoverable oil. The analysis indicates little opportunity for a 20 percent rate of return to be achieved. These results assume that grass roots investments are required for all oil production and transportation and that no incremental use of the TAPS line would be possible at the time of development.

Evaluation of non-associated gas resources showed that when applying a 10 percent return criterion the risked mean assessment of 68 TCF of potentially recoverable non-associated gas is reduced to 10 TCF of economically recoverable gas. In no case was a 15 percent rate of return shown to be achieved. No evaluation was made of the more complex economics of producing associated gas, which could improve the prospects of gas development. Gas transportation from the North Slope was evaluated only on the basis of transporting LNG by tanker from different ports. No case comparable to the proposed Alaska Natural Gas Transportation System (ANGTS) was developed, nor were evaluations of the economics of the incremental use of the ANGTS line developed. Use of this system could substantially increase the economically recoverable gas.

Although considerable variation was shown in the economics for different areas, the uncertainties inherent in estimating all factors in frontier basins, especially the undiscovered resource base, suggest that none of the prospective basins should be excluded from early leasing and exploration.

Impacts

While benefits of oil and gas operations have been demonstrated, it is inevitable that substantial oil and gas development in the

U.S. Arctic regions will have some impact on rural Alaskan populations and on the surrounding environment. The experience of the petroleum industry in recent years demonstrates that such impacts can be managed in a beneficial manner with minimal adverse effects on the environment.

The Arctic area contains about 45,000 inhabitants located in six regional centers and about 60 small villages. This population is distributed over thousands of square miles along the northern and northwestern coasts of Alaska from the Alaskan/Canadian border through the Aleutian Islands. Because oil and gas development is likely to occur only at a few specific points, many of the native villages will not directly experience the impact of development. In the few communities that would be directly affected, expansion will occur in community structure, shoreline resources, local labor markets, and housing. Employment and business opportunities will evolve that could benefit those who choose to participate. In order to maximize these opportunities and minimize any adverse impacts, it is necessary to develop adequate long-term planning and good industry/native relationships.

Environmental impacts can be minimized or avoided in the Arctic by operating practices that have been and continue to be developed by the oil and gas industry in their operations throughout the world, particularly at Prudhoe Bay, the TAPS corridor, the Cook Inlet, the North Sea, and the Canadian Arctic. The Arctic environment is both fragile and biologically important; however, the risk of significant disturbance can be minimized. Accelerated activities in new geographic areas will require an extension of existing technology. However, no problems are perceived that are beyond the projected capability of the industry. As discoveries of oil and gas are made, additional site-specific data will be developed, and research, development, and information gathering will continue. With this information and a continuing commitment to good practices by industry, environmental impacts should be negligible and oil and gas development can proceed safely and successfully in the Arctic.

Regulation

Both the leasing of prospective areas and the permitting of operations in the Arctic are under government control. A multitude of statutes, regulations, and policies have been developed at federal, state, and borough levels, resulting in an elaborate series of regulatory constraints that have increased costs and delayed all aspects of oil and gas development. A major impediment to Arctic development would be removed if these policies and procedures were simplified and expedited.

The aggressive leasing program undertaken by the State of Alaska has made the present Prudhoe Bay development possible. Most of the rest of the area onshore is under federal control and has been closed to development for many years. A limited program to open a portion of the NPRA is under way, but most of the highly prospective North Slope area under federal jurisdiction is still unavailable for exploration activity. The offshore leasing schedule as of July 1981 does not offer some of the most promising areas until 1984 or later. Acceleration and simplification of leasing for these areas would allow oil and gas development to proceed more effectively.

The complicated regulatory system that has been imposed on the industry needs a complete redesign with the permitting and leasing agencies operating under a clear federal policy to expedite Arctic development. Revisions in statutes, regulations, and policies at all levels of government are necessary to accomplish such a simplification. Specific recommendations for such revisions are made in this report.

CHAPTER ONE: RESOURCE ASSESSMENT

Definition of the U.S. Arctic Regions

An assessment of oil and gas resources was conducted for all areas under U.S. resource jurisdiction north of the Aleutian Islands offshore and north of the Brooks Range onshore. This total area was divided into three regions, as shown in Figure 1 of the Preface. Each region exhibits grossly similar physical conditions, and each reflects a certain common level of industry expertise in the Arctic. These regions are:

- Region I—onshore, north of the Brooks Range
- Region II—the Bering Sea
- Region III—the Beaufort and Chukchi Seas.

The Arctic was further divided into 20 geologic, geographic, or jurisdictional areas, as shown in Figure 2. An area may contain more than one geologic province, or it may be a portion of a single geologic province. Some provinces were divided into separate areas by the continental-shelf to continental-slope limit, which is at or near the 650-foot (200-meter) water depth. The 20 areas are identical to those used by the USGS in their resource assessment.

International Jurisdiction

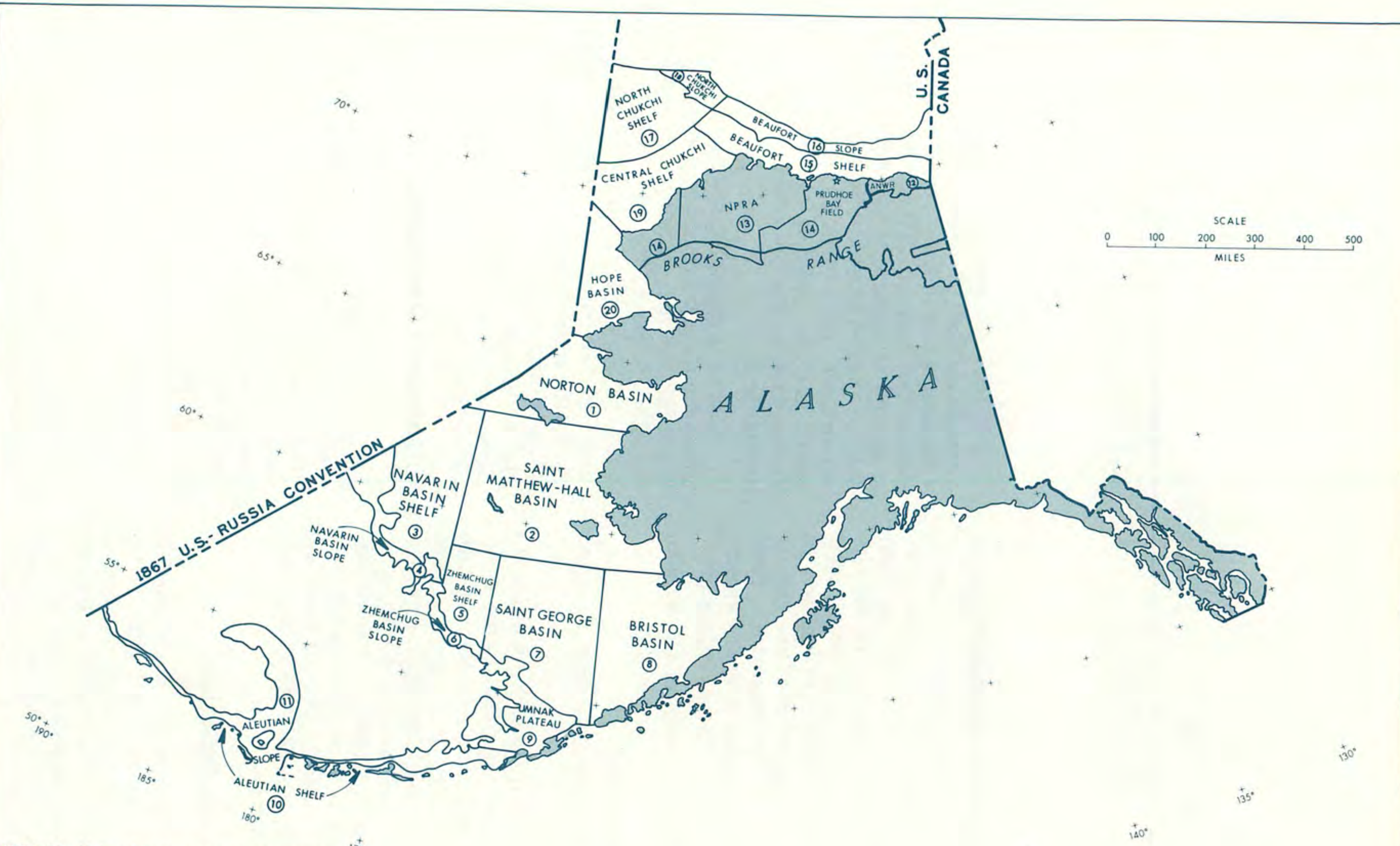
For the purpose of this study, the U.S. Arctic extends offshore northward to the limit of the continental shelf/margin, as defined by the Draft Convention on the Law of the Sea. The western limit of U.S. jurisdiction, in the Bering and Chukchi Seas, is defined by the U.S.-Russian Convention of 1867. No agreement exists as to the continental shelf boundary with Canada; for this assessment, a hypothetical equidistant line or the Canadian 200 nautical mile limit was used as applicable. To the north, these lines are joined by a limit line determined in accordance with Article 76, paragraphs 4(a)(i) and (ii), and 5, 6, and 7 of the Draft Convention on the Law of the Sea, as shown in Figure 3.

Several promising sedimentary basin areas extend across maritime boundaries: to the east are the Beaufort Shelf and the Beaufort Slope; to the west are the North Chukchi Shelf, the Central Chukchi Shelf, and the Navarin Basin Shelf. All areas fall under the resource jurisdiction of one of the three littoral nations, i.e., the United States, the USSR, or Canada, as determined in accordance with Article 76 and by bilateral agreements negotiated or to be negotiated.

Discovered Resources

The "most likely" discovered resources of oil and oil-equivalent gas on the North Slope of Alaska were estimated by the State of Alaska, as of August 1980, to be 16.5 billion barrels. Of this amount, 10.2 billion barrels were oil and 6.3 billion barrels were oil-equivalent gas, which converts to 35.4 TCF of gas.

This "most likely" estimate is based on the geology and technology known at the time the estimate was made. Because some of the parameters were not known with certainty, the "most likely" value was bracketed by high and low estimates. The low estimate given by the State of Alaska was



NOTE: The United States has not fully resolved its Continental Shelf boundaries with other states concerned. The lines on this map are for purposes of illustration only and do not necessarily reflect the positions or views of the United States with respect to the boundaries involved.

Figure 2. Jurisdictional Areas.
(Encircled numbers correspond to the numbered areas listed in Table 1.)

Hypothetical Limits of the U.S. Continental Margin in the Arctic

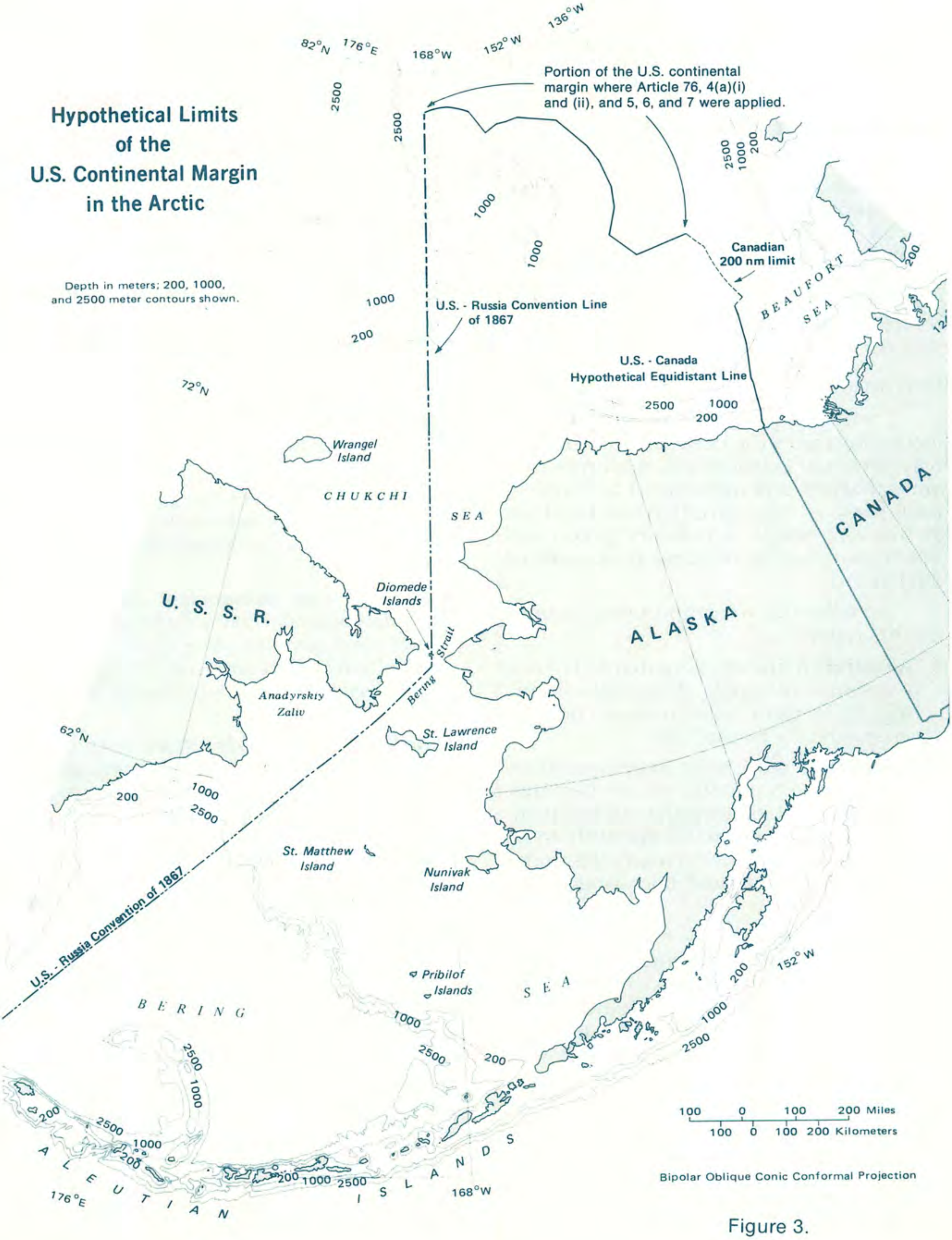


Figure 3.

14.5 billion barrels of oil and oil-equivalent gas; the high estimate was 18.6 billion barrels. These estimates will be revised as more geological or engineering data become known, as technological advances are made, and as economic conditions change.

Undiscovered Resources

An assessment of the undiscovered recoverable oil and gas resources in the Arctic provides the basis for determining the oil and gas potential. This chapter defines the terms used in the resource assessment; describes the methodology employed; and discusses the estimates, compares them with other public estimates, and discusses their reliability.

Definitions

A review of published resource assessments illustrates the need for definitions of resources and categories of resources that are consistent and meaningful to nontechnical persons. The definitions and text are as free as possible of industry jargon and words that require recourse to specialized dictionaries.

The following are definitions developed for this report:

- ***Resource:*** A known accumulation of or a new source of supply of naturally occurring oil or gas that is now or could be conventionally recoverable.
- ***Proved reserves:*** The estimated quantities of naturally occurring oil or gas that geological and engineering studies demonstrate with reasonable certainty to be recoverable from known reservoirs under existing economic and operating conditions.
- ***Probable reserves:*** The estimated quantities of naturally occurring oil or gas, in addition to proved reserves, that geological and engineering studies indicate are likely to be recovered from partially defined reservoirs under existing economic and operating conditions.
- ***Discovered resources:*** Proved reserves plus probable reserves.
- ***Undiscovered resource base (undiscovered resources):*** A tentatively estimated, undrilled quantity of naturally occurring oil or gas presumed to exist, in accord with regional geological analyses, that would be conventionally recoverable from fields larger than 1 million oil-equivalent barrels regardless of present accessibility or economics. Confirmation of the existence and quantity of this base is dependent upon the results of future drilling.
- ***Total oil and gas resources:*** The sum of discovered resources and undiscovered resources.
- ***Oil-equivalent gas:*** Gas volume that is expressed in its energy equivalent in barrels of oil, and that is reconvertible to gas volume at 5,600 cubic feet of gas per barrel of oil equivalent.
- ***Major field:*** One that contains at least 50 million recoverable barrels of oil and oil-equivalent gas.
- ***Small field:*** One that contains between 1 and 50 million barrels of oil and oil-equivalent gas.
- ***Adequacy chance:*** The probability that at least one major field exists. (Corresponds in principle to the "marginal probability" of the USGS.)
- ***Natural gas categories:*** Associated—overlies and is in contact with crude oil in the reservoir. Non-associated—in reservoirs that do not contain significant crude oil. Dissolved—in solution with crude oil in the reservoir.
- ***Natural gas liquids (NGL):*** Portions of recoverable natural gas that are liquefied at the surface in separators or in process plants.

The oil and gas volumes that qualify as resources for consideration in this report are those that can be produced by conventional methods known and used in 1981. Conventional in this sense means production of oil or gas to the surface from a well as a consequence of: natural pressure within the subsurface reservoir; artificial lifting of oil from the reservoir to the surface, where economically applicable; and maintenance of reservoir pressure by means of water or gas injection.

Neither highly viscous oil nor gas hydrates, both of which occur on the North Slope, were considered resources for the purposes of this study. Highly viscous oil of less than 15° API has been encountered in significant volumes in the subsurface and may be produced economically in the future, but no information exists at this time to indicate that it can now be produced economically. Gas hydrates occur in reportedly large quantities in the soil and shallow subsurface of Alaska, both onshore and offshore. This "frozen gas" is also found in a dispersed form in permafrost, but nowhere has the means of economic production been demonstrated.

Methodology

The method used in the NPC assessment of Arctic oil and gas potential was an averaging of anonymously supplied expert opinions. The objective was to determine both risked mean and highside (1 percent probability) resource assessments of Arctic oil and gas potential for each of the 20 areas. Accumulation and averaging of the assessments from each of the experts taking part in the survey were performed by an independent third party, Price Waterhouse & Co., to protect the confidentiality of the proprietary information used by the individual participants.

The assessment procedure required a representative of each of the 20 organizations that participated in the survey to submit unrisked distribution curves that represented probability versus potentially recoverable amounts of oil and gas that might exist in each of the 20 areas, irrespective of the geological or economic risks. Each participant was also required to provide his estimate of the adequacy chance that the geological controls for oil and gas accumulation—source, reservoir, trap, and recoverability—were sufficient for the occurrence of at least one 50-million-barrel oil-equivalent field. The next portion of the questionnaire required that each participant estimate the percentage of the curve that was oil. The remainder then consisted of gas plus natural gas liquids. The final required portion of the questionnaire asked the participant to state the mean of the probability curve.

The remainder of the questionnaire was optional. Questions included requests for estimates of the mean number of potential fields and the mean major field size; the postulated recovery efficiencies of oil and gas; the NGL content of the gas; the associated and dissolved gas as a percentage of a barrel of oil; the additional potential in small fields [<0.05 billion barrel oil equivalent (BBOE)]; and the portion of the resources that were economically attainable.

These data were submitted directly to Price Waterhouse & Co., which aggregated the 17 individual anonymous responses and derived a single set of probability curves that expressed the composite estimate of the assessment for each basin.

The average adequacy chance for each area was applied to the composite curve to develop a "risked" assessment from which a "risked mean" assessment and a "risked highside" estimate were derived for each of the 20 basins. These data were aggregated using Monte Carlo techniques to arrive at "risked highside" estimates for each of the three regions and a grand total for the Arctic. Details of the method used, as well as the sample questionnaire, are in Appendix C.

Estimates

The estimates of Arctic oil and gas resources indicate the possibility of very large quantities of recoverable oil and gas in the Arctic. Table 1 shows the 20 areas assessed and their hydrocarbon potential expressed in billions of barrels of oil equivalent, as well as their component quantities of oil and gas. The Beaufort Shelf (Area 15), with a risked mean assessment of 12.9 BBOE and a 1 percent chance of 59.0 BBOE, is the area with the highest assessment. This area is also estimated to have the greatest probability (88 percent) for containing at least one major field. The Navarin Basin Shelf (Area 3) has a high assessment for hydrocarbons, with a risked mean assessment of 4.0 BBOE, and although it ranks fourth in hydrocarbon potential, the risked highside of 44.0 BBOE is the second highest estimate. The NPRA (Area 13) ranks third on both bases with a risked mean assessment of 4.7 BBOE and a highside estimate of 24.0 BBOE.

Although some areas have been assessed as having a relatively low potential, this should not preclude them from being considered as prospective basins since the assessment was based on limited data. Additional information obtained in further exploration will undoubtedly cause significant revisions in estimates of potential undiscovered recoverable resources.

TABLE 1

SUMMARY OF U.S. ARCTIC AREA ASSESSMENTS
Undiscovered Potentially Recoverable Hydrocarbons

	Total Hydrocarbons (BBOE)*			Oil (Billion Barrels)		Gas and NGL (TCF)	
	Adequacy Chance§ (%)	Risked Mean	Risked High-side†	Risked Mean	Risked High-side†	Risked Mean	Risked High-side†
1. Norton Basin	43	0.9	7.6	0.3	2.8	3.4	26.9
2. St. Matthew-Hall Basin	26	<0.1	1.3	<0.1	0.2	<1.0	6.2
3. Navarin Basin Shelf	41	4.0	44.0	2.3	25.0	9.5	106.4
4. Navarin Basin Slope	31	0.2	2.8	0.1	1.2	<1.0	9.0
5. Zhemchug Basin Shelf	27	0.2	2.3	0.1	1.4	<1.0	5.0
6. Zhemchug Basin Slope	17	<0.1	0.6	<0.1	0.2	<1.0	2.2
7. St. George Basin	47	2.2	23.0	1.2	12.2	5.6	60.5
8. Bristol Basin	47	1.3	10.8	0.6	5.0	3.9	32.5
9. Umnak Plateau	21	<0.1	0.8	<0.1	0.3	<1.0	2.8
10. Aleutian Shelf	20	<0.1	0.9	<0.1	0.2	<1.0	3.9
11. Aleutian Slope	22	<0.1	1.5	<0.1	0.4	<1.0	6.2
12. ANWR¶	70	3.7	21.7	2.3	13.7	7.8	44.8
13. NPRA**	79	4.7	24.0	2.1	10.6	14.6	75.0
14. North Slope Other	79	4.4	23.3	2.1	11.4	12.9	66.6
15. Beaufort Shelf	88	12.9	59.0	8.2	37.4	26.3	121.0
16. Beaufort Slope	57	2.5	20.4	1.3	11.1	6.7	52.1
17. North Chukchi Shelf	50	2.1	17.0	1.2	9.1	5.0	44.2
18. North Chukchi Slope	34	0.6	6.2	0.3	3.1	1.7	17.4
19. Central Chukchi Shelf	62	3.3	20.5	1.7	10.9	9.0	53.8
20. Hope Basin	40	0.4	4.6	0.2	2.0	1.1	14.6
Areas 1-20 Summation	100	43.6	99.0	24.1	55.0	109.2	246.4

*BBOE = billion barrels of oil equivalent (gas conversion 5.6 TCF per billion barrels).
†Risked highside potentials are at 1 percent probability; they cannot be added directly.
§Chance of finding more than 0.05 billion barrels of oil equivalent.
¶Arctic National Wildlife Refuge.
**National Petroleum Reserve-Alaska.

Undiscovered resources have also been aggregated for the three regions, as shown in Table 2. Region III, the Beaufort and Chukchi Seas, with a risked mean assessment of 21.8 BBOE and a risked highside assessment of 67.0 BBOE, has the greatest potential. The risked mean assessment for the total Arctic is 43.6 BBOE and the total risked highside assessment is 99.0 BBOE. In the case of the aggregate for the total Arctic, a lowside estimate was made. The composite curve shows a 99 percent chance of finding at least 13 BBOE.

From the foregoing resource assessment it is concluded that the areas listed in the following tabulation are the most prospective.

Map Code	Area	Region
3	Navarin Basin Shelf	II
7	St. George Basin	II
8	Bristol Basin	II
12	ANWR	I
13	NPRA	I
14	North Slope Other	I
15	Beaufort Shelf	III
16	Beaufort Slope	III
17	North Chukchi Shelf	III
19	Central Chukchi Shelf	III

No ranking is intended in this list, nor were the basins omitted from the list judged nonprospective. Factors other than estimated resources, such as economics, field size,

TABLE 2

REGIONAL SUBTOTALS
SUMMARY OF U.S. ARCTIC AREA ASSESSMENTS
Undiscovered Potentially Recoverable Hydrocarbons

		Total Hydrocarbons (BBOE)*	
	Adequacy Chance§ (%)	Risked Mean	Risked Highside†
Region I—North Slope Onshore (Areas 12-14)	99	12.8	37.0
Region II—Bering Sea (Areas 1-11)	99	9.0	52.0
Region III—Beaufort and Chukchi Seas (Areas 15-20)	100	21.8	67.0
REGION TOTALS	100	43.6	99.0

*BBOE = billion barrels of oil equivalent (gas conversion 5.6 TCF per billion barrels).
†Risked highside potentials are at 1 percent probability; they cannot be added directly.
§Chance of finding more than 0.05 billion barrels of oil equivalent.

technology, and transportation routes, strongly influence the final judgment of which basins are most promising from an oil industry viewpoint.

Preliminary economic judgments of the various basins were developed from the optional portion of the questionnaire and are reported in Appendix C. Limited responses suggest that 14 billion barrels of oil, 34 TCF of non-associated gas, and 20 TCF of associated gas, or a total of 24 billion barrels of oil and oil-equivalent gas, would be economically recoverable. More detailed economic analyses based on these resource assessments and other factors developed in this report are the subject of Chapter Six.

Comparison with Public Estimates

Comparison between resource assessments is difficult due to differences in the methodologies employed. However, there is general agreement between the NPC and the USGS on total Arctic potential. The USGS estimates a total risked mean Arctic hydrocarbon potential of 33.0 BBOE, and the NPC indicates a total risked mean hydrocarbon potential of 43.6 BBOE. Table 3 shows a comparison of USGS and NPC estimates by area. The National Petroleum Council assessment includes 2.5 billion barrels of NGL; the USGS does not include NGL. The difference between the two assessments is approximately 20 percent when the total NGL is removed from the NPC estimate.

There are similarities in the estimates for individual areas, such as the Beaufort Shelf, which has a risked mean assessment of 13.2 BBOE according to the USGS and 12.9 BBOE by the NPC. There are also some substantial differences in area estimates; an example is the Navarin Basin Shelf, for which the USGS estimates a 1.7 BBOE potential and the NPC estimates a 4.0 BBOE potential.

Limitations of Assessments

It is important that those who use resource assessments of this type be aware that the numbers presented do not constitute quantitative predictions of volumes of oil and gas that will be discovered in any one of the geological provinces, basins, or regions. Many with estimated potential may turn out to be nonproductive. One or more areas may yield ultimate recoveries approaching or exceeding the corresponding highside estimate. It is most likely that the 43.6 BBOE risked mean total undiscovered resource

TABLE 3

USGS vs. NPC RISKED MEAN ASSESSMENTS
Undiscovered Potentially Recoverable Hydrocarbons

Curve Number and Area	Estimated Undiscovered Recoverable Resource Base (BBOE)*	
	USGS 1981 Risked Mean†	NPC Risked Mean§
1. Norton Basin	0.38	0.9
2. St. Matthew-Hall Basin	0.00	<0.1
3. Navarin Basin Shelf	1.68	4.0
4. Navarin Basin Slope	0.15	0.2
5. Zhemchug Basin Shelf	0.07	0.2
6. Zhemchug Basin Slope	0.00	<0.1
7. St. George Basin	0.83	2.2
8. Bristol Basin	0.39	1.3
9. Umnak Plateau	0.00	<0.1
10. Aleutian Shelf	0.00	<0.1
11. Aleutian Slope	0.00	<0.1
12. ANWR	3.29	3.7
13. NPRA	3.60	4.7
14. North Slope Other	4.77¶	4.4
15. Beaufort Shelf	13.21	12.9
16. Beaufort Slope	1.54	2.5
17. North Chukchi Shelf	1.45	2.1
18. North Chukchi Slope	0.40	0.6
19. Central Chukchi Shelf	1.17	3.3
20. Hope Basin	0.08	0.4
Total Assessments	33.01	43.6

*BBOE = billion barrels of oil equivalent (gas conversion 5.6 TCF per billion barrels).
†Excludes NGL. Minimum field size included ranges from <1 to 400 million barrels.
§Includes NGL (2.5 BB). Minimum field size included is 1 million barrels in all areas.
¶Equals total USGS assessment of North Slope onshore minus the special DOI assessments of NPRA and ANWR.

base for all areas will be closest to reality. The assessment does provide a basis for future petroleum planning and policy and it provides a quantitative basis for comparison of the assessed basins with others similarly assessed.

Arctic Resources as a Part of Total U.S. Resources

Assessments of undiscovered recoverable resources in the total United States as well as in just the lower 48 states have been made by others, but direct comparison with the NPC Arctic results is not technically valid because of the differing methods and assumptions used. However, the 43.6 BBOE risked mean undiscovered resource base for the U.S. Arctic as determined by the NPC may encompass a significant portion, perhaps as much as 40 percent, of the total undiscovered recoverable oil and gas resources remaining within the jurisdiction of the United States. On the basis of oil resources alone, as much as 50 percent may occur in the U.S. Arctic.

Future Resource Assessment

No further resource assessment is warranted for these same regions until the most promising geological provinces and jurisdictional areas identified herein have been tested by drilling and significant new geological, geophysical, and engineering data are available.

CHAPTER TWO: DESCRIPTION OF THE ENVIRONMENT

Physical

Region I—Onshore, North of the Brooks Range

Region I encompasses the drainage basin of all rivers flowing north from the divide of the Brooks Range into the Chukchi and Beaufort Seas of the Arctic Ocean. The total area of the region is approximately 51.8 million acres (81,000 square miles), about the size of the State of Idaho.

The North Slope consists of three physiographic provinces: the Brooks Range, the foothills, and the coastal plains. The Brooks Range includes rugged peaks of 8,000 to 9,000 feet. The area is snow- and ice-covered most of the year. Mountain slopes are sparsely vegetated and devoid of trees. Valley floors are covered with alpine tundra-heath. The foothills are rolling plateaus 80 to 100 miles wide rising upward into the mountains to the south. They are covered by tussock-heath and are dominated by cottongrass. There are extensive stands of willow and birch along the stream banks. The coastal plains province is treeless and vegetated by grasses, low sedges, and shrubs.

The tundra is a transition zone between the barren polar pack ice and the wooded tracts of boreal forest to the south. Like the Great Plains, which it resembles physiographically, it is a region of subtly varied landscapes, a rolling, nearly level terrain interrupted by the meandering courses of Arctic rivers and dotted with numerous lakes and ponds.

The unique climate of the Arctic tundra is distinguished by the regular occurrence of long, very cold winters, short, cool summers, and a low annual fall of rain and snow.

The climate close to the sea is more moderate than farther inland and the marine influence is seen in the times and amounts of precipitation as well as in more moderate coastal temperature extremes.

Summer is usually damp, raw, and chilly, despite the prolonged period of daylight. It is the season when the weather is most nearly uniform. Average temperatures are above freezing, but there is no complete freedom from frost.

Winter is most intense in February, the month during which the lowest temperatures are usually recorded. Overall snowfall is light, although windblown drifts can be large and are composed of snow with a surprisingly high density and strength. Wide expanses of frozen ground are left completely bare. The lakes are ice covered most of the year. Lake ice thicknesses in excess of 6 feet are common. Many of the lakes are quite shallow and freeze to the bottom. A characteristic shared by all areas of the region is the presence of permafrost, which may reach depths as great as 2,000 feet. The climate of the region can be described as cold and dry.

Since water is frozen nine months of the year, hydrological events are limited to the short summer seasons. Peak flows of large rivers and tundra streams occur with breakup of the ice in early summer, when streams carry heavy sediment loads. Melting snow is the source of early flow, and rainfall maintains stream and river flow in the summer. Water quality is good on the Arctic Slope, with the exception of high sediment concentrations in rivers during periods of high runoff and concentrations of salts due to freezing in deep pools.

Gravel and coarse sand are valuable resources for construction on the Arctic Slope. North and west of the Colville River, gravel resources are limited. East of the Colville River, gravel is found along streams originating in the Brooks Range. Gravel is also found in beaches, spits, and barrier islands.

The region contains a number of long-established communities, the largest of which is Barrow. It includes the NPRA, the Arctic National Wildlife Refuge (ANWR), and the oil field at Prudhoe Bay.

Region II—The Bering Sea

Reduced visibility related to fog and blowing snow and the presence during the winter months of a highly mobile annual ice cover is characteristic of this region. The nature of the ice cover varies greatly from north to south. Just north of the Aleutian chain, ice is light and is restricted to shallow water. In these regions the greatest environmental hazards are the large waves that develop as intense storms cross the area. Waves become less of a problem in the winter, as their development is hindered by the presence of ice. The thickest ice reported in the region is the highly deformed and rafted ice that occurs north of St. Lawrence Island. Thicknesses as great as 30 feet have been reported. Large ice pileups can occur on shoals such as those in the vicinity of the Yukon Delta. Heavy ice is not reported in the southern and central regions of the Bering Sea nor in the eastern part of Norton Sound. A characteristic of the Bering Sea ice pack is its mobility; daily drifts of 6 to 10 miles are common.

A number of islands in the Bering Sea have been inhabited for long periods of time. These include St. Lawrence, Nunivak, the Pribilofs, and the Aleutian Chain.

Region III—The Beaufort and Chukchi Seas

This region comprises the Alaskan sector of the Chukchi and Beaufort Seas, which are marginal seas of the Arctic Ocean. The environment of this area is poorly documented as there are no permanent observation sites north of the coast. The only islands are near the coast and are not inhabited except for Kaktovik, off the ANWR. In the Chukchi and Beaufort Seas heavy sea ice can be present at any time of the year. At sites along the coast, the ice retreats some distance offshore during July, August, and September. Heavy pack ice is never far away and can be pressed against the coast by a shift of wind. Multi-year ice is found in the coastal zone. The ice is highly deformed and ridges with thicknesses of over 150 feet have been reported. Ice drift velocities (one to two miles per day) are less than in the Bering Sea. Ice islands with lateral dimensions of several miles are known to occur. Wave heights are limited by the presence of pack ice and are low in the summer. The sea floor is furrowed by numerous gouges produced by grounded pressure ridges and ice island fragments.

There is currently no oil or gas production from this offshore region; the giant Prudhoe Bay field is located on the coast. Some offshore oil and gas discoveries have been made in the Mackenzie Bay area of Canada. Exploratory drilling is under way at numerous shallow-water sites within the barrier islands of Alaska, and several discoveries have been reported.

Specific Environmental Factors

The quality and quantity of scientific physical data necessary or desirable for Arctic engineering design vary widely. While enough information is known to allow safe installation and operation of conservatively designed exploration, production, and transportation facilities, more information is needed to develop optimum designs.

Variation of Light and Darkness

Both Regions I and III have periods of continuous daylight during the summer and continuous darkness during the winter. This is not a serious operational constraint.

Visibility

The main factors producing reduced visibility are blowing snow and fog. If three-mile visibility is required for unrestricted aircraft operations, Barter Island in the

Beaufort Sea, Tin City on the Seward Peninsula at the Bering Strait, and St. Paul Island in the southern Bering Sea would be closed 22 percent, 30 percent, and 20 percent of the time, respectively. Umiat, which is in the interior of Region I, has fewer periods of reduced visibility than coastal sites such as Barrow or Cape Lisburne.

Air Temperature

Summer temperatures are variable onshore, ranging from below freezing to over 85°F inland. The offshore temperatures reflect the presence of cold water and pack ice and are slightly above freezing from the southern Bering Sea to the eastern Beaufort Sea. Winter temperatures show a consistent decrease to the north, where lows along the Beaufort coast reach -60°F. The low temperatures are not appreciably colder than many sites in the populated central area of Alaska.

Wind Speed

The windiest known locations are at the Bering Strait and on the islands in the Bering Sea. These conditions are representative of the offshore environment. Estimates of the 100-year maximum sustained wind are higher for the Bering Sea (110 knots) than for the Chukchi (97 knots) and Beaufort Seas (81 knots). The Bering Sea is closer to the center of the intense storms that characteristically move west to east across the Gulf of Alaska.

Wind Chill

The combined chilling effect of the wind and low ambient temperatures is called the wind chill factor. Low equivalent wind chills are common in all three regions during the winter months. For example, during January wind chills are below -40°F roughly 40 percent of the time. To avoid frostbite, workers must be protected. Summer wind chill factors at Umiat, the one inland station on the North Slope, are appreciably warmer than for equivalent temperatures at sites in Regions II and III because there is less wind there.

Precipitation

Total annual precipitation is light, ranging from 10 inches or less along the Beaufort and Chukchi coasts to as much as 30 inches in the southern Bering Sea. The mean annual snowfall shows a similar pattern, ranging from 20 inches in the north to 60 inches in the south. Snow in the Arctic causes greater problems than would be expected from its measured depths because high winds cause severe drifting around manmade structures, greatly reduce visibility, and redistribute the snow over wide areas.

Permafrost

Permafrost is any earth material that remains frozen from at least one winter to the next. Water within the soil and underlying rocks is frozen by the low surface temperatures. Continuous freezing over many winters causes the permafrost boundary to migrate downward into the earth, reaching depths greater than 2,000 feet. The active zone at the surface is two to three feet deep and freezes and thaws during the year.

Placing structures on this active zone or drilling through the permafrost adds heat and the ice melts, potentially causing structural collapse or severe damage. Soil and gravel in permafrost are difficult to excavate as permafrost is very cohesive.

Industry has much experience with construction in permafrost terrain in the Prudhoe Bay field and the Trans-Alaska Pipeline. In Region I, industry currently has the experience and the technology to design and construct oil and gas facilities where permafrost exists.

Region I, the North Slope, is almost completely underlain by permafrost. Subsea permafrost is absent in Region II under the Bering Sea except at locations where shoreline retreat has been very rapid. In Region III the situation is different from Regions I and II in that subsea permafrost can be present near shore. Here, permafrost can exist at temperatures that are appreciably warmer than those found in typical onshore permafrost and is more susceptible to thaw and its associated engineering problems. The presence and properties of subsea permafrost can be determined by site-specific investigations undertaken prior to construction. Shallow submarine permafrost could have a significant effect on the cost of some offshore systems in Region III.

Soil Geotechnical Properties

Regional surveys of the distribution of different sediment types have been completed for most of the marine areas. In the nearshore waters of the Beaufort Sea and St. George Basin, a program to determine the geotechnical properties of the sediments has been undertaken by the USGS. Similar studies are planned in other areas. Detailed site-specific geotechnical surveys by industry will be necessary before specific exploration or production activities are initiated.

Seismicity

The seismicity of the Alaskan Arctic offshore areas is highly variable. Based on the regional tectonics, these areas can be divided into two groups: (1) areas near the boundary between the North American and Pacific plates, such as St. George Basin, Navarin Basin, and Bristol Bay; and (2) areas away from the plate boundary, such as Norton Basin, Hope Basin, the Chukchi Sea, and the Beaufort Sea.

The North Slope of Alaska and the continental shelf of the Beaufort Sea are believed to be relatively free of seismic activity except for several earthquakes that have occurred onshore and offshore near Barter Island. Seismicity data gathered over the past 11 years indicate that the earthquakes occurring in the Barter Island region are relatively shallow events, generally with Richter magnitudes of less than 5.0. The largest earthquake during this period had a 5.3 Richter magnitude.

Norton Basin seismicity is relatively insignificant and is not likely to affect the design of offshore structures. Earthquakes of Richter magnitude 5.5 have been predicted for this region.

In St. George Basin, all earthquakes reported for the northernmost areas have been less than Richter magnitude 6.0, but historical records are sparse. The southeastern area at the northwestern fringe of the Aleutian seismic zone, one of the most active areas in the world, has been associated with earthquakes of magnitudes between 7.0 and 7.9. Earthquake severity in this area approximates that in Upper Cook Inlet and off the California coast, where successful oil field operations have been conducted for many years.

Bathymetry

The general characteristics of the bathymetry of Regions II and III are reasonably well known. Improved information is needed for detailed work, particularly in the northern portions of the Chukchi and Beaufort Seas, where the presence of ice during the summer limits the effectiveness of bathymetric surveys. The topography of Region I is the best known, although there are still areas in the interior of the region that have been inadequately surveyed for detailed topographic maps.

Offshore Islands

Offshore islands are numerous in the Beaufort and Chukchi Seas. These islands have a major influence on the nearshore physical and biological environment. The islands effectively moderate the influence of polar pack ice upon the shoreline. During the summer they also partially separate the cold saline waters of the open Beaufort Sea from the warmer brackish waters that flow from east to west in a narrow band along the mainland coast.

Some of these islands are true barrier islands and are associated with a shallow lagoon system. Others are relics of earlier coastal retreat processes and lie farther offshore with deeper waters between them and the mainland. The islands are subject to considerable erosion by wave, wind, and ice action and can change in size, shape, and location after a major storm or a winter season.

Tides

Tides are not an important consideration for offshore design or operations in either the Bering, Chukchi, or Beaufort Seas. The maximum tidal range is small, ranging from 0.6 feet at Barrow to 3.5 feet at St. Matthew Island.

Surges

A surge may occur whenever an intense storm crosses or approaches a coastline. In the Bering Sea six storms have caused major damage since 1900. The best documented storm occurred near Nome in November 1974 and resulted in a water rise of 25 feet. In the Beaufort Sea a severe storm occurred in October 1963 and caused a surge of 10 feet on which 10-foot waves were superimposed. The storm caused extensive damage at Barrow and severe coastal erosion. Models have been developed for predicting surges that take into account the presence of nearby pack ice.

Currents

Information on summer currents is poor, and for winter currents is nearly nonexistent. Currents are generally less than 1 knot, except in the vicinity of the Bering Strait, where a maximum of 2.4 knots has been noted. Data are lacking for the northern reaches of the Chukchi and Beaufort Seas, where ice invariably hinders observations. Available information suggests that in waters shallower than 150 feet currents at most locations will be a fraction of a knot. The importance of currents is that they are a major factor in controlling the velocity at which pack ice drifts. Pack ice is a major operational concern.

Waves

Published estimates of extreme wave conditions for the Bering, Chukchi, and Beaufort Seas give large values for the 100-year wave, ranging from approximately 100 to 140 feet. These estimates are probably erroneous because of the methods and assumptions used. Current industry estimates suggest values roughly 30 to 40 percent less for the Chukchi and Bering Seas and 50 percent less for the Beaufort. To resolve these differences in wave height estimates, high-quality wave data for a variety of different locations and meteorological conditions are needed. A study sponsored by industry is being conducted in the Bering Sea.

Spray Icing

When the sea surface temperature is within 10°F of the freezing point, the simultaneous occurrence of below-freezing air temperatures and high winds generates waves and spray, which can cause ice to form on the superstructures of vessels and platforms. Existing information on this phenomenon is largely based on observations made by fishing trawlers. Large masses of ice can accumulate rapidly. In extreme cases, the stability of small craft is endangered, but large tankers will have no problem. This hazard will be pronounced in the Bering Sea during times when ice is not present to limit wave conditions. Spray icing will have to be considered in the operation of offshore mobile rigs. It is not believed to be a major problem in either the northern Chukchi or Beaufort Seas because of the ice cover.

Ice Types

The main ice types in the areas of interest are first-year and multi-year sea ice, tabular ice islands, and ice island fragments. Their general distribution is well known: all types exist in the Beaufort and Chukchi Seas and only first-year ice occurs in the Bering Sea. There is little quantitative information on the variations in areal percentages of different ice types, particularly for different classes of thinner first-year ice. Improved data on this subject, particularly on spatial distribution of ice within 100 miles of the coast of the Beaufort and Chukchi Seas, would be useful as an aid to navigation through heavy multi-year ice fields.

Ice Thickness Distributions

The related information on ice thickness is more important than ice type. No simple method exists to measure ice thickness from the upper ice surface. The best data are from the upward-looking sonar records made during nuclear submarine cruises across the Arctic Basin. These data are at best limited. Water depth limitations make it difficult to obtain unbiased data from areas that are of present interest for oil and gas exploration. Data are needed on the manner in which ice thickness distribution changes in location seasonally and annually in order to verify ice thickness distribution numerical models.

Ridging

Pressure ridges are formed by differential movements between pack ice floes. Ridge heights of more than 150 feet from the top of sail to the bottom of keel have been observed. Ridges and drifting pack ice can be a menace to artificial gravel islands if they can override the islands. Either shorelines susceptible to ice override should be avoided in siting facilities or suitable defensive structures should be deployed. Indications are that nearshore ice along the coast of the Arctic Ocean is more highly deformed than ice further offshore. There are indications that the intensity of ridging may vary systematically along the coast. Limited information exists on seasonal and annual changes in ridging. Data on ridging in the Bering Sea are limited.

Recent ridging information comes from laser profiles of ridge sails. The keel depth cannot be accurately estimated from surface data. Means of estimating how frequently rare, large pressure ridges form have not been refined. Data on the bulk properties of first-year compressional and shear ridges and of multi-year ridges are not available, and little is known about the forces involved in the ridging process.

Ice Drift Velocity

There are wide variations in observed ice drift rates for the Bering, Chukchi, and Beaufort Seas. In the Bering Sea, speeds are high, averaging up to 0.5 knots. In the vicinity of the Bering Strait, daily drifts of 19 nautical miles (0.79 knots) have been recorded. Data for the Chukchi Sea are poor but drift speeds are believed to be lower. Within Kotzebue Sound the ice is shorefast most of the winter. In the Beaufort Sea drift rates reach 4 nautical miles per day (0.17 knots) with the larger values being observed during the summer at locations near the ice edge, where the floes essentially drift freely. In protected areas within the barrier islands, considerable ice movement data have been collected by oil companies, showing that ice movements over a whole winter are less than a few hundred feet. Few data are currently available for the region outside the barrier islands and inside the edge of the continental shelf, although data collection has started recently using buoys. This ice shows movements of only a few miles over a winter.

Accurate measurements of ice movements are needed for calculating ice force, and for validating improved ice drift and dynamics models. Such models are an essential part of advanced ice forecasting schemes.

Ice-Induced Gouging of the Sea Floor

When the polar pack drifts into the shallower waters of the Alaskan continental shelf, the deeper pressure ridge keels can come into contact with the bottom. The result is a series of gouges in the sea floor. In terms of frequency, up to 400 gouges can be found per nautical mile; occasionally, these are deep. Gouges in excess of 10 feet are found off the Alaskan Beaufort coast. Reasonably good documentation of both gouge depths and spatial frequencies are available for the Beaufort coast out to water depths of 115 feet. Some data exist for the Chukchi and Bering Seas but they are not extensive.

Information is not available to accurately estimate the frequency and depth of rare deep gouges or the forces involved in gouging different types of sediments.

Ice Islands

Ice islands are the icebergs of the Arctic Ocean. They are tabular, originate as the result of the gradual breakup of a fossil ice shelf located along the north coast of Ellesmere Island, and can be large. The best known ice island, T-3, which for a number of years was the base for a U.S. drifting scientific observation station, had initial dimensions of 5 by 11 miles and a thickness of roughly 150 feet. Such large ice islands are rare. No information exists on how many of these exist or their locations as a function of time. There are many smaller ice island fragments for which there is no adequate census, and their current locations are unknown.

Ice Properties

The small-scale properties of sea ice are fairly well known, but published information on the properties of multi-year ice from either undeformed floes or from pressure ridges is lacking. Recent discoveries of strong crystallographic alignments in first-year ice, new data on oriented ice, and studies of the effect of grain size on strength have given a better understanding of ice mechanics. Ice engineering properties are not simply a function of brine content. An improved understanding is needed of changes in bulk strength with changes in sample size in order to estimate the mechanical properties of aggregate assemblies of various ice types acting against an offshore structure.

Although uncertainties exist in the behavior of small "laboratory scale" samples and less is known about the properties of ice masses of the size that would interact with structures, there is enough information on sea ice to give usable estimates of most engineering properties.

Biological

Region I—Onshore, North of the Brooks Range

The area encompassed by Region I has several vegetation-classified areas: high brush, moist tundra, wet tundra, and barren ground. Each of these categories has a definite group of plant life, mammals, birds, and invertebrates, chiefly because of differences in the degree of wetness in the soil. Changes in drainage produce changes in the kinds of plants adapted for growth in each type.

The most striking feature of the tundra is the absence of trees and the low-growing matted or creeping plants that give the appearance of a greenish-brown, low grassland interspersed with boggy ponds and small lakes. The treeless nature of the tundra arises in part because only a shallow zone of near-surface soil thaws during the short summer growing season. Even when frost free, the soils remain cold and waterlogged and prevent development of root systems extensive enough to support trees of forest size.

The water-saturated soils underlain by permafrost contribute to the levelness of the tundra. Even on slight slopes, soils tend to slide downward in a process called solifluction, or soil creep, thus leveling heights and filling in depressions. Solifluction is counteracted, however, by the severe frost action of the Arctic. This produces features called pingos, frost mounds that may be 100 feet or more above the surface of the surrounding terrain. Smaller frost features include tussocks or hummocks a few inches or feet in height, stone rings, and the soil polygons, which are the most distinctive feature to be seen from the air. Differential sorting by frost action of the stones and clays of the peaty soils results in polygonal ridges, the centers of which fill with water.

Plant growth is confined to only the two to four months of the year that temperatures are above freezing; many plants flower within a few days after the snow begins to melt, and some produce ripe seed within four to six weeks. Very few species are annuals. Perennial species reproduce in a variety of ways in addition to flowers and seeds—by producing, for example, runners, underground stems, and bulblets that produce roots and shoots while on the parent plant before they drop to the ground.

The number of species of plants and animals is relatively small as compared to more temperate zones, but the number of individuals per species is usually higher. As a result, food chains are simple and more subject to upset if a critical species decreases in number or is eliminated. There is often a direct relationship from plant producer to animal consumer, with only one or two species involved.

In the high brush area, the animals include shrew, ground squirrel, lemming, porcupine, wolf, red fox, brown bears, weasel, wolverine, otter, lynx, Dall sheep, moose, and caribou. Of these, the fox and the moose are seen often by seismic crews. The fox and perhaps other small animals have been known to cause extensive damage to seismic cables by chewing through the insulation.

The most conspicuous mammal in the moist tundra area is the caribou. Two large herds, the Arctic and the Porcupine, migrate constantly, with the Arctic herd dominant in the western Arctic and the Porcupine herd in the east. Each of these herds is composed of more than 100,000 animals; the total number varies cyclically from year to year. The abundance of caribou draws wolves to the moist tundra in search of food; however, wolves have never been plentiful on the Arctic Slope. The red fox and the Arctic fox overlap in this area, and lemmings are present in the grass, using it both for forage and for insulation in their nests. Musk ox herds, which were re-introduced in 1964-1970 on the ANWR after an absence of 100 years, can be found near Barter Island and Point Thompson.

In the wet tundra area, the most common mammal is the lemming. These are the staple food for the Arctic fox and avian predators. The caribou, wolf, grizzly bears, and wolverine are also present in this sector.

Many mammals, including wolf, red fox, ground squirrel, and hoary marmot, den in the dry soil of the alpine tundra. Dall sheep live in the alpine tundra where they feed on benchgrass or lichens in terrain where their climbing ability gives them an advantage over potential predators.

Polar bears are common during the summer months offshore of this region. During the winter and spring they can be found denning along the coast and have occasionally been observed 50 miles inland.

Predatory birds include snowy owls, ravens, golden eagles, the Arctic peregrine falcon, and other falcons and hawks. Nearly all waterfowl migrate out of the Arctic in the winter. Some travel as far as the eastern coast of the continental United States. Hordes of mosquitoes and flies are present and support the seasonally abundant bird life.

Many species of birds and waterfowl forage in the wet tundra, and the production of invertebrates is phenomenal. This abundance accounts for the tremendous number of shorebirds that nest in this habitat. Almost 60,000 collembolas (small flightless insects) have been counted in one square meter of the wet tundra.

Many types of invertebrates, some of which are parasitic, use other animals for their habitat. The rate of roundworm infestation in wolves is known to run as high as 84 percent. Some parasites limit populations of such grazers as the caribou, preventing the tundra from being overgrazed. As many as 17,000 mites have been counted in one square meter of moist tundra.

The locations of potential oil and gas resources and pipeline corridors outlined in this report intercept every type of drainage from small, steep gradient mountain brooks to large meandering rivers. The fish species are as diverse as the stream habitats.

About 20 species of freshwater and anadromous fish (salt water fish that spawn in fresh water) have been recorded on the Arctic Slope. Arctic char, grayling, whitefish, and burbot are the more common species. Arctic char are present in large Arctic Slope rivers. Arctic grayling, whitefish, and burbot are believed to be present throughout the area and are more common in the larger drainages, such as the Colville River. Nonanadromous char are found in lakes and streams. Lake trout are present in the middle and upper Colville River as well as in a number of deep lakes of the coastal plain.

The anadromous char overwinter in freshwater springs and spend the summer months feeding in nearshore estuarine areas. Adult grayling enter tundra streams from overwintering areas (in lakes, spring streams, or mountain streams) to spawn in early June. Some adults leave after spawning, while others remain with fry and juveniles throughout the summer, leaving the tundra streams just prior to freeze-up. There are approximately six species of whitefish; their distribution includes all watersheds from tidewater lagoons to clear, swift mountain streams.

Onshore Pipeline Corridors

Transportation of oil or gas that may be developed may require a land pipeline to reach a tanker terminal for shipment to market. These pipelines would extend beyond the areas considered and will pass through varying biological communities. The several representative corridors shown in Figure 4 would cross the following river systems:

- Wainwright east across NPRA to TAPS corridor (Region I): Meade, Ikpikpuk, Colville, Anaktuvuk, Itkillik, and Kuparuk/Toolik Rivers
- ANWR west to TAPS corridor (Region I): Sagavanirktok, Kavik, and Canning Rivers; possibly the Sadlerochit, Hulahula, Jago, Aichilik, and Kongakut
- Wainwright south to Kotzebue and Nome: Noatak, Selawik, and Kobuk Rivers; De Long Mountains, eastern Brooks Range
- Kotzebue east to TAPS corridor: Kobuk, Alatna, and Upper Koyukuk Rivers
- Nome east to TAPS corridor: lower Koyukuk and Yukon River tributaries
- Nome south to Cook Inlet: coastal streams of Norton Sound, Yukon, Kuskokwim, Hoholitna, Nushagak/Mulchatna Rivers, and Iliamna/Lake Clark complex
- TAPS corridor south from the North Slope to Valdez: see *Summary Report Biological Documentation for Trans-Alaska Pipeline*, 1974, Alyeska Pipeline Service Company.

Large mammals and birds that inhabit the representative pipeline corridors are the same as described for Region I. The Wainwright to Nome corridor passes through an area that includes both the summer and winter ranges of the western Arctic caribou

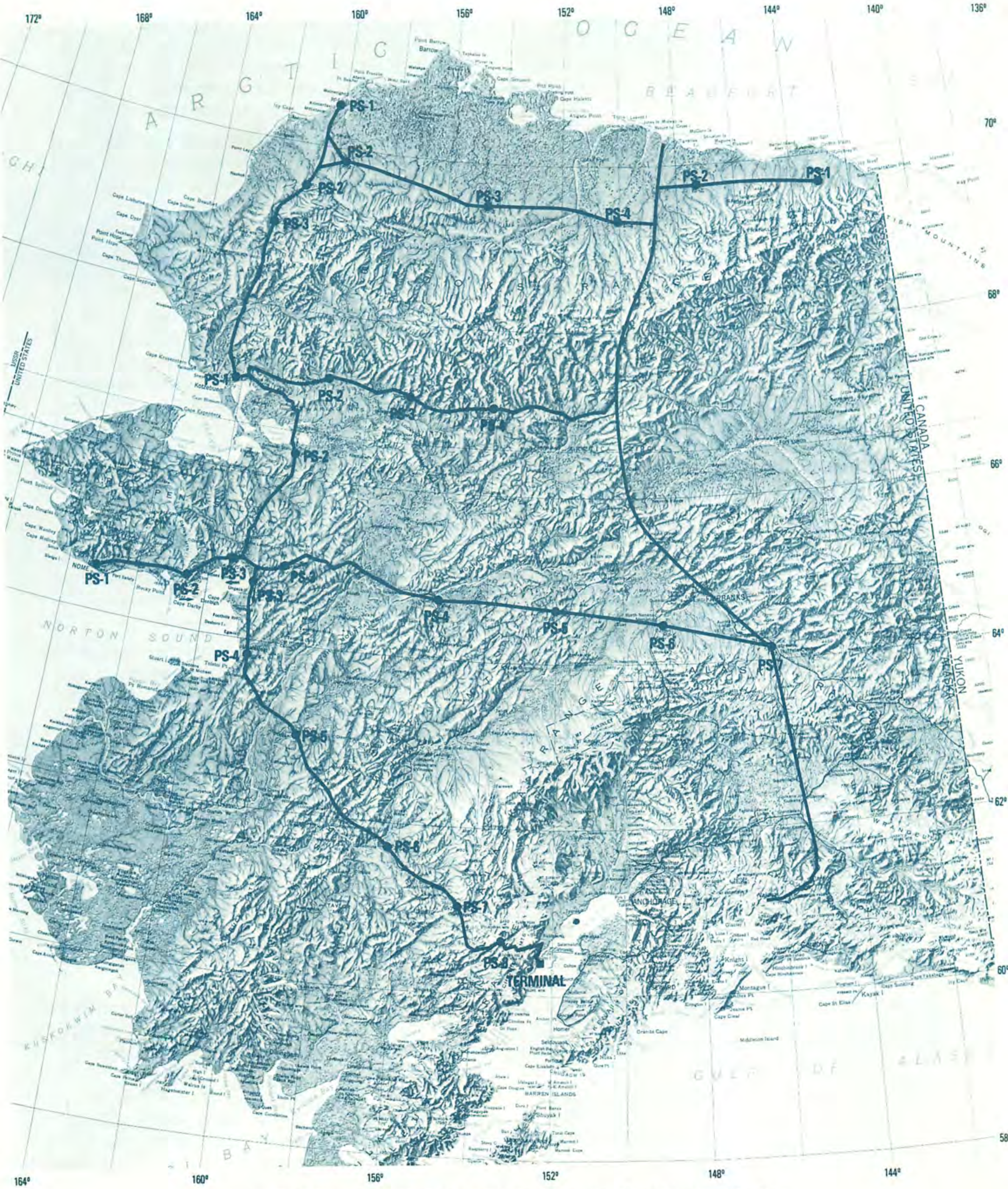


Figure 4. Map of Representative Land Pipeline Corridors—Alaska.

herd. Mountain passes in the Brooks Range and De Long Mountains are used for north-south migration routes. Post-calving movements are circular and take the caribou southwest across this corridor to the high country and, by July, east across the corridor through the De Long Mountains and adjacent foothills.

The representative pipeline corridors cross numerous river systems that are important to commercial and subsistence fisheries. All five species of salmon, grayling, Arctic char, whitefish, and sheefish spawn in these streams and tributaries during the summer months. The Nome to Cook Inlet corridor would cross the upper reaches of some of the most productive fish regions in Alaska.

The main channels of the Yukon and lower Koyukuk Rivers are principal migration routes. Spawning areas for all species, including king, coho, chum, and pink salmon, grayling, Arctic char, whitefish, sheefish, northern pike, and burbot, exist in streams flowing into Norton Sound. Tributary streams of the Yukon River contain spawning runs of king and chum salmon. Along the Yukon River in the sloughs and side channels, lakes, and small tributary streams grayling, northern pike, and burbot occur.

A new line in the TAPS corridor would parallel the existing system, which transports crude oil from Prudhoe Bay to Valdez. It is assumed that the existing haul road would be used and any additional pipeline would be constructed approximately 200 feet from the existing line. The same wide variety of big game animals would be encountered as along the other possible inland Alaska pipeline corridors.

Region II—The Bering Sea

The eastern Bering Sea is characterized by: a broad, relatively shallow continental shelf; narrow constrictions such as Unimak Pass through the Aleutians to the south and Bering Strait to the north; freshwater runoff from major rivers; deltas; islands; and winter ice. These physical aspects establish unusual oceanographic conditions that support a very biologically productive area.

The Bering Sea supports important fisheries and an impressive population of marine mammals, including whales, seals, sea lions, walrus, and sea otters. There are vast numbers of seabirds, and the region is the summer home for millions of migrant waterfowl, shorebirds, and marine birds.

These resources have both shore-based and oceanic aspects. Mammals, birds, and some fish are tied to the shore (or to the ice) for spawning or resting and raising their young. This dependence is focused on islands that offer resting and nursery sites that are relatively free from land-based predators. Recent research has established the existence of several oceanographic fronts in the southeastern Bering Sea. Major food chains, from large stocks of ocean swimming animals to ocean floor animals, are separated in space and organized relative to these fronts. The outermost front is along the continental slope near the shelf break at the 600-foot depth. Shoreward of this, near 300 feet, lies a middle shelf front. Large stocks of birds, mammals, and ocean fish are found in the outer shelf zone between these fronts. An inner front is located near the 150-foot depth. Large stocks of ocean floor animals, fish, and crabs occur in this middle shelf zone.

The ice pack of the Bering Sea is a major component of the habitat of marine mammals. The ice provides a solid substrate upon which mammals can travel, haul out, and, in the case of seals and walrus, bear young. The ice forms a rigid layer through which mammals must find or make holes in order to breathe. The ice edge and open leads are areas of concentrated activity for marine mammals and birds. The open-water accesses move as the ice changes. In particular, the ice edge migrates through the Bering and Chukchi Seas as ice forms in the fall and retreats in the spring. The ice front is a 10- to 40-mile-wide zone at the southern periphery of the pack.

The influence of sea ice dominates the Arctic environment, requiring that its role in any physical or biologic process in the area be considered.

The life histories of the organisms indigenous to the Arctic, from plankton to whales, are determined to some degree by the character and distribution of sea ice in both space and time. This ice is not stable, smooth, and uniform like a freshwater lake, but is an incomplete cover, widely variable in form and structure and typically unstable and dynamic under the influence of surface air and water currents. The percentage of the surface of water covered by ice, ice thickness, degree of pressure ridging, and depth of snow on the ice are important habitat characteristics.

Discussion of biological resources can be divided at the Bering Strait between Regions II and III, but many species of mammals and fish migrate extensively through the Strait. High concentrations of animals exist around a few key areas, such as the offshore islands.

Variable winter/spring conditions along the ice front are reflected by the uneven distribution of marine mammals. Few mammals are found east of 160°W longitude. From 160°W to 162°W, walrus are the most abundant mammal, and from 162°W to 165° W, spotted seals are the most abundant mammal. Spotted seals and ringed seals are the most abundant west of 169°W. They utilize the front intensively throughout the winter/spring period, when they give birth, care for their young, haul out, and molt.

Walrus inhabit moving ice where there is open water and where the ice is thick enough to support their weight. Their winter distribution is in areas of loose-pack heavy ice 30 to 300 miles north of the southern edge of the front, particularly to the southwest of St. Lawrence Island and the inner part of the front west of 160°W longitude.

Bearded seals are widely dispersed in moving ice in winter and spring, when young are born. They live along the front, but the highest population is farther north in heavier ice. Sea lions may haul out on floes along the front, but their population centers are in ice-free areas further south. Some bowhead and belukha whales winter along the front.

Region III—The Beaufort and Chukchi Seas

Polar bears are abundant on drifting pack ice year-round, ranging as far south as the Bering Strait in winter. Winter densities are highest along the northwest coast of Alaska. Polar bears are concentrated on drifting ice during winter because juvenile ringed and bearded seals, the bears' main food, are numerous.

In the fall the formation of shorefast ice along the northern coast of Alaska is an important bridge for polar bears coming to shore from drifting ice. While polar bears prefer dens on land, many dens have been reported on offshore ice. The most important polar bear denning area is along the northern coast, east of Point Barrow, on ice or adjacent land.

Polar bears travel northward from the southern Chukchi Sea in March, prior to ice breakup. Along the northern coast of Alaska in the spring a pronounced movement of bears takes place to the east from areas where ice is breaking up to an area where it is still solid.

Remnants of the pack ice harbor some of the largest annual concentrations of seals. After molting, ribbon seals stay at sea for the summer, spotted seals disperse along coastlines, and bearded seals migrate to summer near the edge of the permanent ice pack.

Walrus move north to feeding grounds in May when the Bering Sea ice pack is rapidly degrading, and by mid- to late June the animals pass through the Bering Strait to the degrading ice pack in the Chukchi Sea.

Belukhas and other whale-type mammals follow the receding ice as they disperse northward and inshore. Few individuals inhabit the loose ice of the front. The zone along the northwest coast of Alaska between the permanent polar ice pack and seasonal drifting ice provides a pathway for north-migrating bowhead whales in spring. The bowhead whale is of special interest because of its importance to the native population. It is an ice-associated whale that has inhabited Arctic waters on both the eastern and western sides of the North American continent. This species was once widely distributed, but the last concentration of bowheads was reported as being restricted to the Bering, Chukchi, and Beaufort Seas, where there were about 2,250 whales in 1979. The bowheads spend most of their lives in or near the edge of the ice pack, migrating north as the ice recedes in the spring, and south as it extends in the winter. They winter in pack ice from St. Lawrence Island south to St. Matthew Island, or, in heavy ice years, to the Pribilof Islands. In the spring, they follow open leads through the Chukchi Sea and around to the Mackenzie Delta area, where they summer. Bowheads may penetrate over 1,500 miles into the pack ice via lead systems, and can break holes in ice up to 10 inches thick.

Rare, Endangered, and Protected Species

The Endangered Species Act of 1973 provides for the conservation of species that are either presently endangered or threatened with extinction. The current list of endangered and threatened species includes eight species of whale (bowhead, gray, fin, humpback, blue, sei, right, and sperm), and four species of birds (peregrine falcon [American and Arctic subspecies], Aleutian Canada goose, Eskimo curlew, and short-tailed albatross) that inhabit Alaska.

In addition to these species, the bald and golden eagle are similarly protected by specific federal law. Disturbing, harassing, or killing of any of these species is punishable by heavy fines, imprisonment, or both.

The Marine Mammal Protection Act of 1972 prohibits the harvest of marine mammals by U.S. vessels or foreign vessels using U.S. ports, with the following exceptions: for subsistence by certain Alaskan natives; for display and scientific collections; and for harvest of the fur seal, which is regulated by international treaty.

CHAPTER THREE: EXPLORATION

History

Exploration in Arctic Alaska began with the U.S. Geological Survey's surface work in 1901. Oil seeps were recorded in 1904 on what is now the National Petroleum Reserve-Alaska (NPRA). This 23.6-million-acre area was designated the Naval Petroleum Reserve Number 4 (NPR-4) by Executive Order in 1923. The Navy sponsored geological mapping from 1923 through 1926 and an extensive geological mapping and drilling program from 1944 through 1953. Nine noncommercial oil and gas fields were discovered. The NPR-4 was redesignated the NPRA in 1976, and jurisdiction was transferred from the Secretary of the Navy to the Secretary of the Interior. The Navy's exploration program on NPRA stimulated industry interest in the North Slope area between the NPRA and the Arctic National Wildlife Refuge (ANWR).

Four cycles of exploration have occurred on the Arctic North Slope since 1962 (Figure 5). Each surge in exploration can be clearly related to acreage availability or the anticipation of acreage availability for private industry exploration.

Cycle I began with basic geological field mapping. As land became available for leasing, blocks of acreage were acquired by various companies. Evaluation of leases by gravity and seismic surveys and exploratory drilling peaked in 1964. Lack of success in exploring the structures in the foothills region led to a decline in activity. Land was still available for lease in 1966, but industry interest was moved from the foothills region northward to state lands by rumors of a federal land freeze. This land freeze occurred in late 1966, and the oil industry was limited to evaluation of state leases acquired in 1964 and 1965.

Cycle II began with the Prudhoe Bay discovery on state land in 1968. Exploration activities surged with efforts to evaluate the significance of Prudhoe Bay, then declined through 1972 as leases were evaluated. Much geologic field work took place in anticipation of possible lease agreements with the natives and the possibility of future state and federal lease sales, but it declined in 1973 as geologic field mapping neared completion in the Brooks Range and foothills, and no new acreage became available.

Cycle III started in the early 1970s with renewed government exploration of the NPRA. Companies that were successful in negotiating land and exploration agreements with the Arctic Slope Regional Corporation conducted additional geologic field studies and seismic evaluation of the foothills area. Speculative and proprietary seismic surveys were conducted in the Beaufort Sea in anticipation of a state lease sale in 1976. Perimeter drilling around the proposed sale area also increased. But all activity decreased as a result of postponement of the sale.

Cycle IV started when the Beaufort-Outer Continental Shelf (OCS) joint federal/state sale was rescheduled. Seismic and drilling activity increased in 1977, 1978, and until immediately before the 1979 sale.

A reasonable projection for the future is that an increase in activity will take place prior to the 1982 offshore sale. After the sale,

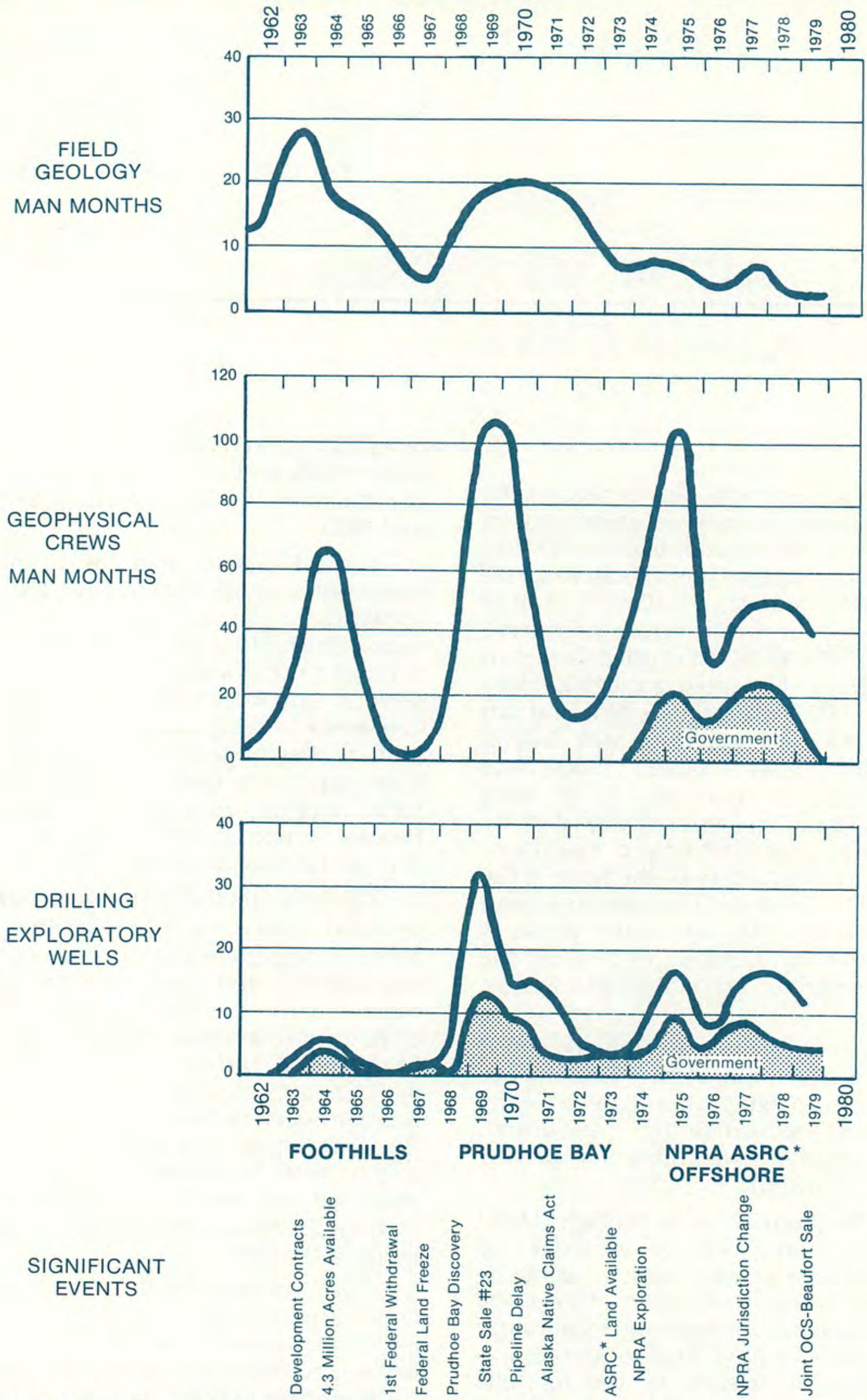


Figure 5. Arctic Slope Exploration Data from American Association of Petroleum Geologists.

Arctic Slope Regional Corporation.

levels will again fall until additional leases become available.

Opening the ANWR or ending the federal land freeze would greatly stimulate additional private industry exploration activity.

Status

Region I—Onshore, North of the Brooks Range

Foothills

A few companies have sufficient gravity studies, magnetics studies, photo surveys, geological field studies, reconnaissance surveys, and detailed seismic surveys to acquire land and drill immediately. Other companies would probably require a year or more to adequately prepare for leasing because of their lack of proprietary data.

Coastal

Most interested companies have extensive geological and geophysical information and are now prepared for any lease sale in the state lands area.

National Petroleum Reserve-Alaska

No industry exploration has been permitted within the boundaries of the NPRA since the area was originally removed from the public domain in 1923. Extensive exploration has been carried out under government contract. Lease sales are scheduled for December 1981 and May 1982. The industry will be prepared for additional sales during the next several years.

Arctic National Wildlife Refuge

The Alaska National Interest Lands Conservation Act (ANILCA) of 1980 allows for preliminary seismic exploration after December 1983 on the 1.2-million-acre ANWR coastal plain following a two-year wildlife study. Exploration is to be limited to the area between the Canning River and the Aichilik River (Beaufort Lagoon) on the coastal plain. No further exploration, leasing, or drilling can be done without Congressional approval.

The area to be opened on the coastal plain within the ANWR covers approximately 1,900 square miles. A 1.5-mile by 1.5-mile grid of vibroseis seismic data in the areas of interest could be acquired by four crews in the field during the first winter season, and by two or three crews in the second season. Individual participants in such a group seismic program could be prepared for a sale the following year. If the seismic effort were reduced to two crews, three seasons would be required prior to a sale.

The seismic programs would be conducted after freeze-up in winter and before breakup in the spring, thus avoiding any conflict with the period of caribou migration across the coastal plain of the ANWR. Migratory birds and waterfowl would not be present in the area while the program was being conducted.

Region II—The Bering Sea

Basic geological field work has been done by industry and government agencies in the surrounding land areas. Gravity, aeromagnetic, and reflection seismic surveys have been run offshore on a reconnaissance basis as well as detailed proprietary seismic surveys in some of the basins.

The exploratory programs in the southern basins (Bristol Bay and St. George) and in the northern basins (St. Matthew-Hall and Norton) are sufficiently advanced that a majority of the interested oil companies would be prepared to bid in a lease sale during 1982 and 1983. Additional Continental Offshore Stratigraphic Test (COST) wells have been proposed and would be helpful. Due to its size and extreme remoteness, the Navarin-Zhemchug basinal complex would need additional seismic data. Proposed additional COST wells would also provide valuable information.

Region III—The Beaufort and Chukchi Seas

Beaufort Shelf

Gravity, magnetics, reconnaissance, and detailed seismic surveys have been made. The location of a lease sale would determine whether additional seismic work was necessary. The industry is prepared to bid immediately in areas adjacent to previous sale areas and would require one season of seismic work in other areas. Several seasons would be needed in more remote areas of deeper water if ice conditions were unfavorable.

Hope Basin

Geology, gravity, magnetics, and reconnaissance seismic data are essentially complete. One season of detailed seismic work may be necessary prior to a sale.

Central Chukchi Shelf

The southern portion and the area within a few miles of the Alaskan coast have been explored by reconnaissance seismic lines. The western portion has no seismic coverage. Approximately two years of successful seismic work may be required prior to a lease sale in the eastern sector. Because of potentially poor, prolonged ice conditions in the western sector, more time would be necessary for seismic work. Ice conditions would dictate the number of years required to complete exploration.

North Chukchi Shelf

Little exploration work has been done in the northern Chukchi Basin. Some basic reconnaissance seismic lines have been run. Several seismic seasons would be required for adequate coverage prior to any lease offering. A clear distinction exists in ice-covered areas between calendar years and successful working seasons.

Current Exploration Technology

Exploration to identify an oil or gas prospect in Arctic regions is fundamentally no different from exploration in any other part of the world. The same basic procedures are used with modifications to accommodate the harsh Arctic environmental conditions.

Geological

The geologist usually looks for three basic elements in the search for petroleum: first, the source beds of shales and limestones that originally contained an abundance of organic remains; next, the porous sandstones or limestones that later became the reservoir beds for migrating oil and gas; and finally, the trap that sealed off the reservoir beds and held the hydrocarbons in place.

Field work in the Arctic is similar to that in other areas except for the short season in the Arctic. Geological crews are transported by helicopter in Arctic areas to avoid terrain damage by wheeled vehicles.

The most important geological activity in frontier offshore areas is the sampling of sea bottom outcrops. In no other way can initial information on the character of the rock, its stratigraphic data, and the thermal history of the subsurface be collected. Outcrops are abundant along the continental slopes of the Bering Sea, and probably along the Chukchi and Beaufort Seas and the flanks of the Aleutian Ridge.

Ocean floor samples are recovered by a grab device lowered from a vessel or from shallow cores obtained by penetrating the ocean floor with jetting action or with a weighted tube, which can penetrate to about 75 feet. Core drilling to a maximum of 350 feet may be done after special permits are obtained.

Photographic and Sonar Surveys

Photographs of terrain taken from aircraft flying at constant altitudes are interpreted in the office; they are used to map surface geology, aid in planning field visits, and select sites for sampling, drilling, and other surface facilities. Photography is done in strips of consecutive exposures with successive overlap of 60 percent to provide for stereoscopic interpretation.

Sonar (reflected sound wave) surveys are used to map the ocean floor in a way comparable to onshore aerial photography. Sonar can measure vertical water depth and, with side scan, reveal the dimensions of submarine ridges and trenches and the shape of the continental slope.

Geophysical

In the search for oil and gas, geophysical and geological studies are complementary. Geophysical measurements taken at the surface provide the major clues for locating potential subsurface reservoirs that may contain hydrocarbons. Sedimentary basins are first located and mapped by broad surveying techniques. The potential of these basins for generating hydrocarbons is assessed and structural traps where oil or gas could accumulate are identified.

Basins are explored by airborne magnetometers, gravity surveys, and other geophysical surveys. The surveys are conducted in the same manner in continental, offshore, and Arctic areas.

The major geophysical technique used in oil and gas exploration is the seismic reflection survey, which is run before the first exploration well is located. Additional surveys help outline a field during development. Interpretation of the sonic wave travel time from the seismic energy source at the surface to one or more reflecting discontinuities and back to the surface at many locations furnishes data to construct subsurface contour maps. Consideration of these maps and supporting geological data can indicate the most likely locations for hydrocarbon accumulation.

For seismic reflection surveys, the energy source at the surface has classically been created by firing a small dynamite charge in a shallow borehole 50 to 200 feet deep. Modern technology has developed other seismic sources to replace the dynamite charge. Compressed air charges are used almost exclusively in marine seismic surveys. Vibratory sources are the fastest growing dynamite replacements on land because of economics, environmental considerations, and technical advantages. A variety of other sources are used for special applications.

Vibrators are used on the North Slope, where seismic work is done only on frozen ground. Compressed air discharged through holes drilled through floating ice is successfully used in the Arctic Ocean. The Beaufort Sea area adjacent to the coast and offshore to the vicinity of ice pressure ridges (about 30-foot water depth) was precisely surveyed using land crew equipment (vibrator sonic source) on the ice when the thickness was 48 inches or more.

Exploration Drilling Systems

Worldwide, offshore exploration drilling is conducted primarily from mobile drilling rigs. In late 1980, the world mobile drilling rig fleet of 471 units in service included 22 submersibles, 115 semi-submersibles, 250 jack-ups, 38 drill ships, 15 dynamically positioned drill ships, and 31 drill barges. These exploratory drilling units have proven their capability, applicability, and seaworthiness in various environmental conditions throughout the world. The types will be described in the NPC report entitled *Environmental Conservation*, to be published in 1982.

Arctic exploration drilling began onshore in 1961 and gradually moved offshore in the early 1970s. A number of wells have been drilled from manmade ice and gravel islands in water depths to about 65 feet. Conventional drilling vessels, such as jack-ups, drill ships, and semi-submersibles, have been utilized in sub-Arctic and Arctic offshore areas during open-water seasons.

Arctic operators have proposed various concepts for operations in ice-covered waters beyond the economic ranges of the manmade islands. These concepts are presented in more detail in Chapter Four.

Exploration Drilling Systems Suitable for the Arctic

Region I—Onshore, North of the Brooks Range

Conventional land drilling rigs modified for extreme cold weather have been used successfully for over two decades in northern Alaska.

Region II—The Bering Sea

Exploratory drilling operations in the nearly ice-free conditions of the southern Bering Sea (Navarin, Bristol, and St. George Basins) could utilize many of the conventional drilling units. The ice conditions and the wind/sea states must be considered for all vessels proposed. For winter operation, these vessels may require modification to prepare them for ice loading.

The northern Bering Sea (Norton) is ice covered for five to seven months annually; seasonal drilling programs using mobile drilling vessels are applicable within their depth range. In water depths of less than 60 feet, artificial gravel islands may be applicable.

Region III—The Beaufort and Chukchi Seas

Up to about 70° latitude in the Chukchi Sea, water is generally less than 150 feet deep and the ice conditions are more severe than south of the Bering Strait. Open sea periods with 50 percent ice coverage last between four and five months. This area may be too shallow for conventional floating vessels. Manmade islands for year-round operations in water depths to 60 feet and perhaps jack-ups with seasonal drilling capability for water depths ranging from 25 to 200 feet in the southern Chukchi Sea are favorable options. Bottom-founded structures such as cone-type gravity platforms may be applicable for year-round operations in water depths ranging from 60 to 200 feet.

North of 70° latitude in the Beaufort and Chukchi Seas, the annual ice-free season may last only one or two months. Ice conditions in these basins are the worst of the offshore basins. Water in the Chukchi Basin is less than 300 feet deep, and the Beaufort Basin extends from the shoreline to about a 700-foot water depth. Manmade islands in water depths of less than 100 feet and gravity cone structures for greater water depths are most favorable in these areas.

Continental Offshore Stratigraphic Test (COST) Wells

A COST well is an important source of information for exploration in OCS frontier areas. The USGS can permit a group of companies to drill such a well in order to obtain geological information. All coring and logging information becomes proprietary to the participating companies, but it is shared with the USGS in confidence. After a lease sale in the area this information may be released to the public by the USGS.

COST wells are located off structure to avoid hydrocarbon accumulations and to obtain maximum stratigraphic information. If oil or gas shows are encountered, the well must be plugged and abandoned immediately. The permit and target depth would ordinarily be the economic basement, or about 14,000 to 16,000 feet below the ocean floor. The same rules for the USGS/OCS apply to securing permits and to drilling, casing, and abandonment as to a regular exploration well. All COST wells must be plugged and abandoned when logging is completed.

Future Exploration Technology

While existing geological and geophysical technology is adequate for assessment of most geological prospects, advanced technology that will have widespread applicability is being developed and should soon be available. Research by industry, the USGS, academia, and geophysical contractors will continue, as demonstrated in the past, to develop the necessary technology.

Greater Computer Capability

There is great potential for enhanced computer capacity to handle the tremendous variety and complexity of geological data. The amount of information now available concerning basins is beyond the capability of current technology to integrate it into a thorough geological study. In the future, it should be possible for each geologist to have a personal computer console capable of accessing all available data and displaying the data as an integrated whole. Portions of the total program are available but the software to integrate all of the data remains to be written. The present computer storage capability is not sufficient to do the necessary tasks at a reasonable cost.

Continuous Coring

Drilling technology that would enable the acquisition of a continuous core while drilling without bringing the drill bit to the surface would be a significant advance. Oil exploration would be improved if the entire geologic section could be measured, examined, and described.

Geophysical

The recording of all parts of the electromagnetic spectrum will eventually be required in exploration. Investigations are required to determine whether additional portions of the electromagnetic spectrum could be useful in providing additional information on the physical properties of the earth. Present exploration techniques individually measure earth properties by visible and infrared light and magnetic, electrical, and sound waves. Computer enhancement of extremely weak signals may make measurement of other parts of the spectrum useful.

The processing of geophysical data is possible in the field at present, but much of the processing still takes place elsewhere. Several months may pass between recording and receiving a final product to be interpreted. If computer capacity to perform the necessary calculations were immediately available in the field, a finished product could be interpreted, changes in program could be accomplished, and possible reshooting might be avoided.

Much effort is involved in obtaining usable seismic records, as evidenced by the persistence, endurance, and sacrifice of the individual members of the crew, all working under difficult operating conditions. Automating more operations would increase efficiency and save time.

Each Arctic environment—onshore, summer, winter, shallow water, and marine—has one particular seismic procedure that gives optimum results. Optimization of field parameters and seismic sources would increase exploration efficiency and result in significant cost savings.

Recording seismic signals through permafrost has been a continuing problem in the Arctic. Applying velocity corrections in both the vertical and horizontal directions as permafrost behavior changes is somewhat empirical. Permafrost responses to changes in depth and temperature can be modeled, but the process is not completely understood.

New methods are needed for seismic exploration under severe ice conditions, especially those involving moving ice. The operating window has been extended slightly but not to the extent required to explore freely in recording grid patterns in ice-prone basins. The physical environment severely limits seismic efforts.

Geological

The publication of industry paleontological information has been limited in Alaskan Arctic regions, and no extensive literature exists. Micropaleontological and palynological studies by industry personnel are often more advanced than those being conducted by government and academia. There is limited exchange of data and correlations between Arctic experts. Publication of such information is desirable.

Many geological societies, government agencies, and others have published atlases of the geology of their particular areas of interest. This has not been done in Alaska, and is needed.

In certain areas of the North Slope, the peculiar Arctic environment and geological history have contributed to the formation of minerals rarely encountered elsewhere in significant amounts. Some of these minerals, such as siderite and pyrophyllite, have been casually mentioned in the literature, but the scarcity of published information has slowed recognition of these well-logging problems by the general industry.

An accurate geological reconstruction of the history of oil generation, migration, and accumulation depends on absolute age determinations of the investigated rocks. Nearly all geological interpretational controversies arise because of the lack of such data. New techniques of dating are essential to the progress of geological understanding.

Cost Factors

All cost data are presented in constant January 1, 1981, U.S. dollars and do not account for future inflation.

It is significantly more expensive to conduct exploration in the Arctic than in the lower 48 states. Costs of each exploration project must be estimated from a "site-specific" analysis and can vary widely depending upon the specific environment at the location of each project, which dictates the technology used. Costs are also based on the availability of equipment in Alaska and the timing of weather windows during which work must be conducted, including the cost of "downtime" due to bad weather. The cost of exploration programs includes only that which might be termed "onsite data gathering" and does not include the significant costs entailed in interpreting and evaluating data. Nor does it include the possible substantial costs caused by delays resulting from changes in governmental policy or delays resulting from regulatory or permitting procedures.

Geological

The most critical cost items are the number of people involved, the duration of the project, and the aviation support required. Costs for helicopter-supported geological field parties for the North Slope, Bering Sea, and Chukchi Sea regions range from $100,000 to $125,000 per month. Estimates are for parties working both from a permanent base and from a temporary camp, based on a duration of 30 days with four geologists, one pilot, and one mechanic. Salary and overhead are $5,000 per month per geologist. Cost assumptions include air transport of fuel, personnel, and camp equipment from Anchorage and two geologists from the western United States. Some chartered, fixed-wing support is necessary throughout the field season.

Geophysical

Region I—Onshore, North of the Brooks Range

Mobilization/demobilization costs and monthly costs are about the same for crews on the ice and on the coastal plain, and will average between $12,000 and $16,000 per line mile. More remote work near the Arctic foothills costs between $25,000 and $45,000 per mile, depending on location, the length of the contract, the type of recording, and many other variables. Processing costs range from $150 to $500 per mile; special processing is necessarily more expensive. Dynamite crews cost about 25 percent more than vibroseis crews.

Work can begin on the Arctic Slope in late November or early December and can continue until breakup, which takes place about May 1. December, January, and February are generally very poor operational months because of near-total darkness. Under such conditions some companies will not operate in areas of rough topography because of the possibility of damage to equipment, which could preclude crews from taking full advantage of the better operational months of March and April.

Region II—The Bering Sea

A fully equipped, marine deep-water common depth point crew will cost between $3 and $4 million per month ($1,500 to $2,000 per line mile), depending on equipment, mileage, and line layout. This estimate would be for a full season or four-month minimum contract and would cover data acquisition only. Average processing costs range from about $250 to $500 per mile. Assuming 2,000 miles per month, processing costs of $500,000 to $1,000,000 per month would be added to the recording costs. The mobilization/demobilization cost is included in this total.

The weather window in the Bering Sea is from June 1 until September 15. Some work might be done in October, but this is uncertain because of the likelihood of storms. The signal/noise ratio of the data decreases later in the season because of deteriorating weather conditions.

Region III—The Beaufort and Chukchi Seas

In the Chukchi Sea, deep-water marine seismic survey costs might run a minimum of $2,000 to $2,500 per mile and could be much higher because there is an average of only one operating season every five years. Experience in this area is limited and costs are based on open-water shooting.

The weather window in the Chukchi Sea is ice dependent. Operations may be possible during portions of July and August, and possibly as late as September 15. In this window, about 2,000 miles per month could be acquired, depending upon ice and weather conditions. Boats in the Chukchi Sea have no nearby port for support and must be entirely self-sufficient.

Costs in the Beaufort Sea for deep-water marine seismic surveys have averaged $8,000 to $10,000 per mile. Boats must be "frozen in" and must be available for a possible 30-day working window. Vessel availability is very limited because an ice-strengthened hull is required.

The Beaufort Sea has a potential window from August 15 to September 15; the longest seismic season experienced lasted six weeks. In recent years, boats have been able to get into the Beaufort Sea only every third or fourth year. The maximum surveyed by any single boat has been about 1,500 line miles.

Drag cable or teleseis surveys from a shallow-draft boat already in the Beaufort Sea that could expect to get between 150 to 600 miles of coverage would cost about $4 million for a complete season. To bring a boat in would cost an additional $500,000 to $600,000 for mobilization and demobilization. Additionally, part of the season would be lost moving to the area. The boats could be supplied and serviced out of Prudhoe Bay, Barrow, or other locations along the coast. The shallow water season ranges from 55 to 85 days in the window from July 15 to October 1 and is strictly ice dependent.

Mobilization and demobilization costs for a Beaufort Sea ice seismic crew run about $400,000 if the crew is already on the North Slope. If the crew is brought up from the lower 48 states, costs could run $700,000 to

$800,000. The crew costs about $1.5 million per month to operate. Costs per mile would average about $8,500 to $12,000. Processing costs average about $750 per mile.

Work on the ice can usually begin between January 15 and February 1 near shore when the ice has frozen to a 48-inch thickness. Ice work further out is not feasible until about February 15 or later. Permit stipulations require that no work be done on the ice in water depths of greater than 18 feet after March 15 because of the possible disturbance to pupping ringed seals. Work may continue on nearshore ice until about May 1 if ice conditions are suitable. Crews are supplied by aircraft out of Deadhorse, Barrow, or Anchorage.

Exploration Drilling Costs

Exploration drilling costs have been estimated by applying a daily rig rate to the estimated time to drill to an objective depth, including moving on and off location. The total exploratory well drilling costs were estimated by adding logistic support to drilling system costs and multiplying by a downtime factor. Any fixed costs, such as gravel islands or access roads, were added. Exploration well cost estimates range from $10 million each on the North Slope to nearly $50 million in the Navarin Basin, and approach $100 million in the Chukchi Basin. Exploration well costs used in the economic analysis are presented in Appendix E, Part I.

Exploration Scenarios

In order to show how the exploration procedures interrelate with an overall oil and gas development program, three example scenarios are presented: one represents North Slope onshore exploration and two pertain to offshore extremes ranging from the Chukchi Sea to the southern Bering Sea. The Beaufort Sea and the region between the Chukchi and Norton Basins would be intermediate situations.

In each scenario it is assumed that the areas described are relatively unexplored, that large areas, completely covering entire structures, are readily available for lease, and that the exploration process is unencumbered by governmental permits and regulation delays. Each scenario represents the minimum time under ideal business conditions. Constant dollars are used in the cost analysis. Costs shown in the illustrations are intended to show the timing and relative amounts of investment only, and were not used in the economic analysis presented in this report.

The assumption is made that a prior two-year period of data acquisition has occurred because of preliminary announcements of forthcoming lease sales.

Region I—Onshore, North of the Brooks Range

A scenario showing typical costs and timing for exploration activities in Region I is presented in Figure 6.

Field work is necessary to define the geology of an area and to understand the regional stratigraphy and structure. Photographic, magnetic, and gravity surveys are either conducted separately or in conjunction with seismic surveys. Locations are determined from data derived from the field and from photo and magnetic surveys. The results of these studies are combined into basic interpretation packages and decisions are made as to the areas that deserve additional exploration.

If leases are to be obtained by competitive bidding, a regional grid of seismic data is acquired, usually by a group of companies that select one company as operator and share costs and basic data. Additional proprietary seismic surveys can be run by any member of the group.

Most of the exploration cost prior to leasing is for seismic operations. Geophysical costs would peak immediately prior to the lease sale and decrease slowly after the sale as individual leases are evaluated and drilling locations selected.

Exploratory drilling starts when rigs are available, permits are granted, construction of drill sites, airfields, and roads are completed, and other support services are in place. If a discovery is made, several wells are necessary in order to delineate the field.

It is assumed that one major field is found and developed by a group of leaseholders in a unit operation. Development drilling is conducted along with exploratory

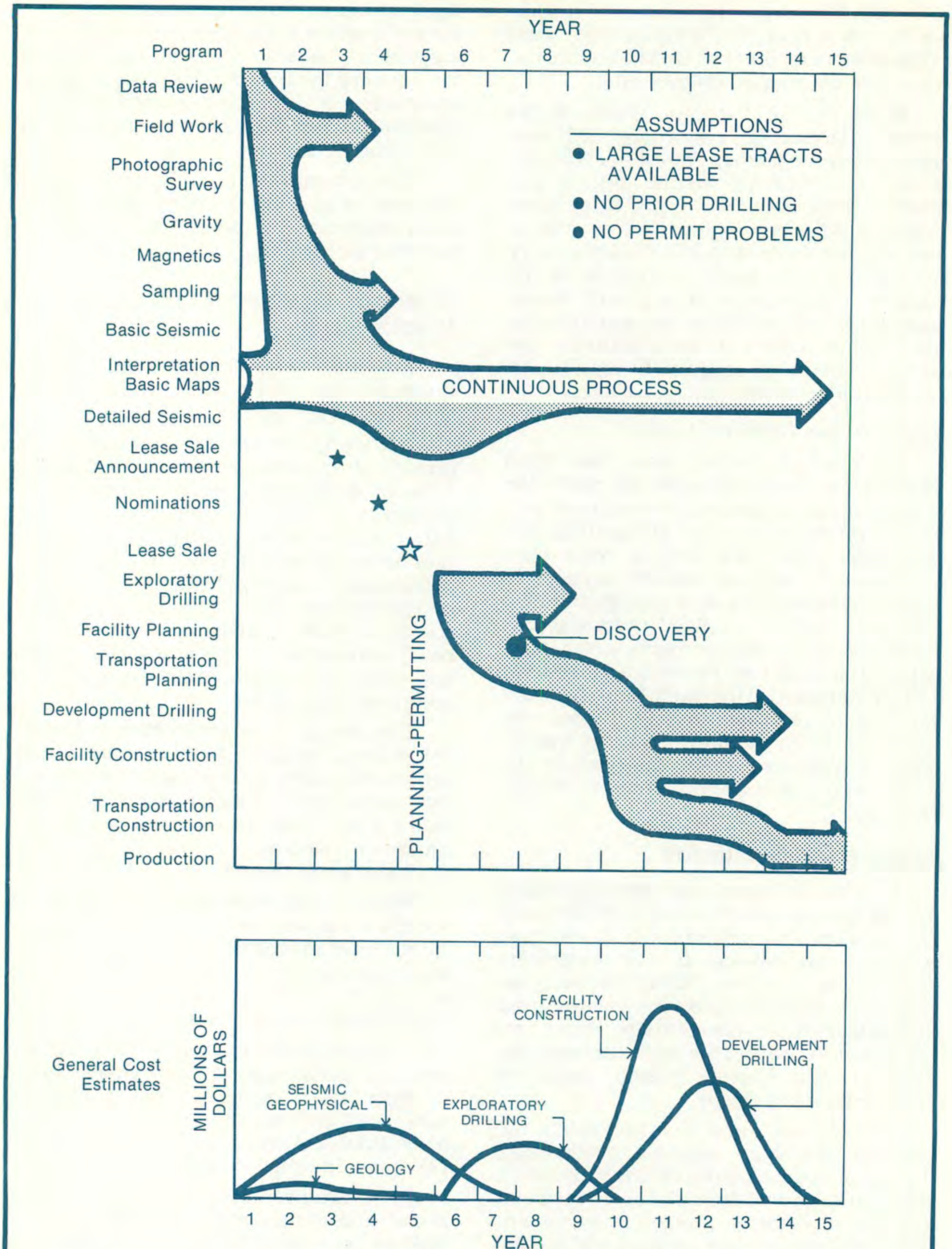


Figure 6. Region I—Onshore Exploration.

extension wells while production and transportation facilities are constructed. The scenarios for production are presented in Chapter Four, and transportation in Chapter Five.

Region II—The Bering Sea (Moderate Ice)

A typical scenario for operating in Region II is shown in Figure 7. When no pack ice is present, offshore Arctic basins can be explored in the same way as other offshore basins throughout the world. The logistics may be difficult for personnel and supplies, but the exploration program is normal. Photographic surveys are not necessary, but bottom sampling for hydrocarbon indications is important.

Outcrops at the margin of the basin are examined for geological clues. Basins can be outlined approximately by aeromagnetic surveys and refined by combined reconnaissance seismic and gravity surveys.

In new, undrilled basins, one or more COST wells are part of the usual exploration procedure prior to a lease sale. Such wells are designed to gather stratigraphic information about the types, composition, age, and maturity of the sediments that fill the basin. Wells are drilled as near to the deepest part of the basin as possible and far from any trapping situation where hydrocarbons could occur.

After a lease sale is announced, detailed seismic surveys are run to evaluate the prospective areas of the basins. In a highly prospective basin, many group shoots and proprietary surveys are run and the geology is reasonably well known prior to bidding.

Exploration drilling will begin as soon as capable mobile offshore drilling rigs can be moved into the area. It is assumed that an operator uses one rig the first year, two the next, and, if there is a significant discovery in the second year, four the following. Several confirmation wells will be necessary because offshore fields must be large and geologically simple to justify development.

Region III—The Beaufort and Chukchi Seas (Severe Ice)

A typical scenario for operating in Region III is shown in Figure 8.

Shifting pack ice and the lack of open-water leads where marine geophysical crews can operate safely are highly significant in the exploration of areas such as the Beaufort and Chukchi Seas. Timing of many exploration programs is dependent upon weather and ice conditions each year, and significant delays must be recognized as a probable part of a program.

Gravity surveys can be conducted on the ice as a separate survey, but they take longer than if conducted by boat. Aeromagnetic data can be recorded as easily as over land. Basic seismic reconnaissance data can be obtained by suitably equipped seismic vessels penetrating open leads in the ice. Seismic programs can be conducted on firm stable ice pack in much the same way as land.

Powerful icebreakers must be available to support the exploration vessels. These icebreakers will be necessary for use in opening leads for seismic lines, escort duties, and support to the working vessels. They could later be used to support exploration drilling.

Costs and economic risks are so great in the severe ice basins that very large fields will be necessary to justify development. To promote a better understanding of the geology, more extensive seismic surveys are required than in less hostile physical environments.

The presence of oil or gas accumulations can be proven only by drilling. Proof of economically recoverable reserves may require more extensive delineation drilling than under less hostile conditions.

As exploration moves further north in such areas as the Chukchi Sea, it will be necessary, in order to provide timely exploration, to develop systems that can drill throughout the year in an ice environment.

Findings and Recommendations

- Operators must have access to accurate weather forecasting in the Arctic.
- Adequate bathymetric maps of the sea bottom in the offshore areas should be available from continuing governmental activities.
- Icebreakers with shallow-water (20 feet or less) capability should be available in the

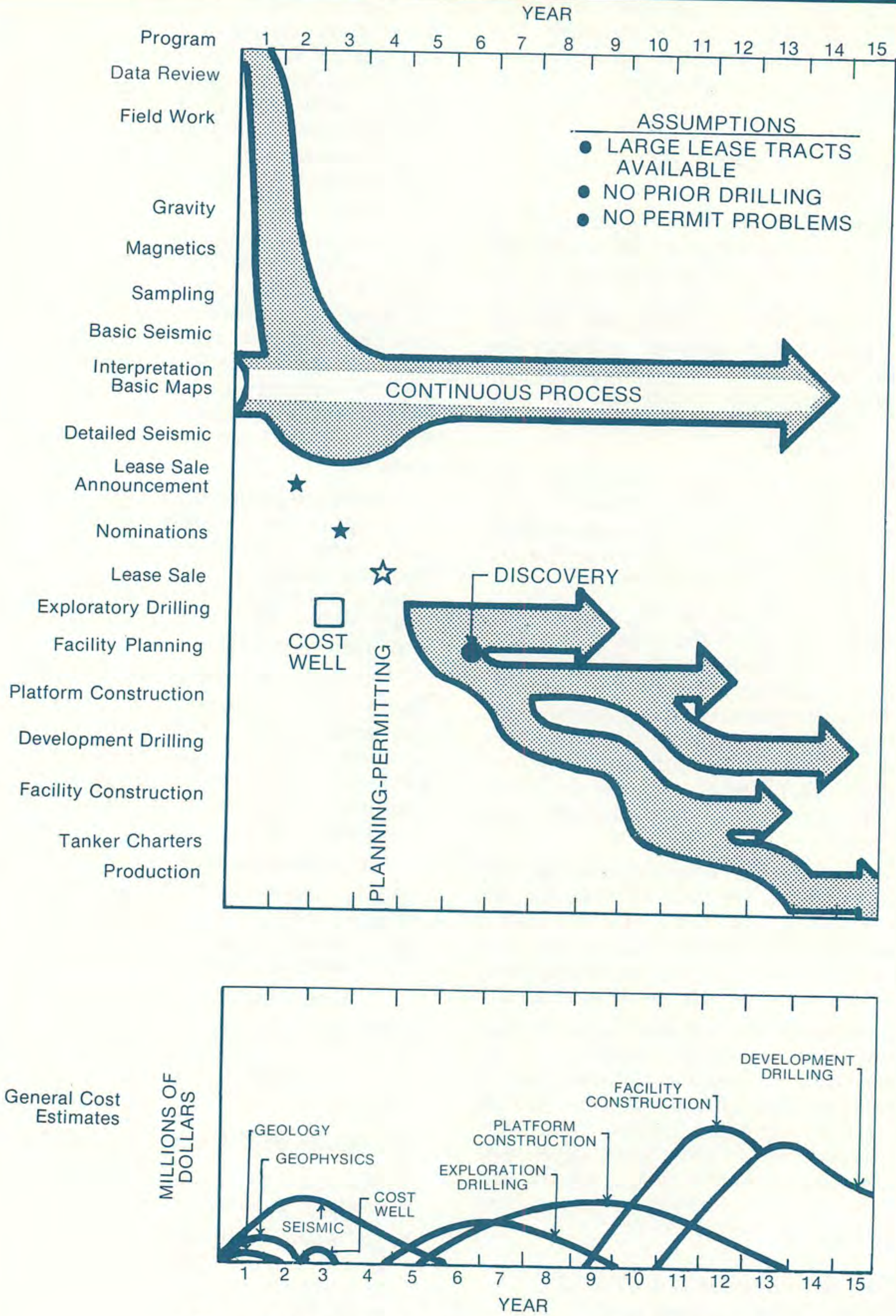


Figure 7. Region II—Offshore, Moderate Ice Exploration.

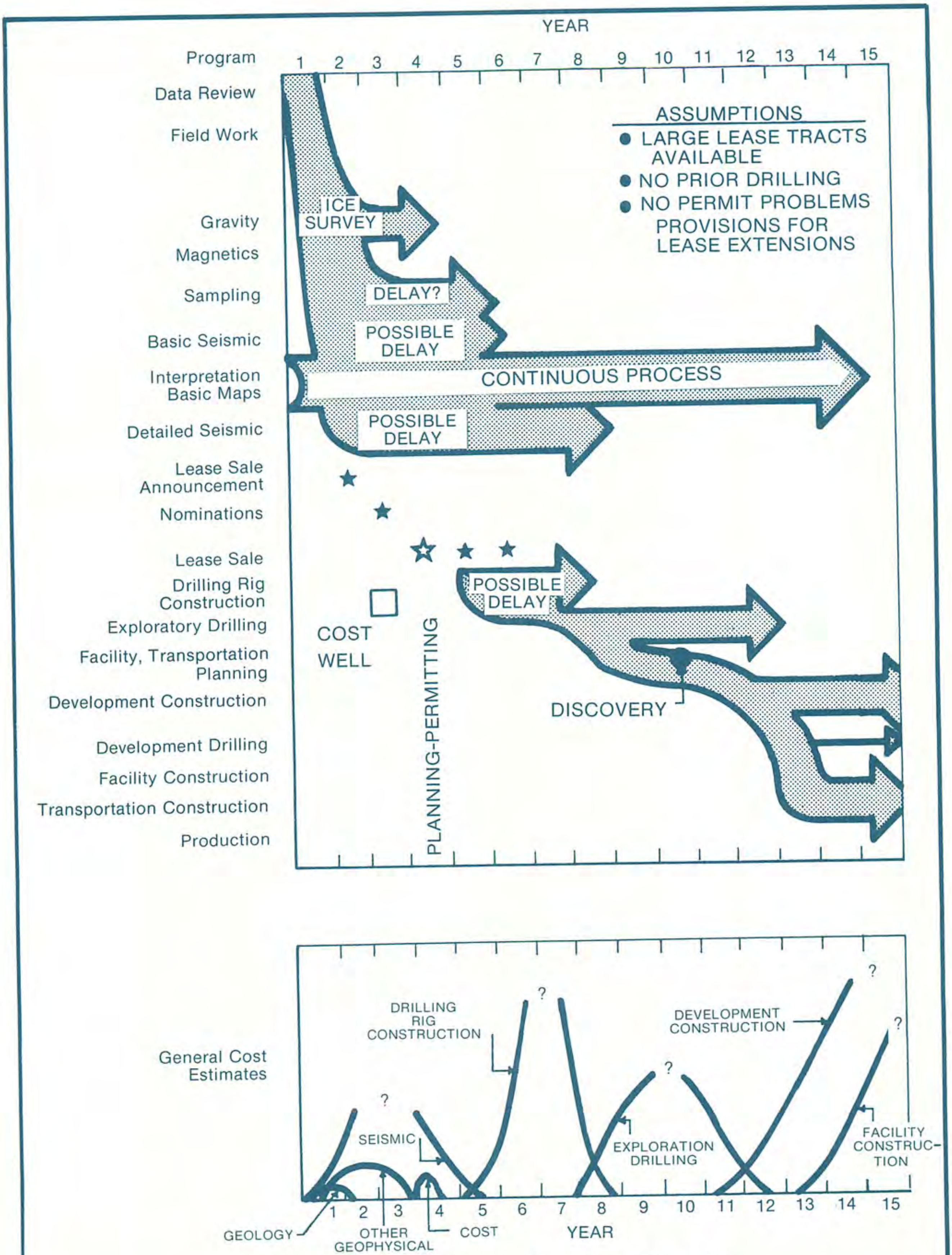


Figure 8. Region III—Offshore, Severe Ice Exploration.

area to help exploration and supply vessels in the ice-covered areas of the Arctic Ocean.

- Cooperation and data exchanges between the countries surrounding the Arctic Ocean on ice conditions, behavior, etc., should be routine.
- Basic geological studies of the natural environmental processes should be encouraged and funded by the government. Academic investigators find it expensive and difficult to plan continuing investigations of problems that require several years of field work and expensive logistic support. Long-range funding should be available for basic scientific investigations of the Arctic.
- Geological information obtained by governmental agencies should be disseminated on a timely and rapid basis.
- Basic long-range funding and adequate staffing should be provided for the Geological Division of the USGS and for other investigators working on long-range Arctic scientific problems.
- The Conservation Division of the USGS should not duplicate the exploratory evaluation work that is done in great detail by the oil industry prior to lease sales, nor should the USGS be required to make economic evaluations of lease tracts. The federal government should take advantage of "free market" bidding to evaluate leases.
- Exploration drilling systems are capable of drilling year-round in Region I, and seasonally throughout Region II and the southern portion of Region III. Systems for exploration drilling year-round in ice-covered areas are under active design and should be applicable in water depths of up to about 200 feet.

CHAPTER FOUR: PRODUCTION

History

From 1944 until 1953, the United States Navy, in conjunction with civilian drilling contractors, conducted an extensive exploratory drilling program on Naval Petroleum Reserve Number 4, now known as the National Petroleum Reserve-Alaska. No potentially commercial production was established.

During 1949 and 1950, in an effort to develop a natural gas fuel supply for Barrow, several South Barrow test wells were drilled, the first of which was placed on production in 1949. These were the first development wells completed in the three regions covered in this report. They furnished proof that hydrocarbons could be produced in the Arctic.

In 1968, the Prudhoe Bay oil field was discovered east of the NPRA within the permafrost area. The field was placed on continuous production when the Trans-Alaska Pipeline System was completed in 1977. During the early 1970s, extensive research and development was carried out to solve the many problems associated with oil operations in the high Arctic. The success of these programs is attested to by the fact that some 350 wells have been completed and oil is being produced, processed, and shipped daily from the North Slope.

There has been no offshore oil or gas commercial production in the U.S. Arctic region.

Status

The Prudhoe Bay field, which is producing 1.5 million barrels per day, represents all of the current oil production in the U.S. Arctic regions. The usual development and production maintenance activities are being carried on. Facilities are being installed for reservoir pressure maintenance by water injection, which is expected to maintain the production level through 1987.

The only new announced production facilities are currently being installed in the Kuparuk field, west of Prudhoe Bay. Production of 80,000 barrels per day is projected for 1982 and is expected to increase to at least 200,000 barrels per day by the mid-1980s.

Current Production Technology

The technology for the drilling and production of oil and gas in Arctic regions is fundamentally similar to that used in other parts of the world. The same basic procedures are used, but with much greater difficulty than in less hostile regions. This report addresses only technology specific to the Arctic. A detailed description of conventional drilling and production technology will be given in the NPC report entitled *Environmental Conservation*, to be published in 1982.

Platforms and Drilling

Region I—Onshore, North of the Brooks Range

The technology for drilling operations onshore in the Arctic has been well established by the Prudhoe Bay operation and it has been clearly demonstrated that operations can be carried out on a large scale without significant deleterious effects on the environment or native population. Aside from the hostile climate and the difficult logistics of operating in an extremely remote location, the most challenging technical problems encountered and solved were related to permafrost. Warm drilling fluids or warm oil in active wells leads to instability of the hole and consequent washouts, sloughing, and slumping. In idle wells, internal and external refreezing can collapse tubing and plug wells. In gas wells, plugging results from freezing of produced water and hydrate formation. These problems have been successfully solved in drilling and production of oil and gas onshore and are not expected to be an obstacle in future operations.

Region II—The Bering Sea

In development of offshore production, a platform structure must be provided for drilling and producing operations. The ability to withstand ice forces is the critical consideration in platform design for this region. Development platforms must be able to support drilling and production operations year-round. Seasonal production of an oil or gas field may be technically feasible, but it may be economically unattractive. With the establishment of a drilling and production structure, operations would be similar to those conducted onshore in Region I except for logistics problems. Since most of Region II is free of permafrost, drilling problems should be less onerous. The ability to cope with wind, waves, fog, and ice is a major challenge to operations.

In the northern Bering Sea (the Norton and St. Matthew-Hall Basins) field development can be safely and successfully conducted in water as deep as 60 feet using gravel islands, as illustrated in Figure 9. Gravel islands in deeper water would require multi-year construction, which is not considered practical due to the severe wave erosion that would occur during the portion of the season when construction must be suspended. In these same areas, gravity-based cone structures as shown in Figure 10 should be applicable in up to about 200 feet of water. In the southern Bering Sea (the Bristol Bay, St. George, Zhemchug, and Navarin Basins), development may be accomplished on gravity-based structures as depicted in Figure 11 in water as deep as 650 feet. Pile-supported structures as shown in Figure 12 may be used in water depths up to 200 feet in the southern Bering Sea. These platforms would be designed so that the wells would be contained inside the legs or within a supporting caisson to protect the wells from ice floes.

Major engineering and systems development remains to be carried out before design of these more novel structures is accomplished. The need to develop such structures will cause the petroleum operators to engage in research and development, data gathering, engineering design, economic analysis, and operations planning. As in the past, conservative designs will be optimized as additional information is developed.

Petroleum industry experience in Prudhoe Bay, Cook Inlet, and North Sea fields has proven that drilling and production can be conducted in cold, hostile, and remote regions, and that facilities for producing at high production rates, over 100,000 barrels of oil daily, can be modularized and successfully integrated into systems at an Arctic site or a platform at sea.

Fields can be expanded incrementally through the use of subsea wells. This method may provide the means for stepping out to reach narrow, elongated reservoirs and deeper water areas than can be reached with directional drilling from the bottom-founded structures. Conventional subsea completion technology would be adaptable to Region II.

Region III—The Beaufort and Chukchi Seas

Region III is dominated by severe sea ice conditions, where a year-round cover of multi-year ice may be encountered. Data on physical conditions in the Beaufort and Chukchi Seas are sufficient for the design and construction of manmade gravel islands in water depths to 100 feet. Gravity-based cone structures are prime candidates for supporting drilling and production facilities in water depths down to about 200 feet in this region.

Production gravel islands and cone structures would be designed for large multi-year ice floes with imbedded consolidated pressure ridges. The force of large pressure ridges requires permanent slope protection for gravel islands and large-base diameters for both gravel islands and cone structures. These permanent foundations

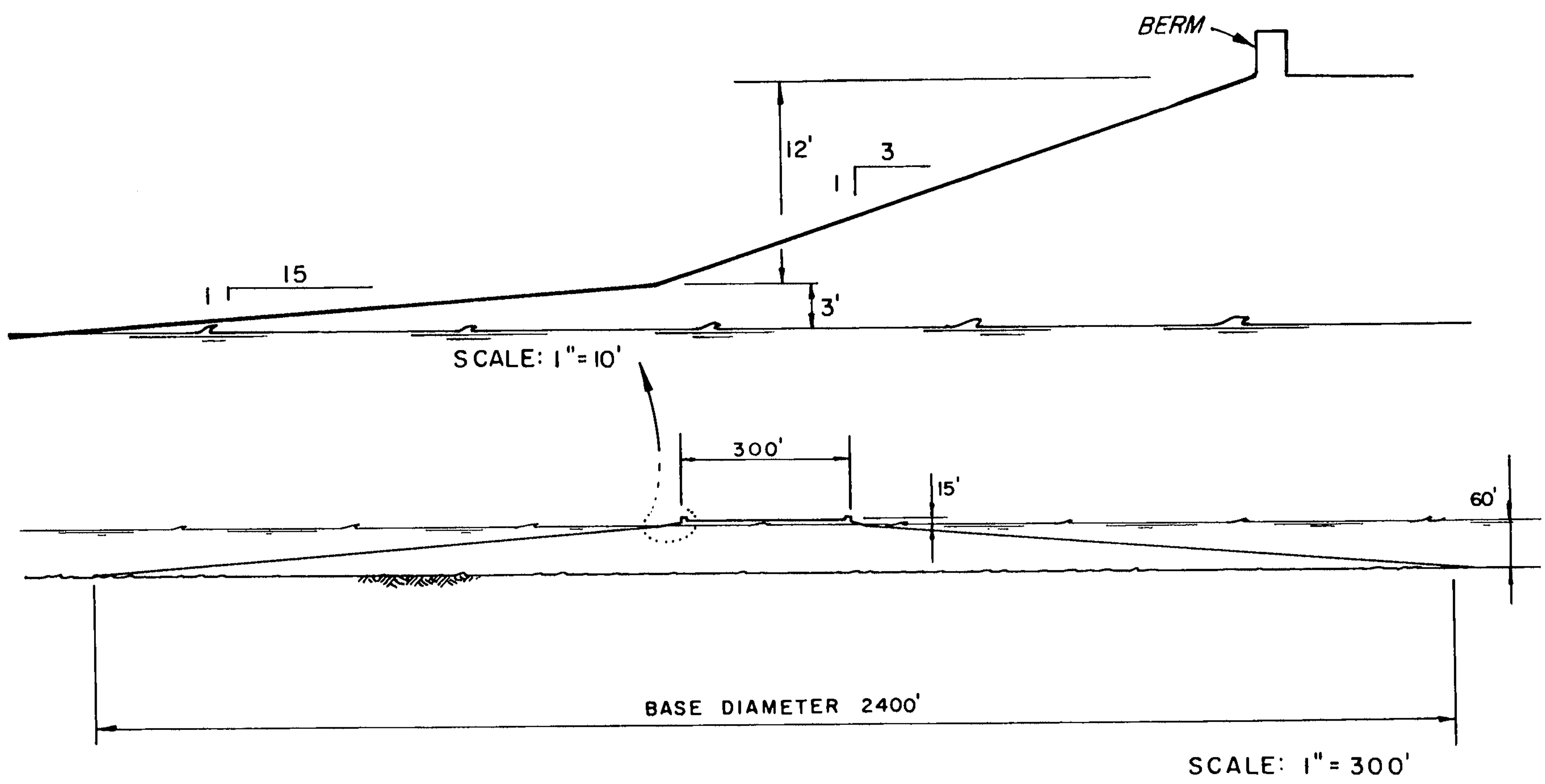


Figure 9. Elevation of Arctic Exploratory Drilling Island.

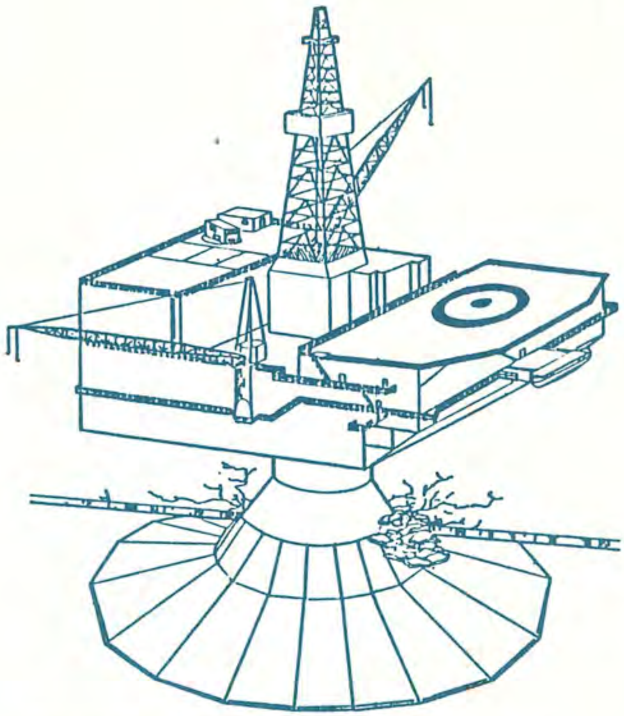


Figure 10. Arctic Conical Gravity Platform.

would be substantially more expensive, perhaps by an order of magnitude, than temporary islands for exploratory drilling.

The costs and duration of the construction season are important in determining the economic water depth limit of gravel islands. In the Alaskan Beaufort and Chukchi Seas the short open water construction season would force gravel islands of large volume into multi-year construction. This factor, plus the high cost of slope erosion protection required for production islands, will likely limit gravel islands to application up to the 100-foot range. Gravity-based cone structure designs applicable for supporting exploration and field development have been investigated for the Beaufort Sea in 150 to 250 feet of water off both Canada and Alaska.

Because permafrost can be encountered offshore, Beaufort and Chukchi Sea wells would probably be completed with casing programs, cementing techniques, and tubing strings similar to those used in onshore wells on the North Slope. Because of the high cost per unit of surface area on gravel islands or other offshore structures, the well spacing at the surface used for onshore clusters of wells may not be economically feasible for offshore wells.

Drilling rigs and support equipment would be conventional, with the exception of the extensive use of low temperature steels in critical components.

By extending current technology, subsea completions could be used for step-out wells in Region III. Concepts include placing the wellhead in a silo below ice gouge depths.

Production Facilities

Production facilities in the Arctic and sub-Arctic, both onshore and offshore, would be based on experience in Prudhoe Bay, the North Sea, and Cook Inlet. A typical onshore production facility consists of:

- Drill pads and flowlines from the drill sites to the central production facility

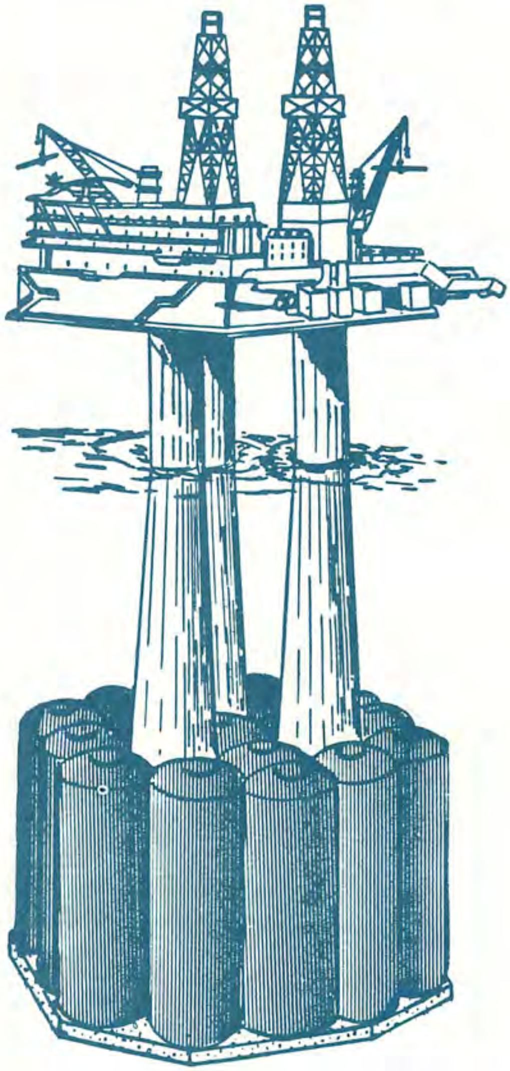


Figure 11. Multi-Tower Concrete Gravity Base Structure.

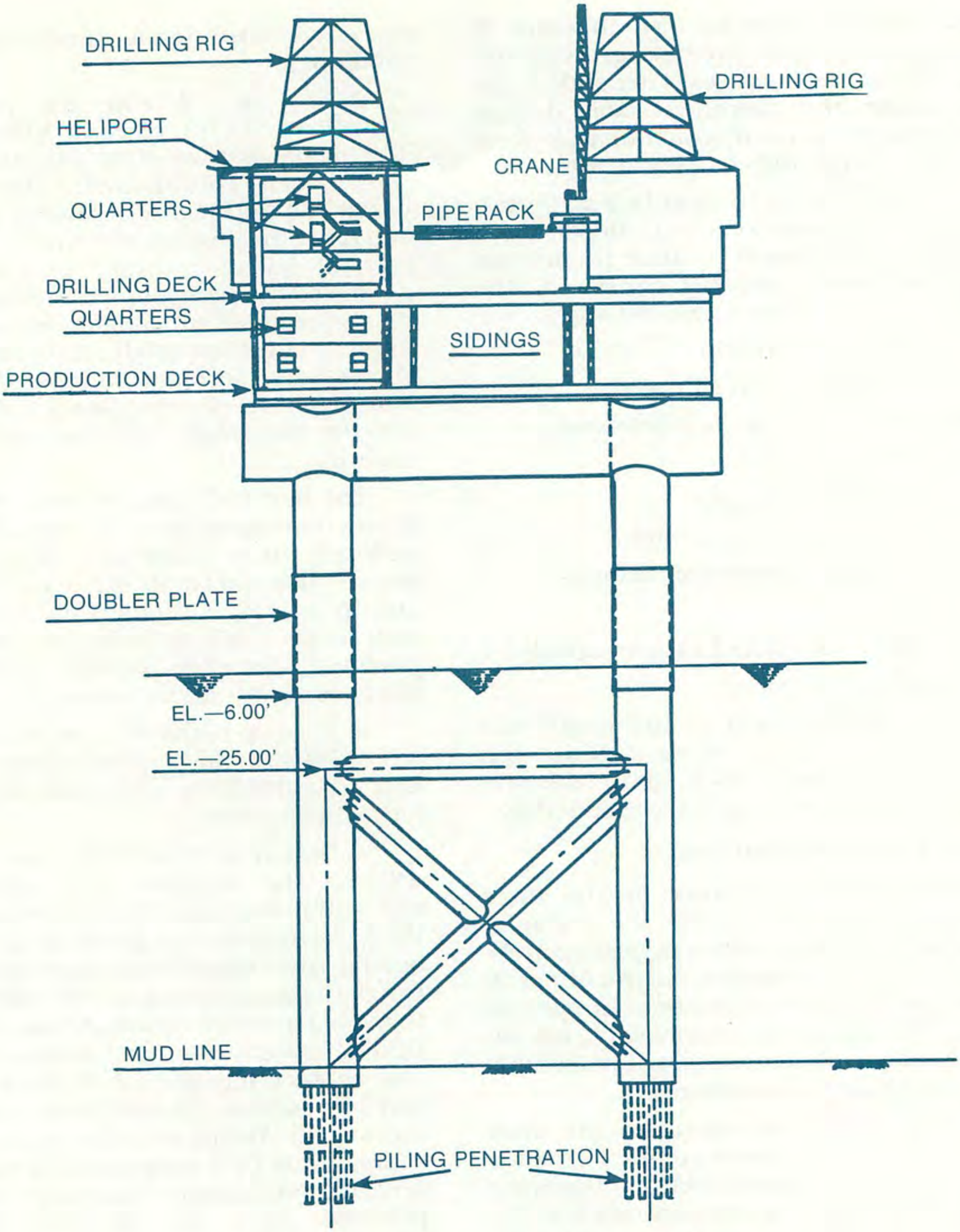


Figure 12. Four-Legged Cook Inlet Structure.

- Central production facilities capable of separating and treating oil and associated gas
- Non-associated gas pretreatment systems to remove liquids and contaminants and dehydrate the gas
- Gathering lines from the central production facility to the delivery point
- Utilities to provide power generation, water, waste treatment, and warehousing and maintenance facilities
- Operation center and construction camp consisting of sleeping, eating, and recreational facilities.

Offshore production islands and platforms for all types of Arctic operations would most likely be self-contained in order to simultaneously drill, produce, process, and ship oil and gas; inject sea water and/or gas; and house the operations and drilling personnel. Such a multi-functional platform requires a large and complex facility.

An effective way to describe a platform's facilities and functions is to divide them into systems. Typical offshore production facilities would probably consist of the following major equipment systems:

- Oil and gas separation
- Oil dehydration and shipping
- Gas dehydration and compression
- Water flood
- One or two drilling rigs
- Utilities and power generation
- Safety and fire protection systems
- Quarters
- Cranes, heliports, and escape capsules
- Supply storage areas.

After construction of the production platform is complete, these facilities can readily be installed, based on an extensive history of successful offshore production.

Production Operations

Production operations in the three Arctic regions are within the realm of existing technology. Technological improvements such as computer control of operations and innovative transportation systems will help reduce the complexity, relative inefficiency, and manpower requirements of Arctic production operations.

Field production operations are those operations related to well production equipment and facilities and their maintenance. Such operations include separation of the well flowstream into its gas, oil, and water components; dehydration and compression of the gas; stabilization and treatment of the crude oil; metering and pumping of the oil to a pipeline system or terminal; treating and disposing of produced water; and water and gas injection for pressure maintenance. Included are numerous activities that support the primary oil- and gas-producing operation. Production operations in the Arctic regions will be similar to those conducted in other areas of the world with special consideration for the harsh climatic conditions.

Safety in oil and gas production operations always receives high priority. The hostile Alaskan environment demands special safety considerations. The physical hazards of working in the cold of Arctic and sub-Arctic regions are well known and are a part of safety training programs. The psychological hazards of working in cold, remote regions are considered, as are the negative effects on productivity and morale. High-quality accommodations, good food, and provision of recreational facilities are effective deterrents to these psychological hazards.

The harsh climate requires that most production operations be carried out in enclosed areas. Adequate safety devices such as fire and combustible gas detectors and fire fighting equipment are necessary. If toxic gases such as hydrogen sulfide are produced, detection devices and special safety measures are necessary.

In Regions II and III, a major challenge will be logistics and transportation in areas that are partially or completely ice covered for many months.

In Region II, a matter of major concern will be the logistics and support of exploration drilling and field development in the Navarin Basin. Locations in Navarin are beyond conventional helicopter range from Dutch Harbor and are near the limit of range from St. Lawrence Island. A boat trip from Dutch Harbor to a central basin location will take between one and a half and two and a half days each way; Dutch Harbor is over 800 miles from Anchorage, the nearest major source of oil field supplies. It is likely that service and support facilities would be provided closer to the field. Potential alternative locations for such facilities include St. Matthew Island (currently a National Wildlife Refuge), anchored vessels, and gravity- or pile-supported offshore platforms.

Construction

An important part of the oil and gas production technology that has been developed in the Arctic is the method for constructing facilities under difficult conditions.

To minimize the impact of this hostile environment on construction, several general guidelines have been successfully followed:

- Sophisticated forward planning for material delivery and construction activities is necessary.
- Major portions of construction work are completed in temperate climates and modules transported to site, which reduces the work required under severe field conditions.
- Construction operations are planned so as to avoid damage to the tundra, pollution of waters, and disturbance of wildlife, both onshore and offshore.

Onshore construction in Alaska for future development of oil and gas resources will benefit from experience at Prudhoe Bay and the Trans-Alaska Pipeline, and from continued exploration efforts.

The concept of modular fabrication in the lower 48 states was adopted to minimize onsite construction on the Alaskan North Slope. Prefabricated modules are barge transported to the field and installed on foundations that are constructed concurrently with lower-48-state fabrication programs. From a barge dock, the modules are transported overland by tracked crawlers or by rubber-tire transporters to the site.

Prefabrication production facility modules are normally transported to a coastal location near the site by barge fleets called "sealifts." There may be several types of skids to be transported, half of which would be major modules. These major modules may include the gathering center, power station, pipeline systems, and operations center. The weight of major modules ranges from 200 to over 1,000 tons, with an average of 15 to 16 modules per sealift.

The concepts for offshore production in the Bering Sea and Arctic Ocean will be tailored to suit the specific environments encountered. Likewise, the construction methods and equipment will vary. The traditional concept of minimizing construction onsite by building elsewhere will be a dominant factor in the offshore areas.

Components for onshore and offshore development could be prefabricated in several areas, including the U.S. West Coast, Canada, the Gulf of Mexico, Japan, Korea, and other temperate locations with established facilities. These areas are experienced in the types of fabrication required. The only exception might be the availability of graving dock facilities with deep-water access for the construction of gravity-type structures.

Artificial gravel islands, similar to those shown in Figure 9, have been constructed for exploration drilling in the Beaufort Sea in up to 63 feet of water. Such islands can be made large enough to support development drilling and production facilities where adequate quality and quantity of gravel is available. Gravel islands are built by conventional dredging methods. The slope near the water line is protected from wave and ice action by an armor, which may be blocks of concrete.

Future Production Technology

Structures

Structural design and construction methods for Region I are state-of-the-art.

For Region II, a variety of conceptual, preliminary, and proven drilling and production platform designs are available for application in the Bristol Bay, St. George, Zhemchug, and Navarin Basins. Due to the remoteness of the Navarin Basin, specialized structures with certain novel features would be considered, most of which are extensions of current technology. These novel features may include:

- Ability to resist ice loads in water depths much beyond those experienced in Cook Inlet
- Transfer of oil or LNG to tankers on a single-point mooring in ice-covered seas
- Storage of LNG, probably in submerged containers, in the field.

In the Norton and St. Matthew-Hall Basins in Region II, and in the Chukchi and Beaufort Basins in Region III, gravel islands and cone structure designs for exploration and field development exist or are in early design stages. Gravel islands can probably be built to a 60-foot water depth in Region II and a 100-foot depth in Region III. Based on model tests of preliminary designs, cone gravity structures may be utilized to a depth of about 200 feet of water. Until a specific need develops, design work for greater than 200 feet of water in severe ice areas will follow the development and application of structures for shallower depths.

For all three regions, improved and novel designs are being pursued through active industry ice and structure research and engineering efforts, including major field- and model-testing programs.

Drilling and Producing Operations

There are many possibilities for enhancement of drilling and producing operations, but few current leads suggest that a major breakthrough is in the offing. Additional learning experience in the field, as well as research and development activities, should produce substantial improvements in efficiencies. They are likely to yield only incremental changes in the methods and costs of operations.

Operations in the northern two thirds of the Bering Sea from November through June will require the support of large helicopters, icebreakers, and supply vessels with ice-strengthened hulls for service. While such operations present a significant challenge, only a slight extension of existing designs will be needed. This subject is discussed in Chapter Five.

Adaptation and development of novel equipment and operating systems for the Alaskan North Slope and offshore areas will proceed as opportunities for concession acquisition, exploration drilling, and field development are provided by leasing and permitting authorities. Anticipation of specific equipment and material needs, particularly for field development, is virtually impossible; thus, long-term, expensive equipment development programs are not likely to be cost effective.

Cost Factors

All cost data are presented in constant January 1, 1981, U.S. dollars and do not account for future inflation. The cost data for the production activities used in the economic analysis are included in Part II of Appendix E.

Drilling

Region I—Onshore, North of the Brooks Range

The day rate of an onshore development drilling rig on the North Slope is approximately $25,000. This includes the cost of the rig, crews, crew transportation, crew quarters, mess facilities and food, and contractor-supplied rig maintenance. The total cost of drilling a development well in the Prudhoe Bay North Slope area is approximately four times the day rate times the number of drilling days. This includes cement, drilling fluid, rig fuel, material transportation, contract services other than drilling, surface and subsurface well equipment, and many other items.

Regions II and III—The Bering, Beaufort, and Chukchi Seas

No field development has occurred in the open seas offshore of Alaska from which development drilling costs in Regions II and III can be accurately extrapolated. Such costs can be approximated utilizing field development experience on the North Slope and in the Cook Inlet of Alaska, and in the northern North Sea of Europe.

Items included in these costs can be divided into onshore camp and operating port, transportation, materials and services, and other costs associated with the rig operation.

Operation of an onshore camp and operating port, complete with facilities to support a major development of 8 or 10 drilling rigs, is estimated to cost about $32 million per year.

Transportation systems will vary widely depending on distance of the field from shore base and on ice and sea surface severity in the area. In the Bristol Bay, St. George, and Navarin areas, multi-purpose vessels, with equipment to transfer water, barite, and cement and to perform anchor handling services, will be utilized. These vessels should cost about $5 million per year to operate. Vessels to stand by in the field for platform emergencies should cost about $3 million per year. Helicopters will be used extensively for personnel transportation to and from the field in all of the areas except some portions of the Navarin, which may be beyond conventional helicopter range from shore. Helicopters can be used for transport between platforms in a field at Navarin. Icebreaking vessels will likely be required during the ice season at Navarin to ensure freedom of radial movement of tankers moored on single-point moorings. They probably would be utilized in the more northerly areas. Icebreaker operating cost is estimated at $13 million annually. In the Norton, Chukchi, and Beaufort areas, where ice coverage and thickness is great for long periods of time, very large helicopters could prove to be a primary transportation unit for personnel and materials. The cost to operate these helicopters may be as high as $20 million per year.

Support logistics are discussed in detail in Chapter Five.

Materials and services for a typical well of 12,000-foot depth are expected to cost $1.7 to $2.5 million, depending on the remoteness of the field. This category includes casing, tubing, wellheads, mud, logging, cementing, and other services.

All other rig costs including rig, drilling crews, catering, rig maintenance, supervision, mobilization, and demobilization are expected to be about $65,000 daily for offshore locations.

Production Facilities

The costs of production facilities offshore were estimated based on North Sea experience. North Sea projects provide an information source and comparison for potential Arctic facility requirements. Considerable judgment and effort are needed to utilize this information in a comparative manner.

Four projects were analyzed and compared to develop the production cost estimates. The installed cost of these North Sea production facilities versus the daily production rate is plotted in Figure 13.

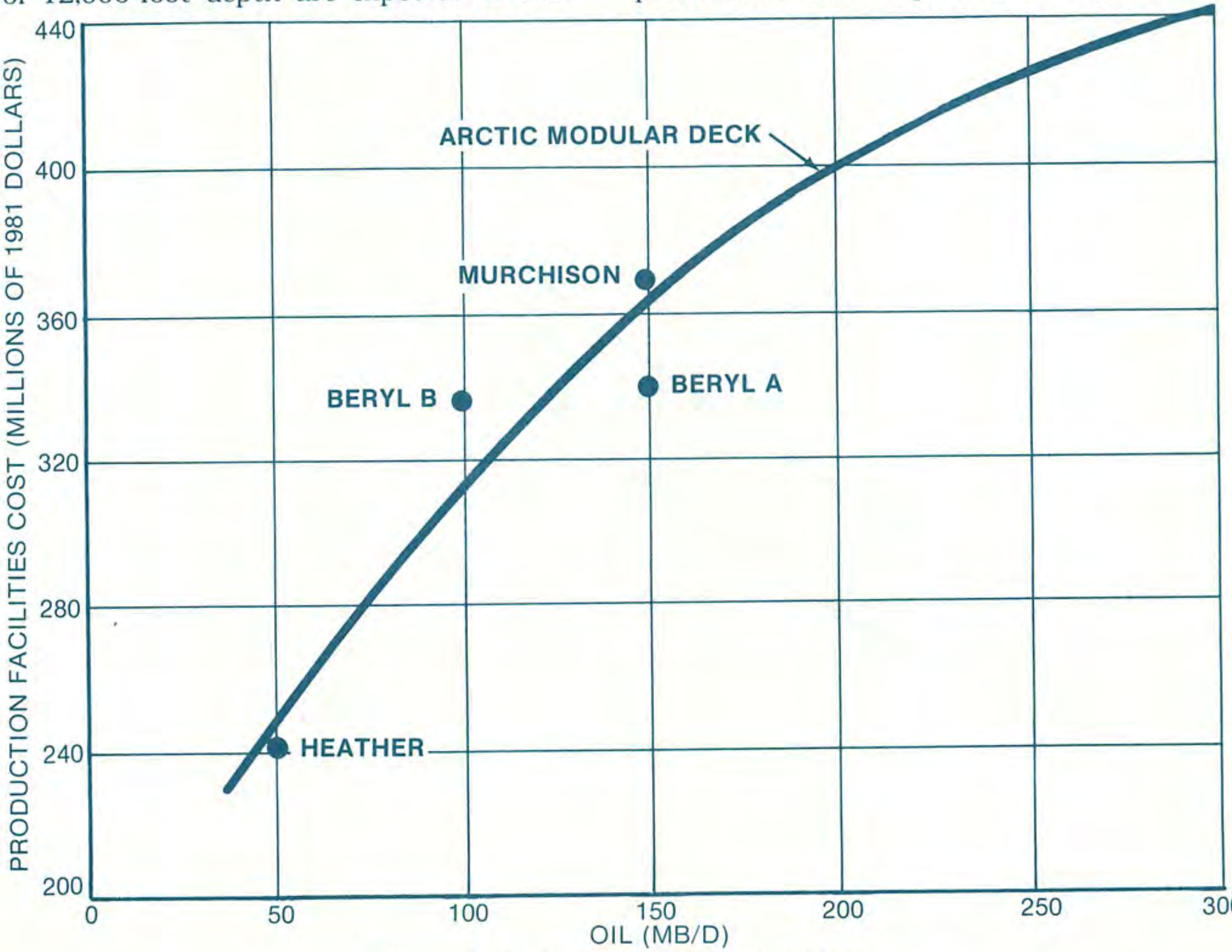


Figure 13. Cost vs. Daily Production Rate.

These costs have been adjusted to a January 1981 time frame. A curve based on these data and showing the projected cost of modular decks for Arctic use is shown in the same figure.

Production Operations

Cost data from offshore operations in the North Sea and Gulf of Mexico and onshore operations at Prudhoe Bay were examined as well as were projected cost data for the offshore regions of this report. Typically, these costs include:

- Labor, supervision, overhead, and administrative costs
- Communications, safety, and catering
- Supplies and consumables
- Routine process and structural maintenance
- Well service and workover
- Insurance on facilities
- Transportation of personnel and supplies.

It was recognized that the logistic support costs could vary considerably by location within a region. Although detailed estimates are beyond the scope of this study, the shaded area in Figure 14 may be considered representative of these variations in transportation costs. For example, annual operating costs for a field in Norton Sound would be represented by the lower part of the shaded area, whereas the operating costs for a field in the Navarin Basin would be near the upper boundary of the shaded area.

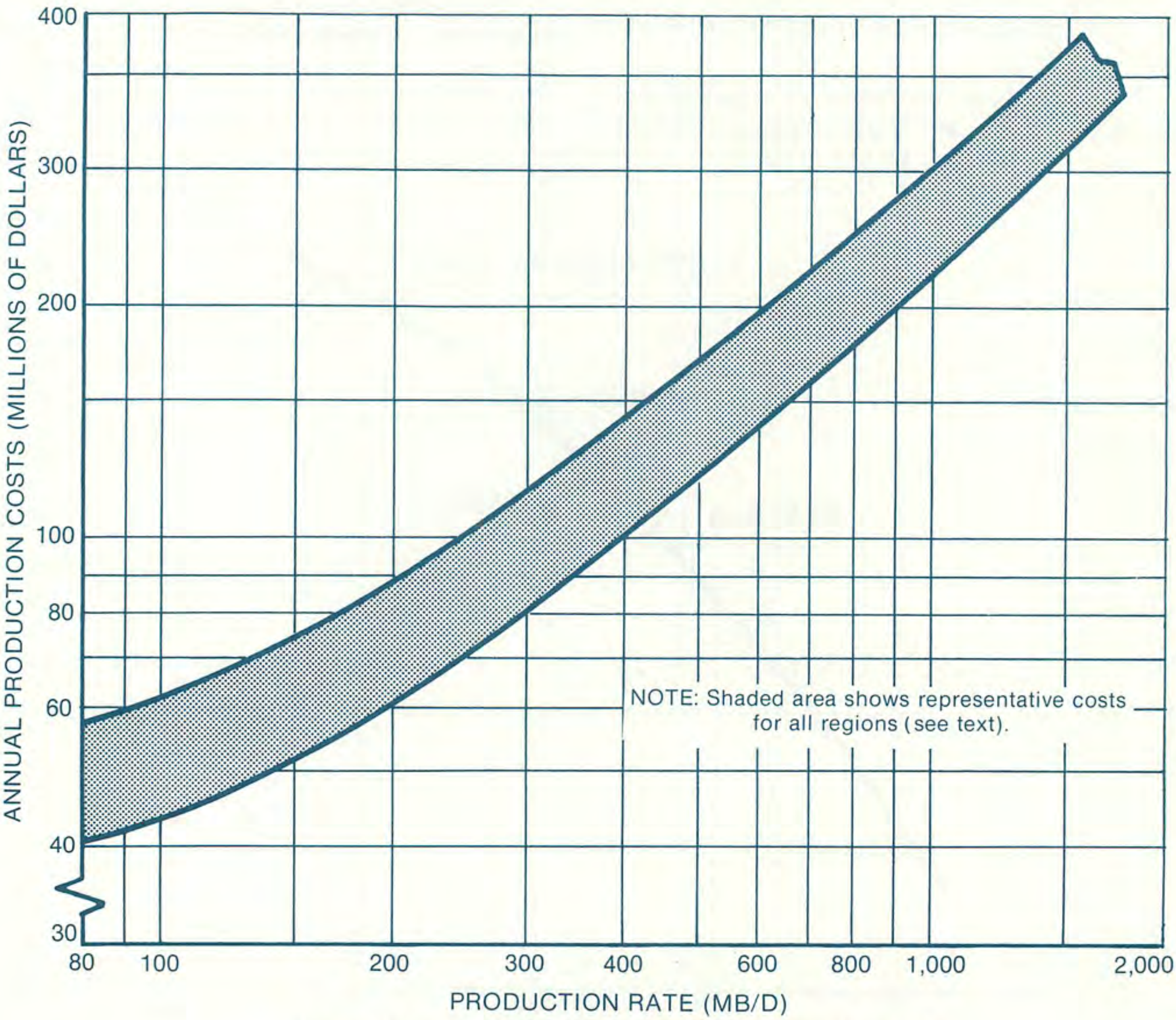


Figure 14. Annual Production Costs vs. Production Rate.

Production Scenarios

Scenarios have been developed for eight areas that are representative of the geological and environmental conditions that will be encountered in the Arctic. These illustrate the wide range of situations and operating modes that Arctic operations will encompass. Oil scenarios were developed for eight areas and gas scenarios were developed for three areas. The oil scenarios are summarized in Table 4 and the gas scenarios in Table 5.

The schedule of activities in these scenarios was developed incorporating exploration, drilling, transportation, regulatory approvals, and field development, and includes appropriate timing. A typical schedule is shown in Figure 15 for the NPRA. A full set of scenario schedules will be found in Appendix D.

In the scenarios it is assumed that exploration drilling or platform construction begins one year after the lease sale and commercial hydrocarbons are discovered 2.5 to 6.5 years after the lease sale, depending on the area. Approval of development plans occurs from 5 to 9 years after lease sale. Time from lease sale until the first production is marketed varies from 9 to 14 years; and time to reach peak production from 10 to 17 years. Production in each case is held at peak level for 2.5 years, after which it declines at an annual rate of 12 percent. Water flooding is assumed for pressure maintenance and secondary recovery, with 0.4 injection wells for each producer. All associated gas is reinjected into the oil reservoir. In all cases, it is assumed that the field will be unitized under one operator.

The times to accomplish drilling and development presented in the scenarios approach the fastest track on which the events could occur. This approach was taken purposely in the development of the projections, since the evaluation of the effects of schedule slippages and delays was made in the economic analyses.

Some of the assumptions used for the projected times, and of other factors that were considered, are as follows:

- Existing laws and regulations would continue to be in effect.
- Delays due to special lease stipulations or legal disputes are not included.
- All permits for development would be processed concurrently and approved by the time the USGS approved the field development plan.
- Delays and seasonal constraints due to ice or winter conditions were considered in projected exploration and production scenarios.
- Projections do not include permitting delays for pipeline rights-of-way or terminals, or onshore support facilities for exploration, production, or pipeline activities.

Findings

Production operations can be conducted safely in the Arctic onshore, and technology for operation in offshore areas is evolving. Present programs on physical data gathering and analysis will contribute to improved structural designs and reduced costs. Data gathering programs can be expected to continue until exploration and development of these regions is fairly routine.

Because of the importance ice plays in many aspects of offshore Arctic structural design, some specific comments on ice research and development programs are appropriate:

- Ice, oceanographic, meteorological, seismic, and geotechnical data gathering and research and development programs, applicable to the Arctic regions addressed in this report, have been carried out and additional programs are under way. Close cooperation of government, institutions, and industry in program planning, execution, and reporting could prevent waste of scarce resources. Such action has already occurred to some degree.
- Improvements are needed in the statistical description of sea ice thickness, extent, velocity, and mechanical properties. Multi-year ice ridges and ice islands are of particular interest.
- Sea ice properties need to be more accurately determined. Included in this area are:
  - Properties of multi-year ice, undeformed and in pressure ridges

TABLE 4

OIL PRODUCTION SCENARIOS

	ANWR	NPRA	Bristol Bay	St. George Basin	Norton Basin	Navarin Basin	Chukchi Basin	Beaufort Shelf
Water Depth (Feet)	—	—	180	425	50	450	120	50
Exploration								
No. of Wells	6	6	6	6	6	6	6	6
Type of Rig	Drilled with Winterized Arctic Land Rig on Gravel Pads	Drilled with Winterized Arctic Land Rig on Gravel Pads	Drilled with Jack-up	Drilled with Semi-Submersible	Drilled with Jack-up	Drilled with Semi-Submersible	Drilled with Mobile Steel Cone	Drilled with Winterized Arctic Land Rig on Gravel Islands
Support Base	—	—	Port Moller	Dutch Harbor	Nome	Dutch Harbor	Wainwright	Prudhoe Bay
Development								
Total Daily Rate (B/D)	250,000	500,000	125,000	250,000	125,000	500,000	250,000	500,000
Type of Platform	Gravel Pads	Gravel Pads	Steel Platforms	Gravity Platforms	Gravel Islands	Gravity Platforms	Monocone	Gravel Islands
No. of Islands or Platforms	4	8	2	4	2	7 Prod. + 2 Service	4	7
No. of Rigs	8	16	4	8	4	14	8	14
Type of Rig	Arctic Land Rig	Arctic Land Rig	Winterized Offshore	Winterized Offshore	Arctic Land Rig	Winterized Offshore	Winterized Offshore	Arctic Land Rig
Total No. of Wells	136	271	68	136	68	271	136	271
Type of Facility	Prudhoe Bay Type	Prudhoe Bay Type	Modular Type	Modular Type	Barge Mounted	Modular Type	Modular Type	Barge Mounted

TABLE 5

GAS PRODUCTION SCENARIOS

	NPRA	St. George Basin	Navarin Basin
Water Depth (Feet)	—	425	450
Exploration			
No. of Wells	6	6	6
Type of Rig	Drilled with Winterized Arctic Land Rig on Gravel Pads	Drilled with Semi-Submersible	Drilled with Semi-Submersible
Support Base	—	Dutch Harbor	Dutch Harbor
Development			
Total Daily Rate (B/D)	1 Billion	1 Billion	1 Billion
Type of Platform	Gravel Pads	Gravity Structures	Gravity Structures
No. of Islands or Platforms	1	1	1
No. of Rigs	1	1	1
Type of Rig	Arctic Land Rig	Winterized Offshore	Winterized Offshore
Total No. of Wells	20	35	20
Type of Facility	Prudhoe Bay Type	Modular Type	Modular Type

- Existence of strong crystallographic alignments and the effect of grain size on strength
- Effect of rate-of-strain on strength
- Changes in bulk strength with changes in sample size.

- Sea-ice-testing and analysis facilities and support staff are quite limited in the United States. The U.S. Army Corps of Engineers' Cold Region Research and Engineering Laboratory (CRREL) in New Hampshire is the only publicly owned facility in the United States that is suitably equipped and active in this type of work at present. CRREL's efforts for those outside the federal government are severely limited because of spending restrictions. Private facilities conduct proprietary work. Approximately two years are required to construct a new facility, and experienced technical and scientific staff are in short supply. CRREL facilities and staff should be made available for an expanded work program for industry.
- Advanced instrumentation for observing, sampling, and testing sea ice needs to be developed. This activity would be a direct outgrowth of sea-ice research and development programs.
- Research on sea-ice structure interactions at appropriate institutions can supplement the intensive industry efforts in this area.

Some general guidelines as to which parts of sea ice characterization and investigation efforts should be emphasized by government and which part by industry are offered:

- Federal programs should focus on collection and characterization of physical environmental data and testing programs important to the solution of important Arctic science and engineering problems.

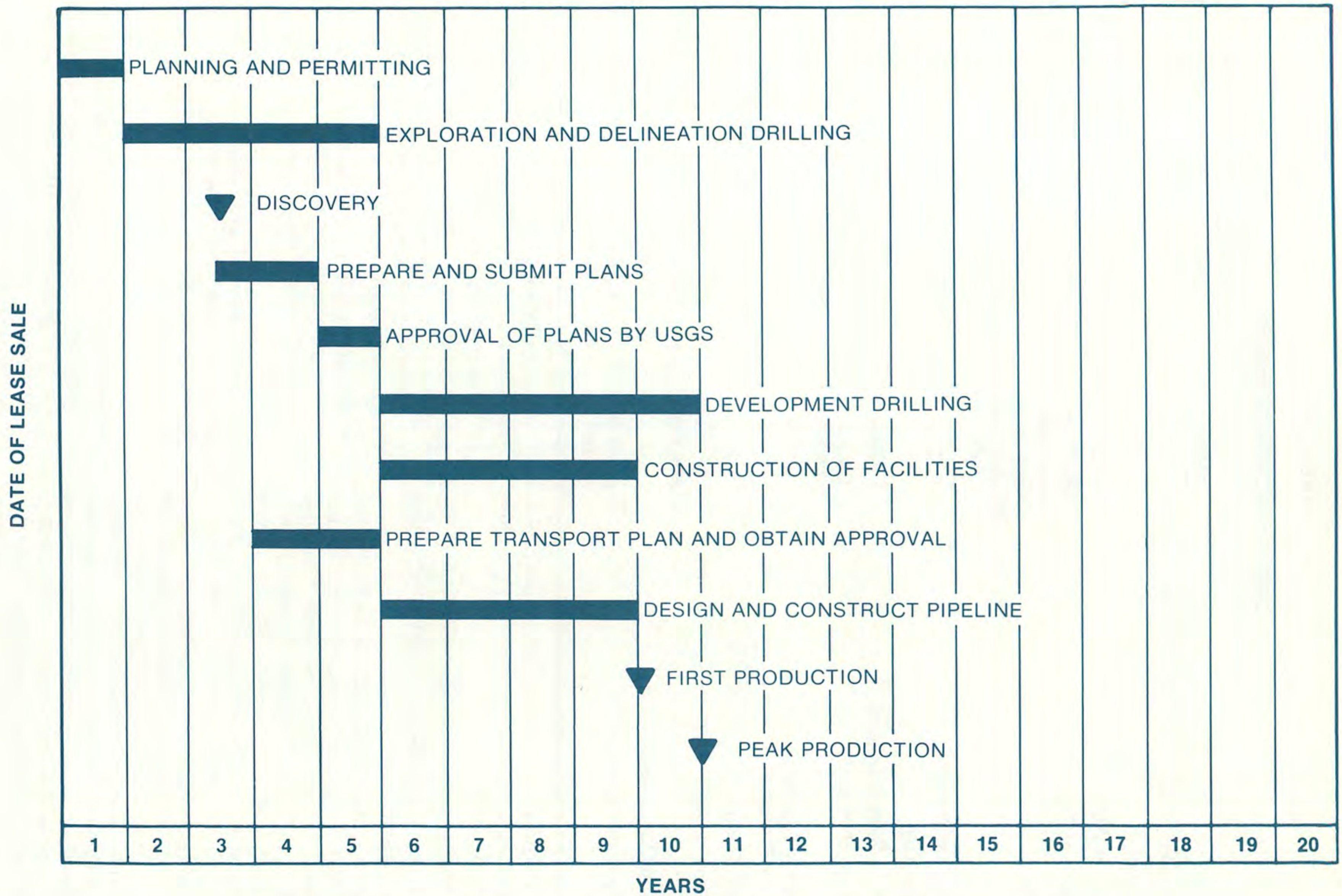


Figure 15. Typical Scenario Schedule—NPRA (Oil Case—500,000 Barrels per Day).

These would most likely be programs and studies of fundamental problems.

- Industry programs, in turn, should focus on equipment and operating systems research and development, on model testing, and on site-specific studies. Collection of data and information on particular engineering designs and operational programs should be primarily an industry function.
- Government remote-sensing and satellite systems have been utilized to gather physical data in the U.S. Arctic. Governmental and industrial needs have been partially met by these systems. Ways should be explored to increase the capability to meet future needs.
- Some overlap between industry and federal programs is inevitable, but open communication and a spirit of cooperation will be necessary to expedite progress.

CHAPTER FIVE: TRANSPORTATION

History

Commercial production of oil and gas in the U.S. Arctic in 1981 consists only of oil production from the Prudhoe Bay field. When this field was discovered in 1968, the two transportation options considered were tanker movement through the Northwest Passage and pipelining across Alaska to an ice-free port. The pipeline option was chosen on the basis of reliability, and pipe was ordered in 1969.

Opposition to the pipeline by environmentalists and issues of land title ownership led to a series of legislative, environmental, and court hearings that delayed the start of construction for five years. Resolution of these controversies could not be accomplished by the courts, and both issues required legislative action by the U.S. Congress. The land title matter was settled by the enactment of the Alaska Native Claims Settlement Act of 1971, and the environmental issues were resolved by the Trans-Alaska Pipeline Authorization Act of November 1973. Only after this legislation was passed were permits issued. Construction began in April 1974, and the pipeline was completed and went into service in mid-1977.

The Trans-Alaska Pipeline is a 48-inch-diameter line designed for a potential capacity of 2 million barrels per day but is equipped in 1981 to deliver 1.5 million barrels per day. It traverses an 800-mile route from Prudhoe Bay to an ice-free terminal at Valdez. The terminal can accommodate four tankers simultaneously and provides an average turnaround time of 24 hours. Successful operation of this system has been achieved; it represents a model for future land pipelines and terminals.

Navigation in Arctic waters started in the mid-1800s with two unsuccessful attempts to penetrate the Arctic ice in the Northwest Passage by John Franklin and Robert McClure. Roald Amundsen made the first successful transit of the Northwest Passage from 1903 to 1906. There were no further significant attempts until the submarine USS *Sea Dragon* in 1960 passed through McClure Strait under the ice to the North Pole and then south through the Bering Strait.

With the discovery of a commercial oil field at Prudhoe Bay, interest in ice navigation was renewed, and in 1969 the SS *Manhattan*, equipped with an icebreaking bow, made a successful transit of the Northwest Passage via Prince of Wales Strait after being turned back from McClure Strait by heavy ice. The performance of the *Manhattan* was extensively studied; it served to advance considerably the state-of-the-art of icebreaking commercial vessels.

Throughout the 1970s, extensive summer trading was carried on through the Bering Strait around Point Barrow to Prudhoe Bay in support of Prudhoe Bay field operations. At the same time, the U.S. Coast Guard continued to extend the state of knowledge by operation of its Wind Class icebreakers to Nome and to the Bering Strait in the winter ice. In 1979, with the delivery of its two Polar Class icebreakers, a joint industry and government program was initiated to further study the problems of ice navigation. In February 1981, the *Polar Sea* successfully completed a continuous ice-breaking passage from Nome to Point Barrow, but during the return trip it suffered rudder damage, developed a propeller bearing problem, and had to winter in. Information and experience in year-round navigation north of the Bering Strait is limited, and opportunities to develop knowledge in this area are substantial.

Marine pipelines have been under continuous development for the past 100 years. The most notable phases of development concerned shallow-water pipelaying to exploit oil production in the normally mild waters of the Gulf of Mexico. Starting in the 1970s this knowledge was extended to the more severe weather environment of the North Sea, and more recently to the 1,000-foot-deep waters of the Gulf of Mexico and the 2,000-foot-deep waters of the Mediterranean Sea.

The first pipeline construction project in Arctic waters was the installation of a 3/4 mile, 18-inch pipeline bundle in 1978. This pilot pipeline, connecting an offshore well with production facilities on Melville Island in Canadian waters, was successfully installed using a special winter construction method of trenching and pipelaying using the ice cover as a work base.

Status

Operation of the TAPS line continues to be fully satisfactory; it has maintained a 1.5 million-barrel-per-day rate. All of this oil is transported from Valdez to the lower 48 states by conventional tankers. As of the end of 1981, approximately 2 billion barrels of oil have been transported through the system.

No other major U.S. Arctic pipelines are in service today. A connecting line from the Kuparuk field west of Prudhoe Bay to the TAPS corridor is under construction. Although no commercial gas pipelines are under construction or are in service, preliminary design is under way for the Alaska Natural Gas Transportation System (ANGTS) that is planned to deliver gas from Prudhoe Bay to the lower 48 states via Canada.

In Canada, studies are currently in progress to evaluate the feasibility of constructing artificial islands in 200 feet of water to provide a foundation for permanent production facilities and a crude oil terminal for Class 10 icebreaking tankers. The Arctic Pilot Project is under way to demonstrate the feasibility of an LNG transportation system to take Arctic gas to market. The project's plans include construction of a gas pipeline across Melville Island, an LNG plant and marine loading terminal, and an LNG supply system employing icebreaking LNG carriers.

New information on Arctic ice is being continuously gathered by both industry and government. Cooperative industry/government studies, arranged by the Maritime Administration, have involved the U.S. Coast Guard's *Polar Star* and *Polar Sea* in the Bering and Chukchi Seas. Ice reconnaissance information is supplied by the National Aeronautics and Space Administration and the National Oceanic and Atmospheric Administration, and ice charts are issued by the Navy based on this and other data. Proprietary industry programs are investigating in detail areas of special interest.

Current Transportation Technology

Oil and gas transportation systems that would be selected by industry must have a high degree of operational reliability. If the transportation system is unreliable, the economic and operational consequences could be severe. Ideally, transportation systems should be able to operate continuously with little or no likelihood of interruption over an approximate 20-year period.

When evaluating a petroleum transport system, the risk of oil spill or environmental damage must be at an absolute minimum. A very high premium must be assigned to transport systems that fulfill these requirements. While economics are an important factor, they must be balanced against the reliability factors developed in the design and in the minimization of environmental risk for a particular transportation system. The concepts of reliability and minimal risk, as well as cost, will be major considerations in the final selection of a transportation system for any real situation.

Land Pipelines

The adequacy of the current state of technology for land pipeline construction and operation has been well demonstrated by TAPS. Any new lines would follow this same technological pattern.

For a crude oil pipeline, direct burial of uninsulated pipe would be practiced to the maximum extent possible, limited by the presence of thaw unstable soils. In those areas where heat from the buried line could cause thawing and line subsidence, aboveground construction techniques would be used, with either refrigerated or conventional piles for line support as local conditions require.

Pump stations would use gas turbine drivers and centrifugal pumps that have demonstrated high dependability and therefore do not require the use of new or unproven technology. The gas turbines would be natural gas fired in all areas where gas can economically be transported, and liquid fuel fired from topping plants that fractionate crude oil at other locations. "Repeatable" designs for pump stations would be sought out to minimize engineering and construction and to ease operator training. Each pump station would have its own permanent living quarters and life support systems for the operational staff. Refrigerated or pile-supported foundations would be used in thaw unstable soil areas.

The pipeline would be operated from a centralized control center located at the shipping terminal, with microwave communication to all pump stations and to remote valve locations.

A haul road and a pipeline work pad would be constructed initially to permit delivery and installation of the pipe. Both would become an integral part of the operating pipeline for purposes of maintenance, repair, and operational needs. Construction camps would be used only during the construction phase and then shut down for relocation. Airfields would be constructed to provide for air delivery of personnel and materials during the construction phase and would be maintained and utilized in the operational phase as well.

The end-of-the-line oil shipping terminal, if located at a relatively ice-free port, would be similar to the current Valdez terminal, with vapor recovery facilities, ballast water treatment, power plant, control system, and the core facilities including tank farm, metering, berths, and loading lines.

A gas line would be installed totally underground using the chilled gas process, construction techniques, and design features developed through the current ANGTS research and engineering efforts. Compressor stations at approximately 100-mile intervals would move the gas through a gas pipeline to a port location for movement as LNG to the West Coast.

Marine Pipelines

No major marine pipeline systems exist in the Arctic. It is considered technically feasible to construct long (up to 200-mile), large-diameter marine pipeline systems in Arctic waters off Alaska. The task of installing and protecting these pipelines, particularly for the northernmost Beaufort and Chukchi Basins, would involve direct extensions of current technology. One major need would be to protect these pipelines from ice scour, probably by lowering the line into the sea floor in trenches.

The major portion of the marine pipelines would be uninsulated. Shore approaches where shallow permafrost could be present would be protected with appropriate insulation. The on-bottom stability of the pipelines before burial would determine either the pipe thickness requirement or, alternatively, the thickness of the concrete weight coating required. A number of combinations of pipe diameter, pipe wall thickness, and concrete coating thickness would be satisfactory.

Trenching by subsea plow and pipeline installation by the bottom-tow method are construction methods considered feasible for the northern basins (Beaufort, Chukchi, and Hope). Pipelaying in the southern basins (St. George and Bristol) could be done by conventional lay barge means. Although conditions and pipelay methods vary between the northern and southern basins, the total pipelay costs on a dollar-per-mile basis are about the same.

The primary reason for trenching in the Arctic is to lower the pipe below ice gouge hazards. Pipe trenching depths would be decided on the basis of acceptable risk since very few deep ice gouges have been found, deep trenching is very expensive, and the majority of gouges are less than three feet deep.

A significant amount of trenching would be required for all basins except Navarin, St. George, and Bristol. In the latter, only shore approaches need to be lowered. In all other basins a clearance of at least three feet would be needed above the pipe for ice gouge protection. Careful selection of pipeline routes could be done in order to avoid trenching depths of more than six feet.

The state-of-the-art of pipeline repair is sufficiently developed to make Arctic marine operations technically feasible. Problems with ice-covered water that hampers diver operations and with excavation of damaged pipeline will make repair operations expensive. Practical considerations dictate that operations for permanent repair take place during the ice-free season.

Marine pipeline operations in the Arctic should be similar to operations further south but will be more difficult and demanding because weather and logistics are more severe. If the oil being transported is waxy, startup problems could exist if the line is shut in and the oil is allowed to approach water temperature. Another concern would be pipeline integrity, which must be rigorously monitored because of the potential for ice damage. There is a potential for maintenance problems with refrigeration systems for permafrost protection at shore approaches.

Marine Terminals (Nearshore)

It is feasible to design and construct nearshore crude oil terminals for the basins located south of the Bering Strait. For Norton Sound this conclusion is qualified by the assumption that grounded ice rubble piles will not interfere with the operation of the terminal. Further work is required to establish a method for predicting a minimum water depth to prevent the formation of rubble piles.

The influence of multi-year ice on the design and operation of an offshore loading berth makes feasibility studies and cost estimates for terminals located north of the Bering Strait tentative.

In general, the technology to construct Arctic and sub-Arctic marine terminals is proven technology. Industry experience with construction and operation of the TAPS terminal at Valdez demonstrates an ability to design and construct facilities that can safely cope with extreme cold, prolonged periods of darkness, and remote and inaccessible locations.

The following are desirable characteristics for a nearshore marine terminal site: proximity to offshore production facilities, proximity to an existing harbor and airport, sufficient elevation to avoid flooding, up to 500 acres of relatively level land near the shore, rapid dropoff of the seabed near the site to a water depth safe for mooring tankers, and soil conditions at the offshore berth sites adequate to support a structure.

The optimal selection of a terminal location requires extensive surveys of many potential sites before a judgment can be made.

A marine terminal consists of three major subsystems: onshore facilities, connecting pipelines, and loading berths.

Onshore facilities consist of everything necessary to receive, store, and pump oil into the pipelines leading to the loading berths. This includes tankage, a vapor recovery system, warehouses and shop buildings, meters and meter-proving equipment, a water supply, sewage treatment, heating systems, storage for oil spill contingency equipment, firefighting systems, fuel storage, fire water storage, a topping plant, and a communications and control center.

Each loading berth is connected to the onshore facilities by pipeline. Onshore and nearshore portions of the pipeline route may contain thaw unstable permafrost, which needs protection from the effects of a hot oil line. Beyond 10-foot water depths, permafrost degradation should not be of concern because the distance to the top of the permafrost should be great enough that any heat effects would be negligible. Permafrost protection would be provided by a gravel causeway constructed for each mooring berth extending out to 10 feet of water. The onshore and nearshore portions of the pipelines would be insulated and buried in the gravel roadway and dock. The offshore portions of the pipelines would be buried to protect the lines from the effects of ice scour. Thermal insulation is not included for offshore line estimates because the large diameters and high flow rates of the loading lines result in small temperature drops.

Loading berths for Arctic terminals require a near offshore structure in order to obtain sufficient draft for tankers, as there are no deep-water port sites in Arctic waters. The structure concept for Arctic terminals shown in Figure 16 is a large-base, monopod-type structure that depends on both gravity and partial burial to keep it in position.

In the offshore structure, risers from the submarine loading lines carry oil to the loading arms shown in Figure 17. The loading arms are fitted with a quick disconnect, which mates with a companion fitting on the tanker bow. The loading arms and hoses are insulated and trace heated to protect the contents from freezing or becoming too viscous to pump.

The mooring system consists of one or more legs, each of which consists of a synthetic rope assembly with back haul winches on the structure and quick-release hooks on the ship. If ice conditions develop to the point where the design load is approached, the ship could either use engines to relieve the strain on the mooring or disconnect and wait until conditions improve. The mooring system would be fitted with suitable strain gauges so that loads in the mooring legs could be monitored continuously and the approach of limiting conditions anticipated.

Marine Terminals (Far Offshore)

It appears that the Navarin Basin, which is remotely situated in the Bering Sea in at

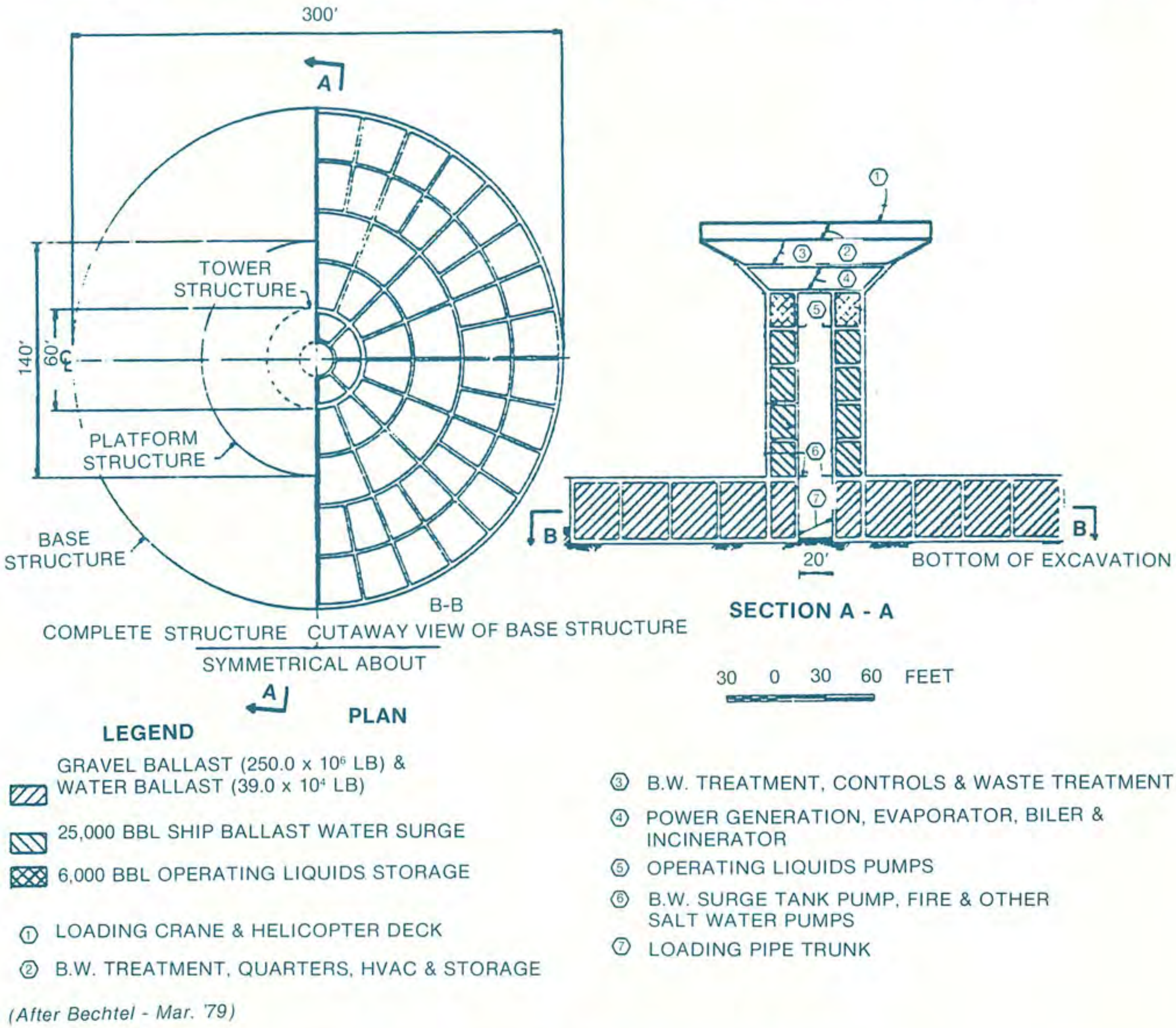


Figure 16. Conceptual Design for Mooring Structure.

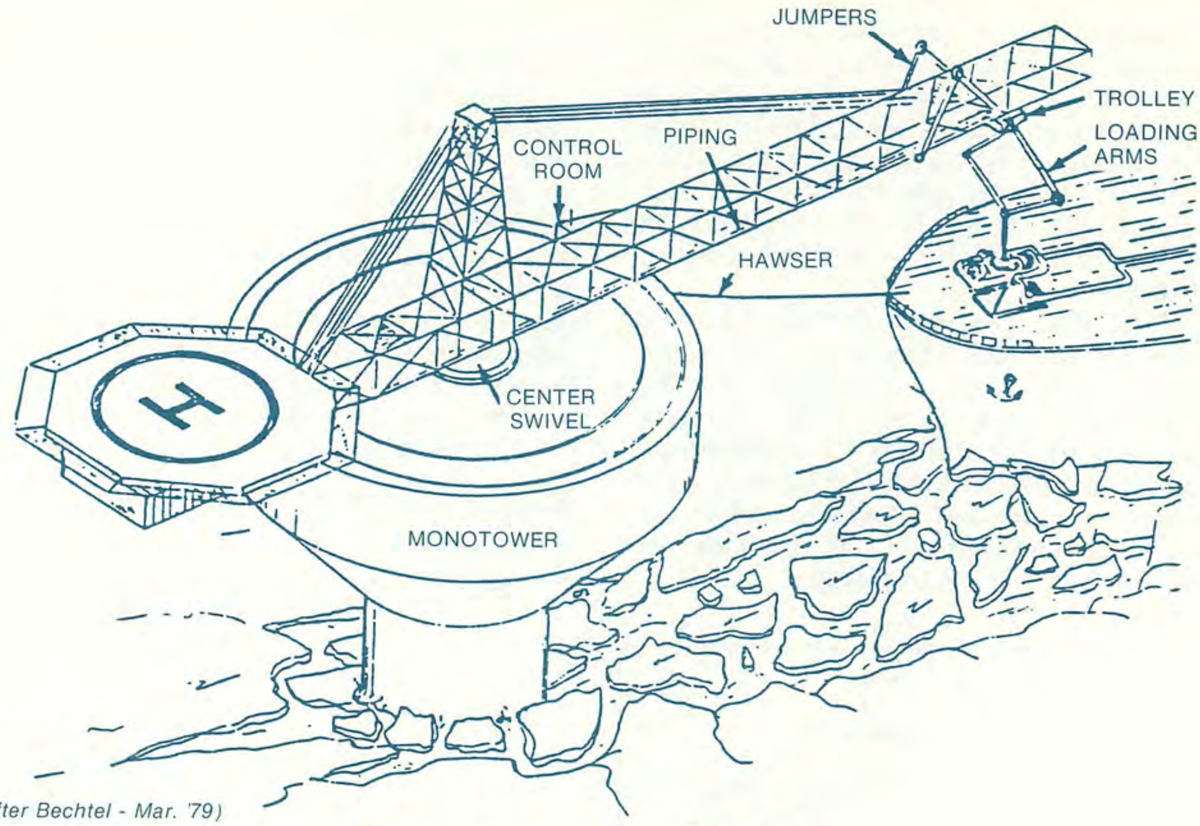


Figure 17. Loading Crane Concept.

least 450 feet of water about 600 miles from the port of Dutch Harbor, will require offshore storage and loading facilities.

Current concepts for oil loading and storage terminal technology for non-ice environments exist for water depths of up to approximately 2,000 feet, although terminals presently in operation extend only to 500-foot water depths. Most of the unexplored Arctic regions with hydrocarbon potential are within the 600-foot depth contour.

The kind of structure required to serve as an offshore loading/storage terminal is dependent upon water depth and the severity of the physical environment, particularly wave action and sea ice. Safety and economy require that each structure be designed for a specific location. Gravity structures, fixed loading towers, and articulated loading towers all appear to be feasible options for deep water.

The fixed loading tower for ice areas is basically the same as the structure used in non-ice environments, with several modifications. Such structures consist of a vertical column topped by loading and mooring facilities rigidly fixed to a piled or gravity base. Although the ice forces in the Bering Sea will necessitate increasing the size and weight of an ice-resistant structure beyond that of a conventional non-ice structure, such concepts are feasible. Concrete structures appear to be more desirable for ice designs than conventional steel structures because of the greatly increased weight that resists sliding and overturning. Concrete gravity-base structures were selected for the cost estimates used in the Navarin Basin economics scenarios. Conical gravity structures, or monocones, are massive concrete and steel structures, which are variations of the conventional gravity-base structure.

Moored ice-strengthened tankers could load oil through systems designed to remain clear of the ice zone, as shown in Figure 17. Oil storage would be provided in the bases and columns of these massive gravity-base structures. The design of such structures is in preliminary stages.

Mooring systems for the fixed tower would be similar to those currently in use, with a hawser mooring to minimize ice loads input to the tower. The hawsers could be affixed to the tankers by means of tension winches similar to systems used in the North Sea.

Several other loading tower concepts have been proposed that may be applicable in very deep ice-covered water beyond the feasible depth for gravity-base designs. These concepts include variations on articulated tower designs, which would be extensions of demonstrated technology used in non-ice regions throughout the world. A novel concept would employ a sea-bottom oil transfer manifold with a marine riser suspended from the hull of a storage or shuttle tanker.

Tankers and Icebreakers

There is every reasonable expectation that ice-capable vessels can be built, powered, and operated to maintain reliable year-round ratable offtake from ports south of the Bering Strait. Multi-year ice is extremely rare in the Bering Sea, and the ice conditions are sufficiently well known and defined that equipment may be designed for such trades.

Year-round tanker operation to ports north of the Bering Strait can probably be established, but reliability is uncertain. The tanker system must be reliable, however, and must provide the rated offtake. Some delay can be accommodated by a slowing of production or additional tankage; gross interruptions would severely affect the economics of a tanker system and consequently jeopardize production of a marginal reserve. Operations north of the Bering Strait carry a high risk of interruption considering the present state-of-the-art of operating commercial vessels in the Arctic.

The use of the U.S. Coast Guard's *Polar Star* and *Polar Sea* in ice trafficability studies has provided useful information on ridging, rafting, multi-year ice extent, and maneuverability. The feasibility of reliable tanker operations in the Beaufort and Chukchi Seas needs to be established through operating experience.

The principal characteristics of ships that could be built for Arctic service have been defined. For oil transport from the Navarin, Norton Sound, Hope, and Chukchi Basins, a 250,000-ton dead weight icebreaking vessel can be expected to supply the trade. This vessel would be 1,450 feet long, would have a draft of 60 feet, a hull depth of 104 feet, and a beam of 170 feet, and would transport approximately 2 million barrels of crude oil. For gas transport from the same basins, an icebreaking LNG tanker of 140,000 cubic meters (880,000 barrels of LNG, or 3 billion standard cubic feet) has been selected. This vessel is 1,250 feet in length, and has a draft of 42 feet and a beam of 140 feet. The Arctic LNG tanker can be shaped to give substantially higher speeds than an icebreaking oil tanker in both open water and ice.

Icebreaking tankers may require icebreaker assistance from time to time. Much has been said in the literature of ice-capable tankers with the implication that such vessels may be built powerfully enough that, with their size and strength, they will be totally self-sufficient in the ice. But even the most ice-capable tanker could eventually be slowed and finally stopped by multiple ridges, contact with multi-year ice, or pressure in the ice. At such times, even these powerful vessels will probably need some icebreaker assistance to help them in backing clear so that they may regain momentum or maneuver. Experience may prove that such icebreaker assistance is not needed south of the Bering Strait, but until such demonstration is made, icebreaker assistance should be considered.

Ice conditions dictate the technical and economic feasibility of a marine transportation system. It is of primary importance to develop representative ice conditions as a function of calendar time. Important ice conditions include broken ice, sheet ice or uniformly thick ice, pressure ridges, and pressure in the ice field. Today's technology can generate data on ice edge, ice flow size, sheet ice thickness, number of pressure ridges, and ice movement. It must be emphasized that ice conditions in the Bering, Chukchi, and Beaufort Seas can vary extensively. Improved knowledge of ice dynamics would be valuable in the design and operation of marine systems to minimize transiting delays.

In addition to developing long-range knowledge of ice conditions, short-term ice reconnaissance and forecasting are needed for efficient operations. Ice reconnaissance is largely dependent on aerial survey methods, but because of the great expense involved in supporting flight programs in the Arctic, aerial survey coverage is limited. Although new instrumentation is being applied to ice reconnaissance, including infrared scanners, laser profilers, and side-looking airborne radar, most of the ice data are still acquired through visual observation. The potential of the satellite for ice reconnaissance was recognized in the early days of the space program, and considerable use has been made of the data from satellite observing systems designed primarily for meteorological purposes. In view of the uncertainties connected with current satellite and overflight methods of ice reconnaissance and the critical need for a marine transportation system to be fully aware of ice conditions, particularly ridging, close-in air reconnaissance support is considered essential. Such air support will be provided by helicopters flown from escort icebreakers.

Navigation in heavy ice is affected greatly by visibility. The avoidance of areas of heavy ice ridging and the selection of leads and areas of minimum ice ridging is dependent on visual observation. When visibility is restricted, navigation in heavy ice will be seriously impaired and passage delayed. Radar is of some assistance in distinguishing areas of heavy ridging from other areas.

Gas Transportation

There are basically four ways in which large volumes of Arctic natural gas can be handled: reinjection, long distance pipeline, liquefaction, and conversion to other products. The last three methods compete as a means of transporting gas to the marketplace in the lower 48 states.

Reinjection is considered only when the delivered gas is not competitive in the market or when it enhances oil recovery. It is the primary method currently employed to handle Arctic natural gas. As the associated gas flow or non-associated reserves increase, ways to market the gas must be considered.

A pipeline is usually the favored method for economy and reliability in moving gas to the marketplace when the distance from the gas source to the distribution system is not great. The economic distance increases with gas volume and decreases with the difficulty of the terrain to be crossed but can be affected by other factors.

Liquefaction can be an economically attractive alternative to a pipeline. This method requires gas pretreatment and liquefaction, cryogenic storage, and marine loading facilities at the liquefaction end; LNG tankers for shipment; and marine unloading, cryogenic storage, vaporization facilities, and a connecting pipeline to market at the receiving end.

Conversion of gas to fuel-grade methanol or other products is another method of transporting Arctic gas. A fuel-grade methanol project would consist of gas pretreatment, conversion, storage, and marine loading facilities at the source end; methanol tankers for shipment; and marine unloading, storage, and a distribution system at the receiving end.

The technology exists, using proven equipment, for an LNG or methanol terminal to be located in northern Alaska. This is based on the use of grounded barges with prefabricated facilities for processing, storage, and utilities. The major uncertainty in building or operating any terminal in northern Alaska is in maneuvering, docking, and loading the tankers in an ice environment. A potential solution may be to use the rejected process heat to help maintain a relatively ice-free condition in an enclosed or partially enclosed harbor area.

In relatively ice-free southern Bering Sea locations such as the Navarin Basin, the process and utility facilities for up to a nominal 2 billion standard cubic feet per day LNG terminal could be mounted on a platform. Fixed storage and loading facilities are only in the conceptual stages for an offshore location. The concept of floating LNG storage built to shipping standards is proven; the technology for an LNG transfer system from a fixed platform to floating storage or tanker is available but has not been proven. The cost of southern Alaskan floating storage would be four to five times the cost of an onshore conventional double-wall metal tank system.

For a given inlet volume, the construction and operating costs of a large methanol production terminal will exceed the combined costs of an LNG liquefaction terminal and its associated receiving terminal. The lower cost of methanol storage is more than offset by the higher cost of process facilities. Methanol conversion uses approximately 40 percent of the feedgas as fuel, compared to less than 10 percent for LNG liquefaction and vaporization. This difference will become increasingly important as the wellhead value of gas increases.

Marine transportation of methanol from an ice-free area is considerably less expensive than the marine transportation of LNG. In severe ice areas, the relative difference in marine transportation costs will be less significant.

An important consideration for a large project is the distribution system at the receiving end that is required to utilize the product. LNG can be vaporized and then delivered through the extensive existing natural gas distribution system. Large quantities of fuel-grade methanol must be either reconverted to synthetic natural gas or have an infrastructure developed for its use as a liquid fuel. There is no direct market for a large baseload quantity of fuel-grade methanol.

Support Logistics

Logistic support for Alaskan oil and gas exploration and production activities will be required for both land and offshore operations. The construction of TAPS and the planning activity now under way for the ANGTS have shown that logistic support for land operations, including pipelines, is well within present technological capabilities. The greater concern will be the logistic support required for offshore operations conducted in ice-covered water.

The western and northern coasts of Alaska offer only limited facilities to support the marine activities necessary for offshore oil exploration and production activities. Only four communities with a population in excess of 2,000 exist: Nome (3,100), Barrow (2,715), Kotzebue (2,526), and Bethel (3,576). Other, smaller communities are isolated from land transportation at all times and from marine transportation in the winter. Electrical power, water, and sewer facilities will have to be expanded in any community to accommodate the influx of permanent and temporary workers. The infrastructure at Deadhorse can support additional land activities in the Prudhoe Bay area, but its marine potential is limited to receiving barge lifts during August and September.

Heavy concentrations of supply boats, tugs, and barges provide a potential for minor oil spills. Special petroleum transfer facilities should be considered for extreme cold weather operations. Spill cleanup needs must be addressed for all seasons of the year, including heavy ice cover.

If a year-round logistical support is required in ice-covered harbors, harbor ice management must be addressed. Repeated traverses of the harbor by supply vessels could cause ice buildup. Disposal of this ice must be considered in the harbor design.

Search and rescue activity in remote Arctic locations offshore during the winter must play a prominent part in operational planning. Excellent communications and electronic tracking of surface vessels and aircraft must play a very important part in the support base activity.

Support logistics include a wide variety of facilities and activities. The main requirements are as follows:

- A basic port facility, plus specialized facilities to support long-term drilling, production terminals, and pipelines
- Temporary shore facilities to support construction activities: platforms, terminals, and pipelines
- Airports and heliports, fixed-wing aircraft and helicopters
- Icebreakers for winter port and terminal ice clearing
- Icebreaking barges for supply operations
- Service vessels and tugs.

Transportation along the western coast of Alaska north of the Aleutian chain would be restricted to boat and airplane because of the rugged terrain and the lack of populated communities. Road construction appears to be too costly for the benefits that might be derived.

Helicopter support for exploration and development operations in the Bering Sea should be able to be conducted up to 300 miles from an operating base. The current capability of the helicopter to complete this mission is limited. The Boeing Vertol 234, a derivative of the U.S. Army Chinook, has a rated range of 574 nautical miles and can carry up to 44 passengers; the useful load of the Chinook is approximately 23,000 pounds.

Other manufacturers, such as Bell, Sikorsky, and Aerospatiale, are designing and developing heavy twin-engine helicopters that will carry up to 21 passengers over 400 miles at speeds of 165 miles per hour. As distances from shore increase, payload will decrease to accommodate additional fuel to complete the mission.

The instrumentation on helicopters has advanced significantly in recent years, allowing for precise navigation. Operators in Alaska currently have the authority to make approaches to offshore platforms at half-mile visibility with a 100-foot ceiling. Currently, passengers' safety and comfort features are being incorporated into helicopters that will increase passenger acceptance on longer flights.

The logical way to move heavy supplies and equipment to the west coast of Alaska is by ship or barge. Freight service and railbarge service to Alaska from Seattle is offered by several companies. Port facilities along the west coast of Alaska are limited and most heavy equipment for oil field activities would probably be handled by barge. It is possible that large landing craft could be a versatile and useful means of shipping during initial exploration and later shore-facility construction.

Marine service bases would be an integral part of any development program along the Alaskan coastline. Their construction would involve staging areas, with continuous operation, providing drilling materials and support equipment from the coast to the offshore fields. Size and function would vary considerably with offshore activity. The marine service base would remain the longest lived of any activity related to offshore development. Marine service bases must be carefully conceived and efficiently planned to make positive contributions to the stability and economic diversification of western Alaska.

Service bases are required from the time crude oil or natural gas exploration is initiated to the point at which production ceases and the production equipment is dismantled. The entire range of activities offshore in the exploration for and the production of oil and gas resources require support from onshore facilities. This support is an integral part of the process in the exploration for and the production of offshore oil and gas.

A shore base to support offshore oil and gas activity must be selected with care so as to minimize the risk of causing delay to the high-cost offshore operations. The following requirements are desirable and perhaps essential for an efficient service base: proximity to offshore activities, a sheltered harbor of suitable size and draft with available capacity, an adequate waterfront site with contiguous backup lands, a good airport or heliport, adequate roads, and proximity to an established community with an established infrastructure.

Future Transportation Technology

Land Pipelines

The presence or absence of thaw unstable soils remains the greatest unknown factor affecting the cost of Arctic pipelines. Development of new technology that can define thaw stability of soils to a depth of 50 feet from rapidly acquired surface measurements would accelerate and optimize Arctic pipeline construction.

Marine Pipelines

Aside from the need for site-specific climatic, bathymetric, sea ice, ice gouge, sea bottom, and seismic data for the various basins, there is a need for additional knowledge on pipeline protection methods and pipe connection and repair methods.

Terminals

Further studies are needed to provide a sound basis for optimizing the design of Arctic offshore terminals, especially regarding the maneuverability of tankers in ice near mooring berths and the transfer of LNG from offshore platforms to tankers.

Engineering designs for remote offshore loading and storage terminals should also continue to be refined.

Tankers

Considerable development will be required to optimize designs for icebreaking tankers and their support vessels. Ice navigation is a fruitful area for study in order to maximize the effectiveness of Arctic fleets. There is a need for greater knowledge of ice conditions and ice dynamics north of the Bering Strait, as they affect navigation, in order to appraise the needs and risks of operation in the Chukchi and Beaufort Seas.

Gas Transportation

The technology required for producing LNG in Alaska currently exists, and no major technical developments affecting the economic attractiveness of an LNG project are expected within the foreseeable future. Current technology can be refined to better utilize the colder ambient conditions and to simplify operating and maintenance requirements. The fuel efficiency of gas turbines may be improved, but this will not significantly lower the cost of LNG. Improved construction techniques for barge mounting and operating under Arctic conditions could potentially reduce initial costs, reduce the construction schedule, and improve reliability.

Continuing improvements have been claimed in low pressure methanol reactor technology. The prudent application of these improvements could alter the capital cost, operating complexity, and efficiency of a methanol project, but should not significantly affect its overall economics. There is also the potential for economy of size in the support and utility requirements. Improvements in construction techniques could benefit a methanol plant.

Research is now being done using natural gas as a feedstock for direct catalytic conversion into gasoline without going through the methanol stage. If this technology can be developed with favorable economics it could offer another option for marketing Alaskan natural gas.

Cost Factors

All cost data are presented in constant January 1, 1981, dollars and do not take into account future inflation. The cost data for the transportation activities included in the economic analysis are found in Part III of Appendix E.

Land Pipelines

The cost of a 42-inch land pipeline to handle 1 million barrels of oil per day was estimated to be about $12 million per mile, including new haul roads where necessary and pump stations. The cost is dependent upon the terrain. Fifty percent of the pipeline was assumed to be above ground and 50 percent buried.

Construction schedules of three or four years are projected for the land pipeline projects; if a haul road must be constructed first, a minimum of four years will be necessary. These completion times assume that all permits have been obtained and no subsequent permitting delays are encountered. It was assumed in development of the economic scenarios for this report that two years will be necessary to prepare permit applications and to obtain permits for pipelines.

Marine Pipelines

Marine pipelines were considered in the St. George, Bristol, Norton, Hope, Chukchi, and Beaufort Basins.

Although conditions and pipelaying methods vary between the northern and southern basins, the total pipelaying costs (on a dollar-per-mile basis) are about the same.

Order-of-magnitude cost estimates show that installation of a 36-inch-diameter pipeline to produce either 1 million barrels of oil or 1 billion cubic feet of gas a day would cost a minimum of $5 million per mile of pipeline. Adverse weather and regulatory delays would raise this figure. Actual costs could be 50 to 100 percent higher.

Terminals

Total capital costs for a 500,000-barrel-per-day terminal are estimated at $1.5 billion. For a 1-million-barrel-per-day terminal, total costs are estimated at $1.9 billion.

Capital costs are relatively insensitive to the length of the net open-water construction season for all sites south of the Bering Strait. Capital costs would begin to increase significantly for sites where the net offshore construction season is less than 100 days.

Operating and maintenance costs for a 500,000- and a 1-million-barrel-per-day terminal are estimated at more than $31 million per year and $33 million per year, respectively.

Tankers and Icebreakers

For oil transport in the Navarin, Norton Sound, Hope, and Chukchi Basins, a 250,000-ton icebreaker tanker can be expected to supply the trade. The cost of one vessel is estimated to range from $190 to $380 million, depending on the type of service. From 3 to 13 of these vessels will be required to transport up to 1 million barrels of oil per day.

For gas transport from the same basins, an LNG icebreaker tanker of 140,000 cubic meters has been selected. Cost estimates for an icebreaking LNG tanker range from $300 to $510 million. From 6 to 10 of these vessels will be required to transport 1 billion cubic feet of LNG per day.

Gas Transportation

The capital costs for a land pipeline that can transport 1 billion standard cubic feet per day of gas are estimated to amount to $10 million per mile and will require an operating cost of 1.5 percent of capital per year. Ad valorem taxes of 2 percent are not included in the operating cost estimate. Pipelining gas from the NPRA to Valdez would require an $11 billion capital expenditure.

Liquefaction facilities for 1 billion standard cubic feet per day of gas range from $1.6 billion for a plant onshore in southern Alaska to $2.5 billion for a North Slope installation. Operating costs range from $50 to $80 million per year.

Methanol production from the same quantity of gas on the North Slope requires about $6 billion in capital and $200 million per year in operating costs.

Tanker transportation of LNG would employ the specialized vessels described previously. Methanol transportation costs are similar to those applicable to crude oil.

Support Facilities

Because of the complexity and variety of these activities, costs can only be estimated crudely. Values of $360 to $540 million have been selected, dependent upon basin location. Operating cost estimates range from $70 to $117 million per year. Construction time estimates range from two years for a basic port to 3.5 years for an icebreaker designed for port duty.

Transportation Scenarios

Because of the wide range of transportation choices available, a representative scenario approach has been used to study transportation systems. In considering transportation systems for undiscovered oil and gas resources, it was not possible to assume what capacity would be available in either TAPS or the proposed gas line. Consequently, the scenarios required the conservative assumption that additional lines would have to be built, and where terminals now exist, additional terminals would have to be built or the original terminal would have to be expanded.

The times to develop and start up a transportation system that are presented in the scenarios approach the fastest track on which the events could occur.

Representative locations selected for consideration of Arctic offshore development transportation scenarios are shown in Figure 18. The field locations are based only on what appears to be the center of the basin involved and have no other geological significance. To support exploration, construction, drilling, and production activities, specific localities were designated for possible support bases. Terminal sites were chosen for initial consideration. In the case of Navarin Basin, development structures, producing facilities, and loading terminals will all be offshore. The Beaufort location was not considered for an offshore terminal.

An ice-free transshipment terminal in the vicinity of Dutch Harbor was assumed to be required for all Bering Sea marine oil transport systems. Icebreaking tankers from Wainwright (Chukchi), Nome (Norton), or Navarin are assumed to off-load at the transshipment terminal. Pipelines from the St. George and Bristol areas to Dutch Harbor will deliver oil to the transshipment terminal. Conventional tankers then are assumed to take on oil at Dutch Harbor for transportation to the lower 48 states.

The land pipeline routes developed for the study are also shown in Figure 18. Where possible, several alternate pipeline routes were selected. The scenarios considered for oil transportation are shown in Table 6. Costs were then developed for the selected scenarios. Gas transportation scenarios are more limited and are shown in Table 7; gas liquefaction scenarios are shown in Table 8. A detailed presentation of both oil and gas scenarios and costs is given in Part III of Appendix E.

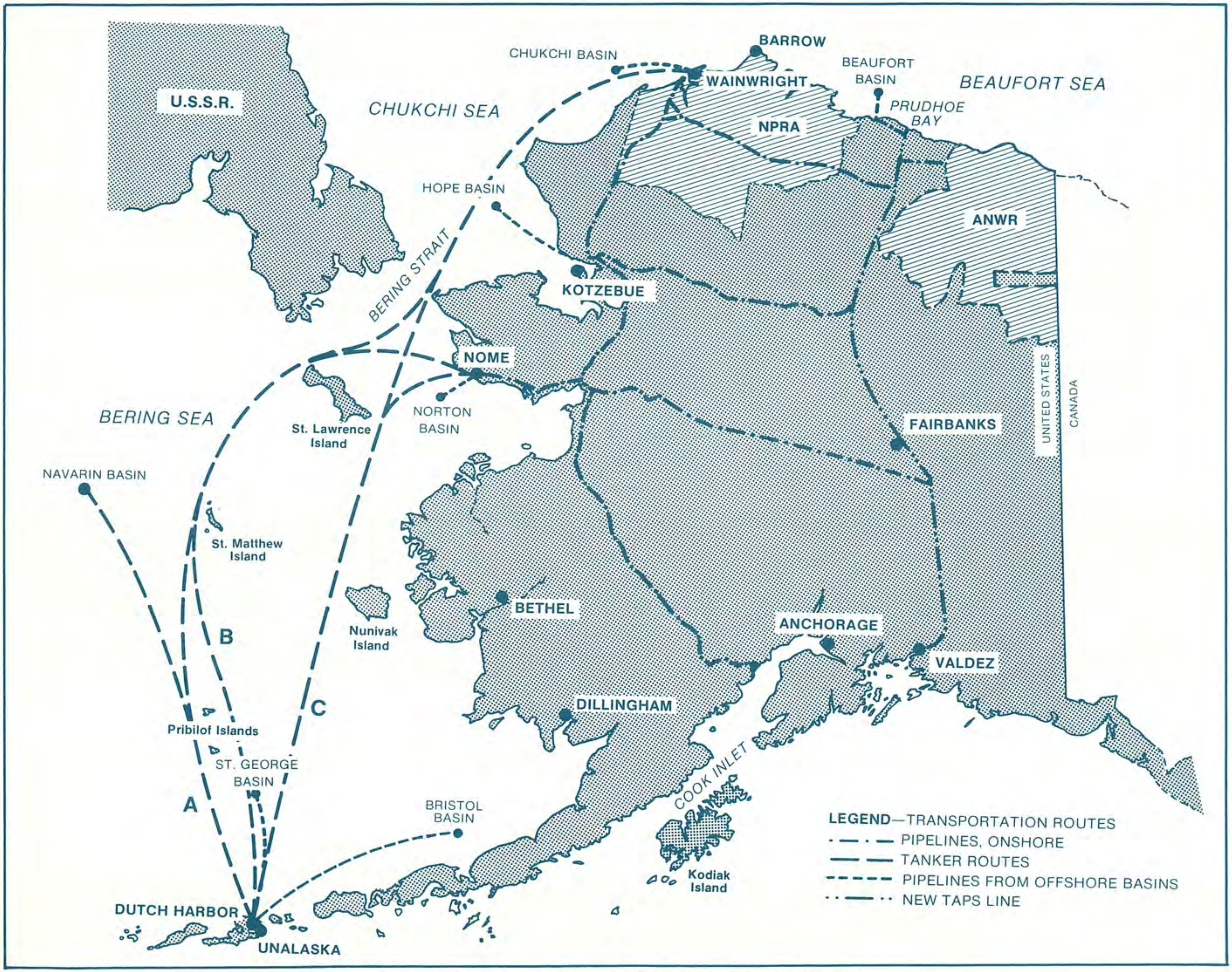


Figure 18. Representative Arctic Transportation Routes.

TABLE 6

OIL SCENARIO SUMMARY

Basin Origin	Transport System
Region I	
NPRA	Pipeline to Wainwright Wainwright to Dutch Harbor (Arctic Tanker*) or Pipeline to Nome Nome to Dutch Harbor (Arctic Tanker*) or Pipeline to Valdez
ANWR	Pipeline to Valdez
Region II	
Norton	Nome to Dutch Harbor (Arctic Tanker*) or Pipeline to Valdez or Pipeline to Cook Inlet
Navarin	Arctic Tanker* to Dutch Harbor
St. George	Marine Pipeline to Dutch Harbor
Bristol (North Aleutian)	Marine Pipeline to Dutch Harbor
Region III	
Chukchi	Wainwright to Dutch Harbor (Arctic Tanker*) or Pipeline to Valdez or Pipeline to Cook Inlet or Pipeline to Nome Nome to Dutch Harbor (Arctic Tanker*)
Beaufort Offshore	Pipeline to Valdez

*Assumes a transshipment terminal at Dutch Harbor.

It should be emphasized that the sites selected for terminals, support bases, and pipelines are only representative. Using the scenario approach, representative locations are adequate for studying overall operational considerations, approximate costs, and general environmental concerns for broad areas. As exploration and development continue, many more detailed studies of possible support bases, terminal sites, and pipeline routes will be conducted before final selections for sites and routes are made.

For the scenarios selected, two production rates for oil and two production rates for gas were chosen for costing purposes. For oil, 1 million barrels per day and 500,000 barrels per day were selected. For gas transportation, 1 billion cubic feet per day and 500 million cubic feet per day were chosen. These rates were considered representative of the peak rates associated with the development of major reserves from each of the basin areas. It was assumed that extrapolation of the cost data could be made to other reasonable producing rates.

Some transportation systems have not been studied in detail, including the use of a marine terminal and tankering out of the shallow Beaufort Sea area. It is expected that potential production from this area would be transported by marine and land pipeline to the TAPS corridor. Most of the basins now proposed to be leased by the Department of the Interior are in relatively shallow water. For this reason, submarine and surface tanker transport systems in the Beaufort were not studied in detail. The probability of utilizing a tanker transportation system in the Beaufort within the next 20 years appears unlikely unless feasibility is demonstrated by advanced operations in less severe areas such as the Chukchi or Canadian

TABLE 7

GAS SCENARIO SUMMARY

Basin Origin	Transport System
Region I	
NPRA	Pipeline to Wainwright Wainwright to U.S. West Coast (Arctic LNG Tanker) or Pipeline to Nome Nome to U.S. West Coast (Arctic LNG Tanker) or Pipeline to Valdez Valdez to U.S. West Coast (Conventional LNG Tanker)
Region II	
Navarin	Direct to U.S. West Coast (Arctic LNG Tanker)
St. George	Marine Pipeline to Dutch Harbor Direct to U.S. West Coast (Conventional LNG Tanker)

Note: LNG tankers are sized and costed to carry product to the West Coast.

TABLE 8

GAS LIQUEFACTION SCENARIOS

Liquefaction Facility	Wainwright	Nome	Valdez	St. George Basin	Navarin Basin
Location	Offshore	Onshore	Onshore	Onshore	Offshore
Type/Process	Modules on Gravity Island	Winterized/ Module	Winterized/ Standard	Winterized/ Standard	Winterized/ Module
Type/Marine	Protected Harbor	Single Point Mooring	Standard	Standard	Single Point Mooring 3 Structures
Water Depth (Ft.)	50	60	N/A	N/A	450
LNG Line	N/A	Pipeline in Tunnel	N/A	N/A	N/A
LNG Storage Type	Special Tanks on Grounded Barges	Special Tanks on Grounded Barges	Standard, Above Ground	Standard, Above Ground	Underwater, Gravity-Based Structure
LNG-Days Storage	8	8	8	8	11

Beaufort Sea. Submarine tankers would be limited to minimum operating depths in the 600- to 800-foot range, which precludes almost all of the area expected to be explored and leased in the foreseeable future.

Findings

All aspects of transportation in the Arctic are affected by the severe climate and the continual need to cope with ice in offshore regions. Additionally, site-specific climatic, bathymetric, sea ice, ice gouge, sea bottom, and seismic data will be necessary as oil and gas development activity needs dictate.

Land Pipelines

- Development of new technology that can define thaw stability of soils to a depth of 50 feet from rapidly acquired surface measurements would have an important effect on the design of new oil pipelines.

Marine Pipelines

Additional knowledge would be valuable on:

- Pipeline protection methods: rapid, effective trenching techniques capable of trenching below ice gouge depths
- Pipe connection and repair methods: rapid, effective techniques for alignment, connection, and repair.

Terminals

Improved Arctic terminal designs would result from studies on:

- The maneuverability of tankers in ice near mooring berths and the cumulative effects of tanker traffic on ice conditions near the berth
- Transfer of LNG from offshore platforms to tankers
- The accumulation of fresh-water ice and sea ice on terminal and tanker structures
- The effect of freezing conditions on synthetic mooring lines
- The minimum water depth required to avoid the formation of rubble piles near a tanker berth
- The physical properties and return periods for multi-year ice and multi-year ice events
- Better definition of the extent of near-shore permafrost.

Tankers and Icebreakers

- Development of optimized designs for icebreaking tankers and their support vessels will be needed as transport requirements increase.
- Improved information on ice conditions and ice dynamics north of the Bering Strait would contribute to better tanker designs and the ability to predict operational capability.
- Methods for improved ice reconnaissance to aid navigation will be needed. Satellite systems appear to hold the greatest promise in this area.
- Improved methods for ice forecasting will be needed.
- Continued operation of Coast Guard icebreakers is needed to further evaluate the technical feasibility of regularly scheduled ship passage.

Support Logistics

- In order to provide year-round logistical support in ice-covered harbors, harbor ice management should be addressed.
- Communications and electronic tracing of surface vessels and aircraft must play a very important part of the support base activity. Development of equipment suitable for use in Arctic regions should be encouraged.

CHAPTER SIX: ECONOMIC ASSESSMENT

Previous chapters have shown that highly significant oil and gas resources are expected to exist in the U.S. Arctic and that industry possesses adequate technology to develop most of these resources. They will be developed only if an adequate economic incentive exists. A limited economic assessment has shown that it is economically attractive to undertake the development of the Arctic resources. This judgment is based on the analysis set forth in this report and on the expertise of the study participants, and is supported by the findings enumerated in this chapter. Certain key assumptions made and bases established in these economic analyses must be kept in mind in interpreting the economic findings since they have significant effects on the analyses and could yield low-side estimates.

Economic Analysis

The economics presented in this study are intended only as an approximation of the economic attractiveness of Arctic oil and gas resources; they do not represent the actual economics of a prospect. They are based on estimated mean resources and typical producing rates and exclude all prediscovery risks, leasing bonuses, and allocations of costs related to dry prospects and basins. They are most closely related to the economics of basin development after pre-lease-sale geological and geophysical surveys, lease sale bidding, and exploratory drilling of unsuccessful prospects have taken place.

The analysis is based on estimated costs and prices as of January 1, 1981, and does not consider an increase in either costs or prices with time. All return on investment results are presented on an after-tax basis, and discounted cash flow (DCF) methods are used throughout the analysis. Representative locations as described in previous chapters have been used for costing purposes; however, actual locations would be developed only after resource discovery and site-specific evaluation.

Since few exploration drilling operations and no petroleum production operations have occurred in the U.S. Arctic offshore, little or no experience exists on which to base accurate estimates of costs and time to carry out development programs. Moreover, the area is remote and has severe weather and sea surface conditions much of the year. As a result, estimates used in the economics were developed from a range of projected information and costs, often involving extensions of proven technological capabilities. Changes in such projected capabilities may increase or reduce the timing and costs of future petroleum exploration and development.

Oil Cases

The economics of the exploration, development, and transportation of crude oil were developed for a selected group of areas defined in Chapter One that were representative of geological and environmental conditions in the Arctic. Cases were established for these areas based on costs and timing as defined in prior chapters. Production rates were selected at three levels to bracket the rate assumed for the NPC risked mean resource assessment of undiscovered oil in the area.

The timing assumptions used are shown in Figure 19 and assume no significant delays in accordance with the scenario descriptions in prior chapters. It should be noted that in no case is oil production achieved in less than 9 years; this extends to as much as 14 years in the more hostile areas. Details of other assumptions used in the cases are given in Part I of Appendix F.

A complete economic evaluation was run on each of these cases using a commercially available computer program that developed such economic indicators as discounted cash flow, DCF return, payout, and profit-to-investment ratio. Numerous sensitivity calculations were made to indicate the effect of prices, costs, timing of development, and other factors on these results.

An important conservative assumption was made for analyzing land transportation costs. It was assumed that it would be necessary to build a new line in the present TAPS corridor and to enlarge or duplicate the terminal facilities at Valdez to handle the increased oil volume. This study fully recognizes the capability of the present TAPS line to handle increased volumes of oil, and that the economic attractiveness of many of the areas in the vicinity of the TAPS line would be significantly increased by transporting the newly found oil through the present TAPS line since the requirement for building an entire new line would be eliminated. However, assuming that total new production would substantially exceed any spare capacity in TAPS, it was considered beyond the scope of this study to allocate TAPS capacity.

Early in the analysis it became apparent that the potential transportation investment required to deliver crude oil to an ice-free port on the south coast of Alaska or in the Aleutians would be a considerably larger portion of the total investment than is normal when evaluating the costs of developing an oil reserve. While the highside reserve estimates in most areas are sufficient to justify independent transportation systems, if each area had to provide an independent transportation system its economics would be less attractive. Consequently, it was found to be desirable to consider the use of one transportation system to move oil from a combination of potentially productive areas. In this way, the transportation costs can be shared by each of the areas and the economic attractiveness increased.

Four separate cases are presented to illustrate a range of attractiveness for economic development. Both stand-alone cases for individual areas and combined cases for groups of areas that share a common transportation system are included. These were chosen from those areas for which technology is considered to be available for development and to determine general economic attractiveness. A far more detailed economic study for each area would have to be conducted before definitive conclusions could be reached.

Stand-Alone Cases

Two of the cases are representative of areas that could stand alone and might support a transportation system. They evaluate the Beaufort Shelf and the NPRA. The assumption is made that no capacity is available in the TAPS line and that the individual areas would have to support their own pipeline to an expanded Valdez terminal.

The NPRA case was evaluated over a range of reserves from 1.0 billion barrels to 4.0 billion barrels. This was done to bracket the assumed resource base from the NPC oil resource assessment of 2.1 billion barrels for that area. All facilities for production and transportation were sized to support the selected rates.

The Beaufort Shelf case was defined for the same production range as the NPRA case to facilitate comparison even though the NPC oil resource assessment estimated 8.2 billion barrels for that area. The major difference in the assumptions for these two cases was the imposition of the Alaska severance tax for the onshore NPRA case.

Combined Cases

The combined cases consider a Northern Group supporting a pipeline similar to that used in the stand-alone cases and a Bering Sea Group supporting a marine transportation system that delivers oil to an ice-free port such as Dutch Harbor.

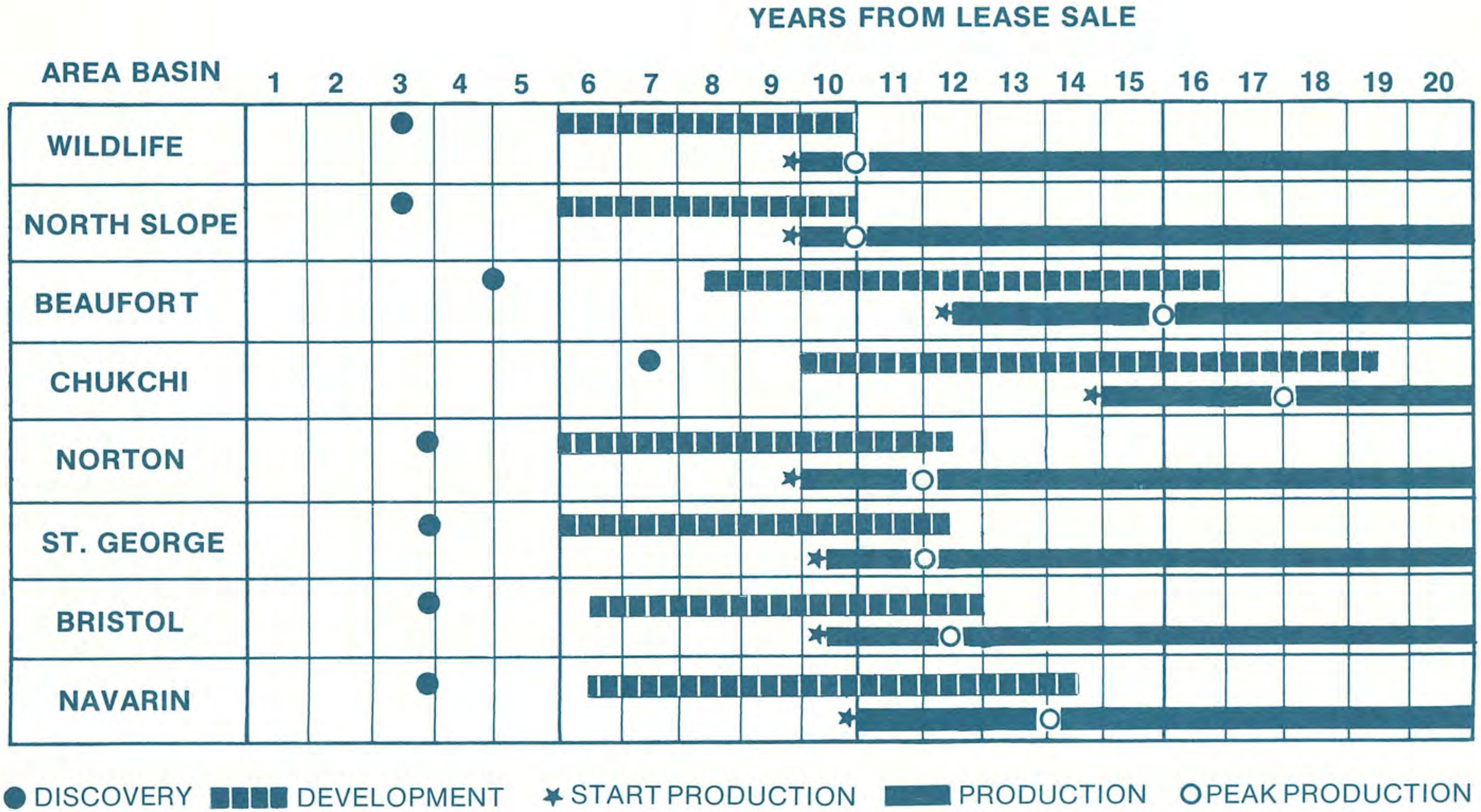


Figure 19. Generalized Timing—Crude Oil Cases.

The Northern Group case combines production from the ANWR, Beaufort Shelf, NPRA, North Slope Other, and North Chukchi Shelf areas. This group of areas was assumed to produce through gathering lines to a central site on the North Slope from which the crude oil is carried to Valdez through a new pipeline in the TAPS corridor. The system is shown in Figure 20. The total reserves produced through this system for the five areas amount to 16.3 billion barrels of oil. The capacity of this pipeline system was selected at 1.5 million barrels of oil per day, which corresponds to a 30-year reserve life.

A further simplifying assumption is that development of individual basins would occur over a period of time to enable each basin to produce unprorated for its entire life and to keep the pipeline full over a 30-year life. Capital is assumed to be available for the field's pro rata share of the main pipeline at the time the USGS sanctions development of that field.

The Bering Sea Group case includes the Navarin Basin Shelf, St. George Basin, Bristol Basin, and Norton Basin areas. Production from this group is assumed to be transported by tanker or pipeline to a common terminal at Dutch Harbor from which the crude oil is transshipped to the south. The terminal system is sized to handle 1.0 million barrels per day. Other assumptions about timing are similar to those for the Northern Group.

The area transportation system is shown in Figure 21 and the routes are developed in Chapter Five. The Nome facilities are 100 percent allocated to the Norton Basin. The Dutch Harbor terminal is shared among Bristol Basin, St. George Basin, Navarin Basin Shelf, and Norton Basin.

Oil Results and Conclusions

The results of the oil economic analyses presented in this report provide a means of judging the relative economic attractiveness of Arctic development based on a set of reasonable assumptions. They do not encompass the many cases that could be calculated nor are they intended to preclude the possibility of other outcomes. This section presents estimates of what could happen under certain assumed technical and economic circumstances and is not intended to represent a forecast of what will occur.

Case Results

The results of the economic evaluations for the various cases are summarized in Figures 22, 23, and 24 where the after-tax return on investment is plotted against area reserves. More detail is given in Part III of Appendix F.

The stand-alone case results are displayed in Figure 22, from which it is evident that large reserves must be available for a single area to support its own pipeline system. In this case, the NPRA, which is estimated by the NPC to have risked mean expected resources of 2.1 billion barrels, would achieve a return of only 8 percent at that level. The NPRA would require a reserve of 3.0 billion barrels to reach a minimum return of 10 percent. The Beaufort Shelf case is somewhat more attractive since it is not carrying the burden of the Alaska severance tax. In this case reserves of 3.0 billion barrels will yield a 15 percent return. This area is estimated to contain 8.2 billion barrels of risked mean expected resources, which would support a transportation system.

Sharing a transportation system can materially reduce the reserve requirement and improve economics. Figure 23 illustrates this for the Northern Group combined case. Here the NPRA provides a return of 17 percent and the Beaufort yields almost a 20 percent return at the 3.0 billion barrel level. Returns of 15 percent result at reserve levels of less than 2.0 billion barrels for both of the stand-alone areas evaluated. This vastly improved result can only be obtained, however, if the total reserves for the group amount to 15 billion barrels since the pipeline costs are prorated on this base.

In the Bering Sea, sharing a marine transportation system would be advantageous for the same reasons suggested for sharing a land transportation system for the Northern Group. The Bering Sea results are plotted in Figure 24, from which it can be seen that a 10 percent return is achieved for all areas even if fewer than 1.0 billion barrels of reserves are discovered in each. A 15 percent return requires greater reserves, especially in the more remote areas

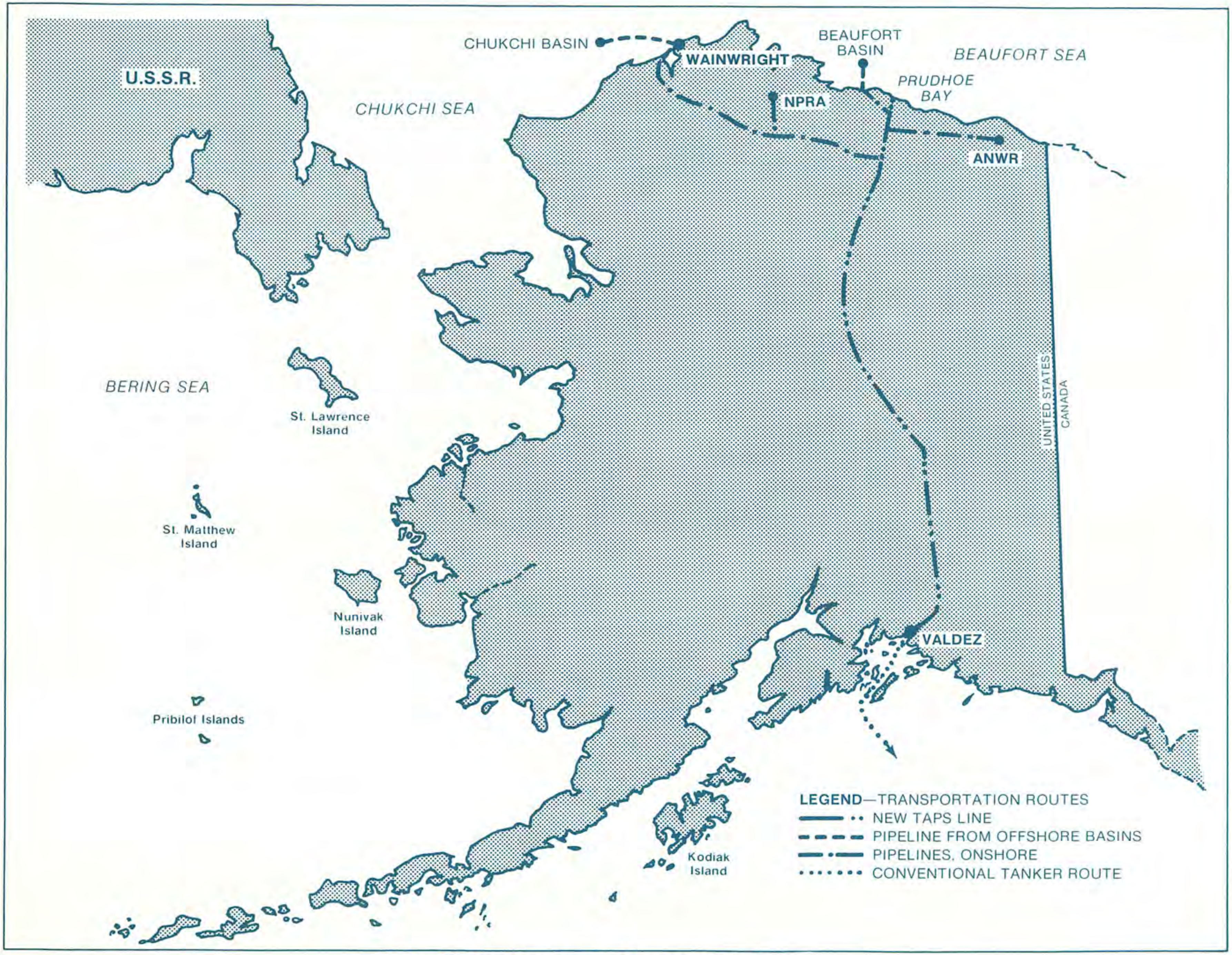


Figure 20. Northern Group Transportation System.

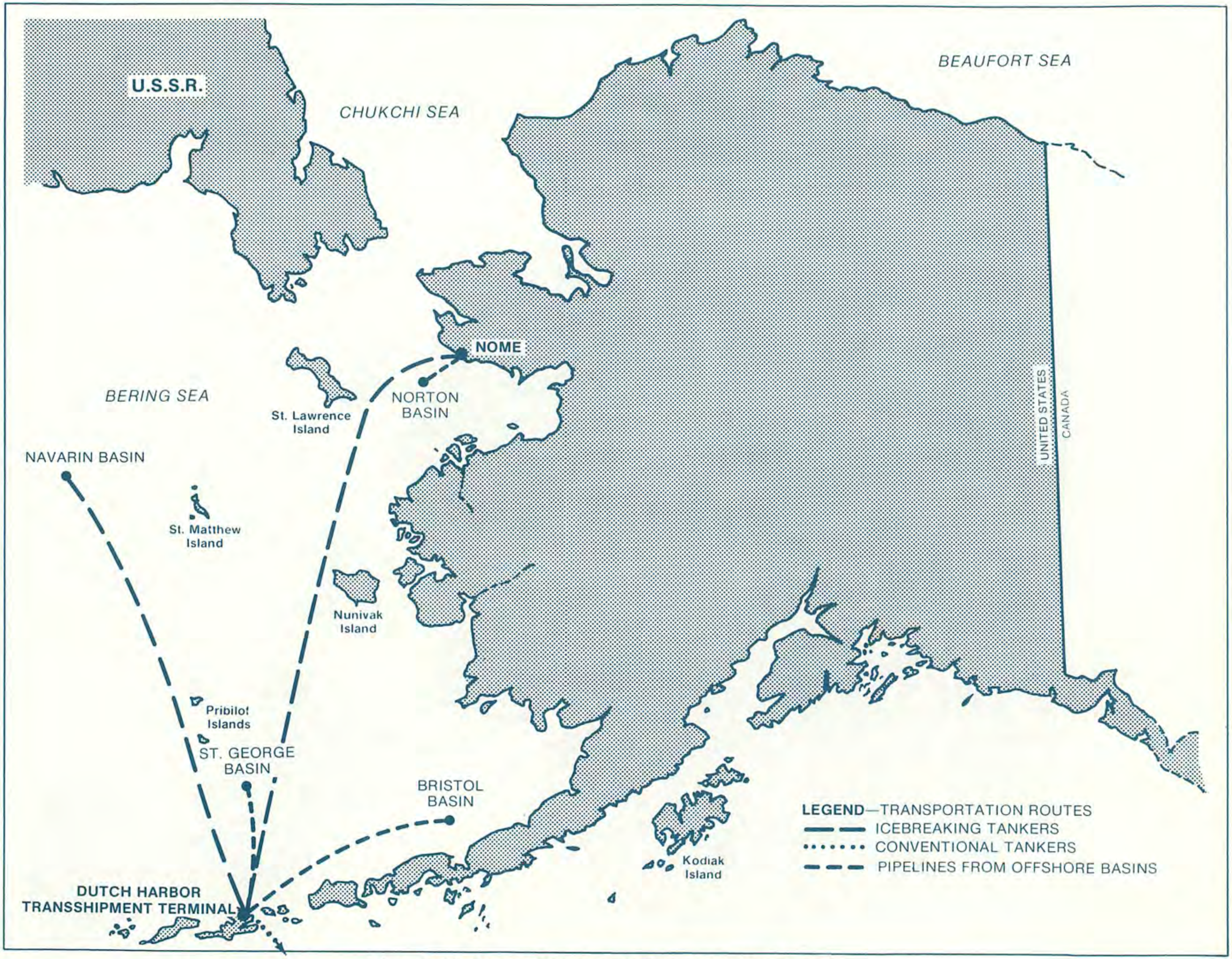


Figure 21. Bering Sea Group Transportation System.

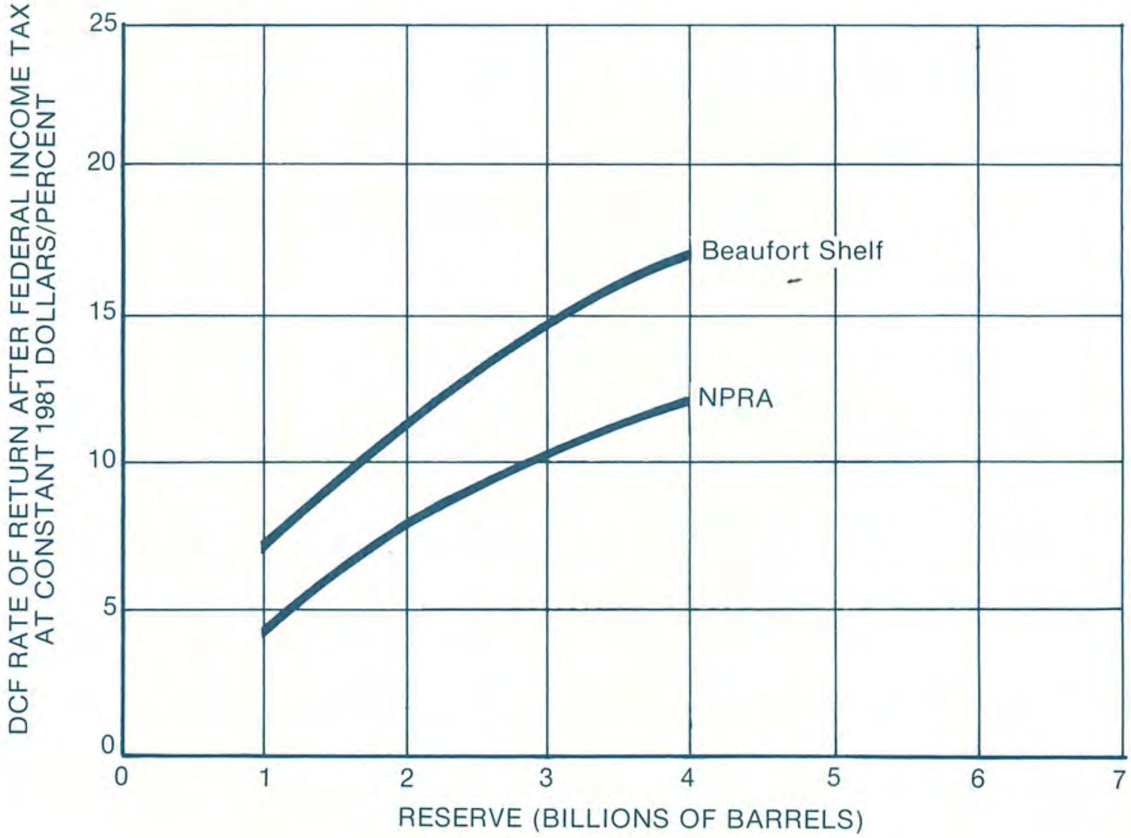


Figure 22. Stand-Alone Cases—Oil.

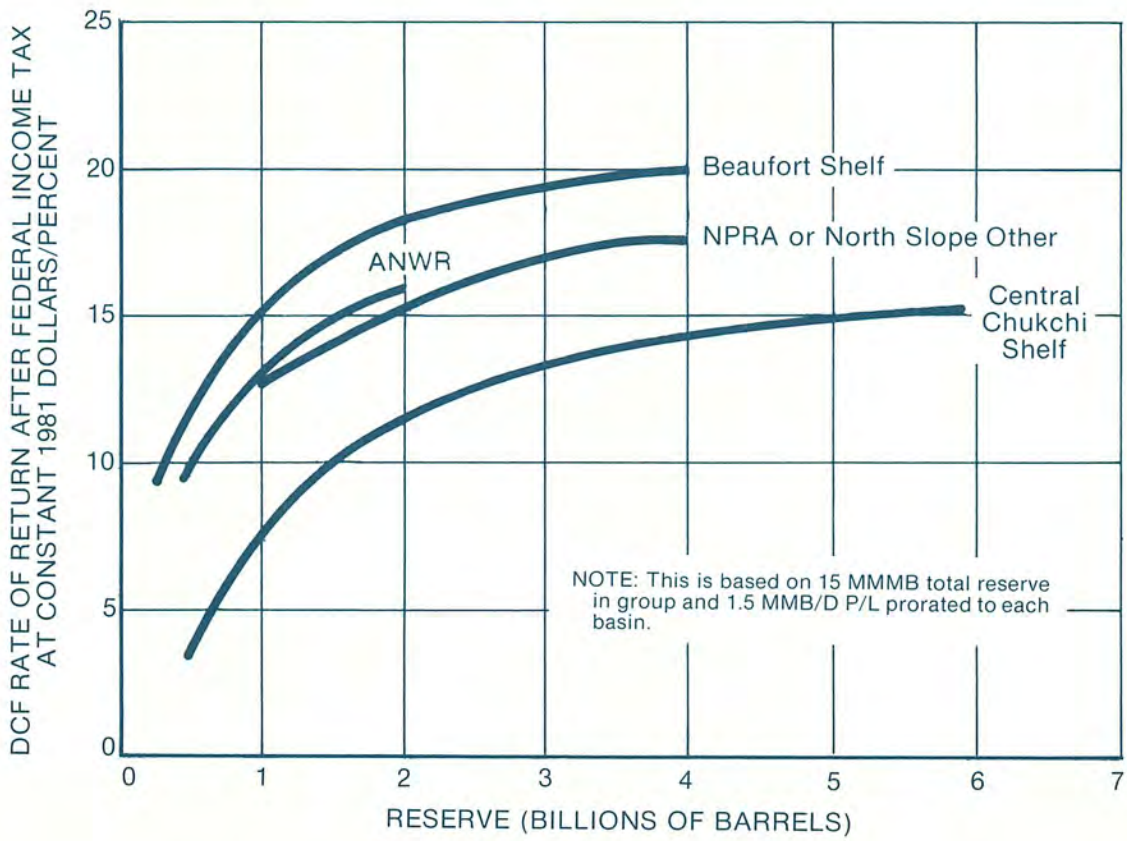


Figure 23. Northern Group Cases—Oil.

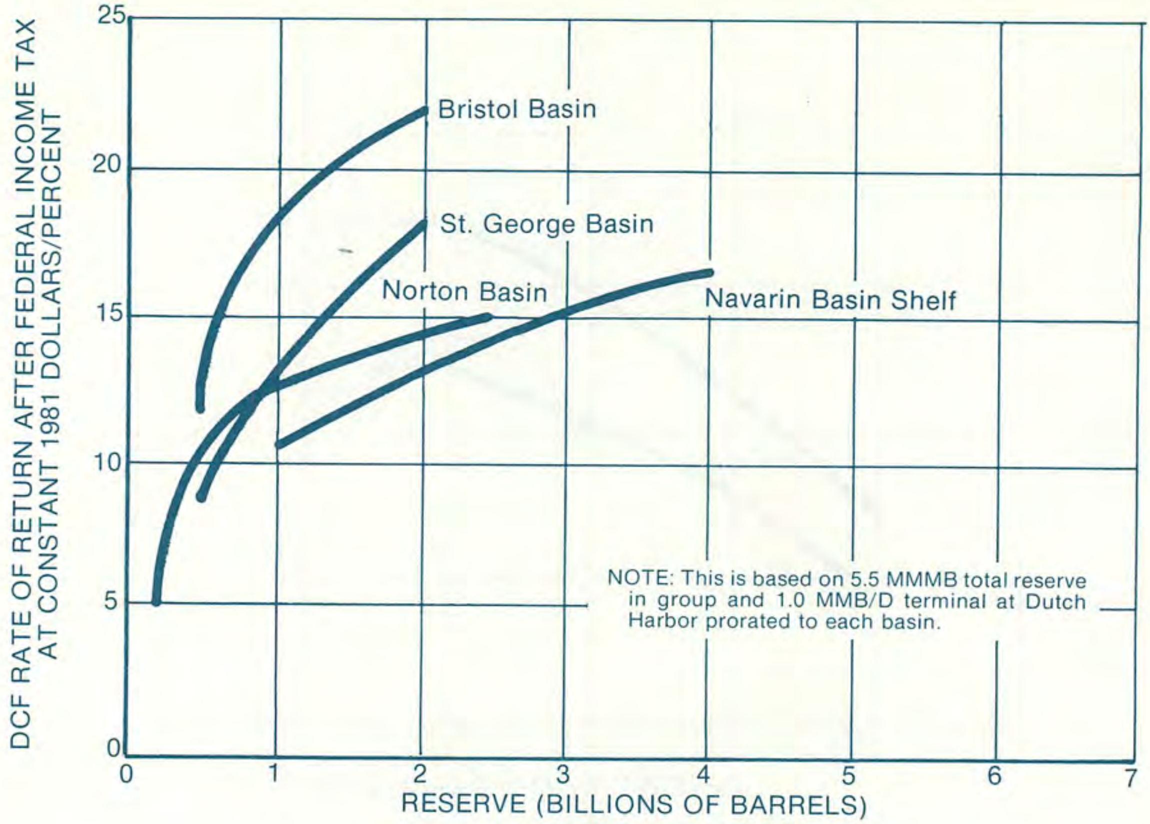


Figure 24. Bering Sea Group Cases—Oil.

such as the Navarin Basin Shelf where 3.0 billion barrels of reserves would be required. In this situation a total reserve of 5.5 billion barrels must be available to support the shared transportation system chosen for this case.

A stand-alone case was not computed for a Bering Sea area. It was assumed that several areas in this region would be productive and, thus, would share a transportation system. If only a single area proved to be productive, economic development still might be possible. A more limited marine transportation system could be employed utilizing onsite loading and avoiding construction of a transshipment terminal.

The results of the economic analysis were examined for after-tax rates of return of 10 and 15 percent in an attempt to cover the range that might be considered attractive by industry. Since these returns were developed on the basis of 1981 constant dollars, they will not correspond to those that would be calculated when inflation is taken into account. The directional effects of varying economic factors are defined by the analysis. Any specific situation would have to be examined in much more detail in order to make decisions as to its economic attractiveness. Such analyses can be made only when comprehensive site-specific information is available, especially documentation of discovered resources.

In all areas studied it is shown that, due to the high cost of oil field development and associated transportation systems, large discovered resources must be available to provide acceptable economic returns. Sharing of transportation systems makes the cases more realistic and materially improves the potential return on investment from each of the areas.

The transportation systems were evaluated as a part of the total investment required for complete development. If transportation were provided by regulated common carriers that traditionally have required a lower return on investment, the economics of the other segments of the development would be improved, increasing the economically recoverable oil resource base available to the nation.

Sensitivity Studies

In addition to the cases described, a number of sensitivity studies were run to establish the effects of oil prices, capital variations, production delays following expenditures, royalties, and income tax credits. Figure 25 shows the effects of a delay for a representative situation in the Navarin Basin Shelf. When production delays are encountered after expenditures have been made, a decrease in return on investment of some 2 percent per year of delay is shown to occur. This can easily cause a marginal project to become uneconomic. Other sensitivity studies are summarized in Part III of Appendix F. No unexpected results were obtained although it is shown that decreased royalties and/or larger investment credits applicable to federal income tax will make a significant improvement in returns and may be a means of making marginal areas attractive.

The economics of exporting new oil production from Alaska were not examined in detail for this report. Under the Trans-Alaska Pipeline Authorization Act of 1973, oil transported through the TAPS line is prohibited from being exported. Consequently, no Alaskan oil has been exported from the TAPS line.

Because of transportation cost savings, exporting to the Far East appears very attractive. It has been estimated that the 1981 cost of $5 per barrel for transportation of oil from an Alaskan ice-free port to the U.S. Gulf Coast market could be reduced to 60 cents for deliveries to the Far East in foreign tankers or $3 in U.S. tankers. The exported supply diverted from the Gulf Coast could be replaced by nearer suppliers of foreign crude oil. The result would be an increase of $2 to $4 per barrel in the wellhead value of Alaskan crude oil. This would substantially add to the income of the State of Alaska and the U.S. government and would increase the nation's economically recoverable oil resource base.

Economic Resource Base

An important result of the economic study is the use of return-on-investment results in combination with the results of the resource assessment to establish the economic resource base. The results of this

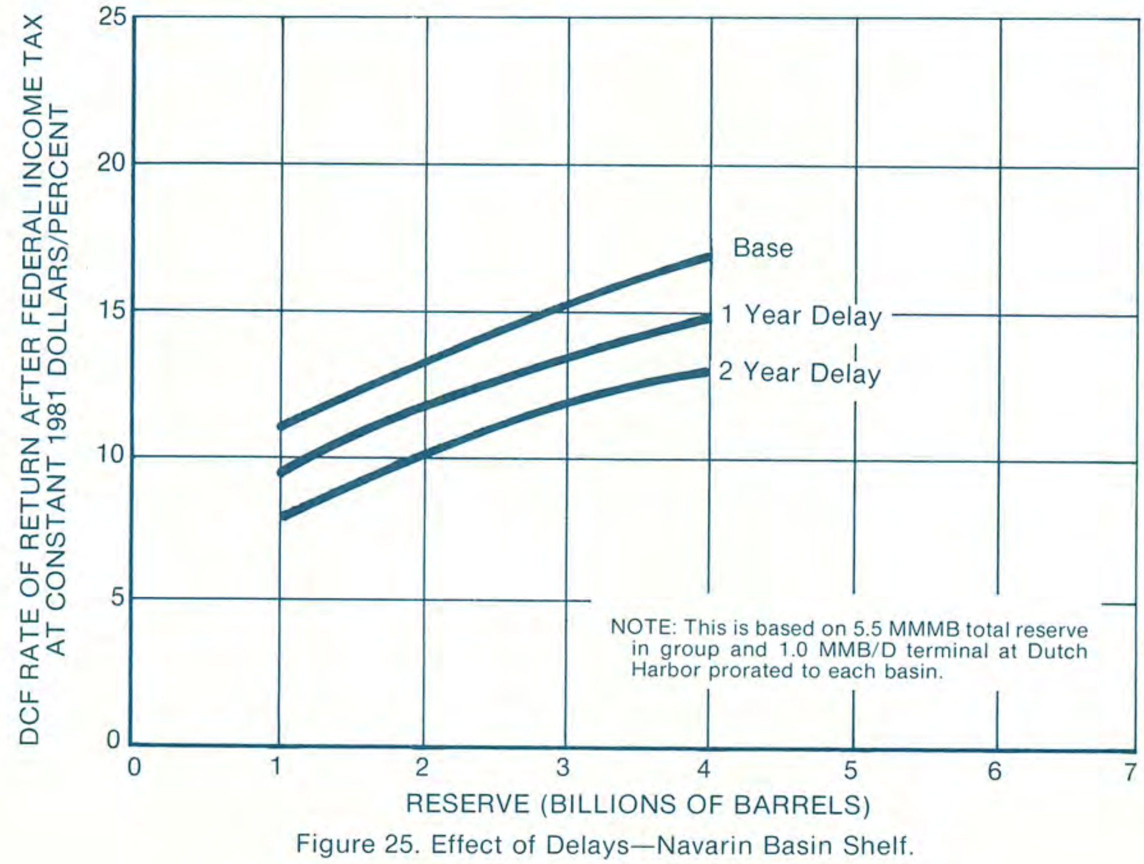


Figure 25. Effect of Delays—Navarin Basin Shelf.

evaluation are summarized in Table 9, and the detailed methodology is described in Part V of Appendix F.

The first two columns of Table 9 present the risked mean values for undiscovered oil by area and the adequacy chance, which depicts the probability of finding a large field in the specified areas as they are reported in Chapter One. The third column shows the minimum economic reserve required to obtain a 10 percent return as read from Figures 23 and 24. Relating this to resource assessment probability curves allows determination of the chance of discovering the minimum economic reserve shown in the fourth column. It also allows the economic resource base for each area to be calculated as shown in the fifth column. Similar figures developed in the same manner for a 15 percent return are shown in the last three columns.

At a 10 percent return, the economic resource base for most areas is only slightly lower than the risked mean undiscovered resource; however, imposing a 15 percent return requirement results in a significant reduction in the economic resource base. For the total U.S. Arctic, the risked mean undiscovered oil resource decreases from 24.1 billion barrels to 20.6 billion barrels at a 10 percent return primarily because some of the more remote northern areas are considered to be technically infeasible to develop at this time. When a 15 percent return criterion is imposed, however, the economic effect is felt and the total economic resource base decreases to 17.8 billion barrels.

Achievement of the economic resource base will require a significant period of time since several of the structures in an area may need to be drilled to reach the minimum reserve. The current lease term of five years may not provide sufficient time for a development to prove economic. Since the lease owners may need to aggregate sufficient reserves to justify a transportation system, an extension of the lease term may be desirable. Increasing the primary term to 10 years would be an improvement but may not be sufficient. A more desirable system would be an automatic "suspension of production," which would allow owners to retain leases with discovered resources until a transportation system becomes economically feasible.

Capital Requirements

The total capital required to develop and produce the expected crude oil resource base in the Arctic region covered by this study is about $95 billion, of which $70 billion is spent in the northern area, with the remaining $25 billion spent in the Bering Sea. These costs do not include sizable lease costs or the exploration expenditures associated with unsuccessful ventures, which will also be substantial.

These data were developed as shown in Table 10. The unit costs of development and transportation for each basin as shown in Part I of Appendix F were multiplied by the economic resource base at a 10 percent return to calculate an expected investment.

There will probably be significant increases in these costs as they actually occur over time due to inflation and revised estimates based on actual expenditures.

Gas Cases

An economic assessment of the exploration, production, and transportation to the lower 48 states of undiscovered non-associated Arctic natural gas was developed for representative cases. This assessment was based on technology, cost, and timing factors established in previous chapters. The analytical approach used was similar to that used to evaluate crude oil.

Of the total 109 TCF of risked mean undiscovered gas resources estimated in Chapter One, 68 TCF are expected to occur as non-associated gas and 41 TCF should be associated with oil production. Evaluations have not been carried out for the more complex economics of associated gas nor were the economics of the incremental use of TAPS or the proposed ANGTS pipeline. It was assumed that associated gas would either be reinjected to maintain reservoir pressure or used as fuel on site.

In order to establish representative cases for evaluation, two Bering Sea locations with substantial resources were selected: the St. George Basin, which exemplifies a fairly accessible area, and the Navarin Basin Shelf, which represents a more remote area. For the North Slope, it was evident that transportation costs would represent a major economic hurdle. Accordingly, this analysis was confined to a

TABLE 9

ECONOMIC RESOURCE EVALUATION

	Undiscovered Resources—Oil		Economic Undiscovered Resources—Oil					
			@10% ROR			@15% ROR		
Area	Adequacy Chance§ (%)	Risked Mean (BBO)	Minimum Economic Reserve (BBO)	Chance For Min. Econ. Reserve (%)	Economic Resource Base* (BBO)	Minimum Economic Reserve (BBO)	Chance For Min. Econ. Reserve (%)	Economic Resource Base* (BBO)
Beaufort Shelf	88	8.2	0.4	88	8.2	1.1	88	8.2
ANWR	70	2.3	0.5	69	2.3	1.6	44	2.1
North Slope Other	79	2.1	0.6	75	2.1	1.6	48	1.8
NPRA	79	2.1	0.6	78	2.1	2.3	46	1.6
Central Chukchi Shelf	62	1.7	1.5	43	1.6	4.5	8	0.5
Navarin Basin Shelf	41	2.3	0.9	36	2.3	2.9	22	2.0
St. George Basin	47	1.2	0.6	39	1.1	1.4	27	1.0
Bristol Basin	47	0.6	0.6	44	0.6	1.2	34	0.6
Norton Basin	43	0.3	0.5	23	0.3	2.5	1	0.0
Beaufort Slope	57	1.3	†	—	0.0	†	—	0.0
North Chukchi Shelf	50	1.2	†	—	0.0	†	—	0.0
North Chukchi Slope	34	0.3	†	—	0.0	†	—	0.0
Other Eight Areas	—	0.5	—	—	0.0	—	—	0.0
Total		24.1			20.6			17.8

§Chance of finding more than 0.05 billion barrels of oil equivalent.
*Risked mean economic resource.
†Not technologically feasible.

TABLE 10

CAPITAL REQUIREMENTS—OIL

	Economic Resource Base @ 10% (MMMB)	Unit Costs Per Barrel		Total Expected Investment		
		Development ($/B)	Transportation ($/B)	Development (MMM$)	Transportation (MMM$)	Total (MMM$)
Northern Group						
Beaufort Shelf	8.2	2.72	0.85	22.3	8.4	30.7
ANWR	2.3	2.75	1.20	6.3	3.5	9.8
North Slope Other	2.1	2.76	1.30	5.8	3.4	9.2
NPRA	2.1	2.80	1.30	5.9	3.4	9.3
Central Chukchi Shelf	1.6	3.80	2.70	6.1	5.2	11.3
Total	16.3			46.4	23.9	70.3
Bering Sea Group						
Navarin Basin Shelf	2.3	4.28	0.57	9.8	1.6	11.4
St. George Basin	1.1	4.20	1.35	4.6	1.8	6.4
Bristol Basin	0.6	3.83	2.22	2.3	1.6	3.9
Norton Basin	0.3	4.55	2.45	1.4	0.9	2.3
Total	4.3			18.1	5.9	24.0
Arctic Total	20.6			64.5	29.8	94.3

single, relatively accessible location, the NPRA, but three transportation alternatives were considered.

The Bering Sea cases are evaluated using resources that include and extend the NPC non-associated gas resource estimate of 5.5 TCF in the Navarin Basin Shelf and 3.8 TCF in the St. George Basin. In the Navarin Basin case, offshore liquefaction and ice-strengthened LNG tankers were used. The St. George case pipelines the gas to the Dutch Harbor vicinity for liquefaction and transport with conventional LNG tankers.

The North Slope cases are evaluated using resources that bracket the NPC estimated undiscovered non-associated resource of 10.9 TCF in the NPRA. Alternative transportation methods were applied as follows:

Alternative 1: Pipeline gas to Nome, liquefy onshore, transport LNG in icebreaking LNG tankers

Alternative 2: Pipeline gas to Wainwright, liquefy offshore, transport LNG in icebreaking LNG tankers

Alternative 3: Pipeline gas to Valdez, liquefy onshore, transport LNG in conventional LNG tankers.

These transportation alternatives and the NPRA production case on a stand-alone basis were selected for economic analysis in the belief that they would represent the best of the individual basin North Slope cases. It was assumed that if none of these NPRA cases provide an adequate return, other potential onshore and offshore North Slope cases would then not be expected to be economically attractive.

In all cases the gas was liquefied, transported as LNG to the West Coast of the continental United States, and regasified. No attempt was made to develop a gas case using a pipeline through Canada similar to the proposed ANGTS pipeline. The most significant assumption in the gas cases was that gas value as regasified was equivalent to crude oil, on a BTU basis. Other assumptions used in the gas cases are detailed in Part II of Appendix F.

Gas Results and Conclusions

As with the oil cases, the results of the gas economic analyses presented in this report attempt to define the relative economic attractiveness of Arctic development based on assumed technical and economic circumstances and are not intended to represent a forecast of what will occur. Many more cases could be calculated.

Case Results

Results of the evaluation of the gas cases are plotted to show after-tax return on investment, as a function of reserves, in Figures 26 and 27. Details of the case results are reported in Part IV of Appendix F. As shown in Figure 26, none of the transportation alternatives considered were significantly different nor did the NPRA cases reach the minimum rate of return of 10 percent.

The Bering Sea cases as plotted in Figure 27 are more attractive since the unit cost of the transportation system is lower than that required for North Slope production. For the Navarin Basin Shelf, a 10 percent return is achieved if 9.5 TCF of gas are discovered; for the St. George Basin 7.5 TCF are required. A 15 percent return is not obtained under any of the gas cases that were studied.

Those conclusions are based on a number of specific assumptions including the assumptions that: gas is equivalent in value on a BTU basis to crude oil, no existing or currently planned transportation facilities would be available, gas would be transported to the lower 48 states as LNG, and all gas resources would be analyzed on a stand-alone basis. The unfavorable economics for moving gas from NPRA led to the exclusion of the entire 36 TCF of onshore and offshore North Slope non-associated gas from the economically recoverable category. However, considering the use of a potentially available pipeline system such as ANGTS could improve the economics of onshore and offshore North Slope gas.

It should be emphasized that neither existing discovered gas resources nor undiscovered gas resources associated with commercial oil development projects have been evaluated.

Sensitivity Studies

Sensitivity studies similar to those made for the crude oil cases were conducted to establish the effects of gas prices and

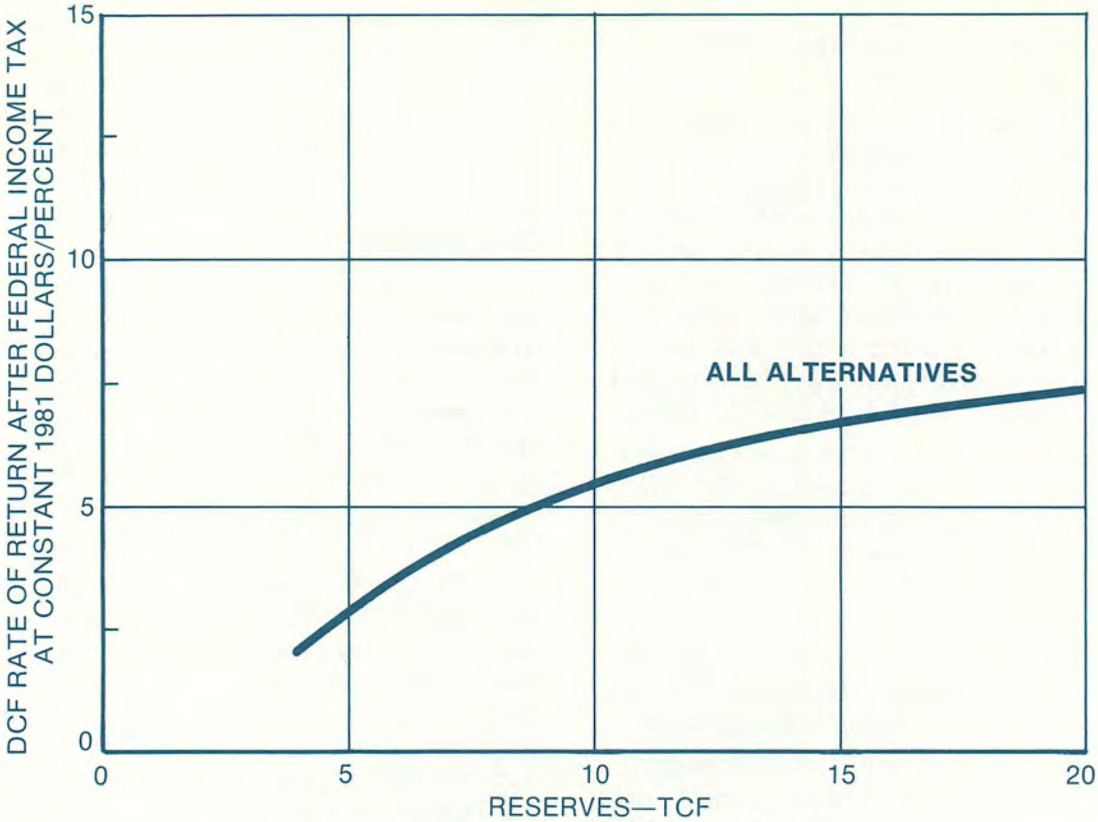


Figure 26. NPRA Cases—Gas.

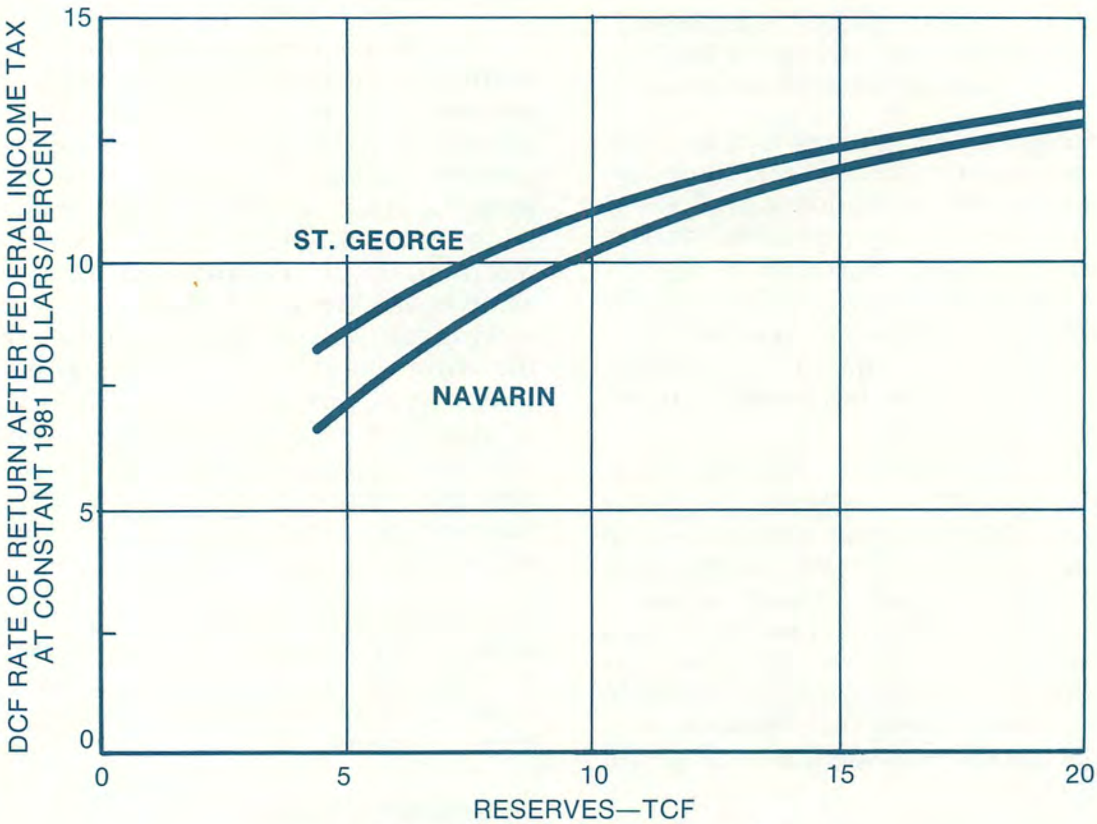


Figure 27. Bering Sea Cases—Gas.

capital variations. Figure 28 shows the effects of a higher gas price on the NPRA cases. Based on the assumptions used in these cases, it appears that a gas price of $8 to $9 per thousand cubic feet would be required to obtain a 10 percent return from NPRA gas. Other sensitivity studies are summarized in Part IV of Appendix F.

Economic Resource Base

The economic resource base for non-associated gas was determined by the same procedures as used for oil. Table 11 details these results as they apply to the specific basins evaluated and as they might be extended to the rest of the Arctic areas expected to contain gas.

Since a 10 percent return on investment is not achieved for any reserve value in the NPRA cases, the economic resource base for all of the non-associated North Slope gas cases becomes zero. The Bering Sea cases, which result in a total economic resource base for non-associated gas of 10 TCF, are somewhat better. This figure compares to a total risked mean undiscovered non-associated resource of 68 TCF. Because none of the cases reaches a 15 percent return, there is no economic resource base for this criterion.

The volume of economically available oil and gas, expressed as the economic resource base, would increase if existing production and/or transportation systems are in place and available at the time of development. This change occurs because the economic analysis assumes that grass roots investments are required for all oil and gas production and transportation.

Capital Requirements

Capital needs to develop the non-associated gas economic resource base on a 10 percent return basis have been developed in the same manner as in the oil cases. These capital requirements are presented in Table 12 and indicate a requirement of approximately $13 billion.

Limitations of Analyses

As with resource assessments, it is important that those who use economic estimates of this type be aware of the inherent limitations of such estimates. The

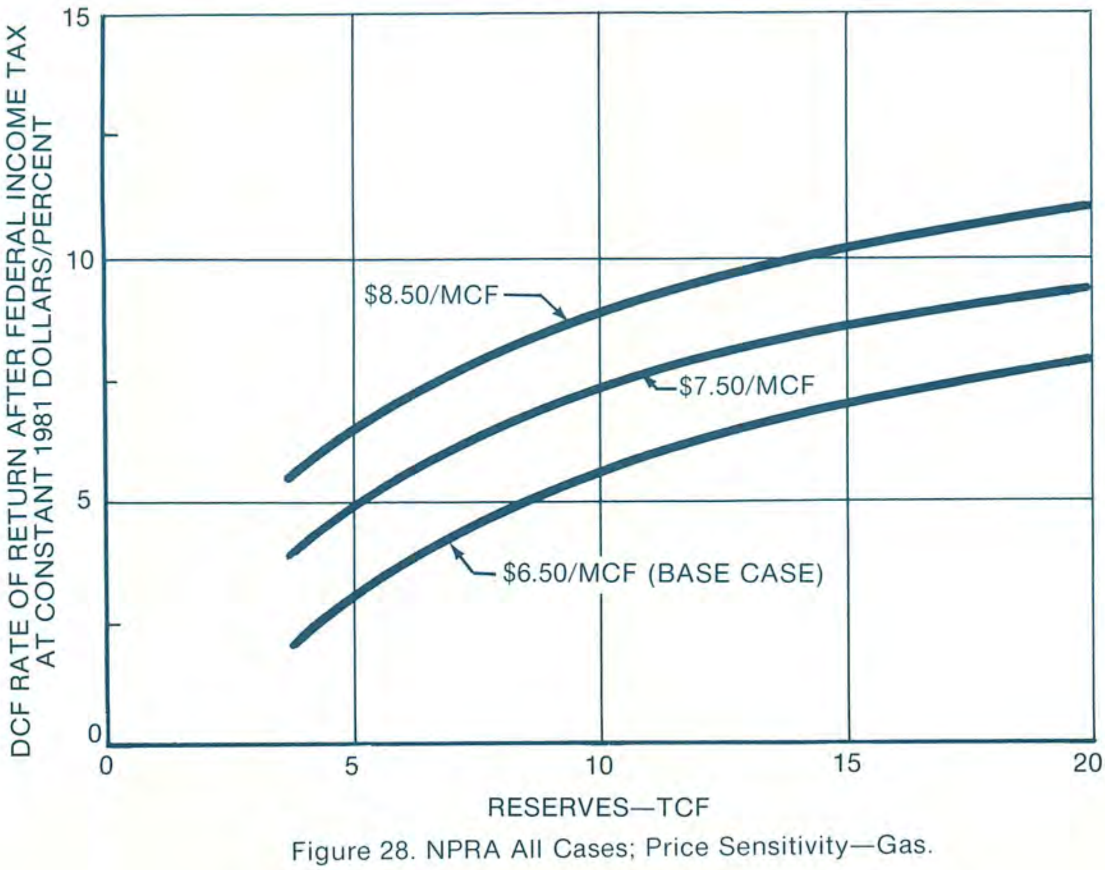


Figure 28. NPRA All Cases; Price Sensitivity—Gas.

TABLE 11

ECONOMIC RESOURCE EVALUATION—NON-ASSOCIATED GAS

	Undiscovered Resources—Non-Associated Gas		Economic Undiscovered Resources—Non-Associated Gas @10% ROR		
Area	Adequacy Chance§ (%)	Risked Mean (TCF)	Minimum Economic Reserve (TCF)	Chance For Min. Econ. Reserve (%)	Economic Resource Base* (TCF)
NPRA	79	10.9	¶	—	—
ANWR	70	3.8	¶	—	—
North Slope Other	79	8.7	¶	—	—
Beaufort Shelf	88	12.6	¶	—	—
Central Chukchi Shelf	62	5.5	¶	—	—
Hope Basin	40	1.0	¶	—	—
Beaufort Slope	57	4.1	†	—	—
N. Chukchi Shelf	50	3.5	†	—	—
N. Chukchi Slope	34	1.2	†	—	—
Navarin Basin Shelf	41	5.5	9.5	18	4.5
St. George Basin	47	3.8	7.5	16	2.7
Bristol Basin	47	2.9	7.5	14	1.8
Norton Basin	43	2.5	>10	<7	<1.1
Other Seven Areas	—	1.6	—	—	—
Total		67.6			<10.1

§Chance of finding more than 0.05 billion barrels of oil equivalent.
*Risked mean economic resource.
¶10 percent return not attained.
†Not technologically feasible.

TABLE 12

CAPITAL REQUIREMENTS—NON-ASSOCIATED GAS

	Economic Resource Base @ 10% (TCF)	Total Unit Costs ($/MCF)	Total Expected Investment (MMM$)
Navarin Basin Shelf	4.5	1.08	4.9
St. George Basin	2.7	1.23	3.3
Bristol Basin	1.8	1.41	2.5
Norton Basin	<1.1	>1.8	>2.0
Total	<10.1		>12.7

results are particularly sensitive to the specific assumptions used as a basis for the analysis. For example, some companies utilizing their own internal assumptions and assessments have developed considerably more optimistic estimates of economically recoverable gas. In general, more confidence should be placed in the aggregated economics for all resources rather than for specific resource components or specific areas.

Even though associated gas was not included, the aggregated total economically recoverable resources as developed in this chapter amount to 22.4 billion barrels of oil and oil-equivalent gas. For comparison, the aggregated responses to the optional economics portion of the resource assessment questionnaire as reported in Table C-3 of Appendix C indicate that 24.1 billion barrels of oil-equivalent resources would be expected to be economically recoverable. While these independent approaches to the evaluation of the undiscovered resources may differ in regard to specific resource and area estimates, the totals are in remarkably good agreement.

Economic Findings

The economic assessment of Arctic oil and gas resources described in this chapter supports the following findings:

- Large discovered resources are required to economically develop Arctic oil and gas due to the high cost of oil field development and associated transportation systems. Such resources could be derived from one or many fields in a single area or could become available by combining the resources of several adjacent or economically related areas. Development cannot proceed economically, particularly as to transportation, until an adequate reserve is defined. An automatic "suspension of production" provision should become a part of leasing policy so that marginal discovered resources can be retained by the lease owner until economic transportation can be justified.
- Areas defined in the NPC resource assessment that have crude oil resources in excess of 0.4 to 1.5 billion barrels, depending on location, can be developed to yield a 10 percent return on investment. Those containing more than 1.1 to 4.5 billion barrels would provide a 15 percent return. However, there is little opportunity for a 20 percent rate of return to be achieved or exceeded. Based on the highside resource estimates, most areas would be economically attractive. Considering the uncertainty of resource assessments in frontier areas, all Arctic areas can be considered as having development potential. Until a considerable amount of exploratory drilling is conducted in each and every basin, any assessment of potential resources or economically recoverable resources and whether the resources will be oil and/or gas must be taken as a preliminary estimate.
- The risked mean assessment of 24.1 billion barrels of oil noted in Chapter One is reduced to 20.6 billion barrels of

economically recoverable oil if a 10 percent return criterion is applied and technically infeasible areas are deleted. At a 15 percent return, this is reduced to 17.8 billion barrels of economically recoverable oil. An important assumption was that no existing transportation facilities would be available. In this analysis, only the Beaufort Slope and the North Chukchi Shelf and Slope beyond 200 feet are considered technically infeasible to develop with present or developing technology. No attempt has been made to forecast production rates for any area as this would involve timing assumptions that could not be substantiated.

- If all economic crude oil resources assumed to exist were discovered and developed, a total capital investment of about $95 billion would be required. This estimate and all other economics are based on constant January 1981 dollars. Leasing costs and unsuccessful exploration expenditures are not included and will be substantial.
- Non-associated natural gas resources in excess of 7 to 10 TCF are required to obtain a 10 percent return on investment in the Bering Sea. New onshore and offshore North Slope undiscovered non-associated gas resources are not shown to attain a 10 percent return for any reserve level. In no case was a 15 percent rate of return achieved. These conclusions are based on a number of specific assumptions including the assumptions that: gas is equivalent in value on a BTU basis to crude oil, no existing or currently planned transportation facilities would be available, gas would be transported to the lower 48 states as LNG, and all gas resources would be analyzed on a stand-alone basis. The unfavorable economics for moving gas from NPRA led to the exclusion of the entire 36 TCF of onshore and offshore North Slope non-associated gas from the economically recoverable category. However, considering the use of an available pipeline system such as ANGTS could improve the economics of onshore and offshore North Slope gas. Undiscovered gas resources associated with commercial oil development projects and existing discovered gas resources such as those that support the proposed ANGTS pipeline have not been evaluated.
- The risked mean assessment of 68 TCF of non-associated gas is reduced to 10 TCF of economically recoverable gas for a 10 percent return criterion. The Navarin Basin Shelf, the St. George Basin, and the Bristol Basin can be shown to provide this minimum return. Associated gas was not evaluated. The exclusion of associated gas sets aside 41 TCF of the assessed 109 TCF of undiscovered recoverable natural gas from consideration. Some individual companies, utilizing their own internal assumptions and assessments, have considerably more optimistic estimates of economically recoverable gas.
- Development of the expected economic non-associated gas reserves in the Bering Sea would require a total capital investment of $13 billion. As in the case of oil, leasing costs and costs for unsuccessful exploration are not included.
- Production of oil and gas from prospective Arctic areas will not occur sooner than from 9 to 14 years after the lease sale date. The planning, permitting, exploration, development drilling, design work, facility installation, and transportation system construction in the remote Arctic regions all require extended time.
- All of the economic analyses have been shown to be highly sensitive to changes in timing and costs. This is caused by the large front-end investments required, particularly in transportation.
- The quantity of economically recoverable undiscovered oil resources in the U.S. Arctic could be increased by exporting this oil to the Far East and replacing it in the lower 48 states with oil from nearer suppliers. Transportation cost differentials for oil delivery to the Far East rather than the U.S. Gulf Coast could improve the wellhead economics by $2 to $4 per barrel.

CHAPTER SEVEN: COMMUNITY IMPACTS

Introduction

Many benefits accrue to Alaska residents because of the oil industry's participation in the state. These benefits are rarely publicized and are not generally recognized by the public.

By far the most prominent benefit realized is that of money—either derived from lease sales, royalties, production taxes and other taxes, or from money spent in the general economy by corporations, businesses, and individuals carrying out oil industry activities. This money filters through the entire state economy and funds many desirable programs that would have otherwise been impossible. Direct and indirect financial assistance by state agencies has been possible only because of increased income derived from oil industry activities.

The presence of the Prudhoe Bay field and supporting facilities has given public access to the previously inaccessible North Slope. An oil company built and donated the air facility at Deadhorse to the state at no cost. Studies of the wildlife, necessary for planning for the health and preservation of the biological community, have been financed by industry. Investigations into the archaeology of the Arctic have also been financed. Direct funding of scholarships, training programs, and facilities has been made by oil companies either as part of a leasing agreement or as a community service gift. Oil company facilities have been available as an emergency source of medical aid and for emergency communications, and company personnel and equipment have been used in search and rescue operations. In general, oil company personnel participating in Alaskan operations are civic-minded individuals and are often active members of their local communities.

While the benefits of oil and gas operations have been demonstrated, it is inevitable that substantial oil and gas development onshore or offshore in Alaska will affect the rural populations and their communities both socially and economically. Adequate long-term planning, good communication, and appropriate government and industry actions need to be developed for rural communities in order that the effects of these impacts may be manageable and beneficial.

The magnitude and location of oil and gas developments can only become defined as discoveries are made. Some scenarios may not develop at all because oil and gas resources may not be found in all areas for which scenarios have been drawn. Where major developments do occur, they would cause changes in community structure, shoreline resources, local labor markets, and housing. Local political and economic structures would also be affected. In some of the northern and western regions of Alaska, cultural and subsistence patterns as well as the relationship of the people to the land may be altered.

The potentially affected area stretches from the Alaska-Canada border in the extreme northeast, along the state's northern and northwestern coasts, and along the western and southwestern coasts through the Aleutian Islands.

Native Lifestyle

The 45,000 inhabitants of this area, who make up 11 percent of the state's population, are predominantly Eskimo, although Aleuts compose a significant portion of the population in the extreme southwest. Most of this population is distributed among approximately 60 small villages, of from 100 to 500 inhabitants, and a few regional centers of from 1,500 to 3,500 inhabitants. These regional centers, Barrow, Kotzebue, Nome, Bethel, Dillingham, and Unalaska, serve as transportation, communication, political, corporate, and administrative hubs of the respective geographic subregions. The regional centers typically have a sizable non-native population and a comparatively substantial wage-based economy. This is in contrast with the more rural villages, which typically have only a few non-native school teachers living year-round, and the smaller villages, in which much of the wage employment that exists is highly seasonal. A significant portion of the cash that enters an area comes through state and federal transfer payments.

In a typical Alaskan village, approximately 100 to 300 residents live under isolated conditions. Except for the surrounding area, where access can be along the river system by boat in the summer and by snow machine in the winter, the village can be reached only by air. Two-way communication with other areas frequently depends solely on one village telephone and one land radio. Utilities consist of a central village well and a village-owned power plant. Community facilities are limited to a Bureau of Indian Affairs (BIA) school, a state-operated high school, a church, a community hall, a traditional council office, one privately owned store, a post office, and a health clinic. The village is governed by a council, which is federally recognized under the Indian Reorganization Act. Average land entitlement for a village under the Alaska Native Claims Settlement Act of 1971 (ANCSA) is 115,200 acres.

In some ways, life in Alaska can be very similar to life in the lower 48 states. Urban living can be comfortable, with all the material conveniences found in any American city. However, Alaska is also a land of great contrast. Life in an Alaskan village, in contrast to life in a major Alaskan city, can be quite austere. There is often no running water. Sewerage is frequently inadequate. Communication systems are poor or non-existent. Home heating fuel costs at least $2 to $3 a gallon. Costs for electricity can exceed 40¢ per kilowatt hour.

Despite these and additional hardships, village living is usually the first choice of the Alaskan natives. Times have changed rapidly in Alaska in the past 10 years, and the effect on villages has been dramatic. Satellite communication has provided television to many remote communities, allowing rural residents a glimpse of the western world and all it has to offer. Technology has replaced many of the traditional tools of the subsistence lifestyle. As an example, snow machines have replaced dog teams, and outboard engines are used in seal and walrus hunting. But modern equipment has placed a larger demand for cash on many villages, as has electricity and the use of fossil fuel for heat.

This demand for cash has lured many into an economic trap. Seasonal restrictions on hunting and fishing prevent villagers from moving back into a complete subsistence lifestyle, and there is no economic base that can provide wages to buy goods and services, which are needed particularly in larger villages. People are torn between moving to larger population centers in search of jobs and remaining in villages, where jobs are few. Those who remain rely on public assistance to provide the cash needed for material goods.

Throughout the area, unemployment is high compared to the rest of the state and nation, and per capita income is low. Federal, state, and local government activities provide most of the employment; in terms of employment opportunity, these are followed by regional and village corporations, and to some extent, commercial fishing. An exception occurs in the North Slope Borough, where employment in the areawide borough government and in petroleum-related industries has expanded significantly as a result of the Prudhoe Bay development, the Trans-Alaska Pipeline, and related construction activities sponsored by both local government and industry.

Subsistence activities—the hunting of large and small game animals, sea mammals, and birds; the catching of fish; and the gathering of wild berries, greens, and eggs—play a vital role in the economies of all the villages and, to a lesser extent, in the regional centers. Subsistence activities are also significant to the cultural integrity of area residents.

The subsistence economy is one in which all economic activity is carried out for the purpose of present consumption. Economic decisions are based on traditional patterns rather than on strictly financial objectives, such as maximizing profit or growth. These traditional objectives do not require that each household or family necessarily provide for all of its own needs, since extensive bartering activity, as well as some cash transactions, may be an integral part of the system.

Alaska's native people are ethnically diverse and geographically dispersed throughout the state. Traditionally, distinct territorial boundaries between Aleuts, Eskimos, Athabascan Indians, and the major southeastern Indian groups (Tlingits, Haidas, and Tsimshians) existed. Each pursued its own characteristic way of life and, for the most part, had little to do with others except through carefully guarded trading systems or outright war.

For the most part, the Eskimos live in coastal areas of northern and western Alaska. The northern people speak the Inupiat dialect and live, generally, along the Arctic coast from Canada to Point Barrow, Point Hope, and the Kotzebue-Seward Peninsula area.

Alaska's southern Eskimos speak the Yupik dialect. They live in the wide, flat Yukon-Kuskokwim Delta and Bristol Bay drainages, where they fish and hunt small game.

The Aleuts live on the Alaska Peninsula and the Aleutian Islands, which extend westward from the mainland into the Bering Sea. Like the northern Eskimos, they traditionally take their living from the fish, shellfish, and sea mammals of the area. All rely heavily on subsistence resources.

The Alaskan natives are a racially identifiable people with strong, enduring, traditional ties to the environment, and with a cultural history and value system quite different from the Euro-western economic system.

Fisheries

Fisheries are very important to Alaska, both socially and economically. This includes subsistence and sports fishing, limited commercial fisheries throughout the river systems and coastal waters, and large commercial fisheries in the Bering Sea. The total dockside value of U.S. salmon and crab fisheries in the Bering Sea area in 1979 was reported to be $350 million. Potential exploration and production operations and possible pipeline corridors could interface with these fisheries.

Subsistence fishing is the most important fishing activity on the Arctic Slope. Arctic char and whitefish species are important to the gill net fishing of the coast and lower reaches of the Colville River. Grayling and burbot are also harvested where plentiful near Arctic communities, and occasionally in nearby rivers in late winter for overwintering fish. Sport fishing is extremely limited on the North Slope due to the remoteness of this area. It has been increased only slightly by the oil development at Prudhoe Bay. The Arctic cisco supports a small commercial fishery in the Colville River Delta.

The Kobuk River and other systems that flow into Kotzebue Sound contain substantial king and chum salmon runs, which support a commercial fishery harvest of mostly chums. Although not large by Alaska standards, this fishery contributes significantly to the local economy. Sheefish also support a commercial fishery in the Kobuk-Selawik Rivers. Most are sold locally, but some reach markets in Anchorage and Fairbanks. An important subsistence activity of the Kotzebue coastal and Kobuk River villages is the harvest of chum salmon, whitefish, sheefish, pike, Arctic char, and burbot. Other villages along the upper Koyukuk River utilize sheefish, whitefish, and pike. The Kobuk-Selawik River system produces the largest sheefish in Alaska and, therefore, is the most widely publicized sheefish angling river system in Alaska.

The Norton Sound commercial salmon fishery is relatively small but vital locally. Pink and chum salmon compose about 90 percent of the annual catch. All five species of salmon are harvested from the Yukon with the major commercial fisheries located in the lower 150 miles of the river. Limited commercial fishing is widely dispersed throughout the upper Yukon drainage where it is quite important to local village economies. Subsistence fishing along northern Norton Sound is primarily for king, coho, chum, and pink salmon. King and chum salmon are important subsistence fish along the Yukon River and some northern pike are taken for food. The chum salmon harvest in the Bristol Bay and Yukon River area is the largest in Alaska. In the Norton Sound area, particularly around Nome, salmon, Arctic char, and grayling support limited recreational fishing. In general, there is little sport fishing along the Yukon, except for some pike and salmon fishing in several tributary streams.

In the Kuskokwim drainage system, commercial harvests of king, coho, and chum salmon are small but very significant to local communities. The Kvichak River system, including Lake Iliamna/Lake Clark, is the largest producer of sockeye salmon in Alaska. A major commercial salmon fishery, including all five species, is the economic mainstay for the area and the state. Kuskokwim subsistence fishing is the largest in the state, with chum and king salmon being the two most important species. In the Lake Iliamna/Lake Clark drainage, residents also take significant numbers of salmon and other varieties for subsistence. Sport fishing in the Kuskokwim is generally limited to king and coho salmon, and sheefish near population centers. The Lake Iliamna/Lake Clark area attracts anglers from around the nation and the world. Trophy rainbow trout and grayling are present, along with the five species of salmon, char, and lake trout.

Five species of Pacific salmon are harvested in the coastal southern Bering sea, with sockeyes and pinks being the most important commercially from Unimak pass to the Kuskokwim Delta. The world-famous sockeye salmon runs of Bristol Bay provide the major source of income to resident villagers either by direct participation in the fishery or seasonal employment in canneries. Salmon fisheries are also important locally in the northern Bering and southern Chukchi Seas, although they are of minor significance in the state's total salmon harvest.

King crabs, tanner crabs, pink shrimp, and herring presently constitute important commercial fish resources in the eastern Bering Sea and Aleutian Islands. Razor clams and surf clams hold some potential to support commercial fisheries. The king crab fisheries in this region are among the most important shellfish fisheries in the world. At present the major U.S. fishing areas for blue king crab are in the vicinity of the Pribilof Islands, and for red king crabs are over an extensive area of the shelf between the Alaska Peninsula and the Pribilofs. Tanner crabs have been the direct target of a fishery since 1964, but prior to that date were taken incidentally in the king crab fishery. The Bering Sea U.S. herring catch is a relatively small part of the total ex-vessel fishery value but increases severalfold after processing.

The groundfish resources of the eastern Bering Sea and Aleutian Island regions are among the most productive in the world. This eastern Bering Sea Fisheries Conservation Zone is long line fished intensively year-round, at rates approaching overexploitation of several species, by fleets from five nations. In order of highest reported tonnage these include Japan, the USSR, the Republic of Korea, Poland, and Taiwan. About 1 million metric tons per year, or 95 percent of the reported catch, is by foreign fleets; only 5 percent is by the U.S. fleet. Foreign bottom fishing occurs between the 300- and 600-foot depths and focuses on pollock. Other important species include Pacific Ocean perch, Pacific cod, halibut, atka mackerel, sablefish, and yellowfin sole.

The fishing industry is the economic mainstay of the Dutch Harbor, Unalaska community. Dutch Harbor was reported to be the leading port in the United States in the value of seafood landed in 1979 due to the shrimp and king crab fishery. The seasonal nature of the fishing industry has a tremendous impact on the community. The permanent resident population of 1,000 increases to approximately 5,000 with the influx of transient fishermen and processing and cannery workers. These transients include Alaskans, and many from other states and several foreign countries.

In addition to fisheries, commercial harvesting of the northern fur seal of the Pribilof Islands is of national and international concern. Each year approximately 90 percent of the world's northern fur seals congregate on these islands to pup. Under a treaty between Japan, Canada, and the United States, several thousand bachelor seals are harvested, providing a major source of employment for the island residents.

Native Organizations

Under the ANCSA, 12 regional profit-making corporations were created. Six of these are likely to be affected by possible oil and gas developments. Village profit-making corporations in native communities may also be affected. Each region also has a nonprofit corporation responsible for a variety of human services and for some economic development planning.

The six regional profit-making corporations and their corresponding nonprofit corporations, along with their related prospective basins, in descending order from the north, are:

- The Arctic Slope Regional Corporation and North Slope Borough (ANWR, NPRA, Chukchi, and Beaufort Basins)
- The NANA Corporation and Mauneluk (Hope Basin)
- The Bering Strait Corporation and Kawerak (Norton Basin)
- The Calista Corporation and Association of Village Council Presidents (Norton Basin)
- The Bristol Bay Native Corporation and Bristol Bay Native Association (North Aleutian Shelf)
- The Aleut Corporation and the Aleut Pribilof Islands Association (Navarin Basin, St. George Basin, and North Aleutian Shelf).

The ANCSA entitled Alaska's native corporations to approximately 40 million acres throughout the State of Alaska in addition to a cash settlement. Although much of this land has yet to be conveyed, the regional and village corporations acting for their some 70,000 shareholders will eventually become the state's largest private landowners. The regional corporations receive surface and subsurface titles in their own right and also have subsurface title to the lands selected by the village corporations. Thus, much of the land upon which onshore facilities might be sited, or upon which environmental effects stemming from Arctic oil and gas development activities might impinge, will be owned either by regional or village corporations.

The native nonprofit organizations that function within the regional boundaries set by the ANCSA act as quasi-governmental service and planning organizations. The politics, communications, and services evident in these regions through these nonprofit organizations have provided the basic structural elements of regional government.

Local Government and Community Issues

Communities within these regions that may be affected include Point Barrow, Wainwright, Kotzebue, Shishmaref, Nome, Unalakleet, Nelson Lagoon, and Unalaska. Any of these communities affected by a specific oil or gas development would need to plan for expansion of existing facilities in order to accommodate any sizable onshore installations related to the development. In all of them, housing is at a premium, appropriate land on which to site facilities is limited, and existing services and utilities would probably need to be expanded.

Most of the area addressed in this report is in the state's unorganized borough, where there are no regionwide governments in the traditional sense. Most incorporated communities within the region have a population of 25 to 400, and a few have more than 400 residents. Some communities are not incorporated. Thus, the range of powers, particularly in taxation, development, and land infrastructure planning, is limited. A further limitation stems from the fact that, even where taxing powers exist, there is little or no tax base to support local government.

The North Slope Borough is an exception. A strong, financially able form of regional government was organized in response to the tax base created by the development of oil and gas in that region. Taxes on industry directly support all the functions of government, including capital improvements projects. The growth of the North Slope Borough population can be attributed to the development of this single industry. Among the positive aspects of this government are its objectives of protecting and enhancing the interests of the North Slope Eskimos. There is a strong commitment to the protection of subsistence interests and the protection of the Eskimo whaling tradition as well as cultural aspects that surround that tradition.

Statutes regulate the division of authority between incorporated cities and boroughs and describe the way in which powers may transfer or be assumed by the borough. After the borough assumes a power, that power may no longer be exercised by a city within the borough.

Many federal and state financial assistance programs are granted to municipal corporations. The state's revenue sharing program helps municipalities provide certain basic services, including police and fire protection, land-use planning, health and hospital facilities, pollution control, parks and recreation facilities, road maintenance, and transportation facilities. Only as cities or boroughs of a population of more than 25 are incorporated can they assume local authority for such critical functions as public education and land-use planning. Smaller boroughs, however, have the mandatory functions of public education.

The NPRA falls within the boundaries of the North Slope Borough, and, as such, is subject to those regulatory powers possessed by the borough that are not constrained by federal or state law.

Coastal Management Programs

State

In passing the Alaska Coastal Management Act of 1977, the state legislature directed local communities to develop coastal management programs suitable for responding to and directing the siting of energy facilities along the Alaskan coastline.

The act stipulates that regional divisions of the unorganized borough may be organized as Coastal Resource Service Areas (CRSA). District coastal management programs can be developed for each CRSA under the direction of a coastal resource service area board elected by the area's residents. These CRSAs are to have boundaries congruent with Rural Education Attendance Areas (REAA), which were formed in 1976 with elected boards to place limited powers of self-government in the hands of local people.

Residents of three areas in the unorganized borough have voted to organize CRSAs in the Bering Sea region. These areas include the NANA Coastal Resource Service Area, the Bering Strait Coastal Resource Service Area, and the Yukon/Kuskokwim Delta Coastal Resource Service Area. In addition, residents in at least two other regions in the unorganized borough have expressed interest in the organization of CRSAs. The Bristol Bay region has begun an educational/informational project on coastal management, a process that can usually lead to the organization of a CRSA. The Aleutian/Pribilof Islands region has recently expressed interest in coastal management. None of the organized coastal resource service areas has completed development of a coastal management program. Most efforts and funds have been expended on informational/educational projects.

Funding to develop and implement district coastal management programs is provided by the State of Alaska Department of Community and Regional Affairs (DCRA) to coastal communities on a 20 percent local match basis. Eighty percent matching funds are granted the state by the federal Office of Coastal Zone Management, while the 20 percent match must come directly from local appropriations. Since most of the Bering Sea region has little or no tax base, it has been extremely difficult for CRSA boards to provide the required 20 percent match.

Federal

Section 308 of the federal Coastal Zone Management Act (CZMA) established the Coastal Energy Impact Program (CEIP) to assist coastal states and local governments in studying and planning for onshore impacts that may result from federal OCS oil and gas operations.

To help state and local governments minimize adverse impacts from energy-related activities in the coastal zone, Congress authorized the appropriation of $2.2 billion over a 12-year period beginning in 1976. Funds allotted to Alaska during the federal fiscal years 1977-1981 included over $6.7 million in grant funds to prepare for the effects of coastal energy development, $1.3 million in grant funds for mitigating unavoidable losses of environmental and recreational resources, and $50 million in loan funds to provide facilities and service in anticipation of onshore impacts. The DCRA is responsible for administering CEIP funds in Alaska.

No CEIP funds have been allocated to coastal communities in the Bering Sea region since CEIP regulations restrict eligibility to local governments with the authority to levy taxes, of which there are few in western Alaska. The DCRA has recently applied for CEIP funds to evaluate alternatives for siting energy facilities in the Bering Sea region.

The goal of the project proposed by DCRA is to evaluate choices for siting major energy facilities related to proposed state and federal oil and gas lease sales in the Bering Sea, and to systematically assess the needs for and timing of further studies, plans, and capital improvements arising from various siting choices.

The study would address facilities required during all phases of oil and gas development in the Bering Sea. Impacts from energy facility siting are usually the most direct, intense, and long lasting of any impacts related to oil and gas development. Site selection could affect such factors as population size and composition, traditional use of natural resources, and water quality.

Factors Affecting Social and Economic Impacts

A variety of factors affect the degree to which development might change the social and economic patterns of a surrounding region or nearby community. These factors include the degree to which the development is either isolated from or integrated with the community. Direct impacts would be less severe if the developed site is isolated and provides most of its own services, such as in the case of Prudhoe Bay. Social and economic effects would increase in proportion to the extent to which industry makes purchases in the community and the degree of integration of industry families into the community.

Other potential effects would depend upon the extent to which local labor would be employed, whether sufficient land is available for industrial sites and housing, and if plans fit a normal zoning pattern or would require special arrangements.

The degree to which an industry facility would use existing transportation facilities (primarily airports and docks with connecting road systems) and existing utilities such as power, water, sewer, and solid waste disposal is also a major factor. Developmental impacts would vary according to the degree to which the site uses or expands existing facilities or develops its own systems.

Another factor affecting social and economic impacts is the extent to which an industrial site depends upon existing community services, such as police, fire protection, recreation, schools, and churches, and the extent to which these services must be expanded to handle new demands. Recreational activities could also have social and economic effects. For example, industry personnel might hunt and fish and therefore might affect native subsistence patterns.

Moreover, these factors are influenced by community characteristics. The larger the community population, the more able and willing is the community to integrate a new set of businesses and residents. Also important is the way in which the community views new people, new things, and a faster pace of life. A "young" community with a diverse population would be more flexible and willing to adapt to development, while an older, more settled community might resist change.

Similarly, a community with a diversified economic base has a larger pool of skills among its labor force than a community that is not diversified. Thus, a diverse community would incur greater economic benefit than a community that is not diverse, and would be more open to employment in Arctic oil and gas development.

Communities that exercise the power of planning and have land-use development controls are better able to influence the type and extent of development than communities lacking these powers. An important factor that would affect social and economic impacts is the degree to which an individual or group can speak and act on behalf of the community as a whole. If one group is able to plan and develop a strategy for elements of community and development interaction such as local hire, site of the facility, and acceptable recreation versus nonacceptable recreation, the community will be in a better position to influence the type of onshore development and its direct and indirect effects.

There is some apprehension that social pressures leading to increased alcoholism and drug abuse may occur in communities near development sites, and that unfavorable interaction in the community from nonresident workers may occur. Another concern is the extent to which local hiring practices will be applied in the community, and an accompanying concern that the influx of new money may result in increased prices for existing goods and services. Concern also exists as to the extent to which facilities sited in the area will contribute, through taxes, to defraying the costs of expanding needed public facilities and services. There is concern over the degree to which a major influx of new persons into the region will increase competition for limited natural resources.

A major concern is that a large oil spill will occur as a result of oil developments, thus damaging the biological resources upon which residents depend for subsistence and commercial fishing purposes. As an example, concern has been expressed for the possible effects on bowhead whales should an oil spill occur in ice-confined waters at the time of migration through the area. An accompanying concern is the possible effects of chemical disposal, such as those resulting from drilling muds.

Recommendations

It is recommended that two major areas be addressed in order to effectively manage the impact of future oil and gas development on the Alaskan native population.

- Comprehensive planning covering all aspects of resource development as it relates to the natives should be undertaken. These planning activities should have as their specific objectives clearly defined programs for expediting timely petroleum exploration, production, and transportation activities. The industry should cooperate with the community in identifying locations for support bases, ports, terminals, construction yards, pipelines, and new communities. The community should cooperate with the industry in planning for expansion of housing, utilities, schools, hospitals, communication, transportation, and recreational facilities. Support and participation by industry, government, and native organizations will be necessary to ensure that beneficial impacts are achieved.
- Meaningful and honest communication must be established between the potentially affected public, industry, governmental officials, and researchers engaged in lease sale preparation and development plans. Major emphasis should be on the practical realities of OCS exploration and development processes.

Planning

Planning should be in a fashion appropriate to the status of resource development, which would become more intensive as resources are discovered and evaluated. The different phases of OCS activity should be clearly identified in the federal planning processes, and adequate information requirements and funding to local or regional planning organizations should be made available to ensure that the right planning is done at the right time.

Particular attention should be focused on improving the effectiveness of state and federal funding to local governments that are not adequately assisted under current programs to cover the costs of planning for community infrastructure and transportation, and to communities or regional planning organizations to pay for the social and infrastructure costs of effects directly due to development activities.

Exploration Phase

After the lease sale, the public is aware of which tracts have been leased but is unaware of which will be explored first; the impacts of exploration can therefore be estimated only partially. An example of the useful planning that might occur at this phase would be the identification of areas in which onshore physical activities should be avoided or installations prohibited. Selected areas onshore may then be preserved and the remaining area made available for site selection.

Production Phase

After exploration has been completed, assuming there is a commercial find, the location and scope of activities related to production can be anticipated. Planning that could realistically anticipate which onshore sites would be affected may begin. At this stage, and only then, can communities have access to adequate information to do the specific local planning necessary to cope with any impacts that will occur from development and production of hydrocarbons.

Recommendations for long-range planning include providing to the affected native groups and individuals:

- Information and education regarding the different roles of regulatory agencies and their functions and limitations
- Educational programs for schools in areas that may be impacted by development
- Assistance to local governments that have planning responsibilities by providing them with helpful information
- Information so that they may be better able to relate to the options of a stronger economic base for their local government or regional planning organization; their businesses, either native-owned (ANCSA or subsidiaries) or privately owned; their personal options regarding employment or educational opportunities; and the realities of oil spills and chemical pollution that may affect their communities
- Further discussion with both native leaders and community leaders regarding their expressed interest in development of a discussion forum to enhance the flow of information regarding resource development scenarios and socio-economic concerns, with emphasis on means of avoiding adverse environmental or socio-economic impacts.

It is recommended that funding be made available to local governments to assist in planning for community infrastructure and transportation needs in cooperation with industry development plans.

Furthermore, it is recommended that appropriate funding be made available to communities or regional planning organizations in order to cover the social and infrastructure costs of impacts due directly to development. The emphasis on assistance to communities should be related to the national interest in energy self-sufficiency, and also related to the benefits that the federal and state governments expect to derive from the industry.

Communication

A major problem exists in that insufficient information regarding the activities of the oil industry is transmitted to regions and communities. Dissemination of information regarding specific industry activity usually takes place through third parties via Bureau of Land Management (BLM) scoping meetings, hearings, environmental impact statements (EIS), or through special interest groups.

Expanding the communication of scientific, technical, environmental, and social information between native groups and the oil and gas industry would do much to alleviate this problem. It is recommended that the implementation of such communication and coordination processes be undertaken with the federal role limited to one of encouragement, support, and participation when invited.

CHAPTER EIGHT: ENVIRONMENTAL PROTECTION

History

Concerns for the environment have paralleled industry exploration and development of the North Slope. During the Navy's early efforts before 1953 on NPR-4 there was little appreciation for the fragility of the tundra and the permafrost areas. In the first few seasons of exploration activity the tundra was damaged where exploration vehicles operated on surface-thawed permafrost and tracks eroded during summer runoff. Many of these early damaged areas have been revegetated with grasses planted by the industry, but some remnants of the damage are still visible. Wheel and track vehicles are no longer used on thawed permafrost, and geophysical seismic work is conducted only on snow-covered frozen ground.

Development of the Prudhoe Bay field and construction of the Trans-Alaska Pipeline System and the Valdez terminal were conducted under the most rigorous design and quality control specifications ever imposed upon onshore petroleum operations. Operational experience has proven the adequacy of these production and transportation systems. The environment has been protected and oil spills have been minimal.

The experience of the industry working in cooperation with federal, state, and local authorities over the past 20 years has proven the adequacy of risk avoidance technology for Arctic onshore operations.

The industry brings to the Arctic Alaska offshore regions vast experience in conducting successful exploration and production operations throughout the world. Offshore technology has evolved over more than 30 years and includes experience in such hostile environments as the North Sea, the Cook Inlet, the Gulf of Alaska, and the Canadian Arctic. This technology has been successfully applied to offshore exploration in the Alaskan Beaufort Sea with no significant environmental impact.

The biological communities both onshore and offshore of Alaska are extensive and important. Historical disruption of these communities has been geographically limited and scattered. Industry has the experience and technology to protect the environment. Although accelerated activities in undeveloped areas will require an extension of existing information and technology, no problems are perceived that are beyond the demonstrated capability of the industry to solve. Prudent designs and methods of operation will allow oil and gas development to co-exist with commercial fisheries, recreational activities, and subsistence needs that are dependent on biological resources.

Environmental Risks

Onshore Operations

Seismic work, exploration and development drilling, and the construction of winter or all-weather roads, pipelines, airstrips, borrow pits, production facilities, and housing all have the potential of damaging habitat, disrupting caribou and waterfowl, and interfering with subsistence activity. However, the technology and operational practices developed in the Arctic have greatly reduced the potential for environmental damage.

A reliable estimate of the size and number of oil and gas fields to be developed in the future cannot be made until the Arctic Slope is adequately explored. It is unlikely that any individual discovery will be as large as the Prudhoe Bay field. Discoveries will not necessarily be concentrated in any particular Arctic Slope area and the impacts associated with individual developments will probably be smaller than those of Prudhoe Bay. The location of future discoveries will influence the potential environmental impact, depending upon the local physical environment and biological community. The location of discoveries determines the length and location of pipelines or marine terminals to deliver production to market.

Environmental risks or issues, as perceived by various groups in recent years, are illustrated by the various environmental impact statements prepared for Arctic Slope and adjacent area developments. Several geographical features are ecologically important:

- Coastal wetlands are important to waterfowl and other migrating birds.
- Barrier islands, lagoons, and bays are important for birds, marine mammals, and anadromous fish.
- Major river flood plains are important to mammals.
- Coastal meadows near Teshekpuk Lake, Prudhoe Bay, and Barter Island are principal caribou calving areas.

Tundra

The tundra vegetation blanket insulates and preserves the permafrost. Disruption of this blanket changes the thermal balance of the permafrost, generally resulting in thaw, subsidence, and erosion. Vehicular traffic can destroy or damage the vegetation and underlying soil in wet sedge meadows and upland tussock tundra zones.

Less damage to the wet sedge meadows and upland tussock tundra results from winter traffic, but repeated traffic will damage the vegetative cover.

Air Quality

Air quality on the Arctic Slope is generally good. It has not been a major issue but it will restrict development if areas are designated as Class I (virtually pristine) under the Prevention of Significant Deterioration (PSD) provisions of the Clean Air Act. It has been proposed that the NPRA be set at Class I as an interim measure, limiting its potential development.

Water Quality

Water quality can be influenced by oil and gas activities primarily as a result of improper treatment and disposal of waste. The primary wastewaters discharged from oil and gas operations are treated sanitary wastewater produced with oil and surplus drilling fluid. If improperly treated and disposed of, it could represent a potential health problem. Industrial wastewater discharge to the surface has been minimal. Some secondary recovery waterflood projects may result in the discharge of relatively large volumes of backwash water to offshore waters through filters used to clean sea water.

Runoff from facility sites, if not properly contained, could carry oils and other pollutants spilled or leaked at the sites into lakes and streams. With oil and gas activity, the potential for oil spills exists, even though there is a low probability of their occurrence. The potential for oil spills will be a major concern associated with oil and gas activities. Construction in streams, stream crossings, and related activities can result in siltation.

Land

The removal of gravel or construction on exposed beaches or barrier islands could increase erosion or otherwise change depositional patterns along the coast. Gravel borrows change the land form.

Roads, pads, power lines, pipelines, and production treating and servicing facilities require land and are highly visible, particularly on the relatively featureless coastal plain.

Fish

Several species of fish move annually from the major North Slope rivers in the spring and early summer to the shallow coastal waters of the Beaufort Sea to feed. They return each fall to freshwater streams to spawn and overwinter. The ability of these anadromous species to move significant distances along the rivers and coastline to feed is believed to be essential in maintaining stable populations.

Construction of causeways for handling supplies from marine barges or other structures may have the potential to block or delay the movement of these fish along the coast. The west dock at Prudhoe Bay has been studied extensively, particularly in regard to fish movements. The causeway was not found to block or significantly delay fish movement. Additional studies are being conducted on a new causeway extension to determine the long-term effects on the movements of fish, food supply, and feeding habits.

Large volumes of gravel are required for construction of work pads, roads, and airfields in order to prevent degradation of the permafrost and damage to vegetation. This gravel is obtained for onshore activities either by scraping exposed river bars or from gravel borrows. In streams, these activities can cause siltation or rechanneling of streams. A recurring problem has been to identify overwintering, spawning, and migration habitats within specific water systems prior to construction. Road and other construction activities have the potential to block migration routes.

Water is obtained in the winter from deep holes in major rivers or from deep lakes, whether natural or artificially deepened. Excessive water removed from deep holes in rivers that are also overwintering locations for fish can be detrimental. If waste is discharged under the ice, the oxygen supply could be depleted, thereby endangering fish.

Terrestrial Mammals

Caribou are believed to require relatively free access to large areas of the Arctic Slope, and can be susceptible to disturbance, harassment, and overharvest. The greatest concern is related to caribou calving and pre- and post-calving migration. Any change in migration patterns has the potential to affect native access to caribou used for subsistence. Work sites, roads, and pipelines located across caribou migration routes or near calving areas could possibly affect the herd. However, there is evidence that such developments have little or no direct effect on caribou. Easier access to caribou migration routes resulting from roads, scheduled airline routes, and general population increase associated with oil and gas development could result in increases disturbance and increased hunting pressures.

Wolves, wolverines, and grizzly bears also range over large areas. The moose population is limited by the availability of riparian habitat in the winter.

Arctic fox and polar bears could change feeding and denning patterns because of aircraft and ship traffic and other noise and visual disturbances along the coast. Construction camps associated with oil and gas development and transportation corridors may attract wildlife, particularly bears, wolves, and fox, if edible waste is not disposed of properly. Fur-bearers and small game species will not be greatly affected by development.

Birds

Large and important populations of waterfowl and other birds use the Arctic Slope for nesting, molting, staging, and feeding.

Development results in increased road traffic, aircraft flights, and operation of stationary equipment. Associated noise and visual disturbances, particularly in the exposed coastal zone, could disrupt birds and might cause desertion of nests, abandonment of feeding, resting, and molting areas, and possible overuse of adjacent undisturbed areas. The risk of oil spills exists with oil and gas development. Birds are among the most vulnerable of wildlife to oil spills.

Road traffic can cause an accumulation of dust or snow during the winter months. In the spring, these dusted snows are the first to melt, providing a haven for early arriving birds. This could result in abnormally high localized concentrations of birds and could affect vegetation patterns.

Offshore Operations

Petroleum development and production will require space for platforms or artificial islands, logistic support, tanker terminals, transportation routes including ocean floor pipelines and causeways to artificial islands, and associated facilities. Further space will be required for the disposal of dredged material. Any loss of habitat will be small because space requirements for oil and gas facilities are not particularly large.

Many habitats are viewed as having major value for their productive roles and often acquire protected status. The Alaskan OCS area is characterized by major seasonal concentrations of many otherwise wide-ranging species. These areas are often given protected status because of their productive roles.

Noise and Disturbance

Human activity associated with petroleum development and production creates a sphere of activity and noise beyond the spaces required for facilities and transportation routes. It has been suggested that some marine animals may avoid these areas of activity and noise.

Both belukha and bowhead whales utilize the lead system in the ice along the Chukchi Sea coast to initiate their spring migrations to the Beaufort Sea. Belukha whales depend on the nearshore waters for feeding and calving during summer. Kasegaluk Lagoon is the most important area for resident belukhas along the Chukchi Sea coast. Increased small boat activity in the lagoon has caused some changes in belukha distribution and in utilization of the area.

Tanker Terminals

Representative nearshore tanker terminal sites have been suggested for estimation of transportation costs. To accommodate a 60-foot-draft tanker, sites are at a 75-foot water depth, 2.5 to 5 miles offshore. Two sites are in the Chukchi Sea and four in the Bering Sea. The Navarin terminal would be in the southwest Bering Sea, more than 500 miles from Dutch Harbor, in at least 450 feet of water.

The terminal site off Point Belcher, near Wainwright in the Chukchi Sea, would directly interface with the population of gray, bowhead, and belukha whales and of walrus, seals, and polar bears. Spring migrations of whales and walrus pass this point and are harvested along nearshore leads near Point Hope, Wainwright, and Barrow.

Whales and seals pass through the Cape Espenberg site on Kotzebue Sound. Adult and juvenile migratory salmon move through the area to and from their natal streams. Concentrations of herring and tanner crab exist offshore at Cape Espenberg.

Adult salmon migrate along the Norton Sound shoreline through the Nome Terminal site, moving to spawning streams from June through September. Juvenile salmon descend streams in the spring and spend one or more months foraging in nearshore waters.

An important king crab fishery is located offshore of Nome. The gray whale migration route parallels the shoreline approximately three to five miles offshore in the vicinity of Nome.

Adult salmon migrate through the Port Moller site on Bristol Bay, and juvenile salmon may spend several months rearing in the nearshore waters. Herring have spawning grounds between Port Moller and Herendeen Bays.

Port Moller has a large population of walrus, whose numbers vary from year to year. A major pupping area for Harbor seal is located approximately 10 miles west of the area.

The major interface at the St. George Basin or the Dutch Harbor transshipment site off Unalaska Island in the Aleutians would be with the fishing fleet moving through Unalaska Bay to and from the fish processing plants. Salmon, king and tanner crab, and shrimp are taken commercially in Unalaska Bay. Interface with marine mammals would be minimal.

Interface can be expected at the Navarin site with the groundfish fishery. Knowledge of the early and sensitive stages in the life history of these fish populations in the Bering Sea is lacking.

The Alaska peninsula is one of the more important habitats for waterfowl. It is a major staging and resting area for waterfowl migrating through on their way to wintering and nesting areas. A number of waterfowl and seabird species are utilized for food and recreation and contribute substantially to the diet of villages, particularly along the west coast of Alaska.

Tanker terminal interface with waterfowl will be minimal. Major concerns would be damage to waterfowl habitat by oil spills, particularly during peak waterfowl concentrations in the spring and fall.

Terminal facilities at all representative sites are expected to have no appreciable effect on the seabird populations. The locations of critical water habitats should be known in case of an oil spill so that proper containment and exclusion measures can be carried out.

Tanker Routes

For a discussion of environmental risk, representative tanker routes have been selected between Dutch Harbor in the Aleutian chain to the Wainwright, Kotzebue, and Nome areas, as shown in Figure 18 in Chapter Five. Since sea ice in the Bering Strait and the Chukchi Sea cannot be avoided during most of the year, the routes between the Bering Strait and representative shore facilities in the Wainwright and Kotzebue areas do not vary seasonally. From about June to November, the eastern Bering Sea is virtually free of ice. In November, the ice edge begins to move from the Bering Strait in a southwesterly direction and extends to, or somewhat west of, the Pribilof Islands in February through April, after which it recedes.

Alternate tanker routes have been scheduled during certain seasons to avoid biologically sensitive areas and severe ice problems.

As shown in Figure 18, Tanker Route A would be used during February, March, and April, the most severe ice season. Tanker Route B would be used during May, December, and January. Tanker Route C would be used during the remaining summer and fall months. No environmental problems are expected south of St. Lawrence Island unless an oil spill occurs. The lower half of Route A would be used to transport crude oil production from the Navarin Basin throughout the year. The route passes through the winter feeding grounds of the bowhead whale and an area occupied in the winter by a large population of belukha whales and walrus. The route is the same one used in the spring by migrating bowhead and belukha whales, which travel through leads in the ice. Based on the experience along the California coast, tanker traffic is not likely to disturb the whales. Further information on potential reaction of the bowhead to marine traffic through leads needs to be developed.

Tanker Route C, when it passes between St. Lawrence Island and the Bering Strait, encounters the summer feeding grounds of a population of gray whales and the northern range of the feeding grounds of the right whales.

During some of the months that Route C is used, heavy traffic by fishing boats traveling to and from fishing areas could occur. The route passes through or by king and tanner crab fishing areas, one southeast of the Pribilofs and another northeast of St. Lawrence Island. Tanker traffic through these areas could interfere to some degree with crabbing activities. All routes converge through the Bering Strait and continue to Wainwright.

During the spring and fall, bowhead and belukha whales migrate along the route from the Bering Strait to Wainwright and ringed seals winter along the ice leads. During the summer, a portion of the gray whale population feeds shoreward of the route. Its feeding area is extremely large, extending all the way south along the Alaskan coast to Unimak Pass and along the eastern and southern coast of Siberia. The density of the whales along the route will probably be variable. Numerous seabird colonies are present along the route.

Approximately one 250,000 deadweight ton tanker passage per day could move 1 million barrels per day of crude oil through the Bering Strait. Two passages in three days could move 1 billion cubic feet per day of LNG.

Unimak Pass, which is 25 nautical miles wide and 180 feet deep, is the probable passageway for tanker traffic through the Aleutian Islands. Most of this traffic would probably be conventional tankers trading between a Dutch Harbor transshipment terminal and the U.S. West Coast. Depending upon the tanker size, one or two tankers would move through the pass per day, either northward or southward, to transport 1 million barrels per day of oil. Two passages in three days would be required to move 1 billion cubic feet per day of LNG. These tanker passages could approach current traffic levels on an annualized basis but would be much less than present traffic during peak seasons.

The pass is used by various species of whale and by the fur seal as a seasonal migration route. The gray whale uses Unimak Pass exclusively on its migratory route from Mexican waters to those of northern Alaska. The gray whale makes the longest migration of any mammal and is the best known and studied of all whales. Numerous charter vessels, which are used by whale watchers to observe gray whales along this migratory route, are hired each year from western U.S. ports. Since no alterations from traditional migratory paths have been observed as a result of this activity, it is reasonable to conclude that the projected level of tanker traffic through Unimak Pass would not seriously impact behavioral patterns of transiting whales.

Risk Avoidance

Onshore

Exploration and production technology and operational practices have evolved on the Arctic Slope that minimize or eliminate most of the risk to the environment associated with oil and gas activities. These practices are adequate for continued or accelerated exploration and development.

None of the operations or potential impacts of oil and gas activities on the environment are novel or unique. All have been encountered in the development of the Prudhoe Bay field, the construction and operation of the Trans-Alaska Pipeline, and exploration on NPRA and other Arctic Slope areas. Protection of the environment with additional petroleum activities is expected to involve an extension of existing technology and practices.

Oil and gas fields are unitized and developments centralized to avoid duplication of facilities, air strips, production pads, access roads, flow lines, and power lines. Wells are drilled directionally from centralized pads. These practices minimize land use and environmental impacts.

To protect permafrost from thaw, buildings are built on gravel pads with refrigerated foundations or on pilings so that heat is not transmitted to the permafrost. Travel is restricted to the permanent roads or to the winter months to avoid damage to the tundra. Thermal erosion resulting from damage to the tundra insulating mat by heat radiated from buildings is recognized and procedures are well established to avoid this erosion.

Knowledge of the life history of the various fish species is important when considering measures for minimizing impacts. Construction practices and timing can be designed to avoid most impacts. Adequate protection of the fishery resources, including the aquatic habitat, can be ensured if stream inventory data on the site-specific level are incorporated into the design and planning of the oil and gas projects. Scheduling of construction to avoid periods of spawning, egg incubation, migration, and sensitive overwintering habitats can minimize the direct impact to fish. Pit excavations may increase local habitat diversity and can provide additional overwintering and rearing habitats for fish.

The State of Alaska requires that certain criteria be met for the design of drainage structures in fish streams to provide for passage of fish. Critical periods of passage are adult spawning migration and juvenile movement to and from rearing areas. The importance of minimizing siltation during critical fish life history stages and to protect food productive capabilities of the aquatic ecosystem is emphasized.

Low-water crossings are a common mode of access on work pads and roads along a pipeline corridor. They are designed for low level traffic use and hold up well with little maintenance if designed properly.

Bridges are utilized on larger streams and rivers where culverts cannot handle the flows. The greatest concerns with bridges and the fish resources are siltation and constriction of the stream channel. This can be alleviated by armoring the abutments and avoiding constriction of the channel.

When withdrawing large quantities of water from streams and lakes during winter months, overwintering fish populations must be considered and pump intakes must be designed to prevent entrainment and entrapment. Removal of water from small streams must not obstruct channels or prevent the normal movement of fish.

Offshore

Potential environmental disturbances resulting from offshore exploration, development, and production activities can be prevented or minimized by good operating practices. Most of the equipment, safety devices, and practices now required by federal regulation (USGS) were developed by the petroleum industry and supporting manufacturers and would be used by the prudent operator even if there were no regulatory requirements.

The casing, pressure control system, and circulating system are basic to control of a drilling well. Steel pipe, called casing, is cemented in the drilled hole. A heavy steel casing head is attached permanently to the casing top, and an assembly called the blowout preventer (BOP) stack is bolted to the casing head under the rig floor where it stays during drilling operations.

When drilling is in progress, drilling fluid, commonly called mud, is circulated down the drill pipe through the rotating bit and upward through the annulus between the drill pipe and the open hole and casing to the surface to discharge over the blowout preventer. Drilling fluid is a complex blend of minerals chemically suspended in a water- or oil-base medium. Its primary purpose is to control formation pressure by the weight of the column of fluid.

The pressure control system is designed to seal a drilling well at the surface of the hole to prevent unwanted flow from the well either through the drill pipe/casing annulus or while the drill pipe is out of the hole. If the well should start to flow, the BOP stack is activated by a hydraulic operating system located at a safe distance from the well bore.

It is industry practice to use many safety devices to protect personnel and also reduce the potential for environmental pollution. These devices include remotely operable fail-closed valves on each producible well, both offshore and in environmentally sensitive areas onshore. Also, manual and automatic remote controls for emergency shutdown are used.

Each well has a manual and automatic surface-controlled safety valve located below the ocean floor. Production platforms are equipped with gas detectors, fire alarm and fire fighting equipment, and personnel escape systems.

A detailed description of drilling and production systems and related safety devices will appear in the NPC report entitled *Environmental Conservation*, to be published in 1982.

Highly trained personnel are essential to safe and efficient operations. Workers receive extensive training in their speciality prior to and after going offshore, whether it be drilling well control, equipment operation and maintenance, safety device surveillance and maintenance, oil spill control, or innumerable other tasks. Each employee is educated in site-specific ecological values.

Risk avoidance may include regulatory restrictions on site use, design, and operation. The site may be classed as being incompatible for a portion of the year. Restrictions may be seasonal or may be designed to provide a window for a specific biological event. Sites have been viewed as inadequately studied, and stipulations have been imposed that require monitoring the environment and shutdown if the monitoring shows that operations are incompatible with environmental protection. Design modifications have been suggested to eliminate perceived impediments to the movement of animals and the movement of fishermen.

Data Needs

Onshore

A large volume of environmental data on the Arctic exists and appears adequate for oil and gas exploration, development, and production. The Arctic Slope is a vast area. The ecological relationships of the Arctic are complicated but not as complex as those of many other areas of the world. As with all natural systems, much study is needed to understand them, and knowledge continually builds.

Enough information appears to exist to compatibly manage fish, wildlife, and other resources with oil and gas activities. A general consensus exists that a continuing research and monitoring program relative to the Arctic Slope ecosystems is desirable. This program needs to be well planned with specific goals, have strong coordination and agreement among the various disciplines involved, and have long-term and consistent funding.

There is a need to improve the process whereby easily accessible and available environmental data are routinely used in regulatory management decisions. Data for management decisions should be based primarily on scientific investigations.

Many of the permit restrictions and lease stipulations are considered overly restrictive by oil and gas operators. Regulatory agencies typically respond that they must make decisions with an "adequate" margin of safety to protect the environmental resources because of the lack of data. It is desirable to have more data available. It is just as desirable to make better use of the data that are available and only to stipulate studies by applicants that are clearly needed and are considered likely to be productive.

Offshore

Information on important species is available from the Alaska Department of Fish and Game, which prepares maps in rather extensive detail for each of the proposed lease sale areas. These maps show the important species that are present in the area, and provide some insight into the migration dynamics of these species, their specific locations in a given area, and some understanding of biological productivity, especially of fish, shellfish, and sea mammals. An extensive literature has developed on the species inhabiting the Bering Sea and Norton Sound that forms a good basis for further understanding of the ecosystems in these areas.

An information base has been developed for the central nearshore U.S. Beaufort Sea, the St. George Basin, the Norton Sound, and the Hope Basin through various scientific studies, including the Outer Continental Shelf Environmental Assessment Program (OCSEAP) sponsored by the Bureau of Land Management. A comparable information base should be developed for the other offshore areas, notably the Navarin Basin, the eastern and western Beaufort Sea, and the Chukchi Sea. To achieve this objective more quickly and economically, some redirection of the OCSEAP program is advisable. Greater emphasis should be placed on applied field studies and on laboratory work designed to reflect field conditions. For example, further information on potential reaction of the bowhead to marine traffic through ice leads needs to be developed. Work not directly related to offshore petroleum activities should be eliminated in the absence of a clear need. The planning of the study program should be done in cooperation with local interests.

These data will assist the regulatory agencies and the petroleum industry in identifying sensitive sections of a lease area, in the placement of staging areas, placement of tanker and pipeline routes, location of terminals, and identification of sensitive shoreline areas to be protected in the event of a major oil spill.

Data Needs Recommendations

Research and development directed toward establishing environmental baseline data are of vital importance in the oil and gas permitting process. The federal government should make these requirements known at the earliest possible time and provide adequate communication to avoid duplication of efforts and unnecessary studies by government agencies and industry. Federally funded research programs should be directed toward the collection and characterization of fundamental data and testing programs of broad issue. Timely and rapid dissemination of information obtained by government agencies is of importance.

Additional environmental data will be required as new oil and gas exploration, development, and production projects are undertaken. The value and effectiveness of the data can be increased by:

- Improving the direction and management of the existing federal environmental research programs, which would include consistent federal funding, data management, and interdisciplinary coordination
- Focusing on studies that will increase understanding of ecosystem function and improve the capability for predictions of a system's responses to changes.

Waste Disposal

Waste Material Disposal

It is industry practice to apply high standards for treatment of wastewater from living quarters at production and exploration locations. Depending on site-specific state water quality requirements, treatment may be by biological methods, physical/chemical methods, or both. At Arctic locations sewage sludges are ordinarily incinerated, but other disposal options include sanitary landfills.

Common practice in the Arctic is disposal of combustible waste by incineration. The resulting ash plus any noncombustible and nonhazardous solids are ordinarily landfilled in approved sites.

Waste hydrocarbon fluids can sometimes be burned, perhaps as a supplemental boiler fuel. It may be desirable to apply waste oils or oily water to gravel roads as a dust control. Industrial wastewater can be treated to remove harmful substances in compliance with state water quality standards and may then be discharged to the environment. Underground injection of waste liquids is an option where geological investigation shows that this practice will not be harmful to potable groundwater resources.

A considerable body of regulation has recently been issued by the federal government in support of the Resource Conservation and Recovery Act. These regulations identify a variety of waste material as "hazardous" and set forth certain operational and record-keeping requirements for any operator who generates, stores, processes, transports, or disposes of such hazardous wastes. The state needs to designate strategically and conveniently located hazardous waste disposal sites at locations selected in cooperation with the industry.

Drilling Fluid Disposal

During exploration and development drilling it is necessary to dispose of surplus drilling fluid and well cuttings excavated from the borehole. Disposal must be done in an environmentally acceptable manner.

The most common additives used in water-base drilling fluid are natural minerals such as barite (barium sulfate) for weight and bentonite (clay) as a thickener. Lignite or lignosulfonates (a paper mill byproduct) and a variety of other chemicals and inert materials may be added to produce the desired fluid qualities to maintain borehole stability.

Surplus water-base drilling fluids and cuttings are considered benign. Onshore disposal will vary with local environmental conditions and regulations. The practice on the North Slope is to spread cuttings on field gravel roads or in a landfill. Surplus drilling fluid is injected into a disposal well. Disposal offshore is usually directly into the sea and, in ice-covered areas, would be discharged under the ice.

Oil-base (diesel oil) drilling fluids are used under particular conditions where water-base fluids are unsatisfactory. They are seldom used offshore because of the environmental risk. Their high cost can justify the return of oil-base fluids to the supplier for processing and re-use. They are never discharged into the environment.

There have been extensive studies of the fate and effects of the discharge of water-base drilling fluids and cuttings to the marine environment, including recent work in the Cook Inlet and the Beaufort Sea. In these studies, evidence of lethal effects have been found only in the immediate vicinity of the discharge—from the burial of bottom organisms directly under the discharge rather than through toxic effects. Where such burial has occurred, repopulation has been rapid.

Studies of the fate and effects of drilling fluid and cutting discharges in cold regions have corroborated findings elsewhere in the world. These studies have shown that such discharges do no measurable harm to the environment or to marine resources in the area. Low-level sublethal toxic effects have not been observed in other areas, especially the Gulf of Mexico, where long-term oil and gas operations have occurred.

Produced Water Disposal

In onshore areas in Alaska, water produced with the oil is ordinarily reinjected. This water may contribute a large portion of the total water injected for pressure maintenance and secondary recovery purposes. In offshore locations, produced water is treated to remove oil and discharged to the marine environment.

Past treatment practices in Alaska have been for the removal of the "oil and grease" component of produced waters prior to discharge. The State of Alaska has a new standard for control of total aromatic hydrocarbons that will require a level of treatment that is beyond present technology.

Fate and Effects of Oil in the Marine Environment

Fate of Spilled Oil

Oil in Open Sea

When oil enters the marine environment, it is affected by a number of climatological and environmental factors that progressively change its physical characteristics and determine the ultimate fate of the spilled oil. Some oil is transported to the atmosphere by evaporation of the lighter ends and by wave-induced spray. A portion of the light fraction of spilled oil enters the water column and is dissolved or suspended in the upper few feet. Some of the heavy fractions of spilled oil may sink to the ocean floor.

The oil residues in the water column or on the bottom are ultimately assimilated by the environment, primarily by biological degradation, which transforms hydrocarbons into successively simpler compounds, ultimately into carbon dioxide and water. The bacterial organisms that accomplish biological degradation occur naturally throughout the world. Although their concentration has been observed to increase rapidly in the presence of spilled oil, the degradation process is relatively slow. Acceleration by the introduction of hybrid bacteria and nutrients has met with limited success.

Oil reaching a shoreline may or may not accumulate there depending on the type of shoreline, the level of water energy at the location, and the type of oil. For example, heavy oil will normally accumulate on gently sloping beaches but may not accumulate along rocky headlands. Oil deposited on beaches may be removed by subsequent tidal action. The most common type of oil residue to reach a shoreline and the most difficult to clean up is a high viscosity water and oil emulsion, light enough to float, that may form from heavier oil fractions.

Oil and Ice Interaction

Oil deposited on ice will spread, searching out cracks and depressions in the surface. Oil discharged under ice cover will pool in domes and pockets that characterize such ice cover and migrate upwards through the ice via brine channels created by partial desalinization during freeze-up. If upper ice layers are composed of fresh water, as is the case when rain or melted snow freeze on sea ice, this migrating oil may be trapped in the ice, where it will remain until breakup.

In broken ice situations oil will remain trapped between floating pieces of ice, slowly becoming thinner as it spreads along paths between the pieces.

Oil exposed to seawater and the atmosphere under ice conditions will undergo similar degradation as in open water; however, cold temperatures will tend to slow these processes.

Effects of Oil

The dilution potential of the open sea and natural dispersion and weathering minimize the biological damage from offshore spills. Adults of swimming species are not acutely affected by crude oil in concentrations of less than 100 parts per million. Potential risks from such spills include the effects on waterfowl and the effects on plankton. While populations of these species in the immediate area could be substantially reduced, the affected life forms are usually numerous, reproduce in large numbers, and are normally subjected to high natural mortalities. It is unlikely that a marine oil spill would cause long-term or pervasive damage to the total population of any species.

A more detailed discussion of the fate and effects of oil in the marine environment will be presented in the NPC report entitled *Environmental Conservation*, to be published in 1982.

Oil Spill Countermeasures

The Arctic presents a broad range of operating conditions that must be considered in oil spill contingency planning. During the Arctic winter there are frozen seas and ground surfaces, with extremely cold temperatures, snow, wind, and long periods of darkness. Summer conditions include: open water, occasionally with small icebergs; soft, spongy land surfaces; and long daylight hours. Between these two seasons are brief periods of either spring breakup or fall freeze-up. Tiny streams during spring melt periods can become great ice-choked torrents.

Contingency Planning

Every oil production operator is individually responsible for prevention of oil spills, and if one should occur, he is fully responsible for cleanup. In response to these obligations, the operator develops a comprehensive oil spill contingency plan that includes a trained standby organization with the authority to act immediately in an emergency. Adequate spill control and cleanup equipment and materials must be available for timely deployment.

It is usual practice for each onshore operator to have the necessary oil spill equipment available. In coastal and offshore areas where the risks and consequences are greater, operators form mutual assistance organizations that make available a pool of material, equipment, and expertise. Such organizations have been functioning for years in the coastal producing areas of California, the Gulf of Mexico, and major harbors. Alaska has three active organizations: Cook Inlet Response Organization (CIRO), Gulf of Alaska Cleanup Organization (GOACO), and Alaskan Beaufort Sea Oilspill Response Body (ABSORB). A yet unnamed organization is being formed for the Bering Sea.

ABSORB is an association of 14 companies with interests in the Alaskan Beaufort Sea. A full-time director is employed and periodic training is conducted for member companies' personnel. ABSORB owns oil spill equipment, such as booms, skimmers, and barges, that are available to member companies. Each operator is still responsible for control of its own spill, and other members will assist on request.

A very important part of ABSORB's activity is research and development of oil spill control techniques in Arctic waters. Current research includes investigating long-term weathering of crude oil under ice offshore and testing new dispersants designed to be effective in cold, quiet water without stirring.

Oil Spill Control Techniques

Oil spilled on open water can be contained by booms during the initial phase of cleanup operations to prevent the spread of oil and to protect environmentally sensitive areas. Conventional booms (flexible water piercing barriers) are designed for open water conditions and have limited use in the presence of ice. However, with adaptation and strengthening they may be effectively utilized during freeze-up or breakup conditions. Special heavy-duty booms that have been successfully left in place during winter months in the Arctic as secondary containment around an oil tank barge are available.

Under calm water conditions, an air bubble barrier may be used to provide protection for sensitive areas. A notable advantage is that marine traffic is not impeded by bubble barriers.

Skimming systems are used to recover oil spilled on water after containment has been accomplished or determined to be impractical. The most common systems use one of four principles to collect the oil in a tank from which it can be pumped for disposal.

Weir-type skimmers operate on a principle that may be likened to submerging a pail closed end down. Oil floating on the water surface flows over the weir's edge and into a tank.

Disk skimmers utilize the oleophilic (oil-adsorbing) properties of vertically mounted, parallel rotating metal disks. Oil adhering to the disks is wiped off by rubber or plastic blades and deposited in a tank.

Rope-mop and belt skimmers also use the oleophilic/hydrophobic (oil-absorbing, water-rejecting) properties of the material of which they are made. Rope mops or belts that have been oil soaked by being drawn through an oil spill are passed through a series of wringer rollers, which squeeze oil from the material into a holding tank.

Vortex-type skimmers separate oil from water by centrifugal force. The skimmed mixture is introduced into drums or cones and set into a circular motion. The heavier water is propelled to the periphery while the lighter oil moves toward the center where it is discharged into storage.

Recently, chemical dispersants have been successfully applied to offshore oil spills. The early dispersant applications received widespread adverse publicity since the dispersant/oil combination proved toxic to marine organisms. Dispersant technology has improved markedly over the past decade, resulting in products and procedures that are vastly more effective yet are environmentally acceptable. Dispersants are a valuable oil spill contingency agent and may be utilized to minimize oil spill encroachments on environmentally sensitive species and their habitats.

A promising technique for disposing of oil spilled on ice is by burning it in place. Under Arctic conditions, pack or shorefast ice often enhances the burning of oil slicks by trapping oil in relatively small areas. Air-deployable ignitors, designed to be dropped from helicopters, have been developed that are effective in initiating combustion without the hazard of placing personnel on the ice.

Helicopter transportable waste oil combustion equipment has been developed for rapid deployment to remote spill sites to facilitate the ultimate disposal of recovered oil. Barge-mounted oil-burning equipment has also been developed.

Fortunately, there have been few incidents of large spills in the presence of sea ice; consequently, the opportunity to scientifically observe the behavior of such spills has been limited. Some laboratory and modest-scale field tests have been conducted, but more data are needed in order to more accurately assess the effects of oil on fish, birds, and marine mammals, and to improve the ability to predict the fate and behavior of spilled oil.

Where a continuous sheet of stable ice has formed over a body of water, the properties of the ice may be employed to advantage in containing spilled oil. Water sprayed on the surface of the ice will form a thicker section of ice that will act as a containment barrier. Snow berms on land or sea ice surfaces sealed by sprayed water can provide temporary containment around a potential or actual spill site.

Oil spills during winter in the Arctic inland area pose different problems and offer some unique response advantages when compared with spill response in temperate climates. When ground and air temperatures are below the pour point of spilled oil, the oil will solidify on the surface and resist spreading. Snow, acting as a natural absorbent material, will soak up spilled oil and further resist spreading. The solidified oil can be disposed of with earth-moving equipment.

Oil Spill Trajectory Modeling

Trajectory models for oil spills on water are used to assist in developing spill scenarios for contingency planning and training and during an actual spill to predict where oil may contact the shoreline. In a reverse application of this technique, models are sometimes used for estimating the location and time of discharge for a spill of unknown origin.

The vagaries of weather and tide create inherent difficulties for spill trajectory modelers. Nevertheless, the quality of predictions from open water models has improved substantially during recent years. Some modeling of oil movement in the presence of sea ice has been attempted, but techniques that give consideration to the presence of floating ice need further development.

Safety

The primary concern during spill response activities in the Arctic is for safety of personnel. The operation of heavy equipment and aircraft in severe climatological conditions presents dangers not encountered in other areas of the world.

Search and rescue facilities capable of responding to emergency situations in the Arctic are severely limited. Therefore, a somewhat modified response requirement should be considered for spills in Arctic areas. The regulatory requirement to respond to and attempt cleanup of small amounts of spilled oil posing negligible environmental risk should be balanced against the very real dangers in placing men and machines on ice.

Oil Spill Countermeasure Recommendations

- Additional research on the effectiveness of dispersant chemicals under Arctic conditions should be encouraged, including field testing. Permit conditions for testing and approval procedures for use of dispersants in actual responses should be reviewed and simplified in order to maximize efficiency and effectiveness.

- Spill response priorities that give safety and logistics factors primary consideration should be established specific to Arctic conditions.
- Ongoing research on the fate and effects of oil spilled under ice conditions, trajectory analysis, probability assessment, sensitive shoreline identification, and equipment development should be encouraged.
- Cooperation and data exchange among neighboring countries engaged in Arctic spill research should be encouraged to maximize research efforts.
- The U.S. Coast Guard should be allocated adequate resources to allow for expanded search and rescue capabilities in Arctic waters, commensurate with the nation's need for domestic oil and gas production in the area.

CHAPTER NINE: REGULATORY CONSIDERATIONS

Introduction

A multitude of statutes, regulations, and policies have been developed at the federal, state, and borough levels that are designed to avoid undesirable impacts from oil and gas development on the environment and the population. Many other laws and administrative actions have sought to promote oil and gas development, maximize government leasing income, promote competition, and achieve other purposes. As a result, an elaborate series of regulatory constraints have been imposed on oil and gas operations that have increased costs and delayed all aspects of development.

The confusion and overlapping jurisdictions created by these statutes are often compounded by the regulatory agencies' internally generated policies and procedures. Although all of the regulatory agencies involved perceive their actions as making positive contributions to the proper development of oil and gas resources, the net effect of their activity is to materially hinder the progress of such development. The combination of overzealous regulatory actions and the many problems associated with development in a remote, hostile climate has significantly delayed oil and gas exploration, production, and transportation in the U.S. Arctic. The specific impact of these governmental activities is evident upon examination of the factors involved in the leasing of prospective areas and the permitting of exploration, production, and transportation operations.

Leasing

All of the land and OCS in the U.S. Arctic that is prospective for oil and gas development is under the control of federal, state, and local governments or native corporations. If industry is to establish an active development program, leasing of these resources must be accelerated. Prohibiting or delaying exploration of prospective areas prevents the needed assessment of potential resources so vital to the nation's energy future.

The important contribution of the Prudhoe Bay field to the nation's energy supply has been made possible by the aggressive leasing program pursued by the State of Alaska, which made over one million acres available in 1969. The major delays in leasing public lands in the Arctic have come from the federal sector. All federal lands in Alaska were withdrawn from oil and gas leasing from late 1966 until December 1980, when the President signed the Alaska National Interest Lands Conservation Act (ANILCA). This legislation resolved some of the problems that led to the prior ban on mineral development. The current status of federal land is outlined below.

Region I—Onshore

National Petroleum Reserve-Alaska

The 23.6-million-acre National Petroleum Reserve-Alaska was opened to private leasing in December 1980, when Congress passed the Department of the Interior Fiscal 1981 Appropriations Act. The act included a mandate to hold the first competitive lease sale within 20 months from the date of the act. The requirement to complete an environmental impact statement was waived by Congress for the first two sales, to encompass a cumulative total of no more than two million acres.

The Call for Nominations for tracts to be offered for lease was published in December 1980. The first sale has been scheduled for December 1981 and the second for May 1982. The Department of the Interior intends to lease up to two million acres as a result of these first two sales. Future lease sales will be held according to a schedule to be developed later.

Arctic National Wildlife Refuge

The Arctic National Wildlife Refuge (ANWR) comprises 18 million acres, approximately 1.2 million acres of which are in the coastal plain area.

Under ANILCA, the coastal plain will undergo a study by the Department of the Interior to analyze potential impacts of oil and gas exploration, development, and production on wildlife. The Secretary must publish the first results of the study before June 1983 and the Secretary must publish regulations governing exploratory activities before December 1983. After the regulations are published, exploration plans may be filed; the Secretary has 120 days to approve the plan or require modification. No exploration plan can be approved before December 1983.

The Secretary must, no sooner than December 1985 nor later than September 1986, report to Congress on his findings, evaluations, and recommendations as to the oil and gas potential in the coastal plain study area.

The remaining 16.8 million acres of the Arctic National Wildlife Refuge contain approximately 8 million acres of legislatively designated wilderness. The 8.8 million acres of nonwilderness designation in the refuge will be included in the Alaska Mineral Resource Assessment Program. Exploratory drilling of oil and gas test wells is specifically prohibited in the minerals assessment program.

Production of oil and gas from the Arctic National Wildlife Refuge is prohibited and no leasing or other development leading to the production of oil and gas from the refuge can be undertaken until authorized by an act of Congress.

Central Arctic Area

The Central Arctic area contains approximately 4.5 million acres and is composed of all lands north of latitude 68°N between the NPRA and the ANWR. The ANILCA requires a study of the oil and gas potential of these lands with recommendations for alternative transportation routes. The study must also address the wilderness potential. The final study report is due in 1988.

National Parks and Preserves

National parks and preserves are legislatively closed to all mineral exploration, development, and production.

Remaining Federal Lands

The remaining federal lands remain under the jurisdiction of the Bureau of Land Management (BLM). An undetermined amount of these lands may eventually be conveyed to the State of Alaska or to native corporations. These lands are subject to the Alaska Mineral Resource Assessment Program and to the oil and gas leasing program for "non-North-Slope" federal lands.

Regions II and III—Offshore

The five-year Outer Continental Shelf leasing schedule has changed frequently during the past decade, often to delay, cancel, or exclude given tracts from particular lease sales. During the period 1978 to 1980, as many as five different schedules were proposed. The July 1981 proposed five-year OCS schedule provides for sales in seven Arctic area federal OCS planning areas, as shown in Table 13.

Leasing Recommendations

It is recommended that the general concept of accelerating OCS lease schedules be followed and federal leasing policies be implemented to give the earliest possible access to public lands with promising resource potential and to allow areas with the greatest resource potential to be offered early in the lease schedules, consistent with environmental and economic concerns.

TABLE 13

SALES PROVIDED FOR IN JULY 1981 PROPOSED FIVE-YEAR OCS SCHEDULE

Basin	Sale Number	Date
NPC Region II		
Norton	57	November 1982
	88	October 1984
	99	October 1986
St. George	70	February 1983
	89	December 1984
	101	December 1986
Bristol (N. Aleutian)	75	April 1983
	92	April 1985
Navarin	83	March 1984
	107	March 1986
NPC Region III		
Beaufort (Diapir)	71	September 1982
	87	June 1984
	97	June 1986
Chukchi (Barrow Arch)	85	February 1985
Hope	86	July 1985

More specifically, the following changes in leasing policy are recommended:

- Near-term lease schedules (one to two years) should be maintained in order to allow the industry to develop bid information in an orderly and cost-effective manner. Financial resources and technical manpower are wasted when lease sale dates are postponed or cancelled.
- Acreage offered for the first sale in a frontier area should, to the extent possible, cover the major structural features of the entire basin or area of interest in order to provide for orderly exploration and development and to expedite justification of expensive oil and gas transportation systems. This may require coordination of lease sales between federal, state, and native corporations. Coordination of lease sales should be normal practice in all areas as long as this does not lead to delays.
- The level of government involvement in the economic evaluation of energy resource potential should be kept to a minimum. The competitive nature of the oil industry with its diverse concepts, multiple interpretations, experience, and willingness to invest capital provides a more accurate evaluation of tracts in a competitive bidding situation than is possible by a government agency. The attempts by the Department of the Interior to develop economic evaluations of lease tracts are responsible for significant delays.
- The length of time required by the Department of the Interior to complete prelease administrative activities should be greatly reduced, especially in frontier areas. Elimination of sequential activities would do much to decrease delays.
- Leasing of prospective acreage is fundamental to an oil and gas development program. It is also necessary to make land available for support bases, terminals, pipelines, etc. Provision for such acquisitions should be made at the time of the lease sale. All lease terms and stipulations should be explicitly defined prior to the lease sale.

- Bids should not be rejected nor should tracts be deleted when competitive bidding occurs, especially in frontier areas. These are high risk areas where economic analyses are critical to exploration and development procedures. Bid rejection is one of the factors that can significantly delay or even stop exploration in a basin. The national goal of developing Arctic resources in an expeditious manner will suffer when bids are rejected and portions of structures remain unleased.
- In frontier areas such as the Arctic, the primary lease term for OCS leases should be at least 10 years. Remote operating areas combined with hostile climate require lengthy lead time preparations. Seasonal restrictions in drilling and in logistic support may exist. Leases should include provisions for automatic "suspension of production" for noncommercial discoveries that are unable to justify a transportation system.
- Larger tract sizes that conform with environmental study areas should be considered in frontier areas,with provisions to ensure participation from all segments of industry. Size should be determined by considering all geological and operational problems within the frontier area.
- No more than one bidding factor should ever exist for the same competitive lease sale at the same time due to the difficulty of quantitatively evaluating the highest bid in multiple-bid-factor cases.
- Formation of exploration units should be encouraged to allow sharing of risks in frontier areas.

Permitting

Permitting problems are a significant delaying factor in developing petroleum production in the U.S. Arctic. Development is seriously impeded by increased costs, uncertainty in manpower assignments, excessive administrative requirements, and the cumulative effect of numerous small, unanticipated delays. All of the permitting agencies derive their jurisdiction from statutes, but the resultant regulatory structure has become a proliferation of complex agency procedures, overlapping jurisdictions, and regulations that sometimes exceed the letter and intent of the statute. In some cases, federal, state, and local policies and regulatory requirements differ enough to cause serious delays and inefficiencies in petroleum development activities.

Often situations develop where one regulatory agency is charged with monitoring the activity of another, with the net result being that no agency is in a position to exercise effective leadership. Delays are inherent in the system inasmuch as there is a general reluctance for agencies to set reasonable time limits for other agencies for submittal of their reviews.

Permitting problems also result when regulatory powers are assigned to agencies that do not have sufficient technological expertise to deal with those activities. This can result in unjustified, restrictive permit stipulations that may have no direct relationship to the permit use, impede development, and have little environmental or social benefit. Stipulations should be technically supported, should be regarded as interim measures that reflect the state of knowledge and perception of potential risk at the time they are imposed, and should be subjected to periodic reviews by affected parties as more information is developed. Stipulations developed for a particular situation should not be applied unnecessarily to later leases.

It is recommended that the following broad changes be made in the permitting process:

- A specific existing agency should be designated the responsibility for expediting permitting actions in the Arctic. A common procedure should be established to ensure that both its own permits and those of other involved agencies are expedited.
- Cost/benefit analyses should be required by all levels of government for any regulation, existing or proposed, as is currently required by the federal government.
- Policies balancing various national and local goals should be followed rather than the concept of "zero impact" on the environment.
- Regulations should be applied by personnel who understand the industry they are regulating.

- Basic regulatory objectives should be more precisely defined and more consistently applied.

Regulatory Reform Recommendations

In order to facilitate policies of accelerated Arctic oil and gas development, a number of specific actions in regard to statutes, regulations, and policies will be needed to reform leasing and permitting procedures. An example of one of the more serious regulatory situations is the federal Coastal Zone Management (CZM) consistency process in which federal agency permits cannot be approved without state certification of consistency with the state coastal zone management program. This procedure has led to permitting delays and permit stipulations that have significantly slowed oil and gas development.

Under the current regulatory structure of agencies having conflicting and overlapping powers, there is little opportunity for an agency to exercise a leadership role in achieving energy development objectives. Implicit in the following discussion of specific regulatory reforms is a recognition of the need for specifically designated government agencies to assume appropriate leadership roles to expedite energy development.

Coastal Zone Management Act

The federal Coastal Zone Management Act (CZMA) of 1972 was designed to encourage states to manage the development of the coastal zone through improved planning and enforcement of environmental laws. Adoption of a state coastal program is at the state's option; however, considerable incentive exists for the state to do so in the form of federal financial assistance and the granting of certain powers over federal actions. Unfortunately, the federal and Alaska CZM statutes interact to create a multi-agency review and approval process that is confusing and time consuming. This process often leads to inclusion of unsupported stipulations in oil and gas permits.

As with any major legislative and regulatory package, numerous constituencies have grown up around the CZM issues. Those charged with protecting local values are strongly in favor of the provisions that give local control over federal and state actions. The administration of the State of Alaska feels that the Alaska Coastal Management Program (ACMP) can be made to work through amendments to the act currently being considered in conjunction with implementation of uniform procedure regulations; as regards the federal CZMA, the administration endorses the position that states should retain the right to review and approve consistency determinations on OCS activities. On the other hand, from the viewpoint of most permit applicants, major changes in the ACMP legislation and agency regulation, other than those currently proposed by the administration, are the alternative to outright repeal.

In recognition of these seemingly irreconcilable differences strongly held by a few study participants, the Council recommends that all parties consider the following actions as a means to achieve concurrently their environmental, social, and energy goals:

- Amend the federal Coastal Zone Management Act to eliminate the consistency certification provisions of Section 307 *solely* for those federal and federally permitted activities that lie outside the coastal zone of the state.
- Suspend implementation of the Alaska Coastal Management Program, as amended, pending a prompt and thorough evaluation to determine if implementation is in the best interest of all concerned parties.

  If an objective evaluation of the effects of the ACMP shows that it will not provide significant incremental benefits to communities while minimizing permitting delays, the ACMP should be repealed. If the ACMP is repealed, funding for comprehensive and continuing planning for local interests should be ensured through other means.
- Limit federal and state agencies to single reviews of permit applications and to specified time limits.
- Explicitly justify and scientifically support all operational stipulations to eliminate those that are based only on conjectural fears of environmental harm.
- Encourage continuing constructive communication between the parties involved in order to lead to a better understanding

of the conflicting viewpoints and their eventual resolution.

North Slope Borough Interim Ordinance

On December 4, 1979, the North Slope Borough (NSB) adopted an "interim ordinance," which became effective on January 2, 1980, to serve as a district coastal management program (under the Alaska Coastal Management Act) until the borough could have a program approved by the state. The ordinance asserts broad authority in the borough over oil and gas activities on key proven and prospectively productive state lands, including the Prudhoe Bay unit and the 1979 Beaufort Sea lease sale acreage. Provisions in the ordinance duplicate the authority vested in state and federal agencies under pre-existing procedures. The ordinance authorizes the borough to grant permits for areas already under the permitting authorities of state agencies and retains for the borough the right to disapprove an activity that has been previously approved by the state.

The Council acknowledges the strongly held feelings of the North Slope Borough and the oil and gas operators on this issue. The borough feels that it can be assured of the protection of the Arctic environment, wildlife, and wildlife habitat only through local permitting of oil and gas operations. Permit applicants feel they have demonstrated abilities to prevent or mitigate adverse impacts on the environment and that existing federal and state procedures provide adequate safeguards.

As with the CZM issues, these seemingly irreconcilable positions must be the subject of continuing interactions among federal and state agencies, NSB, and industry. The Council makes the following recommendations to serve as a basis on which to build a resolution of these issues:

- The NSB should remove the restricted or prohibited use provisions of the existing interim zoning ordinance, which attempt to establish broad regulatory authority in the NSB over state and federal permitted oil and gas activities.

  The existing interim zoning ordinance should be replaced with a set of well considered regulations that (1) provide protection for the values and concerns of the local people commensurate with the extent of the NSB's local authority under existing state statutes, and (2) accommodate the development of oil and gas resources. Any such regulations should not overlap existing federal and state permitting procedures.

- State and federal permitting authorities should promptly provide the NSB with informational copies of all pertinent permit applications (excluding proprietary and confidential information) and the borough should protect local values and concerns by participating in the public comment and review processes under existing state and federal permitting authorities.

It should also be noted that the recommendations of the Council are not substantively changed by the draft North Slope Borough Comprehensive Plan and Zoning Ordinance, which the borough has proposed to replace the Interim Zoning Ordinance.

Alaska National Interest Lands Conservation Act (ANILCA) of 1980

Congress enacted the Alaska National Interest Lands Conservation Act in 1980 to incorporate "national interest lands" into the federal lands systems. The act withdrew 104.2 million acres for conservation units, where exploration and development would be subjected to varying degrees of restrictions. Of the total lands affected, 56.7 million acres were designated as wilderness, never to be touched by development. Unfortunately, the oil, gas, and mineral potential of these lands has not been evaluated to allow a rational decision to be reached balancing concerns regarding wilderness protection and development of a national economic resource. Much of this land overlies known but untested geologic basins that could contain substantial hydrocarbon reserves. It is recommended that:

- The designation of wilderness areas under the ANILCA be modified to permit evaluation of the resource potential and consideration of compatible multiple use of such areas, including oil and gas exploration and development

- Regulations be promulgated under Title III (National Wildlife Refuge System) to make refuge lands available for oil and gas exploration and development
- Legislation be enacted to allow an accelerated resource study of the Arctic National Wildlife Refuge and to authorize earlier leasing.

U.S. Army Corps of Engineers Section 404 Permitting Process

The U.S. Army Corps of Engineers (COE) regulates any discharge of dredged or fill material into the "waters of the United States." These waters have been defined to include wetland areas under authority granted by Section 404 of the Federal Water Pollution Control Act, as amended by the Clean Water Act of 1977. The COE, under its Section 404 permitting procedures, is obligated to consult with a number of state and federal agencies and obtain their approval before a permit can be granted.

Many agency comments propose permit stipulations that have not been scientifically substantiated. Among the most constraining stipulations are those that limit drilling or construction activities to narrow seasonal "windows" to avoid potential disruptions to wildlife species. The COE may reconcile these stipulation requests to some extent, but more often they result in the operator accepting an unjustified stipulation so that the project can be implemented.

The scope of the problem in handling agency stipulation requests has been increased by the COE designation of non-alpine tundra areas as "wetlands," thus expanding its jurisdiction to include lands up to 80 miles inland from the Beaufort Sea coast, encompassing virtually all areas of current petroleum production activity. By this action the COE imposed jurisdiction over a vast area in which the environment is already adequately protected under other federal and state laws. Moreover, the COE review accepts comments and imposes stipulations on activities outside its own statutory permitting authority, which is only over the discharge of dredge or fill materials into navigable waters. It is recommended that:

- The COE not impose stipulations upon any operations other than those resulting in the discharge of dredge and fill material into navigable waters.
- The Clean Water Act be amended to make it clear that the inland tundra (state lands) area was not intended to be placed under COE jurisdiction. Instead, COE jurisdiction should be limited to wet tundra areas immediately adjacent to rivers, continuous streams having flows greater than 5 cubic feet per second, or the ocean. This definition would not apply to sheet-water flows associated only with spring breakup.
- The COE should expeditiously classify coastal wetlands into critical and noncritical areas, based on a systematic inventory or relative habitat values. Regional or general construction permits should then be issued for the noncritical areas to expedite permitting. The criteria for critical areas should be rigorously defined so as to include only areas that are truly critical.
- The administrative authority of the COE should be exercised to eliminate duplicate reviews by other agencies, to set reasonable time limits for responses of state and federal agencies, and to eliminate any agency-requested stipulations that lie outside the scope of the COE's permitting authority such as seasonal drilling windows.

The National Pollution Discharge Elimination System (NPDES) as Administered by the Environmental Protection Agency (EPA)

The Clean Water Act of 1972, as amended, makes it unlawful to discharge pollutants into water without a permit. All oil- and gas-related discharges require permits regardless of their impact on the environment. These permits are issued under the NPDES, which is administered by the EPA. There is a lack of specific, uniform effluent guidelines for the discharges associated with oil and gas activities. Setting of these guidelines is at the discretion of regional personnel. These guidelines are sometimes set at unduly low levels. The permitting process is further aggravated by EPA's chronically slow processing. An additional complication arises for discharges into state water, which must satisfy the conservation requirements of a Water Quality Certificate from the Alaska Department of Environmental Conservation.

NPDES regulations do not distinguish between types of discharges. No distinction is made in the application format, data required, or the approval process required by EPA. For example, EPA does not distinguish between transient mobile sources, one-time discharges of water used for pressure-testing pipelines, and large continuous discharges by sewage treatment plants. Under the regulations, interested third parties can challenge the terms and conditions of any permit and keep that permit from becoming final through administrative challenge. Often the applicant accedes to unreasonable permit stipulations so that he may get started with his project.

It is recommended that:

- The EPA regional offices impose realistic permit conditions for safeguarding water quality. These should be attainable with the use of reasonable and prudent treatment equipment/facilities and remain practical for field applications. In addition, the recommendations should consider the type and magnitude of the receiving waters.
- Inconsistencies between state and EPA standards should be resolved, and state requirements should be no more strict than those of the EPA.
- EPA should be required to accelerate its chronically long approval process, which, in some cases, takes a year or longer.
- A general permitting system should be adopted for NPDES discharges associated with similar petroleum industry activities within a specific area. This approach has been adopted by the EPA for the Gulf of Mexico. The EPA should consider a system that would result in the issuance of a general permit for NPDES discharges for each sale area prior to the awarding of leases in the area.
- The act should stipulate that previous studies concerning the impacts of discharges in other areas may constitute sufficient evidence of the environmental consequences of the proposed discharge.
- EPA procedures should be modified to recognize that administrative challenges to a permit will not preclude a permit from becoming final if, in the judgment of the EPA, the permit is otherwise ready for approval.

Safe Drinking Water Act and Underground Injection Control (UIC) Program Regulations

Under the Safe Drinking Water Act, the Environmental Protection Agency has promulgated UIC regulations. These regulations were formulated even though principal petroleum-producing states including Alaska have demonstrated the adequacy of existing state programs for protection of groundwater resources and the act provides for control by those states exercising such measures. Under the Waxman-Gramm amendment the states can obtain additional flexibility to administer their own programs without having to follow exactly the requirements of the EPA regulations.

It is recommended that:

- The EPA adhere to those provisions of the Safe Drinking Water Act that specifically allow states with effective control to continue such controls in accordance with existing state laws and regulations
- Alaska seek primacy for UIC control under the Waxman-Gramm amendment.

Environmental Impact Statement (EIS) as Required by the National Environmental Policy Act (NEPA)

Congress passed the National Environmental Policy Act in 1969. This act set forth a national policy:

> . . . to encourage harmony between man and his environment; to promote efforts to prevent or eliminate damage to the environment and promote the health and welfare of man; to encourage a better understanding of ecological systems and natural resources that are

important to the nation; and to create a Council on Environmental Quality.

The act has been interpreted to require preparation of a detailed EIS by the cognizant federal agency for every "major federal action significantly affecting the quality of the human environment." The agency had to describe impacts on the environment not only of the proposed action but of possible alternatives to the proposed action. Individual OCS lease sales and permits for construction projects have been viewed as major federal actions, thus triggering the EIS requirement of NEPA.

The current process for development of an EIS for a lease sale area delays oil and gas exploration and development significantly. Massive EISs are prepared for each new lease area despite the fact that most of the anticipated impacts have been dealt with in EISs for previous sales. One result of this exercise is the inefficient utilization of scientific and technical personnel in government and industry. Despite the EIS process, stipulations for lease operations continue to be generated long after the lessee has acquired his lease.

Since the draft EIS contains worst-case oil spill scenarios and other conjectured impacts, the public hearings on the draft EIS disturb the citizens who attend them and create opposition toward the sale, which may lead to deletion of tracts or postponement of the sale.

It is recommended that:

- The Department of the Interior administratively determine that comprehensive EISs for lease sales are required in frontier OCS basins only once prior to the initial sale in the basin. This first environmental assessment would cover the whole basin area; subsequent lease sale EISs should henceforth be limited to updating and reviewing differences between particular sale areas within the basin and any environmentally significant new information related to the basin.
- The BLM should ensure that lease terms and stipulations are sufficiently explicit so that operating requirements are defined to the maximum feasible extent prior to a lease sale.
- The USGS should administratively determine that a separate environmental report is unnecessary if a presale EIS has been prepared; an exploration plan containing adequate shallow hazard, drilling structure, well-drilling design, and contingency plans has been submitted; and all important environmental issues have been covered in the presale EIS.
- No permit should require additional site-specific EISs except for "major federal actions significantly affecting the quality of the human environment" that were not considered in the original EIS. The basinwide EIS contains enough data to allow for environmental protection during routine development and transportation activities.
- Where the state has assessed the environmental impacts of oil and gas activities on state lands, the state's assessment should be adopted where possible as an adequate environmental assessment or EIS for related federal permits.
- The worst-case scenarios presented in an EIS should be clearly identified as events with a very low probability of occurrence. These should be more properly presented with an explanation that the expected environmental and socio-economic impacts would be much less severe than the worst case. Benefits that would accompany oil and gas development should also be discussed.
- The EIS process should be revised to ensure that oil spill predictions and all other discussions are based on relevant up-to-date data. Recent oil spill statistics reflect a significantly reduced spill probability, which is associated with modern operating practices and safety equipment. These statistics should be used for EIS spill predictions instead of the outdated statistics that are currently being used by the BLM.
- The EIS should, consistent with regulation, be clearly labeled as an aid to Secretarial decision making with an indication that the document presents worst-case and improbable scenarios and should not be used for local planning. In frontier areas especially, it should be supplemented by positive efforts on the part of the

preparing agency to inform the local community of relevant data that may not be included in the EIS.

- NEPA should be amended to require participation, through the submission of comments, in the public review of a draft EIS as a prerequisite to establishing legal standing to bring a citizen suit attacking the adequacy of that EIS. A specific time limit should be placed on the filing of suits.

- The duplicative and time-consuming effect of dual regulation of OCS activities by the OCS Lands Act and the NEPA could be obviated by amending the OCS Lands Act, to provide that compliance with the environmental requirements of the act would constitute compliance with the requirements of the National Environmental Policy Act.

Other Regulatory Constraints

Numerous other major regulatory problem areas exist. For example, depending on how they are applied, the Wild and Scenic Rivers Act could isolate northwestern Alaska from any pipeline connection, and the Endangered Species Act could block exploration activity in large, prospectively productive areas. Enforcement of still other statutes and regulations, such as the Beaufort lease stipulation that requires a pilot test structure to be in place for two years prior to use in water depths beyond 43 feet, may delay permitting to the extent that a construction "window" is missed and a project postponed for a year or even cancelled.

Recommendations for correction of other regulatory constraint problems follow a similar pattern and are detailed in the working papers of the Environmental Protection Task Group. See Appendix G for information on the working papers.

APPENDICES

APPENDIX A:
REQUEST LETTER

COPY

UNITED STATES
DEPARTMENT OF ENERGY
Office of the Secretary
Washington, D.C. 20585

Mr. C. H. Murphy, Jr.
Chairman, National Petroleum Council
1625 K Street, N.W.
Washington, D.C. 20006

April 9, 1980

Dear Mr. Murphy:

The future of United States domestic oil and gas production is of great concern. In the lower 48 States we are depleting our proved reserves of oil and gas twice as fast as we are finding new reserves. Since alternative and renewable energy sources may take years to produce in substantial amounts, oil and gas development in frontier regions represent two of our best hopes for energy supplies in the near term.

The Alaskan North Slope province and Arctic area Outer Continental Shelf appear to be the frontier regions with the highest potential for significant oil and gas resource development. Unfortunately, the exploration and development of these resources is not proceeding as quickly as we might wish.

I request that the National Petroleum Council undertake a comprehensive study of Arctic area oil and gas development. Specifically, the study should include: resource assessment information; an engineering economic analysis for exploration, development, and production activities; a state-of-the-art presentation on the adequacy of available recovery technology and prospects for innovative technology required by the harsh Arctic climate; an assessment of the environmental impact of Arctic oil and gas operations and of the available mitigating measures; a comprehensive review of the adequacy of the existing oil and gas transportation infrastructure and proposals for improving this situation; and a discussion of any international jurisdictional questions that may affect Arctic area development.

For purposes of this study, I will designate R. Dobie Langenkamp, the Deputy Assistant Secretary for Resource Development and Operations, Resource Applications, to represent me and to provide the necessary coordination between the Department of Energy and the National Petroleum Council.

Sincerely,

/s/ CHARLES W. DUNCAN, JR.

Charles W. Duncan, Jr.
Secretary of Energy

Background Information on the National Petroleum Council

In May 1946, the President stated in a letter to the Secretary of the Interior that he had been impressed by the contribution made through government/industry cooperation to the success of the World War II petroleum program. He felt that it would be beneficial if this close relationship were to be continued and suggested that the Secretary of the Interior establish an industry organization to advise the Secretary on oil and natural gas matters.

Pursuant to this request, Interior Secretary J. A. Krug established the National Petroleum Council on June 18, 1946. In October 1977, the Department of Energy was established and the Council's functions were transferred to the new department.

The purpose of the NPC is solely to advise, inform, and make recommendations to the Secretary of Energy on any matter, requested by him, relating to petroleum or the petroleum industry. The Council is subject to the provisions of the Federal Advisory Committee Act of 1972.

Matters which the Secretary of Energy would like to have considered by the Council are submitted as a request in the form of a letter outlining the nature and scope of the study. The request is then referred to the NPC Agenda Committee which makes a recommendation to the Council. The Council reserves the right to decide whether or not it will consider any matter referred to it.

Examples of recent major studies undertaken by the NPC at the request of the Department of the Interior and the Department of Energy include:

- *Environmental Conservation—The Oil and Gas Industries* (1971, 1972)
- *U.S. Energy Outlook* (1971, 1972)
- *Potential for Energy Conservation in the United States: 1974-1978* (1974)
- *Potential for Energy Conservation in the United States: 1979-1985* (1975)
- *Ocean Petroleum Resources* (1975)
- *Petroleum Storage for National Security* (1975)
- *Enhanced Oil Recovery* (1976)
- *Materials and Manpower Requirements* (1974, 1979)
- *Petroleum Storage & Transportation Capacities* (1974, 1979)
- *Refinery Flexibility* (1979, 1980)
- *Unconventional Gas Sources* (1980)
- *Emergency Preparedness for Interruption of Petroleum Imports into the United States* (1981)
- *Environmental Conservation— The Oil and Gas Industries: An Overview* (1981)

The NPC does not concern itself with trade practices, nor does it engage in any of the usual trade association activities.

Members of the National Petroleum Council are appointed by the Secretary of Energy and represent all segments of petroleum interests. The NPC is headed by a Chairman and a Vice Chairman who are elected by the Council. The Council is supported entirely by voluntary contributions from its members.

National Petroleum Council Membership 1981

ABERNATHY, Jack H.
Vice Chairman
Entex, Inc.

ALHADEFF, Victor D.
Chairman
ENI Corporation

ALLEN, Jack M., President
Alpar Resources, Inc.

ANDERSON, Robert O.
Chairman of the Board
Atlantic Richfield Company

ANGELO, Ernest, Jr.
Midland, Texas

BAILEY, R. E.
Chairman and
Chief Executive Officer
Conoco Inc.

BASS, Sid R., President
Bass Brothers Enterprises, Inc.

BAUER, R. F.
Chairman of the Board
Global Marine Inc.

BELFER, Robert A., President
Belco Petroleum Corporation

BOOKOUT, John F.
President and
Chief Executive Officer
Shell Oil Company

BOWEN, W. J.
Chairman of the Board
Transco Companies Inc.

BRUMLEY, I. Jon
President and
Chief Executive Officer
Southland Royalty Company

BUFKIN, I. David
Chairman and
Chief Executive Officer
Texas Eastern Corporation

BURTIS, Theodore A.
Chairman of the Board
Sun Company, Inc.

CALAWAY, James C., President
Southwest Minerals, Inc.

CARL, William E., President
Carl Oil and Gas, Inc.

CARVER, John A., Jr.
Director of the Natural
Resources Program
College of Law
University of Denver

CHAMBERS, C. Fred, President
Chambers Oil & Gas

CHANDLER, Collis P., Jr.
President
Chandler & Associates, Inc.

CHENAULT, James E., Jr.
President
Lone Star Steel

CLARK, E. H., Jr.
Chairman of the Board
President and
Chief Executive Officer
Baker International

COPULOS, Milton
Energy Analyst
Heritage Foundation

COX, Edwin L.
Oil and Gas Producer
Dallas, Texas

DORN, David F., President
Forest Oil Corporation

DOUCE, William C.
President and
Chief Executive Officer
Phillips Petroleum Company

DURST, Roy T.
Consulting Engineer
Fort Worth, Texas

EMISON, James W., President
Western Petroleum Company

EVANS, James H., Chairman
Union Pacific Corporation

FAHERTY, John E., President
Crown Oil and Chemical Company

FOSTER, John S., Jr.
Vice President
Science and Technology
TRW Inc.

GALLAND, R. I.
Chairman of the Board
American Petrofina, Incorporated

GARVIN, C. C., Jr.
Chairman of the Board
Exxon Corporation

GARY, James F.
Chairman and
Chief Executive Officer
Pacific Resources, Inc.

GARY, Joe F., President
Sooner Petroleum Company

GERTZ, Melvin H.
Chairman of the Board
Guam Oil & Refining Company, Inc.

GLANVILLE, James W.
General Partner
Lazard Freres & Company

GONZALEZ, Richard J.
Energy Economic Consultant
Houston, Texas

GOSS, Robert F., President
Oil, Chemical and Atomic Workers
International Union

GOTTWALD, F. D., Jr.
Chief Executive Officer,
Chairman of the Board and
Chairman of Executive Committee
Ethyl Corporation

GRAHAM, David B.
Deputy General Counsel
Velsicol Chemical Corporation

HAIR, Jay D.
Executive Vice President
National Wildlife Federation

HALBOUTY, Michel T.
Consulting Geologist and
Petroleum Engineer
Houston, Texas

HAMILTON, Frederic C., President
Hamilton Brothers Oil Company

HAMMER, Armand
Chairman of the Board and
Chief Executive Officer
Occidental Petroleum Corporation

HAMON, Jake L.
Oil and Gas Producer
Dallas, Texas

HARBIN, John P.
Chairman of the Board and
Chief Executive Officer
Halliburton Company

HARTLEY, Fred L.
Chairman and President
Union Oil Company of California

HAUN, John D.
Evergreen, Colorado

HAYES, Denis
Golden, Colorado

HEFNER, Robert A. III
Managing Partner
The GHK Company

HESS, Leon
Chairman of the Board and
Chief Executive Officer
Amerada Hess Corporation

HINERFELD, Ruth J., President
League of Women Voters
of the United States

HOOPMAN, H. D.
President and
Chief Executive Officer
Marathon Oil Company

HUDSON, Mary, President
Hudson Oil Company

HUFFINGTON, Roy M., President
Roy M. Huffington, Incorporated

HUTCHISON, William L.
Chairman of the Board and
Chief Executive Officer
Texas Oil and Gas Corporation

JACOBY, Professor Henry D.
Director, Center for Energy
Policy Research
Massachusetts Institute
of Technology
Sloan School of Management

JONES, A. V., Jr.
Partner
Jones Company

KANEB, John A., Chairman
Northeast Petroleum
Industries, Inc.

KELLER, George M.
Chairman of the Board and
Chief Executive Officer
Standard Oil Company of California

KETELSEN, James L.
Chairman and
Chief Executive Officer
Tenneco Inc.

KLINKEFUS, John T., President
Berwell Energy, Inc.

KOCH, Charles G.
Chairman and
Chief Executive Officer
Koch Industries, Inc.

LICHTBLAU, John H.
Executive Director
Petroleum Industry
Research Foundation, Inc.

LIEDTKE, J. Hugh
Chairman of the Board
Chief Executive Officer
Pennzoil Company

McAFEE, Jerry
Chairman of the Board
Gulf Oil Corporation

MacAVOY, Paul W.
Frederick William Beinecke
Professor of Economics
Yale University

MacDONALD, Peter, Chairman
Council of Energy Resource Tribes

McGEE, D. A., Chairman
Kerr-McGee Corporation

McKINLEY, John K.
Chairman and
Chief Executive Officer
Texaco Inc.

McMILLIAN, John G.
Chairman and
Chief Executive Officer
Northwest Alaskan
Pipeline Company

McWILLIAMS, W. K., Jr.
President
W. K. M. Investments, Inc.

MAGUIRE, Cary M., President
Maguire Oil Company

MARSH, C. E., II
President
Mallard Oil & Gas Company

MASSELLI, David C.
Antaeus: Resources Consulting

MAYER, F. R.
Chairman of the Board
Exeter Company

MEDDERS, Thomas B., Jr.
Partner
Medders Oil Company

MILLER, C. John, Partner
Miller Brothers

MOFFETT, James R.
Chairman and President
McMoRan Exploration Company

MONTGOMERY, Jeff
Chairman of the Board
Kirby Exploration Company

MORAN, R. J.
Chairman and
Chief Executive Officer
Moran Energy Inc.

MOSBACHER, Robert, Chairman
Mosbacher Production Company

MURPHY, C. H., Jr.
Chairman of the Board
Murphy Oil Corporation

MURRELL, John H.
Chief Executive Officer
DeGolyer and MacNaughton

NORDLICHT, Ira S., Esquire
Holtzmann, Wise & Shepard

O'SHIELDS, R. L.
Chairman and
Chief Executive Officer
Panhandle Eastern
Pipe Line Company

PARKER, Robert L.
Chairman of the Board and
Chief Executive Officer
Parker Drilling Company

PETERSEN, Sidney R.
Chairman of the Board and
Chief Executive Officer
Getty Oil Company

PETTY, Travis H.
Chairman of the Board
The El Paso Company

PHILLIPS, John G.
Chairman of the Board and
Chief Executive Officer
The Louisiana Land
& Exploration Company

PICKENS, T. Boone, Jr.
President and
Chairman of the Board
Mesa Petroleum Company

PITTS, L. Frank, Owner
Pitts Energy Group

POOLER, Rosemary S.
Commissioner
Public Services Commission

RICE, Donald B., President
Rand Corporation

RIDGWAY, Julius M.
President
Coastal Exploration, Inc.

ROBERTSON, Corbin J.
Chairman of the Board
Quintana Petroleum Corporation

ROSAPEPE, James C., President
Rosapepe, Powers & Associates

ROSENBERG, Henry A., Jr.
Chairman of the Board and
Chief Executive Officer
Crown Central Petroleum
Corporation

SIMMONS, Donald M., President
Simmons Royalty Company

SWEARINGEN, John E.
Chairman of the Board
Standard Oil Company (Indiana)

THOMAS, Robert E.
Chairman of the Board
MAPCO Inc.

TRIMBLE, George E.
Chairman of the Board and
Chief Executive Officer
Aminoil U.S.A., Inc.

TRUE, H. A., Jr.
Partner
True Oil Company

WAIDELICH, Charles J.
President and
Chief Executive Officer
Cities Service Company

WARD, Martin, President
United Association of Journeymen
and Apprentices of the
Plumbing and Pipe Fitting
Industry of the United States
and Canada

WARNER, Rawleigh, Jr.
Chairman of the Board
Mobil Corporation

WARREN, John F.
Independent Oil Operator/Producer
Austin, Texas

WARREN, J. N.
Chairman of the Board
Goldrus Drilling Co.

WHITEHOUSE, Alton W., Jr.
Chairman of the Board and
Chief Executive Officer
The Standard Oil Company (Ohio)

WILLIAMS, Joseph H.
Chairman of the Board and
Chief Executive Officer
The Williams Companies

WRIGHT, M. A.
Chairman of the Board and
Chief Executive Officer
Cameron Iron Works, Inc.

YANCEY, Robert E., President
Ashland Oil, Inc.

ZEPPA, Keating V., President
Delta Drilling Company

APPENDIX B: STUDY GROUP ROSTERS

National Petroleum Council

Committee on Arctic Oil and Gas Resources

Chairman

Robert O. Anderson
Chairman of the Board
Atlantic Richfield Company

Government Cochairman

Jan W. Mares
Assistant Secretary for
Fossil Energy
U.S. Department of Energy

Ex Officio

John F. Bookout
Chairman
National Petroleum Council

Ex Officio

Robert Mosbacher
Vice Chairman
National Petroleum Council

Secretary

Marshall W. Nichols
Executive Director
National Petroleum Council

* * *

I. David Bufkin
Chairman and
Chief Executive Officer
Texas Eastern Corporation

Theodore A. Burtis
Chairman of the Board
Sun Company, Inc.

Melvin H. Gertz
Chairman of the Board
Guam Oil & Refining Company, Inc.

James W. Glanville
General Partner
Lazard Freres & Company

Frederic C. Hamilton, President
Hamilton Brothers Oil Company

Dr. Armand Hammer
Chairman of the Board and
Chief Executive Officer
Occidental Petroleum Corporation

Arctic Oil and Gas Resources

John P. Harbin
Chairman of the Board and
Chief Executive Officer
Halliburton Company

Fred L. Hartley
Chairman and President
Union Oil Company of California

Dr. John D. Haun
Evergreen, Colorado

H. D. Hoopman
President and
Chief Executive Officer
Marathon Oil Company

James L. Ketelsen
Chairman and
Chief Exective Officer
Tenneco Inc.

Dr. Paul W. MacAvoy
Frederick William Beinecke
Professor of Economics
Yale University

John G. McMillian
Chairman and
Chief Executive Officer
Northwest Alaska Pipeline Company

John H. Murrell
Chief Executive Officer
DeGolyer and MacNaughton

Travis H. Petty
Chairman of the Board
The El Paso Company

John G. Phillips
Chairman of the Board and
Chief Executive Officer
The Louisiana Land &
Exploration Company

Theodore Snyder*
Immediate Past President
Sierra Club

*Member until July 2, 1981.

National Petroleum Council

Coordinating Subcommittee of the Committee on Arctic Oil and Gas Resources

Chairman

Dr. Howard A. Slack
Vice President - Technology
Atlantic Richfield Company

Assistant to the Chairman

Dr. K. A. Smith, Director
Arctic Energy Resources Study
Atlantic Richfield Company

Government Cochairman

Gerald J. Parker
Program Engineer
Oil Division
Office of Oil, Gas and Shale
Fossil Energy
U.S. Department of Energy

Secretary

John H. Guy, IV
Deputy Executive Director
National Petroleum Council

* * *

Lawrence A. Dinneen
Executive Vice President
Arctic Slope Regional Corporation

L. W. Funkhouser
Vice President
Exploration and Production
Standard Oil Company of California

John N. Garrett
Manager - Business Research
Gulf Oil Exploration &
Production Company

Dr. John D. Haun
Evergreen, Colorado

Dan B. Johnson
Senior Vice President
Tenneco Oil Company

Michael McIntosh
Vice Chairman
Natural Resources Defense Council

P. David Mantor
President
Hamilton International Oil Company

Terry Miller
Lieutenant Governor of Alaska

Donald F. Rodgers*
Director of Energy and
Government Relations
International Brotherhood of
Teamsters

E. Robert Schroeder
Vice President
DeGolyer and MacNaughton

Dr. Carleton B. Scott, Director
Environmental Sciences Department
Union Oil Company of California

C. H. Siebenhausen
General Manager Purchasing
Shell Oil Company

J. Frank Wolfe, Manager
Production Operations Division
Exxon Production Research Company

*Member until June 5, 1981.

Special Assistants

Benjamin A. Oliver, Jr.
Assistant Committee Coordinator
National Petroleum Council

James W. Winfrey
Consultant
National Petroleum Council

National Petroleum Council

Jurisdictional Issues Task Group of the Committee on Arctic Oil and Gas Resources

Chairman

John N. Garrett, Manager
Business Research
Gulf Oil Exploration &
Production Company

Assistant to the Chairman

David M. Delgado, Economist
Gulf Oil Exploration &
Production Company

Government Cochairman

Peter M. Frank
Assistant Director & Legal Counsel
of Naval Petroleum & Oil Shale
Reserves
U.S. Department of Energy

Secretary

Benjamin A. Oliver, Jr.
Assistant Committee Coordinator
National Petroleum Council

* * *

John A. Dugger
Foreign Affairs Officer
Office of Consuming Nations
Office of International Affairs
U.S. Department of Energy

Frederick Monroe
Special Assistant for Science and
Technology, Oceans, Polar,
Environmental, Narcotics, and
Refugee Affairs
U.S. Department of State

Dr. Robert W. Rowland, Chief
Branch of Pacific-Arctic
Marine Geology
U.S. Geological Survey

Sandra Seim
Assistant Division Chief
Bureau of Land Management
Division of Offshore Resources
U.S. Department of the Interior

George Taft, Director
Office of Law of the Sea
Negotiations
U.S. Department of State

Sue Wolf
Realty Specialist
Bureau of Land Management
(Alaska)
U.S. Department of the Interior

National Petroleum Council

Resource Assessment Task Group
of the
Committee on
Arctic Oil and Gas Resources

Chairman

E. Robert Schroeder
Vice President
DeGolyer and MacNaughton

Assistant to the Chairman

Ronald E. Watson
Vice President
DeGolyer and MacNaughton

Government Cochairman

Lawrence B. Luhrs
Physical Science Administrator
Office of Oil and Natural Gas
U.S. Department of Energy

Secretary

John H. Guy, IV
Deputy Executive Director
National Petroleum Council

* * *

Dr. Ronald C. Crane
Division Geologist—Alaska
Exploration Department - Western Region
Chevron U.S.A. Inc.

Paul S. Day
Senior Regional Geologist
Gulf Oil Company

James E. Eason
Petroleum Geophysicist
Division of Minerals and Energy Management
Department of Natural Resources
State of Alaska

Douglas G. Garrott
Operations Manager - Offshore & Alaska
Exxon Company, U.S.A.

Charles W. Hayward
Manager of Geology - U.S. Frontier
Sunmark Exploration Company

C. J. Lewis
Operations Manager - Exploration Group
Sohio Petroleum Company

Dr. Robert H. Nanz
Vice President of Western Exploration and Production Operations
Shell Oil Company

Daniel E. Nedland
Staff Geologist
Atlantic Richfield Company

Richard D. Nehring
Social Scientist
Rand Corporation

James E. Nielson
Managing Director
Nielson International

John M. Parker
Independent
Englewood, Colorado

Roy E. Roadifer
Chief Geologist
Mobil Oil Corporation

Dr. Loring P. White
Operations Research Analyst
U.S. Department of the Interior

Resource Assessment Task Group

Special Assistants

J. W. Dowden
President of Husky and
NPR Operations
Husky Oil Company

M. C. Forrest
Pacific Division
Exploration Manager
Shell Oil Company

Dr. William R. James
Geologist
Exxon Production Research Company

Dr. Michael J. Marfleet
Regional Geologist
Western Region Exploration
Sohio Petroleum Company

Dr. David A. White
Research Advisor
Exxon Production
Research Company

USGS Liaison

Dr. Betty M. Miller
Assistant Director
for Eastern Region
U.S. Geological Survey

National Petroleum Council

Exploration Task Group
of the
Committee on
Arctic Oil and Gas Resources

Chairman

L. W. Funkhouser
Vice President
Exploration and Production
Standard Oil Company of California

Government Cochairman

Philip F. Kennon
Program Analyst
Office of Oil and Natural Gas
U.S. Department of Energy

Assistant to the Chairman

Dr. Ronald C. Crane
Division Geologist—Alaska
Exploration Department -
Western Region
Chevron U.S.A. Inc.

Secretary

James W. Winfrey
Consultant
National Petroleum Council

* * *

Neal P. Cramer
Vice President
Western Geophysical Company

Roger C. Herrera
Alaska Exploration
Operations Manager
Sohio Alaska Petroleum Company

Thomas A. Hudson
Project Operations Manager
Chevron U.S.A. Inc.

Fred M. Mayes
Vice President - Technology
Sun Company, Inc.

Dean L. Morgridge
Senior Exploration Geologist
Exxon Company, U.S.A.

L. E. Redman
Director of Exploration
Energy Resource Group
Cities Service Company

David W. Scholl, Geologist
Pacific Arctic Branch of
Marine Geology
U.S. Geological Survey

Randall H. Skiff
Assistant Manager of Geoscience
Murphy Oil Corporation

W. K. Stenzel
Coordinating Manager
Production Exploration,
U.S. and Canada
Marathon Oil Company

Special Assistant

William J. Whaley
General Manager
Esso Seismic, Inc.

National Petroleum Council

Production Task Group
of the
Committee on
Arctic Oil and Gas Resources

Chairman

C. H. Siebenhausen
General Manager Purchasing
Shell Oil Company

Government Cochairman

Dr. Mark A. Alexander, Engineer
Leasing Policy Development Office
U.S. Department of Energy

Assistant to the Chairman

Irvin B. Boaz
Senior Staff Civil Engineer
Shell Oil Company

Secretary

James W. Winfrey
Consultant
National Petroleum Council

* * *

Ralph H. Coffman
Vice President - Operations
Rowan Drilling - U.S.

Dr. Hans O. Jahns
Research Scientist
Exxon Production Research Company

Graham E. King
Director - Operations Studies
Arco Oil & Gas Company

George E. Mott, Manager
Central Offshore Engineering
Texaco Inc.

Dr. Terry D. Petty
Vice President - Design and Engineering
ODECO

Professor William M. Sackinger
Geophysical Institute
University of Alaska

W. H. Silcox
Supervising Engineer
Offshore Technology Planning Staff
Standard Oil Company of California

Rodney A. Smith,
Deputy Conservation Manager of Offshore Field Operations
Alaska Region
U.S. Geological Survey

Victor V. Staffa, Director
LNG Systems
Tennessee Gas Transmission

W. F. Weeks
Research Glaciologist
Cold Region Research and Engineering Laboratory
U.S. Army Corps of Engineers

Dr. Jay B. Weidler
Senior Vice President
Brown & Root, Inc.

Robert T. Wheeler, Manager
Planning and Valuation
Western Region - Oil and Gas Division
Union Oil Company of California

Special Assistants

C. V. Chatterton
Vice President
Rowan Drilling - U.S.

E. Darron Granger
Project Engineer
Tennessee Gas Transmission

Lawrence K. Shaw
Senior Project Engineer
Oil and Gas Products
Brown & Root, Inc.

National Petroleum Council

Transportation Task Group
of the
Committee on
Arctic Oil and Gas Resources

Chairman

J. Frank Wolfe, Manager
Production Operations Division
Exxon Production Research Company

Assistant to the Chairman

Fredric H. Deily
Senior Research Associate
Exxon Production Research Company

Government Cochairman

John Stefano
Office of Energy Supply and Transportation
U.S. Department of Energy

Secretary

James W. Winfrey
Consultant
National Petroleum Council

* * *

William S. Dehn, President
Sea Ice Consultants, Inc.

Captain R. R. Garrett, Chief
Marine Science and Ice Operations Division
U.S. Coast Guard

David M. Hickok, Director
Arctic Environmental Information and Data Center
University of Alaska

Zelvin Levine, Director
Office of Advanced Ship Operations
U.S. Maritime Administration

W. D. McLean
Senior Vice President
Vessel Operations
Crowley Maritime Corporation

Elmer A. Milz, Manager
Transportation Research and Engineering Department
Westhollow Research Center
Shell Development Company

Virgil Rinehart, Director
Office of Maritime Technology
U.S. Maritime Administration

William F. Schill
U.S. Fleet Manager
Chevron Shipping Company

Larry R. Sweet
Research Manager
Department of Transporation and Public Facilities
Division of Planning and Programming
State of Alaska

Transportation Task Group

Dr. George P. Vance
Senior Associate Engineer
Mobil Research and
Development Corporation

John M. Viehweg
Vice President
Northwest Alaskan Pipeline
Company

Richard P. Voelker
Vice President
ARCTEC, Incorporated

Robert C. Wahrmund
Consultant

Special Assistant

T. L. Setchfield
Research Specialist
Exxon Production
Research Company

National Petroleum Council

Economics Task Group
of the
Committee on
Arctic Oil and Gas Resources

Chairman

P. David Mantor, President
Hamilton International Oil Company

Assistant to the Chairman

Richard J. Redmore
Chief Reservoir Engineer
Hamilton International Oil Company

Government Cochairman

Peter M. Frank
Assistant Director and Legal
Counsel of Naval Petroleum
and Oil Shale Reserves
U.S. Department of Energy

Secretary

John H. Guy, IV
Deputy Executive Director
National Petroleum Council

* * *

Billy C. Anderson, Manager
Operation Analysis Group
Arco Oil & Gas Company

J. Edward Baker
Vice President and
Director of Oil & Gas
Lazard Freres

Dr. Ronald C. Crane
Division Geologist—Alaska
Exploration Department -
Western Region
Chevron U.S.A. Inc.

Paul S. Day
Senior Regional Geologist
Gulf Oil Company

Roy E. Roadifer
Chief Geologist
Mobil Oil Corporation

E. Robert Schroeder
Vice President
DeGolyer and MacNaughton

Robert T. Wheeler, Manager
Planning and Valuation
Western Region -
Oil and Gas Division
Union Oil Company of California

J. Frank Wolfe, Manager
Production Operations Division
Exxon Production Research Company

Special Assistants

Frederic H. Deily
Senior Research Associate
Exxon Production Research Company

Charles H. Rudolph
Operations Manager
Constellation Group Ltd.

National Petroleum Council

Environmental Protection Task Group of the Committee on Arctic Oil and Gas Resources

Chairman

Dr. Carleton B. Scott, Director
Environmental Sciences Department
Union Oil Company of California

Assistant to the Chairman

Stanley L. Zwicker, Manager
Environmental Programs
Union Oil Company of California

Government Cochairman

Gerald J. Parker
Program Engineer
Oil Division
Office of Oil, Gas and Shale
Fossil Energy
U.S. Department of Energy

Secretary

Marshall W. Nichols
Executive Director
National Petroleum Council

* * *

Marie Adams
Executive Director
Alaska Eskimo Whaling Commission

Glenn J. Akins
Deputy Commissioner
Alaska Department of
Environmental Conservation

Ellison S. Burton, Acting Director
Industrial Planning and
Development Division
Office of Fossil Energy
U.S. Department of Energy

Dr. C. Paul Falls
Environmental Consultant
Arco Oil & Gas Company

Kathryn J. Frost
Marine Mammals Biologist
Alaska Department of
Fish & Game

Donald E. Glass, Manager
Coastal Environmental Activities
Pacific Division Production
Shell Oil Company

William L. Hensley, President
NANA Development Corporation

B. L. Hilliker, Manager
Environmental Protection and
Government Reports
Alyeska Pipeline Service Company

Warren E. Holland
Senior Technical Advisor
Exxon Company, U.S.A.

Donald Hood
Friday Harbor, Washington

Roger Lang, President
The Alaska Native Foundation

Environmental Protection Task Group

E. W. Mertens
Senior Staff Specialist
Marine Environment
Environmental Affairs
Chevron U.S.A. Inc.

Richard V. Shafer, Manager
Environment/Safety/Security
Sohio Alaska Petroleum Company

Lester Suvlu, Director
Conservation and Environmental
Protection Office
North Slope Borough

Special Assistants

Alan A. Allen, Manager
Alaskan Beaufort Sea Oilspill
Response Body (ABSORB)

Raymond Dronenburg
Resource Specialist
Environmental Office
North Slope Borough

Thomas R. Fink, Manager
Environmental Conservation
ARCO Alaska, Inc.

Christopher Joseph
Environmental Engineer
Environmental Sciences Department
Union Oil Company of California

Michael F. Smith
Associate Division Attorney
Exxon Company, U.S.A.

John T. Kopeck
Senior Environmental Engineer
Environmental Sciences Department
Union Oil Company of California

Daniel R. Marlow
District Operating Superintendent
Exxon Company, U.S.A.

Judith Meidinger
Vice President
The Alaska Native Foundation

Douglas R. Redburn
Oceanographer
Management & Technical
Assistance Section
Alaska Department of
Environmental Conservation

APPENDIX C:
RESOURCE ASSESSMENT

PART I:
SURVEY FORM AND INSTRUCTIONS TO PARTICIPANTS

Guidelines for NPC Assessment of Arctic Oil and Gas Potential

Introduction

The following guidelines cover procedures for the NPC assessment of Arctic oil and gas potential. The approach is a delphic-type averaging of anonymous expert opinions cast in a numerical probability format (Figure C-1). Each participant makes his own independent estimates, and those of all participants are mechanically averaged for the final estimates. Estimated are potentially recoverable oil, gas, and natural gas liquid (NGL) resources, geologic risks, economic risks, and postulated average field sizes and recovery efficiencies. Many of these judgments are subjective. Incorporated here, therefore, are some comments on U.S. or world average comparative data that provide perspectives on the estimates.

The three basic steps are to estimate for each area (1) the undiscovered, "unrisked," *possibly existent* amounts of potentially conventionally recoverable oil and gas; (2) the geologically "risked," *probably existent* resource base, in which the "unrisked" possibilities are discounted by the adequacy chance—i.e., the marginal probability or risk-discount factor; and (3) the economically "risked" attainable potential, in which the geologically "risked" probabilities are further discounted by the chance that the resource base is *probably economically exploitable*. For convenience, estimates of possible resources in "major" fields (>50 million barrels of oil or the gas equivalent) are made separately from estimates for smaller fields. Figures C-2 and C-3 summarize for oil and gas, respectively, the key probability curves for potential major fields—the "unrisked" possibility, the geologically "risked" resource base, and the geologically and economically "risked" attainable potential.

Only one total "unrisked" oil-equivalent curve is submitted by each participant for each area, since the other curves are calculated from this single curve.

Only the final averaged "risked" curves of different areas will be added for regional summations of overall potentially existent hydrocarbons. The "unrisked" curves of different areas are never added.

Required Estimates

Each participant assessing a given area *must* provide a probability curve, an adequacy chance, an oil percent, and a value for the "unrisked" curve mean. Of course, anyone may elect *not* to participate in the assessment of any or all areas.

Probability Curve

The first estimate is the "unrisked" curve of probability versus potentially recoverable amounts of major-field oil plus gas plus NGL, all expressed in terms of billions of oil-equivalent barrels (BBOE). For this purpose, gas is converted at the energy equivalency of 5,600 cubic feet per barrel. At this step, the object is to estimate possible recoverable resources that *might exist* in an area, regardless of the geologic and economic risks, which are accounted for later. Figure C-4 is a blank form for the oil-equivalent estimate.

For the "unrisked" curve, the existence of at least one major field containing at least 50 million barrels of oil (0.05 BBOE) or the gas equivalent of roughly 0.3 TCF is provisionally assumed. Thus the curve starts at the top of the graph on the 100 percent chance line at 0.05 BBOE or 0.3 TCF (Figure C-3). *Only if the adequacy entry in Line 1 is 100 percent can the curve start at a larger amount on the 100 percent chance line on the graph.* Curves generally are asymmetric, the lower chances being concave upward with long tails to the right. Curves indicating possibilities of multi-billion barrels reflect possibilities of billion-barrel-plus fields. The maximum potential shown is at the 1 percent chance level.

The BBOE scale on the form is adjustable. A very large assessment curve tail running offscale on the right at 10 BBOE can be brought back at the same probability on the left side by adding 10 to the BBOE scale. Further shifts can be made if the potential exceeds 20, 30, 40, etc., BBOE. The maximum BBOE value should be written where the curve ends at 1 percent chance.

The "unrisked" possible resource should represent hydrocarbons in stratigraphic as well as structural traps. Historically, about 35 percent of U.S. oil and gas is in stratigraphic traps and 65 percent is in structural traps. The proportion in stratigraphic traps typically is less in well structured areas and greater in poorly structured ones.

Adequacy Chance

The Line 1 entry is the estimated chance that the geologic controls of oil and gas—source, reservoir, trap, and recoverability—are *all* adequate to provide at least one 0.05 BBOE (or 0.3 TCF) field at some one place in the area. It is the chance that the "unrisked" curve is geologically appropriate; it denotes, for example, how many of 100 similar areas might actually contain oil or gas in the range postulated in the curve. Geologic risk is represented by the remaining number of these 100 areas that have less oil or gas than the minimum specified on the curve—or in effect, zero oil or gas.

Klemme's data (*Bull. Can. Petrol. Geol.*, 1975, p. 63) suggest that the average chance of a basin being productive of at least one giant field (>0.5 BB) is about 50 percent, the general range for different basin types being from 20 to 80 percent. Basin chances for >0.05 BB fields perhaps average 65 percent. White's data (*AAPG Bull.*, 1980, p. 1175) suggest that productive chances for >0.05 BB fields in individual plays in good basins average about 35 percent within a 15 to 60 percent range for different play types. (The higher basin chances probably reflect the combined chances of two or more plays in many basins.) Obviously, adequacy chances can range from 0 percent for a very poor basin or play to 100 percent for the developing extension of an already richly productive area.

Any submitted probability curve must also have an entry for the adequacy chance in Line 1 (Figures C-2 and C-3), even if that entry is 100 percent. To portray a completely zero assessment, the probability curve is a vertical straight line passing through 0.05 BBOE, and the Line 1 entry is "0."

Oil versus Gas

On Line 2 is entered the percentage of the curve mean that is oil. The remainder of the BBOE consists of gas plus NGL. This required estimate will be used to construct separate curves for oil and for gas plus NGL (Figures C-2 and C-3, respectively). *This entry should be left blank only for completely zero assessments.*

In the United States and much of the rest of the world, oil and gas on the average occur in about equal proportions on an energy equivalent basis. However, many individual basins contain mostly oil, whereas others contain mostly gas. (Some gas is always present with oil, but a few gas areas have virtually no recoverable oil.) Any local indications of gasiness or oiliness carry much weight in estimating oil versus gas proportions.

Mean Assessment

The "unrisked" curve mean BBOE (Line 3A) should be determined by planimetering the area (or counting squares) under the curve: each square inch of Figures C-2 and C-3 represents 0.2 BBOE. As a rough check, the mean can be approximated by dividing 2 into the sum of the values read from the curve at 16 percent and at 84 percent. The means of curves shaped like the final curve of Figure C-3 commonly lie at about the 40 percent chance line.

Optional Estimates

The following entries are important but remain optional to avoid forcing guesses. Blanks will not be counted in the final averaging.

Fields

Line 3B-3C calls for relating the mean "unrisked" curve BBOE (Line 3A) to the product of the average number and size of the postulated major fields. This entry provides the logical basis for the assessment curve mean and is important in economic analyses.

Recoveries

On Line 4 are the average oil and gas recovery efficiencies implicit in the assessment curves. These represent primary plus secondary but not tertiary recoveries. They are useful indicators of the reservoir quality and technologic level assumed, and they are used if necessary to back-calculate the postulated oil or gas in place. Average U.S. oil recovery efficiency is now 32 percent, the range by API district being 13 to 65 percent. A common gas recovery efficiency is 80 percent.

NGL and Gas Factors

Line 5A records the assumed NGL content in barrels per million cubic feet of gas. If the averaged final estimate for a given basin were equal to the U.S. average 30 barrels/MMCF, for example, the NGL assessment curve in BB would be about 0.15 times the gas-plus-NGL curve in BBOE. Average U.S. NGL content for nonassociated gas is 25 barrels/MMCF and for associated-dissolved gas is 45 barrels/MMCF.

Line 5B places on record the postulated cubic feet of associated (gas-cap) plus dissolved gas per barrel of oil. Multiplying this factor by the oil curve gives the associated-dissolved gas curve. This factor in the United States averages 1,500 cubic feet per barrel. (A smaller factor must be used, however, if the oil fraction exceeds 80 percent.) The remaining gas, of course, is nonassociated, which in the United States accounts for 70 percent of the total discovered gas. The result of this procedure should not call for more gas than is estimated for the total assessment, which, in mean TCF, equals Line 2B times Line 3A times 5.6.

Economically Attainable Potential

Line 6 represents the portion of the potentially existent, mean major-field, presently undiscovered oil and gas deemed ultimately to be economically attainable. More specifically, it is the percentage of the mean major-field resource base that would be classed as estimated ultimate recoverable reserves (EURR) in the year 2000, assuming that most major fields would be drilled and delineated by that time. (EURR as of the year 2000 includes proven reserves plus any production from fields discovered after 1980.)

Examples of the economic risks that must be accounted for here are a resource base too small to justify development of a remote area; major-field sizes that are too small, or reservoirs that are too thin or too shallow to be drained economically from platforms; well-producing rates that are too low, reflecting poor reservoir or hydrocarbon quality; subtle traps that would take too much expensive drilling to find; water depths too great or ice conditions too severe for economical production; or gas that is too expensive to process and transport.

Small Field Potential

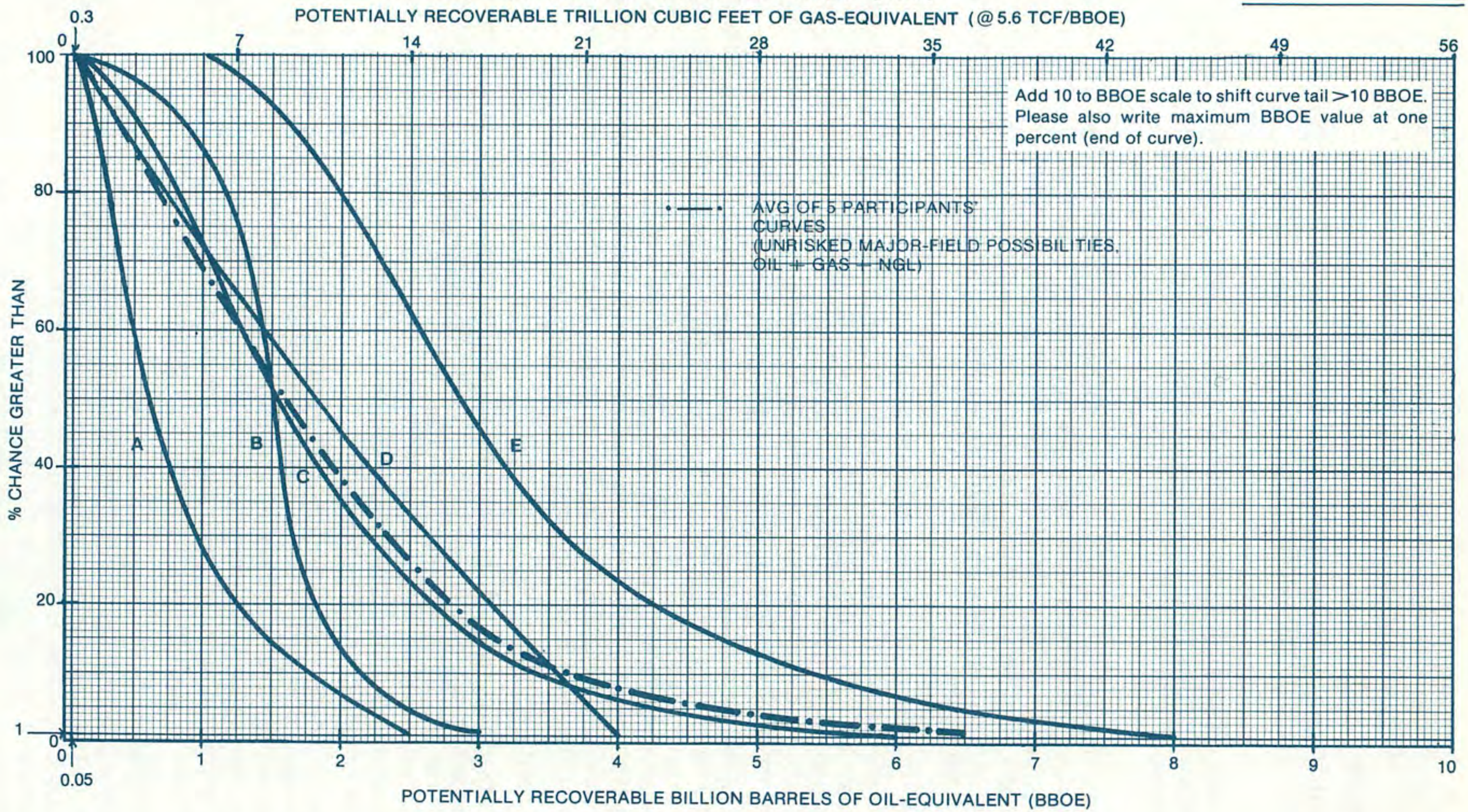
The Line 7 entry is used to estimate the average additional potential, either "unrisked" or "risked," contained in nonmajor fields smaller than AAPG Class A (50 million barrels or 300 BCF) but larger than AAPG Class E (1 million barrels or 6 BCF). This small-field potential is entered as a percentage of the curve mean. This value for all discovered U.S. fields is about 25 percent, but it becomes much smaller if very large fields are present. In California basins, the value is less than 10 percent. Line 7B-7C indicates if any of this small-field potential is considered economic.

CODE NO. ______

UNRISKED POTENTIAL RECOVERY FROM MAJOR-FIELDS

AREA: ______

(Please refer to instruction before completing form)



Required

1. Adequacy chance for at least one major-field ≥0.05 BBOE = ... 60 %.
2. Portion of curve mean that is oil. .... 50 %.
   NOTE: Total Gas% + NGL% = 100 - oil%.

3a. Unrisked mean of above curve ≅ .... 2.0 BBOE.
   NOTE: 3A = 3Bx3C.

Optional

3b. Mean number of potential major fields 8
3c. Mean major-field size .... 0.25 BBOE.
4. Postulated recovery efficiencies (conventional recovery only):
   .... a. oil 30 %.
   .... b. gas 80 %.

Optional

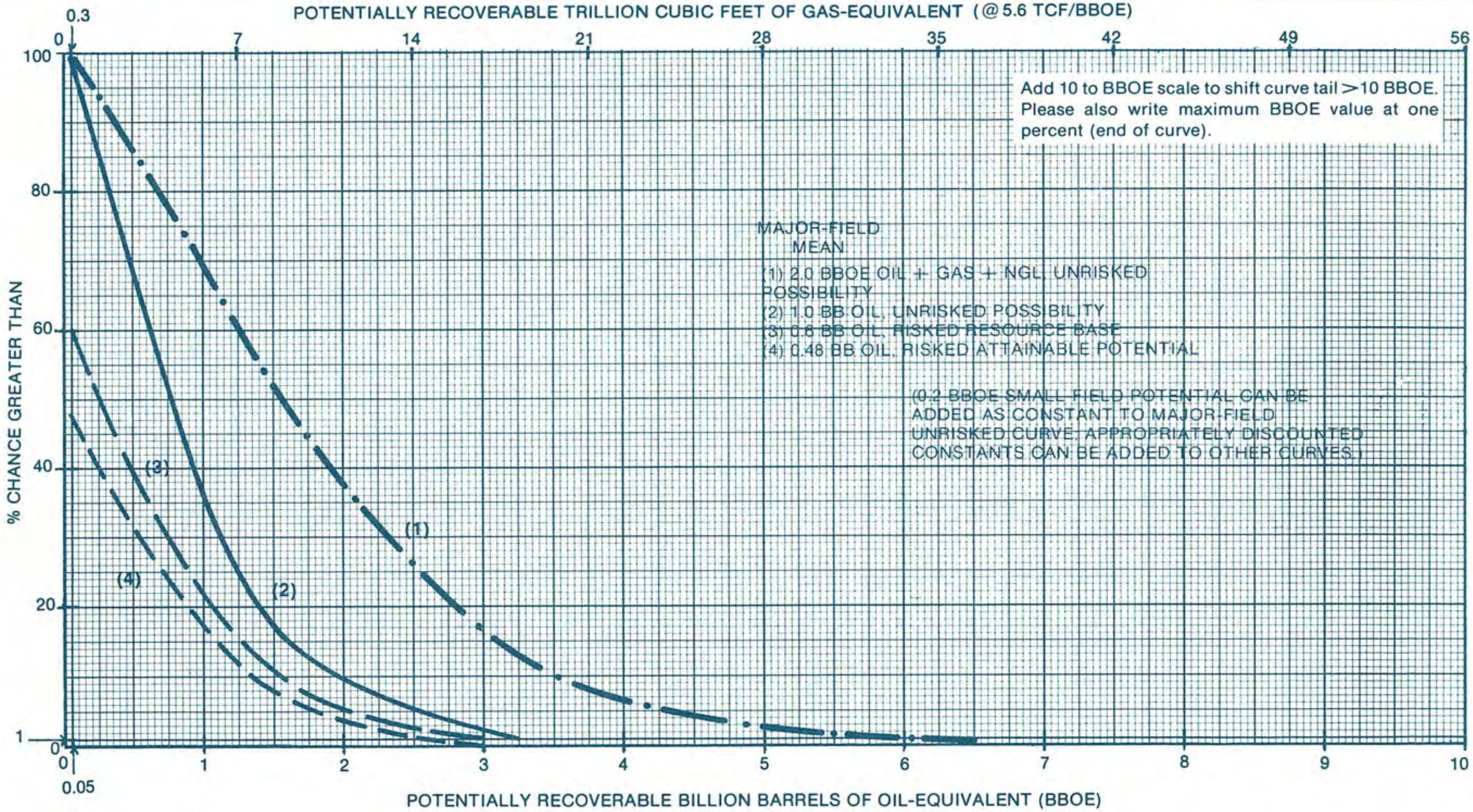
5a. NGL = ... 30 bbl/million cu ft total gas.
5b. Associated + Dissolved Gas = ... 1500 cu ft/bbl oil.
6. Economically attainable portion of:
   .... a. major-field mean oil 80 %.
   .... b. major-field mean gas + NGL 70 %.

7a. Additional potential in small fields < 0.05 BBOE, as % of curve mean .... 10 %.
7b. Economically attainable portion of mean small-field oil .... 0 %.
7c. Economically attainable portion of mean small-field gas + NGL 0 %.

Figure 1.

CODE NO. ________ **UNRISKED POTENTIAL RECOVERY FROM MAJOR-FIELDS** **AREA:** ____________

(Please refer to instruction before completing form)



Required

1. Adequacy chance for at least one major-field ≥0.05 BBOE = ... 60 %.
2. Portion of curve mean that is oil. .... 50 %.
   NOTE: Total Gas% + NGL% = 100 - oil%.

3a. Unrisked mean of above curve ≅ .... 2.0 BBOE.
   NOTE: 3A = 3Bx3C.

Optional

3b. Mean number of potential major fields .... 8 .
3c. Mean major-field size .... 0.25 BBOE.
4. Postulated recovery efficiencies (conventional recovery only):
   .... a. oil 30 %.
   .... b. gas 80 %.

Optional

5a. NGL = ... 30 bbl/million cu ft total gas.
5b. Associated + Dissolved Gas = ... 1500 cu ft/bbl oil.
6. Economically attainable portion of:
   .... a. major-field mean oil 80 %.
   .... b. major-field mean gas + NGL 70 %.

7a. Additional potential in small fields < 0.05 BBOE, as % of curve mean .... 10 %.
7b. Economically attainable portion of mean small-field oil .... 0 %.
7c. Economically attainable portion of mean small-field gas + NGL 0 %.

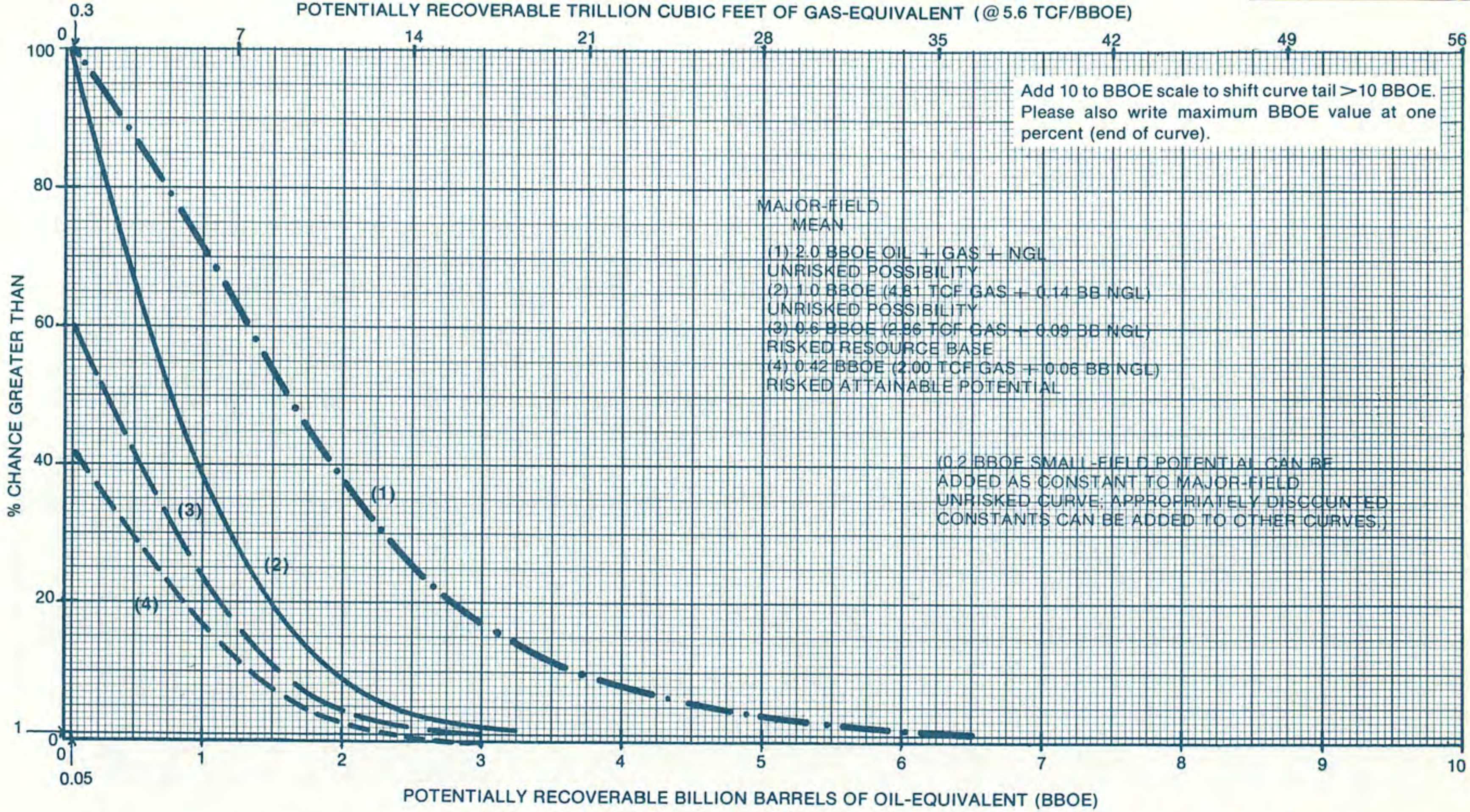
Figure 2.

CODE NO. ________

UNRISKED POTENTIAL RECOVERY FROM MAJOR-FIELDS

AREA: ________

(Please refer to instruction before completing form)



Required

1. Adequacy chance for at least one major-field ≥0.05 BBOE = ... 60 %.
2. Portion of curve mean that is oil. .... 50 %.

   NOTE: Total Gas% + NGL% = 100 - oil%.

3a. Unrisked mean of above curve ≅ .... 2.0 BBOE.

   NOTE: 3A = 3Bx3C.

Optional

3b. Mean number of potential major fields .... 8 .
3c. Mean major-field size .... 0.25 BBOE.
4. Postulated recovery efficiencies (conventional recovery only):
   .... a. oil 30 %.
   .... b. gas 80 %.

Optional

5a. NGL = ... 30 bbl/million cu ft total gas.
5b. Associated + Dissolved Gas = ... 1500 cu ft/bbl oil.
6. Economically attainable portion of:
   .... a. major-field mean oil 80 %.
   .... b. major-field mean gas + NGL 70 %.

7a. Additional potential in small fields < 0.05 BBOE, as % of curve mean .... 10 %.
7b. Economically attainable portion of mean small-field oil .... 0 %.
7c. Economically attainable portion of mean small-field gas + NGL 0 %.

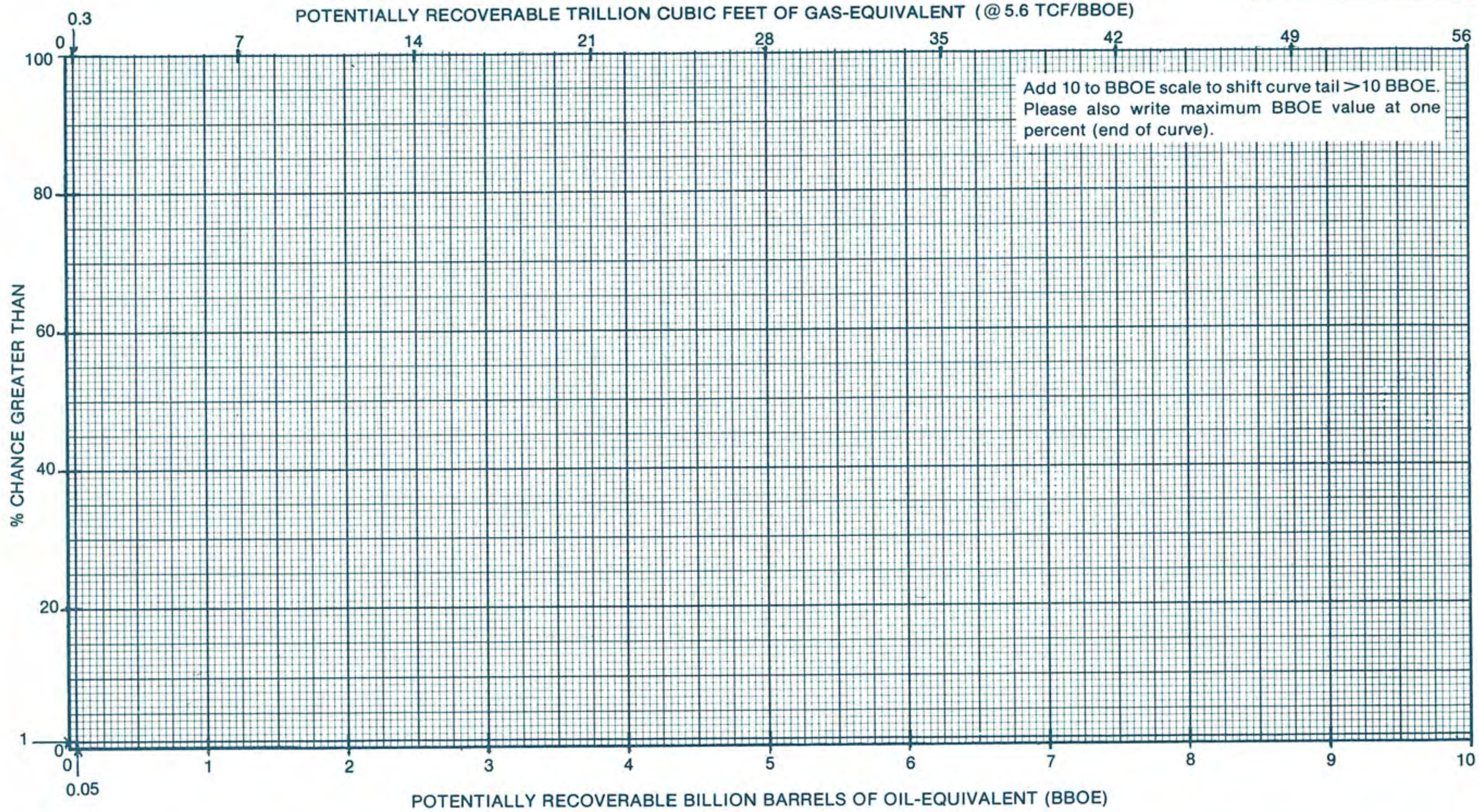
Figure 3.

CODE NO. ________

UNRISKED POTENTIAL RECOVERY FROM MAJOR-FIELDS

(Please refer to instruction before completing form)

AREA: ________________



Required

1. Adequacy chance for at least one major-field ≥0.05 BBOE = ... ______%.
2. Portion of curve mean that is oil. .... ______%.
   NOTE: Total Gas% + NGL% = 100 - oil%.
3a. Unrisked mean of above curve ≅ .... ______ BBOE.
   NOTE: 3A = 3Bx3C.

Optional

3b. Mean number of potential major fields .... ______.
3c. Mean major-field size .... ______ BBOE.
4. Postulated recovery efficiencies (conventional recovery only):
   .... a. oil ______%.
   .... b. gas ______%.

Optional

5a. NGL = ... ______ bbl/million cu ft total gas.
5b. Associated + Dissolved Gas = ... ______ cu ft/bbl oil.
6. Economically attainable portion of:
   .... a. major-field mean oil ______%.
   .... b. major-field mean gas + NGL ______%.
7a. Additional potential in small fields < 0.05 BBOE, as % of curve mean .... ______%.
7b. Economically attainable portion of mean small-field oil .... ______%.
7c. Economically attainable portion of mean small-field gas + NGL ______%.

Figure 4.

PART II:

INSTRUCTIONS TO PUBLIC ACCOUNTANTS

Mechanics of Processing Data from the NPC Assessment of Arctic Oil and Gas Potential

Introduction

The attached four sheets summarize data processing of the anonymous expert opinions gathered from each area for the NPC assessment of Arctic oil and gas potential. Sheet 1 provides the final-estimate average of the "unrisked" probability curves submitted by the participants; Sheet 2 contains the basic data transcribed from the participants' assessment forms and has simple averages where appropriate; Sheet 3 develops the necessary weighted averages; and Sheet 4 displays the final calculated assessment means. The completed sheets will provide a full record of the input, processing methods and assumptions, and final mean values for all assessments.

There are various possible ways to combine and average the participants' expert numerical opinions. But since the independent geologic basis for each participant's estimate is necessarily not disclosed, there is no unique or perfectly correct way to combine the data. Accordingly, we have used a pragmatic approach that simplifies processing and yet preserves the essential statistical weight of each participant's contribution as nearly as possible. The calculation sheets are self-explanatory, but a few comments on basic assumptions and rationales are offered in the following sections keyed to the sheet numbers.

Sheet 1. Average Curve Probabilities

Probabilities at selected BBOE intervals from participants' "unrisked" curves are arithmetically averaged to define the final-estimate curve. The BBOE intervals change from area to area, depending on the magnitude of the submitted curves. Between 10 and 20 intervals will be averaged, and the last one will be at the BBOE point where the participants' probabilities average 1 percent. The maximum BBOE from each participant's curve will be recorded.

Sheet 2. Basic Data

All of the participants' numerical opinions, taken from their assessment forms, are recorded here. The numbers at the tops of the columns refer to the line numbers on the assessment form. Six averages, for Lines 3A, 3C, 4A, 4B, 5A, and 5B, are calculated directly from the submitted values.

Average A_1 for Line 3A, the "unrisked" mean BBOE, is a fundamental estimate that must agree with the value calculated from the area under the final-estimate curve derived from Sheet 1. Averages A_2 through A_6 are for optional entries on the assessment form. The averages will reflect only the number of participants providing entries for each line.

Sheet 3. Weighted Averages

Three fundamental estimates are the "unrisked" mean, the adequacy chance, and the most important individual judgment, the "risked" mean that is the product of the other two. It is not possible to average the submitted values for each of these factors, since any third average will not agree with the first two. Accordingly, we have chosen to average the "unrisked" means (A_1 on Sheet 2) and the "risked" means (A_7 on Sheet 3) directly, and to calculate the average chance factor (A_{15} on Sheet 3) so that the average "risked" mean equals this chance times the average "unrisked" mean. This important step facilitates calculation of the final means on Sheet 4.

The average oil- and gas-plus-NGL fractions (A_{16} and A_{18}, respectively) are calculated similarly, using the corresponding "risked" mean resource volumes as the weight factors. Attainable and small-field fractions are derived in a comparable fashion.

An alternate approach would be to apply each participant's oil fraction (for example) to his own "unrisked" curve, and then to average all curves as on Sheet 1. This procedure would increase the final curve's maximum oil potential but would also increase total processing work by over 400 percent. We decided that disadvantages outweighed benefits and adopted the simpler approach.

Sheet 4. Final Means

The prime advantage of the previously adopted procedures is that all required assessment means, both potentially recoverable and in place, can be calculated compatibly. Separate values are recorded for both major and small fields for each of the three products—oil, gas, and NGL. Totals in BBOE are calculated as a check on the arithmetic.

Summations

Final curves for each different area are summed using standard Monte Carlo techniques to provide the overall Arctic oil- and gas-plus-NGL assessment curves for both resource base and attainable potentials. Only "risked" curves are summed for these purposes.

Some simplifying assumptions are necessary to expedite summations. First, all areas are treated as statistically independent, even though contiguous areas separated only by arbitrary water depth or political boundaries may have some geologic dependencies. Second, oil- and gas-plus-NGL fractions are handled as volume (rather than risk)* splits of the final area BBOE curves; using a risk discount seems less realistic because it would imply that oil and gas might be mutually exclusive and that the chances for either a 0.05 BB oil field or a 0.3 TCF gas field are lower than those for a combined 0.05 BBOE field. Third, small-field mean potentials are added as constants to the major-field curves. All three assumptions seem justified over alternatives because they more closely approximate the state of nature and at the same time offer conveniences in processing. Unfortunately, however, all three assumptions tend to diminish the stated maximum potentials of the final curves. A fourth assumption is that the attainable oil- and gas-plus-NGL fractions are applied as risk discounts to their respective resource base curves, since economic discounts do not change the underlying resource base volumes.

*Risk discounts of curves decrease probabilities but not volume ranges; volume discounts decrease volumes but not probability ranges.

AVERAGE CURVE PROBABILITIES

AREA__________ RECORDERS__________ DATE__________ SHEET 1 OF 4

PROBABILITIES

CODE NO.	BBOE / CURVE	1	2	3	4	5	6	7	8	9	10	11	12	13	14	15	16	17	18	19	20	21
																						MAXIMUM BBOE
	1																					
	2																					
	3																					
	4																					
	5																					
	6																					
	7																					
	8																					
	9																					
	10																					
	11																					
	12																					
	13																					
	14																					
	15																					
	16																					
	17																					
	18																					
	19																					
	20																					HIGHEST MAXIMUM
	Σ																					
	Σ / n																					BBOE

*n = Number of curves.

NOTE: Convert all percentages to decimal fraction when converting probabilities.

NOTE: Participants' entries (code numbers) should be on same curve line on each aggregation sheet.

BASIC DATA

AREA________ RECORDERS________ DATE________ SHEET 2 OF 4

		1	2A	2B(= 1-2A)	3A	3C	4A	4B	5A	5B	6A	6B	7A	7B	7C
CURVE	CODE NO.	ADEQUACY CHANCE	OIL FRACTION	GAS & NGL FRACTION	UNRISKED MEAN BBOE	MEAN FIELD SIZE BBOE	OIL RECOVERY FRACTION	GAS RECOVERY FRACTION	NGL BBL/MMCF	A&D GAS CF/BBL	ATTAINABLE OIL FRACTION	ATTAINABLE GAS & NGL FRACTION	SMALL-FIELD FRACTION	SMALL-FIELD ATTAINABLE OIL FRACTION	SMALL-FIELD ATTAINABLE GAS & NGL FRACTION
1															
2															
3															
4															
5															
6															
7															
8															
9															
10															
11															
12															
13															
14															
15															
16															
17															
18															
19															
20															
Σ															
n															
$\Sigma/$					$A_1^{\cdot}=$	$A_2=$	$A_3=$	$A_4=$	$A_5=$	$A_6=$					

n = Number of responders.

A = Average, calculated only where shown.

A_1 should agree with area under average delphi curve.

WEIGHTED AVERAGES

AREA________ RECORDERS________ DATE________ SHEET 3 OF 4

CURVE	CODE NO.	1x3A RISKED MEAN RESOURCE BASE	1x3Ax2A RISKED MEAN RESOURCE OIL BB	1x3Ax2Ax6A RISKED MEAN ATTAINABLE OIL BB	1x3Ax2B RISKED MEAN RESOURCE GAS & NGL BBOE	1x3Ax2Bx6B RISKED MEAN ATTAINABLE GAS & NGL BBOE	1x3Ax7A RISKED MEAN RESOURCE SMALL-FIELD BBOE	1x3Ax7Ax7B WEIGHTED ATTAINABLE SMALL-FIELD OIL	1x3Ax7Ax7C WEIGHTED SMALL-FIELD GAS & NGL
1									
2									
3									
4									
5									
6									
7									
8									
9									
10									
11									
12									
13									
14									
15									
16									
17									
18									
19									
20									
Σ									
n									
Σ/n		$A_7=$	$A_8=$	$A_9=$	$A_{10}=$	$A_{11}=$	$A_{12}=$	$A_{13}=$	$A_{14}=$

n=Number of responders.

A=Average, calculated only where shown.

$A_{18}+A_{16}$ should equal 1.0.

AVERAGE CHANCE A_7/A_1 ______ A_{15}

AVERAGE OIL FRACTION A_8/A_7 ______ A_{16} *

AVERAGE ATTAINABLE OIL FRACTION A_9/A_8 ______ A_{17}

AVERAGE GAS & NGL FRACTION A_{10}/A_7 ______ A_{18} *

AVERAGE ATTAINABLE GAS & NGL FRACTION A_{11}/A_{10} ______ A_{19}

AVERAGE SMALL-FIELD FRACTION A_{12}/A_7 ______ A_{20}

AVERAGE SMALL-FIELD ATTAINABLE OIL FRACTION A_{13}/A_{12} ______ A_{21}

AVERAGE SMALL-FIELD ATTAINABLE GAS & NGL FRACTION A_{14}/A_{12} ______ A_{22}

AVERAGE NUMBER OF FIELDS A_1/A_2 ______ A_{23}

FINAL MEANS

AREA________ RECORDERS________ DATE________ SHEET 4 OF 4

	UNRISKED	RISKED RESOURCE	RISKED, ECONOMICALLY ATTAINABLE
		POTENTIALLY RECOVERABLE MEANS	
OIL BB MAJORS	$A_1 \times A_{16} =$ ______ A_{24}	$A_{24} \times A_{15} =$ ______ A_{25}	$A_{25} \times A_{17} =$ ______ A_{26}
SMALL	$A_{24} \times A_{20} =$ ______ A_{27}	$A_{27} \times A_{15} =$ ______ A_{28}	$A_{28} \times A_{21} =$ ______ A_{29}
TOTAL	______ A_{30}	______ A_{31}	______ A_{32}
GAS TCF MAJORS	$\frac{5.6\,(A_1 - A_{24})}{1 + .0056\,A_5} =$ ______ A_{33}	$A_{33} \times A_{15} =$ ______ A_{34}	$A_{34} \times A_{19} =$ ______ A_{35}
SMALL	$A_{33} \times A_{20} =$ ______ A_{36}	$A_{36} \times A_{15} =$ ______ A_{37}	$A_{37} \times A_{22} =$ ______ A_{38}
TOTAL	______ A_{39}	______ A_{40}	______ A_{41}
(A&D GAS)	$[A_{30} \times .001 \times A_6] = [\quad][A_{42}]$	$[A_{42} \times A_{15}] = [\quad][A_{43}]$	$[A_{32} \times .001 \times A_6] = [\quad][A_{44}]$
NGL BB MAJORS	$A_{33} \times .001 \times A_5 =$ ______ A_{45}	$A_{45} \times A_{15} =$ ______ A_{46}	$A_{46} \times A_{19} =$ ______ A_{47}
SMALL	$A_{45} \times A_{20} =$ ______ A_{48}	$A_{48} \times A_{15} =$ ______ A_{49}	$A_{49} \times A_{22} =$ ______ A_{50}
TOTAL	______ A_{51}	______ A_{52}	______ A_{53}
BBOE TOTAL	$\frac{A_{39}}{5.6} + A_{30} + A_{51} =$ ______ A_{54} [A_{54} should equal $A_1 \cdot A_1 \times A_{20}$]	$\frac{A_{40}}{5.6} + A_{31} + A_{52} =$ ______ A_{55} [A_{55} should equal $A_{54} \times A_{15}$]	$\frac{A_{41}}{5.6} + A_{32} + A_{53} =$ ______ A_{56}
		IN-PLACE MEANS (TOTALS ONLY)	
OIL BB	$A_{30}/A_3 =$ ______ A_{57}	$A_{31}/A_3 =$ ______ A_{58}	AVERAGE LARGE UNRISKED FIELD SIZE BBOE FOR USE IN ECONOMIC ANALYSIS
GAS TCF	$A_{39}/A_4 =$ ______ A_{59}	$A_{40}/A_4 =$ ______ A_{60}	
NGL BB	$A_{51}/A_4 =$ ______ A_{61}	$A_{52}/A_4 =$ ______ A_{62}	$\frac{\text{max @ 1\% on unrisked curve}}{\text{unrisked curve mean } A_1} \times A_2 =$ ______ A_{65}
BBOE	$\frac{A_{59}}{5.6} + A_{57} + A_{61} =$ ______ A_{63}	$\frac{A_{60}}{5.6} + A_{58} + A_{62} =$ ______ A_{64}	

COMPUTING QUARTILES

Given a column of N valid entries, let $X_1, X_2, \ldots X_N$ represent these entries reordered from *highest to lowest* (X_1 is the largest value, X_2 is the next largest, . . . X_N is the lowest value). Then the median, high quartile, and low quartile (as used in this reporting scheme) are defined by the following formulas:

N	Median	High Quartile	Low Quartile
4	NA*	NA	NA
5	X_3	NA	NA
6	$(X_3 + X_4) \div 2$	NA	NA
7	X_4	X_2	NA
8	$(X_4 + X_5) \div 2$	$(3X_2 + X_3) \div 4$	$(X_6 + 3X_7) \div 4$
9	X_5	$(X_2 + X_3) \div 2$	$(X_7 + X_8) \div 2$
10	$(X_5 + X_6) \div 2$	$(X_2 + 3X_3) \div 4$	$(3X_8 + X_9) \div 4$
11	X_6	X_3	X_9
12	$(X_6 + X_7) \div 2$	$(3X_3 + X_4) \div 4$	$(X_9 + 3X_{10}) \div 4$
13	X_7	$(X_3 + X_4) \div 2$	$(X_{10} + X_{11}) \div 2$
14	$(X_7 + X_8) \div 2$	$(X_3 - 3X_4) \div 4$	$(3X_{11} + X_{12}) \div 4$
15	X_8	X_4	X_{12}
16	$(X_8 + X_9) \div 2$	$(3X_4 + X_5) \div 4$	$(X_{12} + 3X_{13}) \div 4$
17	X_9	$(X_4 + X_5) \div 2$	$(X_{13} + X_{14}) \div 2$
18	$(X_9 + X_{10}) \div 2$	$(X_4 + 3X_5) \div 4$	$(3X_{14} + X_{15}) \div 4$
19	X_{10}	X_5	X_{15}
20	$(X_{10} + X_{11}) \div 2$	$(3X_5 + X_6) \div 4$	$(X_{15} + 3X_{16}) \div 4$
21	X_{11}	$(X_5 + X_6) \div 2$	$(X_{16} \quad X_{17}) \div 2$
22	$(X_{11} + X_{12}) \div 2$	$(X_5 + 3X_6) \div 4$	$(3X_{17} + X_{18}) \div 4$
23	X_{12}	X_6	X_{18}
24	$(X_{12} + X_{13}) \div 2$	$(3X_6 + X_7) \div 4$	$(X_{18} + 3X_{19}) \div 4$
25	X_{13}	$(X_6 + X_7) \div 2$	$(X_{19} + X_{20}) \div 2$

*NA — Not applicable to NPC study. See Table 1.

Reporting Specifications

1. If *fewer than four* validated responses are available for any NPC area, the only results to be reported for that area is the number of validated submittals received (counting validated zeros).
2. For NPC areas with four or more validated "Minimum Requirement" submittals the amount of detail reported depends on the number of valid responses received for each entry. Report should be made for *each column* on Sheets 1 through 3, in the level of detail defined in Table 1 below. BB and TCF units, and all decimal fractions should be reported to two decimal places. Mean major field size, NGL ratio, and A and D gas ratio should be reported to three significant figures.

Table 1. Items checked are to be reported for *each*[1] of the columns on Sheets 1-3.

Report Item	**Number of Validated Column Entries**				
	≤4	5	6	7	8 or more
Number of valid entries	X	X	X	X	X
Mean	X	X	X	X	X
Median*		X	X	X	X
Maximum		X	X	X	X
Minimum			X	X	X
High Quartile*				X	X
Low Quartile*					X

*See "Computing Quartiles" for exact definition of these quantities.

3. Reporting is also required for all entries on Sheet 4, unless the column averages incorporated in calculating an entry are not reported due to the above restrictions (fewer than four valid entries in the column).
4. The plot of the aggregate curve, and its planimetered mean, must also be reported.

[1] The one exception to this is column 21 of sheet 1. For this column the maximum value should be reported rather than the mean for those basins with the only 4 validated responses.

CODE NO. ____________

____

____

Check validated items. Circle items which require further clarification from submitter.

Checklist for Validation of NPC Input Forms

Items A - D below must be filled in and validated before a submittal can be included in the study. If any of these items are invalid, the submitter should be contacted in an attempt to resolve the problems. If no valid resolution can be reached the entire submittal must be discarded. No changes or additions to the submittal should be made without verbal confirmation from the submitter, except as noted.

A. *Characteristics of the Curve*

1. The left most point on the curve must be at 100% on the vertical scale. (If the above condition is satisfied but the left most point is not at .05 on the *horizontal* axis, a line may be drawn from .05 to the left most point along the 100% line at the top of the graph to complete the curve. The submitter need not be notified of this addition.) ____________
2. The right most point on the curve must be at 1% on the vertical scale (for the last scale shift). ____________
3. The curve must decrease everywhere or remain flat from left to right. ____________
4. Shifts to higher decades on the scale must have matching points on both left and right margins. ____________
5. The curve cannot contain gaps or overlaps along the horizontal scale. ____________

B. *Adequacy Chance (Item 1)*

1. An entry is required for this item. ____________
2. If the adequacy chance is zero, the curve must be a vertical line at the .05 position on the horizontal scale. If no curve is drawn, this curve position may be assumed without contacting the submitter. ____________
3. The adequacy chance percent cannot exceed 100 or be negative. ____________
4. If the adequacy chance is non-zero but less than 1, the submitter should be contacted to verify that conversion from percent to decimal fraction is actually intended. ____________

C. *Oil Fraction (Item 2)*

1. If the adequacy chance (Item 1) is not zero, an entry is required for this item. (If the adequacy chance is zero and item 2 is blank, a zero may be entered on the form here without contacting the submitter.) ____________
2. The value cannot be greater than 100 or negative (see also checklist Item G3 below). ____________
3. If the value is non-zero but less than 1 the submitter should be contacted to verify that conversion from percent to decimal fraction is actually intended. ____________

D. *Unrisked Mean (Item 3a)*

1. If the adequacy chance (Item 1) is zero, the unrisked mean must be .05 BBOE. (See also checklist Item B2). The .05 value may be entered to replace a blank or a zero entry without contacting the submitter. ____________

2. For submittals with non-zero adequacy chances:

   a) The BBOE volumes at the 84 and 16 percent points should be read and averaged. If this calculated average agrees with the stated mean within 10 percent, no further checks are necessary. ________

   b) If the average calculated above differs by more than 10 percent from the stated mean, the area under the curve to the zero edges of the graph must be planimetered for a closer check. The mean BBOE equals 0.2 times the area under the curve in square inches. If this planimetered mean agrees with the stated mean within 10 percent the stated mean is valid and should be entered in column 3A of sheet 2. If the difference exceeds 10 percent the inconsistency must be resolved with the submitter before the submittal can be included in the study. *It is critical to the study that the unrisked mean be consistent with the curve.* ________

   c) If no entry is provided for Item 3a, the curve must be planimetered as described in step D2(b) above to determine the mean. As a check on this step, D2(a) above should also be taken, and the planimetered value rechecked if a discrepancy is found. The validated planimetered mean must then be verified with the submitter before including any of the submittal in the study. ________

Items E - H below must be validated for each of the optional entries to be included as entries on sheet 2 "Basic Data." Blank entries on the input forms for these items are not counted in N (number of responders). Attempt should be made to resolve any inconsistencies found for the entries for these items. If these attempts are unsuccessful, the invalid entries should be regarded as blank entries, and not be recorded on sheet 2, nor counted in "N" for that column. *Where Item 1 is zero, items 3b through 7c must all be considered blanks regardless of entries.*

E. *High Side Statement on Graph*

   1. The high-side value written out on the graph should agree within 0.1 BBOE of the curve value plotted at the 1% point. Be sure the stated high-side is consistent with any scale shifts. ________

   2. If the high-side value is not written out on the graph, the curve BBOE value read at the 1% point should be used as the entry in column 21 on sheet 1. If the Item 1 entry is zero, the high-side of the vertical curve is 0.05. Verification of these entries with the submitter is not necessary. ________

F. *Mean Number and Mean Size of Fields (Item 3b and 3c)*

   The product of these items should agree within 10 percent to the unrisked mean BBOE (Item 3a).

G. *NGL and Associated and Dissolved Gas (Items 5a and 5b)*

   1. NGL ratios (Item 5a) less than 1 or greater than 100 may indicate an error in units assumed by the submitter and should be verified. ________

   2. Associated and dissolved gas ratios (Item 5b) less than 100 or greater than 3000 may indicate an error in units assumed by the submitter and should be verified. ________

   3. For oil fractions (Item 2) greater than 65 percent a calculation should be made to verify that the fraction of non-associated gas implied by these ratios is not negative. For example, if the A&D gas is 1500 CF/BBL and the NGL is 30 BBLS/MMCF, the oil fraction must be less than 76

percent to accommodate any non-associated gas. The maximum percent of oil allowed can be calculated from the formula

$$\text{Max Pct Oil} = \frac{100}{1 + \frac{G}{5600} \times (1 + .0056L)}$$

where G is the A&D gas ratio (Item 5b), and L is the NGL ratio (Item 5a). If an entry is provided for G but not for L, use L=O to evaluate the formula, but do not include a value for L on sheet 2 for this submittal.

H. *Other Fractions*

All of the entries for the other items (4a, 4b, 6a, 6b, 7a, 7b, 7c) must be between 0 and 100. If any of these entries are non-zero but less than 1, the submitter should be contacted to verify that conversion from percent to decimal fraction is actually intended.

Digitizing

1. The first reading is always 0.05 BBOE at 1.0 P for all curves.
2. The last reading is the final highside BBOE, determined at 0.01 P (See "Algorithm For Finding The One Percent BBOE Point").
3. Divide the interval between 0.05 and the highside BBOE into from 10 to 20 equal divisions that are easily read on the graph—e.g, divisions of 0.25, 0.5, 1.0, 2.0, or 4.0 BBOE.
4. Generally, the first (lowest) and possibly second BBOE divisions should be further cut in half, whereas the last and possibly next-to-last divisions can be taken at double or quadruple the standard interval. In any event, there should be no more than 20 total points for readings.
5. Draw the final curve from the digitized points. If there are any long uncontrolled segments where the true curve position is in doubt, additional intermediate readings may be required (some previously digitized points may have to be dropped to keep the total number at 20 or less).
6. Planimeter the area under the final curve. Each square inch equals 0.2 BBOE. The planimetered BBOE should agree within 10% with the average A calculated on sheet 2 (Basic Data). If these values do not agree, there may be miscalculations in digitizing (sheet 1) or averaging (sheet 2), or errors in some participants' unrisked means (sheet 2) or in drawing the final curve.

Algorithm for Finding the One Percent BBOE Point

As a starting point in selecting digitizing points for averaging the submitted curves, the curve end-point must be found. This will be a trial-and-error process to locate the BBOE value where the average probability over the N curves is one percent (or where the sum equals N). In some cases inspection and a hit-or-miss approach may be effective. Below is a convergent algorithm which can be used to find this BBOE point when simpler methods fail.

A. *Getting Started*

1. Sort input forms into a stack with descending high sides from top to bottom.
2. For the top curve read the BBOE value at the percent point equal to N (the number of curves in the stack). (Call this B_1)
3. Select (from the top down) all curves with a highside greater than this BBOE value. Set the other curves aside. If there are no other curves with greater highsides, *then B_1 is the final answer.*
4. From the retained set of curves, read and sum the probabilities at the B_1 BBOE position. Call this sum P_1.
5. Read the highside BBOE value from the lowest curve in the retained stack. Call this B_2.
6. From all retained curves read and sum the probabilities at the B_2 BBOE position. Call this sum P_2.
7. Compare P_2 to N
   a. If P_2 equals N (within 1) *Then B_2 is the final answer* Proceed to digitizing operation.
   b. If P_2 is less than N skip to beginning of section B below.
   c. If P_2 is greater than N
      (1) set $P_1 = P_2$
      (2) set $B_1 = B_2$
      (3) set aside the bottom curve in the stack
      (4) go back to step A5

B. *Interpolating to the Answer*

1. Calculate a tentative answer from the formula,

$$B^* = B_1 + (B_2 - B_1) \times \left(\frac{P_1 - N}{P_1 - P_2} \right)$$

2. Read and sum the probabilities at the B* BBOE Value. Call this sum P*.
3. Compare P* to N
   a. If P* is equal to N (within ± 1) *Then B* is the final answer.* Proceed to digitizing operation.
   b. If P* is less than N
      (1) set $P_2 = P^*$
      (2) set $B_2 = B^*$
      (3) go back to step B1 above.
   c. If P* is greater than N
      (1) set $P_1 = P^*$
      (2) set $B_1 = B^*$
      (3) go back to step B1 above.

PART III: RESULTS

TABLE C-1

ESTIMATES OF POTENTIALLY RECOVERABLE HYDROCARBONS, U.S. ARCTIC BASINS
(Billion Barrels Oil Equivalent [Gas Conversion 5.6 TCF/BBOE])

	USGS 1981	NPC Resource Base†			NPC Economically Attainable §		
Curve Number and Area	Risked Mean*	% Chance >.05 BBOE	Risked Mean	Risked Highside¶	% Chance >.05 BBOE	Risked Mean	Risked Highside¶
1. Norton	0.38	43	0.87	(7.6)	29	0.47	(6.1)
2. St. Matthew-Hall	0.0	26	0.06	(1.3)	4	0.01	(0.3)
3. Navarin Shelf	1.68	41	4.00	(44.0)	30	2.22	(36.0)
4. Navarin Slope	0.15	31	0.23	(2.8)	6	0.04	(1.2)
5. Zhemchug Shelf	0.07	27	0.17	(2.3)	9	0.05	(1.4)
6. Zhemchug Slope	0.0	17	0.02	(0.6)	2	0.00	(0.1)
7. St. George	0.83	47	2.18	(23.0)	38	1.31	(19.6)
8. Bristol	0.39	47	1.32	(10.8)	38	0.75	(8.9)
9. Umnak Plateau	0.0	21	0.04	(0.8)	2	0.00	(0.1)
10. Aleutian Shelf	0.0	20	0.03	(0.9)	2	0.01	(0.2)
11. Aleutian Slope	0.0	22	0.07	(1.5)	2	0.01	(0.3)
12. ANWR	3.29	70	3.71	(21.7)	67	2.89	(20.2)
13. NPRA	3.60	79	4.69	(24.0)	59	2.95	(21.6)
14. North Slope Onshore (Other)	4.77**	79	4.37	(23.3)	69	3.19	(20.8)
15. Beaufort Shelf	13.21	88	12.88	(59.0)	60	6.97	(50.0)
16. Beaufort Slope	1.54	57	2.46	(20.4)	29	0.73	(12.0)
17. North Chukchi Shelf	1.45	50	2.14	(17.0)	28	0.72	(12.0)
18. North Chukchi Slope	0.40	34	0.65	(6.2)	5	0.05	(1.8)
19. Central Chukchi	1.17	62	3.26	(20.5)	39	1.47	(15.7)
20. Hope	0.08	40	0.43	(4.6)	32	0.30	(4.4)
Total	33.01	100	43.58	(99.0)¶	100	24.14	(74.0)¶

*Excludes NGL. Minimum field size included ranges from <1 to 400 million barrels.
†Includes NGL. Minimum field size included is 1 million barrels everywhere.
§Includes NGL. Minimum economic field/size variable, but is generally >50 million or more barrels.
¶Risked highside potentials are at 1 percent probability. They cannot be added directly.
**Equals total USGS North Slope onshore minus the special DOI assessments given above for NPRA and ANWR.

TABLE C-1 (Continued)

GRAND TOTALS OF NPC ESTIMATES OF POTENTIALLY RECOVERABLE HYDROCARBONS

	Resource Base			NPC Economically Attainable		
Curve Number	% Chance >.05 BBOE	Risked Mean	Risked Highside*	% Chance >.05 BBOE	Risked Mean	Risked Highside*
21. Oil Equivalent (BBOE)†	100	43.58	(99.0)	100	24.14	(74.0)
22. Oil (BB)	100	24.15	(55.0)	100	14.44	(45.0)
23. Total Gas (TCF)	100	94.66	(203.0)	100	47.06	(145.0)
24. NGL (BB)	100	2.56	(5.5)	100	1.25	(4.0)
25. Associated & Dissolved Gas (TCF)	100	34.25	(79.0)	100	17.02	(61.0)
26. Non-Associated Gas (TCF)	100	60.41	(130.0)	100	30.04	(88.0)
Average Oil Fraction of Total BBOE				55%	RESOURCE BASE	
Average Postulated Oil Recovery Efficiency				33%		
Average Postulated Gas Recovery Efficiency				77%		
Average NGL BB/Million Cubic Feet Gas				27		
Average A&D Gas Cubic Feet/BB Oil				1,420		
Average Small-Field % of Major-Field Mean				14%		
Average Attainable Fraction of Oil Resource Base				60%	(Chiefly in Major Fields)	
Average Attainable Fraction of Gas Resource Base				50%	(Chiefly in Major Fields)	
Regional Subtotals (BBOE)						
27. Region I—Onshore, North of the Brooks Range (Areas 12-14)	99	12.77	(37.0)	96	9.03	(32.0)
28. Region II—The Bering Sea (Areas 1-11)	99	8.99	(52.0)	87	4.87	(41.0)
29. Region III—The Beaufort and Chuckchi Seas (Areas 15-20)	100	21.82	(67.0)	92	10.24	(53.0)

*Risked highside potentials are at 1 percent probability. They cannot be added directly.
†Billion barrel oil equivalent; gas conversion 5.6 TCF per billion barrels of oil equivalent.

TABLE C-2

SUMMARY OF NPC ARCTIC AREA ASSESSMENTS

RESOURCE BASE

Economic Study Areas§	BBOE			Oil (BB)			Total Gas (TCF)			NGL (BB)			A&D GAS* (TCF)			NA Gas† (TCF)		
	%	Risked Mean	High-Side	%	Risked Mean	High-Side	%	Risked Mean	High-Side	%	Risked Mean	High-Side	%	Risked Mean	High-Side	%	Risked Mean	High-Side
1,2	59	.93	7.6	45	.33	3.0	57	3.00	27.0	57	.06	.6	45	.45	3.8	57	2.55	21.1
3,4,5,6	75	4.42	44.2	72	2.52	27.7	70	9.33	85.8	70	.25	2.3	72	3.68	36.2	67	5.65	55.4
7,8,9,10,11	87	3.64	23.2	78	1.83	13.0	82	9.08	57.4	82	.20	1.2	78	2.50	15.7	81	6.58	43.7
12	69	3.71	21.5	69	2.34	13.4	69	6.55	38.1	69	.20	1.1	69	3.30	18.7	69	3.25	19.2
13,14	95	9.06	29.6	95	4.21	14.1	95	23.77	82.6	95	.61	2.0	95	5.95	20.3	95	17.82	59.5
15	87	12.88	58.7	87	8.18	36.7	87	22.38	102.6	87	.70	3.2	87	11.70	52.6	87	10.68	48.4
16,17,18	86	5.25	25.2	86	2.82	13.4	86	11.87	56.3	86	.32	1.5	86	3.92	18.8	85	7.95	38.8
19,20	78	3.69	20.5	78	1.92	11.4	78	8.68	49.3	78	.22	1.2	78	2.75	16.4	76	5.93	33.0

ECONOMICALLY ATTAINABLE POTENTIAL

Economic Study Areas§	BBOE			Oil (BB)			Total Gas (TCF)			NGL (BB)			A&D GAS* (TCF)			NA Gas† (TCF)		
	%	Risked Mean	High-Side	%	Risked Mean	High-Side	%	Risked Mean	High-Side	%	Risked Mean	High-Side	%	Risked Mean	High-Side	%	Risked Mean	High-Side
1,2	32	.48	6.0	29	.19	2.2	26	1.46	19.7	26	.03	.5	29	.22	3.2	28	1.24	13.9
3,4,5,6	41	2.31	36.7	36	1.43	23.9	28	4.25	80.3	28	.11	1.9	36	1.69	28.5	28	2.56	42.4
7,8,9,10,11	65	2.08	22.1	56	1.15	11.3	48	4.55	43.1	48	.10	1.0	56	1.28	15.0	47	3.27	28.5
12	67	2.89	20.5	62	1.84	13.1	58	5.01	37.0	58	.15	1.0	62	2.52	17.7	57	2.49	18.1
13,14	87	6.14	26.5	87	3.08	12.7	79	14.97	71.4	79	.38	1.9	87	3.78	18.5	79	11.19	52.7
15	60	6.97	50.2	60	4.74	32.2	48	10.63	77.5	48	.33	2.7	60	5.56	41.0	48	5.07	40.2
16,17,18	53	1.50	17.2	41	1.03	9.4	23	2.33	30.8	23	.06	.8	41	.79	12.6	24	1.54	23.2
19,20	59	1.77	16.2	49	.98	8.6	49	3.86	33.7	49	.09	1.0	49	1.18	11.3	48	2.68	23.7

*A&D Gas — Associated and dissolved gas.
†NA Gas — Non-associated gas.
§Preliminary aggregations not used in final economic study.
% = Chance>.05 BBOE (billion barrel oil equivalent, gas conversion 5.6 TCF/BB). Risked highsides are at 1 percent probability. Oil chance applies to A&D gas; total gas chance applies to NGL.

TABLE C-3
SUMMARY OF NPC ARCTIC AREA ASSESSMENTS

RESOURCE BASE

Original Areas	BBOE			Oil (BB)			Total Gas (TCF)			NGL (BB)			A&D GAS* (TCF)			NA Gas† (TCF)		
	%	Risked Mean	High-Side	%	Risked Mean	High-Side	%	Risked Mean	High-Side	%	Risked Mean	High-Side	%	Risked Mean	High-Side	%	Risked Mean	High-Side
1. Norton	43	.87	7.6	43	.32	2.8	43	2.74	24.0	43	.06	.6	43	.44	3.8	43	2.30	19.9
2. St. Matthew-Hall	26	.06	1.3	5	.01	.2	26	.26	5.4	26	.00	.1	5	.01	.2	26	.25	5.2
3. Navarin Shelf	41	4.00	44.0	41	2.31	25.0	41	8.29	91.0	41	.22	2.4	41	3.38	37.0	41	4.91	54.0
4. Navarin Slope	31	.23	2.8	24	.10	1.2	31	.64	8.0	31	.02	.2	24	.15	1.9	23	.49	6.1
5. Zhemchug Shelf	27	.17	2.3	27	.10	1.4	21	.32	4.6	21	.01	.1	27	.14	2.0	17	.18	2.6
6. Zhemchug Slope	17	.02	.6	3	.01	.2	5	.08	2.0	5	.00	.1	3	.01	.2	5	.07	1.8
7. St. George	47	2.18	23.0	47	1.16	12.2	47	5.10	53.0	47	.11	1.2	47	1.59	16.6	47	3.51	37.0
8. Bristol	47	1.32	10.8	47	.62	5.0	47	3.49	28.0	47	.08	.7	47	.85	6.9	47	2.64	21.0

ECONOMICALLY ATTAINABLE POTENTIAL

Original Areas	BBOE			Oil (BB)			Total Gas (TCF)			NGL (BB)			A&D GAS* (TCF)			NA Gas† (TCF)		
	%	Risked Mean	High-Side	%	Risked Mean	High-Side	%	Risked Mean	High-Side	%	Risked Mean	High-Side	%	Risked Mean	High-Side	%	Risked Mean	High-Side
1. Norton	29	.47	6.1	29	.19	2.20	25	1.40	18.1	25	.03	.4	29	.22	2.9	25	1.18	15.2
2. St. Matthew-Hall	4	.01	.3	0	.00	.00	2	.00	1.4	2	.00	0	0	0	.1	2	.06	1.4
3. Navarin Shelf	30	2.22	36.0	26	1.38	21.00	21	4.08	70.0	21	.11	1.8	26	1.67	28.0	21	2.41	41.0
4. Navarin Slope	6	.04	1.2	6	.02	.70	3	.07	2.4	3	.00	.1	6	.02	.6	3	.05	1.8
5. Zhemchug Shelf	9	.05	1.4	8	.03	.80	6	.10	2.5	6	.00	.1	8	.00	1.1	5	.10	1.4
6. Zhemchug Slope	2	.00	.1	0	.00	.00	1	.00	.2	1	.00	.0	0	.00	0	1	.00	.2
7. St. George	38	1.31	19.6	32	.76	16.30	26	2.73	41.0	26	.06	.9	32	.85	12.6	26	1.88	28.0
8. Bristol	38	.75	8.9	33	.39	4.20	27	1.77	21.0	27	.04	.5	33	.43	5.1	27	1.34	15.9

*A&D Gas — Associated and dissolved gas.
†NA Gas — Non-associated gas.
% = Chance >.05 BBOE (billion barrel oil equivalent, gas conversion 5.6 TCF/BB). Risked highsides are at 1 percent probability. Oil chance applies to A&D gas; total gas chance applies to NGL.

TABLE C-3 (Continued)

RESOURCE BASE

Original Areas	BBOE %	BBOE Risked Mean	BBOE High-Side	Oil (BB) %	Oil (BB) Risked Mean	Oil (BB) High-Side	Total Gas (TCF) %	Total Gas (TCF) Risked Mean	Total Gas (TCF) High-Side	NGL (BB) %	NGL (BB) Risked Mean	NGL (BB) High-Side	A&D GAS* (TCF) %	A&D GAS* (TCF) Risked Mean	A&D GAS* (TCF) High-Side	NA Gas† (TCF) %	NA Gas† (TCF) Risked Mean	NA Gas† (TCF) High-Side
9. Umnak	21	.04	.8	6	.02	.3	7	.12	2.4	7	.00	.1	6	.02	.4	7	.10	2.0
10. Aleutian Shelf	20	.03	.9	4	.01	.2	7	.12	3.3	7	.00	.1	4	.01	.3	7	.11	3.0
11. Aleutian Slope	22	.07	1.5	6	.02	.4	8	.25	5.2	8	.01	.1	6	.03	.6	8	.22	4.6
12. ANWR	70	3.71	21.7	70	2.34	13.7	70	6.55	38.0	70	.20	1.2	70	3.30	19.3	70	3.25	19.0
13. NPRA	79	4.69	24.0	79	2.07	10.6	79	12.81	65.0	79	.33	1.7	79	2.85	14.6	79	9.96	51.0
14. North Slope Other	79	4.37	23.3	79	2.14	11.4	79	10.96	58.0	79	.28	1.5	79	3.10	16.5	79	7.86	42.0
15. Beaufort Shelf	88	12.88	59.0	88	8.18	37.4	88	22.38	102.0	88	.70	3.2	88	11.70	54.0	88	10.68	49.0
16. Beaufort Slope	57	2.46	20.4	57	1.33	11.1	57	5.51	46.0	57	.15	1.3	57	1.80	15.1	57	3.71	31.0

ECONOMICALLY ATTAINABLE POTENTIAL

Original Areas	BBOE %	BBOE Risked Mean	BBOE High-Side	Oil (BB) %	Oil (BB) Risked Mean	Oil (BB) High-Side	Total Gas (TCF) %	Total Gas (TCF) Risked Mean	Total Gas (TCF) High-Side	NGL (BB) %	NGL (BB) Risked Mean	NGL (BB) High-Side	A&D GAS* (TCF) %	A&D GAS* (TCF) Risked Mean	A&D GAS* (TCF) High-Side	NA Gas† (TCF) %	NA Gas† (TCF) Risked Mean	NA Gas† (TCF) High-Side
9. Umnak	2	.00	.1	1	.00	0	1	.00	.2	1	.00	0	1	.00	.0	1	.00	.1
10. Aleutian Shelf	2	.01	.2	1	.00	.1	1	.02	.4	1	.00	0	1	.00	.0	1	.02	.4
11. Aleutian Slope	2	.01	.3	2	.00	.2	1	.03	.2	1	.00	0	2	.00	.0	1	.03	.2
12. ANWR	67	2.89	20.2	62	1.84	13.1	57	5.01	36.0	57	.15	1.1	62	2.52	18.3	56	2.49	18.0
13. NPRA	59	2.95	21.6	59	1.43	9.8	49	7.44	58.0	49	.19	1.5	59	1.65	12.8	49	5.79	45.0
14. North Slope Other	69	3.19	20.8	65	1.65	10.9	58	7.53	54.0	58	.19	1.4	65	2.13	15.2	58	5.40	39.0
15. Beaufort Shelf	60	6.97	50.0	59	4.74	32.0	49	10.63	82.0	49	.33	2.6	59	5.56	43.0	48	5.07	39.0
16. Beaufort Slope	29	.73	12.0	23	.53	7.9	10	.96	21.0	10	.03	.6	23	.32	7.0	10	.64	14.0

*A&D Gas — Associated and dissolved gas.
†NA Gas — Non-associated gas.
% = Chance >.05 BBOE (billion barrel oil equivalent, gas conversion 5.6 TCF/BB). Risked highsides are at 1 percent probability. Oil chance applies to A&D gas; total gas chance applies to NGL.

TABLE C-3 (Continued)

RESOURCE BASE

Original Areas	BBOE %	BBOE Risked Mean	BBOE High-Side	Oil (BB) %	Oil (BB) Risked Mean	Oil (BB) High Side	Total Gas (TCF) %	Total Gas (TCF) Risked Mean	Total Gas (TCF) High-Side	NGL (BB) %	NGL (BB) Risked Mean	NGL (BB) High-Side	A&D Gas* (TCF) %	A&D Gas* (TCF) Risked Mean	A&D Gas* (TCF) High-Side	NA Gas† (TCF) %	NA Gas† (TCF) Risked Mean	NA Gas† (TCF) High-Side
17. North Chukchi Shelf	50	2.14	17.0	50	1.16	9.1	50	4.82	38.0	50	.12	1.0	50	1.65	13.0	50	3.17	25.0
18. North Chukchi Slope	34	.65	6.2	34	.33	3.1	34	1.54	14.7	34	.05	.4	34	.47	4.5	34	1.07	10.3
19. Central Chukchi	62	3.26	20.5	62	1.74	19.9	62	7.47	47.0	62	.19	1.2	62	2.48	15.5	62	4.99	31.3
20. Hope	40	.43	4.6	40	.18	2.0	40	1.21	13.0	40	.03	.3	40	.27	2.9	40	.94	10.1
Areas 1-20 Summation	100	43.58	99.0	100	24.15	55.0	100	94.66	203.0	100	2.56	5.5	100	34.25	79.0	100	60.41	130.0

ECONOMICALLY ATTAINABLE POTENTIAL

Original Areas	BBOE %	BBOE Risked Mean	BBOE High-Side	Oil (BB) %	Oil (BB) Risked Mean	Oil (BB) High-Side	Total Gas (TCF) %	Total Gas (TCF) Risked Mean	Total Gas (TCF) High-Side	NGL (BB) %	NGL (BB) Risked Mean	NGL (BB) High-Side	A&D Gas* (TCF) %	A&D Gas* (TCF) Risked Mean	A&D Gas* (TCF) High-Side	NA Gas† (TCF) %	NA Gas† (TCF) Risked Mean	NA Gas† (TCF) High-Side
17. North Chukchi Shelf	28	.72	12.0	22	.46	6.5	15	1.30	22.0	15	.03	.6	22	.45	7.6	15	.85	14.5
18. North Chukchi Slope	5	.05	1.8	4	.04	1.2	2	.07	2.4	2	0.00	.1	4	.02	.7	2	.05	1.7
19. Central Chukchi	39	1.47	15.7	34	.88	8.7	26	2.88	34.0	26	.07	.9	34	.96	11.1	26	1.92	22.0
20. Hope	32	.30	4.4	21	.10	1.6	31	.98	12.3	31	.02	.3	21	.22	2.7	29	.76	9.5
Areas 1-20 Summation	100	24.14	74.0	100	14.44	45.0	100	47.06	145.0	100	1.25	4.0	100	17.02	61.0	100	30.04	88.0

*A&D Gas—Associated and dissolved gas.
†NA Gas—Non-associated gas.

% = Chance >.05 BBOE (Billion barrel oil equivalent, gas conversion 5.6 TCF/BB). Risked highsides are at 1 percent probability. Oil chance applies to A&D gas; total gas chance applies to NGL.

TABLE C-4

SUMMARY OF POSTULATED NUMBERS AND SIZES OF MAJOR FIELDS

Area or Basin	Corrected Unrisked Average Number Fields*	Mean Field Size (BB)†	Stated Large Field Size (BB)§	Corrected Large Field Size (BB)¶
1. Norton	10.9	.16	.86	.86
2. St. Matthew-Hall	1.0	.22**	3.64 × .34 =	1.24
3. Navarin Shelf	15.0	.58	2.22 × .93 =	2.06
4. Navarin Slope	4.1	.16	.88 × .75 =	.66
5. Zhemchug Shelf	3.3	.17	1.40 × .83 =	1.16
6. Zhemchug Slope	2.7	.05	.47 × .34 =	.16
7. St. George	13.4	.31	1.31 × .93 =	1.22
8. Bristol	12.3	.20	1.00	1.00
9. Umnak Plateau	3.1	.06	.41 × .35 =	.14
10. Aleutian Shelf	2.7	.06	.57 × .35 =	.20
11. Aleutian Slope	2.4	.12	1.12 × .32 =	.36
12. ANWR	6.3	.74	3.47	3.47
13. NPRA	16.9	.31	1.40	1.40
14. North Slope Onshore (Other)	13.0	.38	1.81	1.81
15. Beaufort Shelf	12.0	1.03	6.97	6.97
16. Beaufort Slope	12.7	.31	1.97 × .92 =	1.81
17. North Chukchi Shelf	10.1	.38	1.91	1.91
18. North Chukchi Slope	4.5	.37	1.78	1.78
19. Central Chukchi	8.8	.54	2.65	2.65
20. Hope	5.2	.18	1.07 × .80 =	.86

*Obtained by dividing unrisked mean A_1 (Sheet 2) by rounded unrisked field size A_2. The number of fields calculated as A_{23} (Sheet 3) is discarded.

†Unrisked major field mean size A_2 from Sheet 2, rounded.

§Average A_{65} from Sheet 4.

¶Correction factor is approximated as the point at which the unrisked major field BBOE curve leaves the vertical 0.05 BBOE line; this correction compensates for the effect of zero assessments.

**Reduced from 0.36, which exceeded the unrisked mean $A_1 = 0.22$.

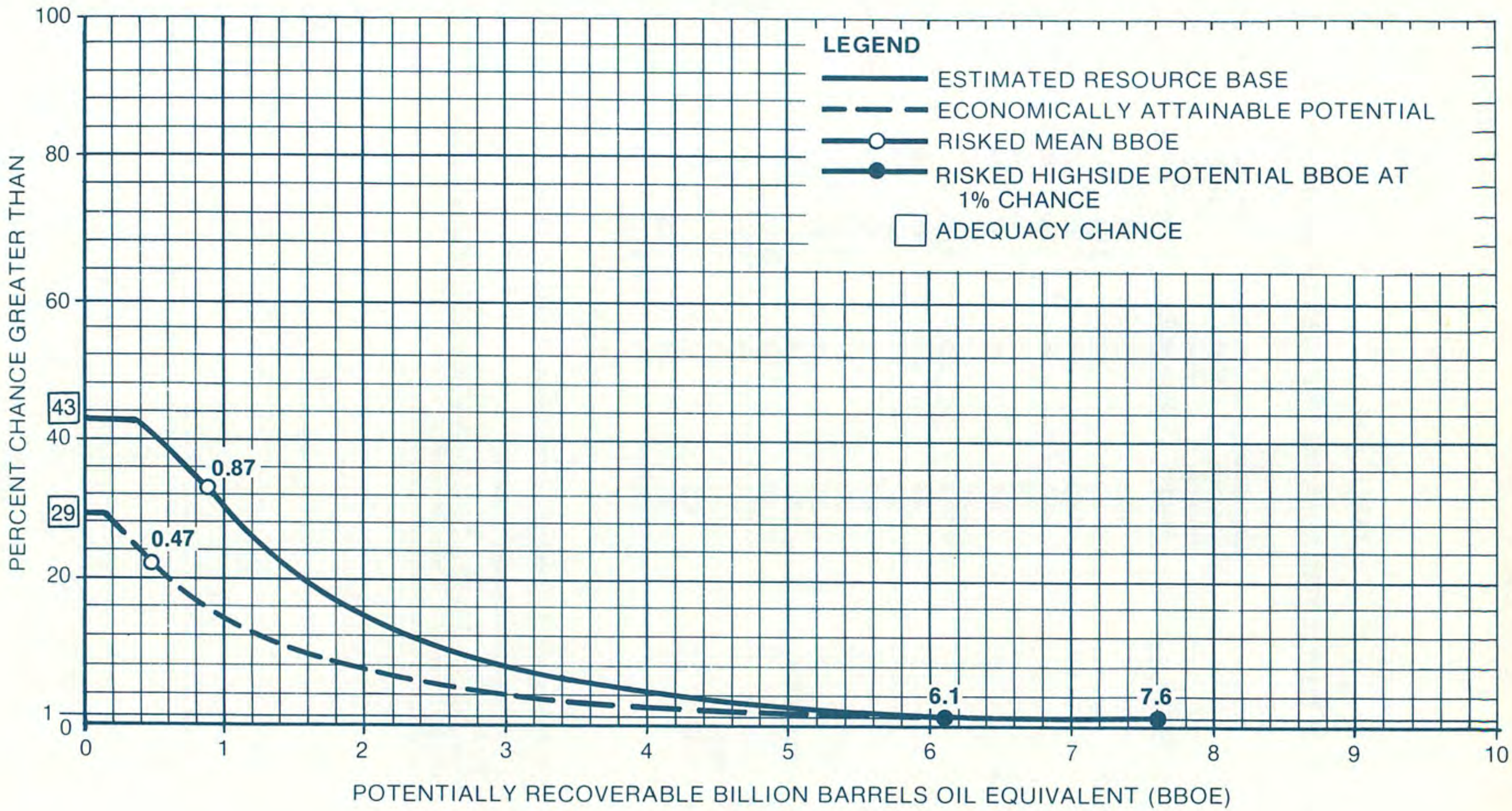


Figure C-1. Oil-Equivalent Risked Potential Recovery, Area 1—Norton.

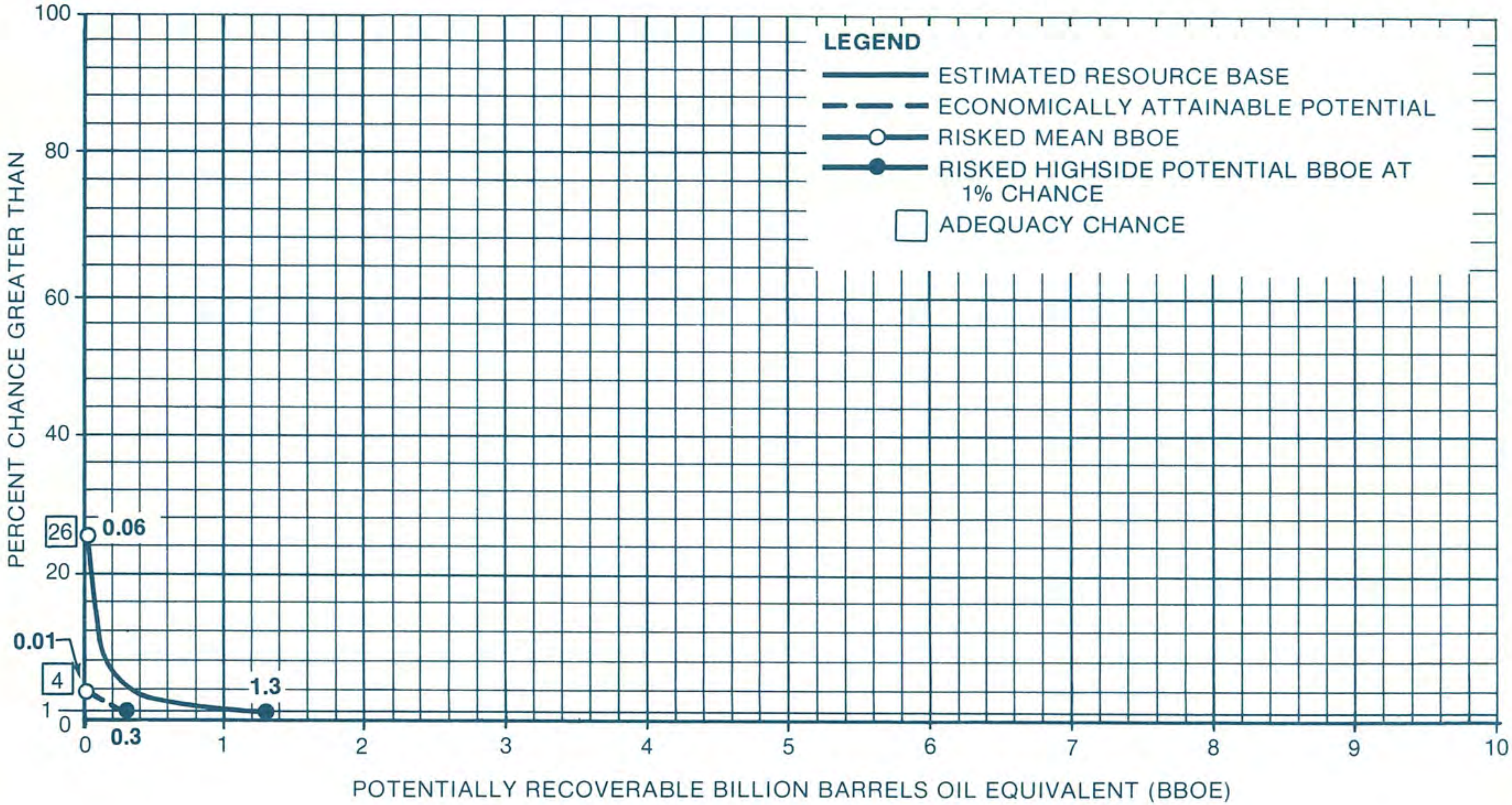


Figure C-2. Oil-Equivalent Risked Potential Recovery, Area 2—St. Matthew-Hall.

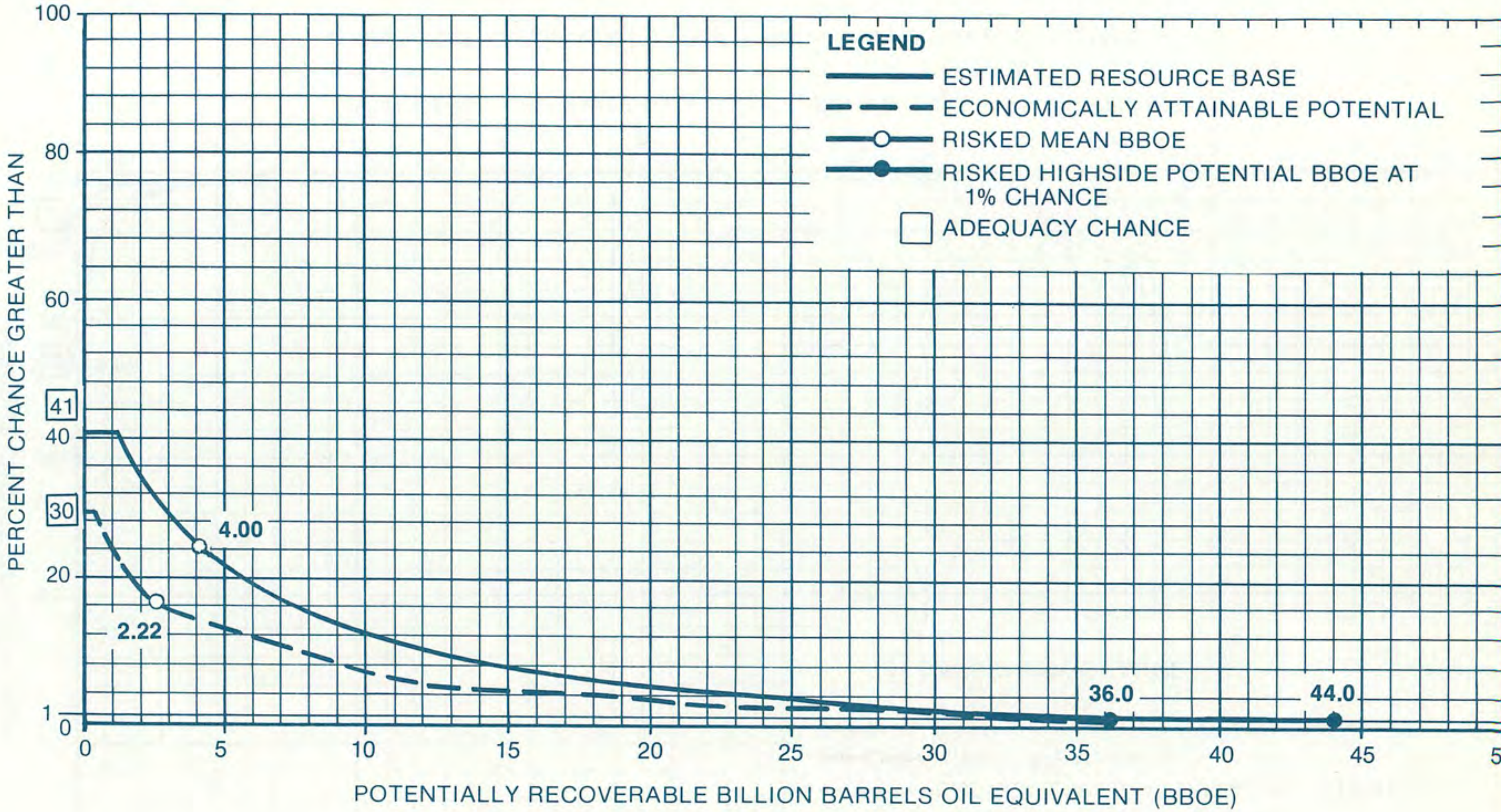


Figure C-3. Oil-Equivalent Risked Potential Recovery, Area 3—Navarin Shelf.

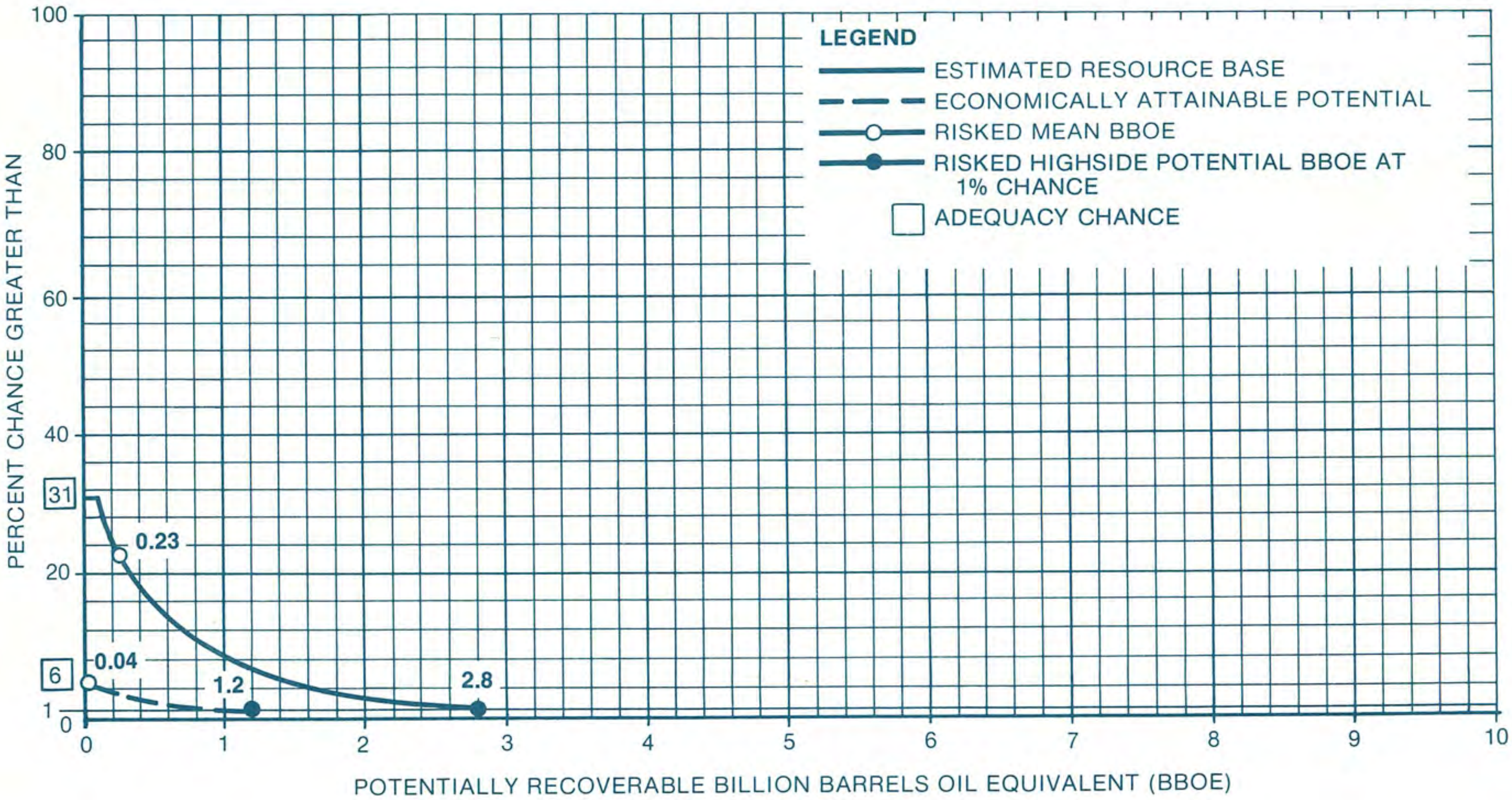


Figure C-4. Oil-Equivalent Risked Potential Recovery, Area 4—Navarin Slope.

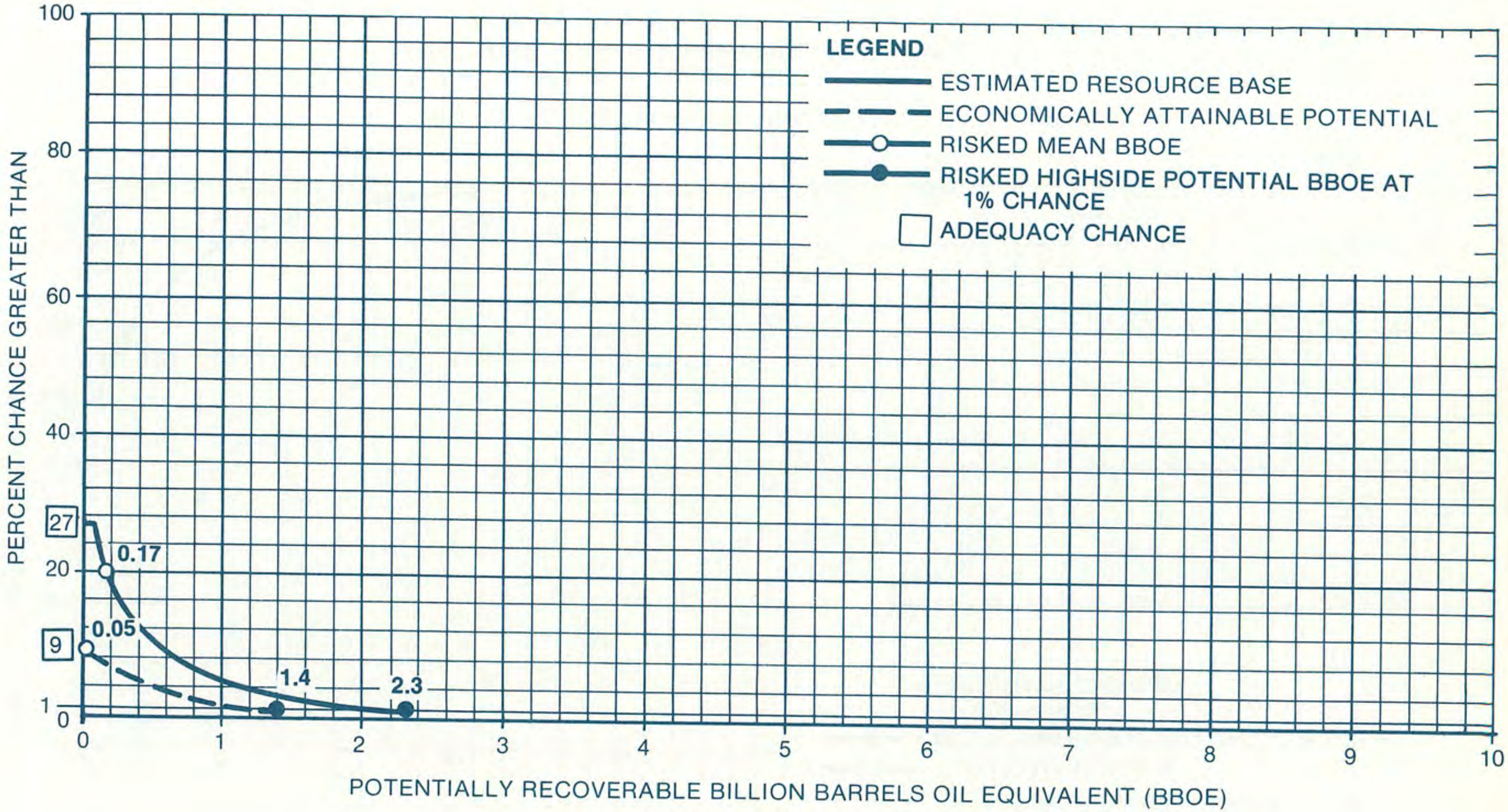


Figure C-5. Oil-Equivalent Risked Potential Recovery, Area 5—Zhemchug Shelf.

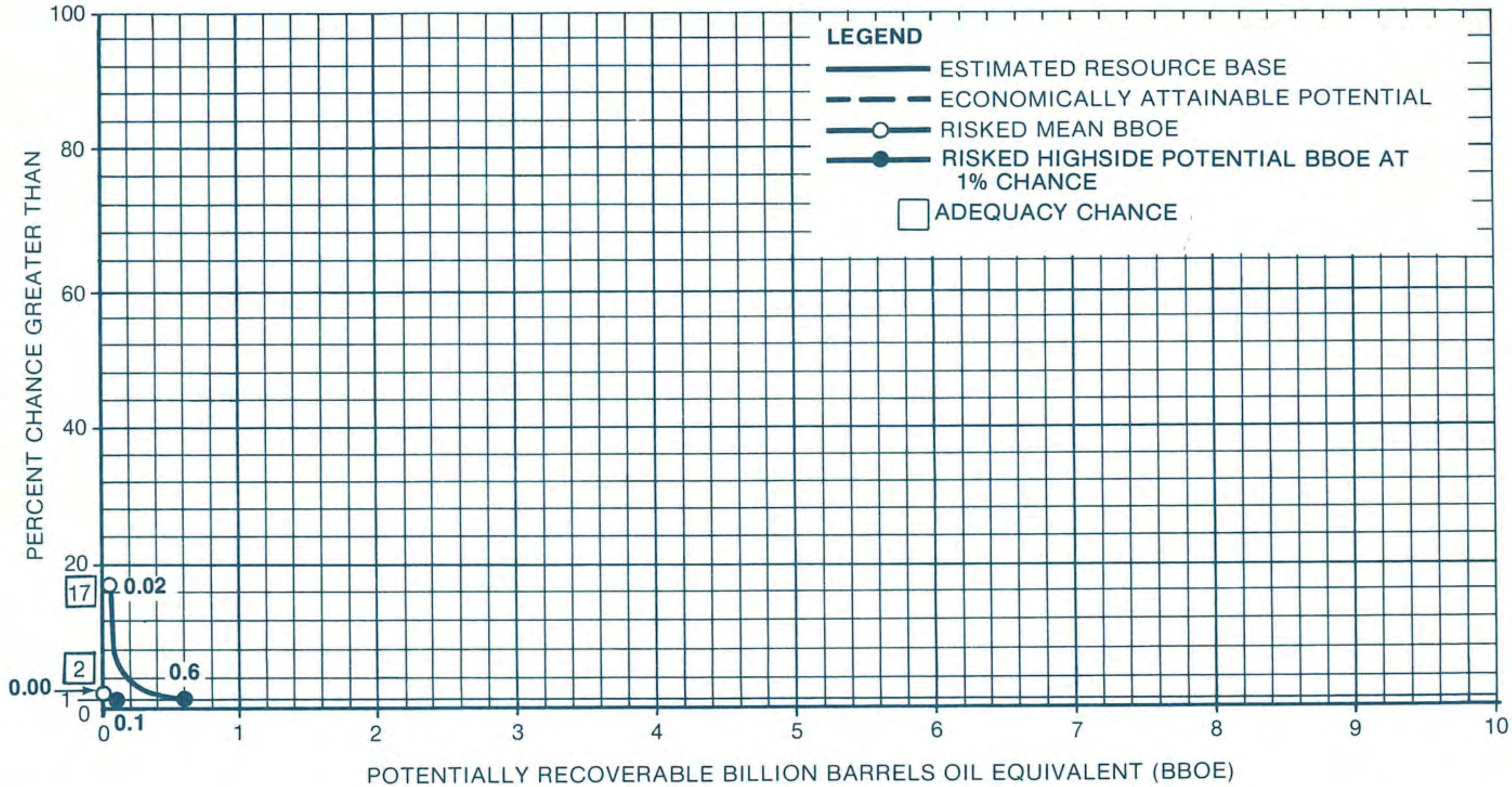


Figure C-6. Oil-Equivalent Risked Potential Recovery, Area 6—Zhemchug Slope.

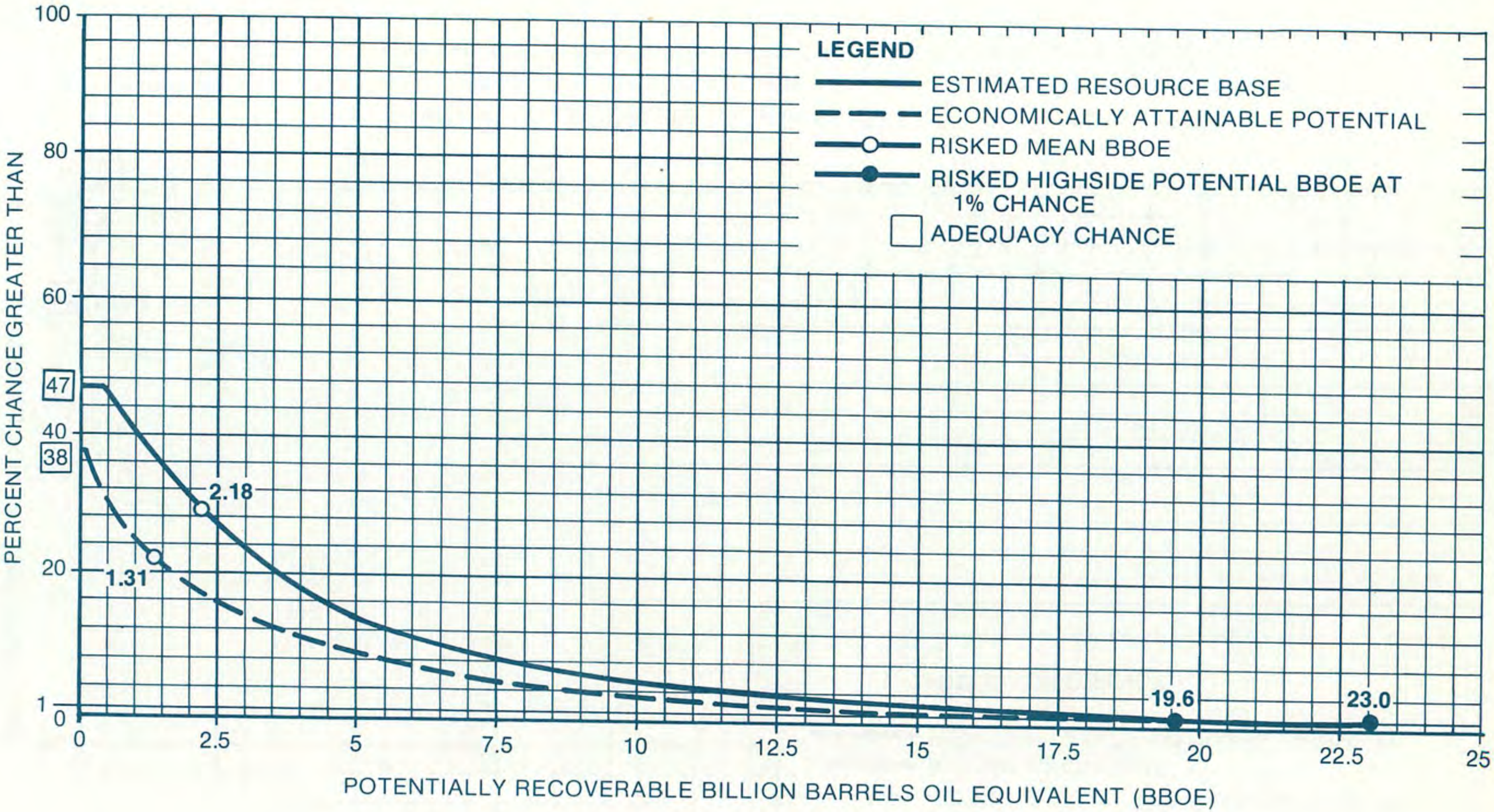


Figure C-7. Oil-Equivalent Risked Potential Recovery, Area 7—St. George.

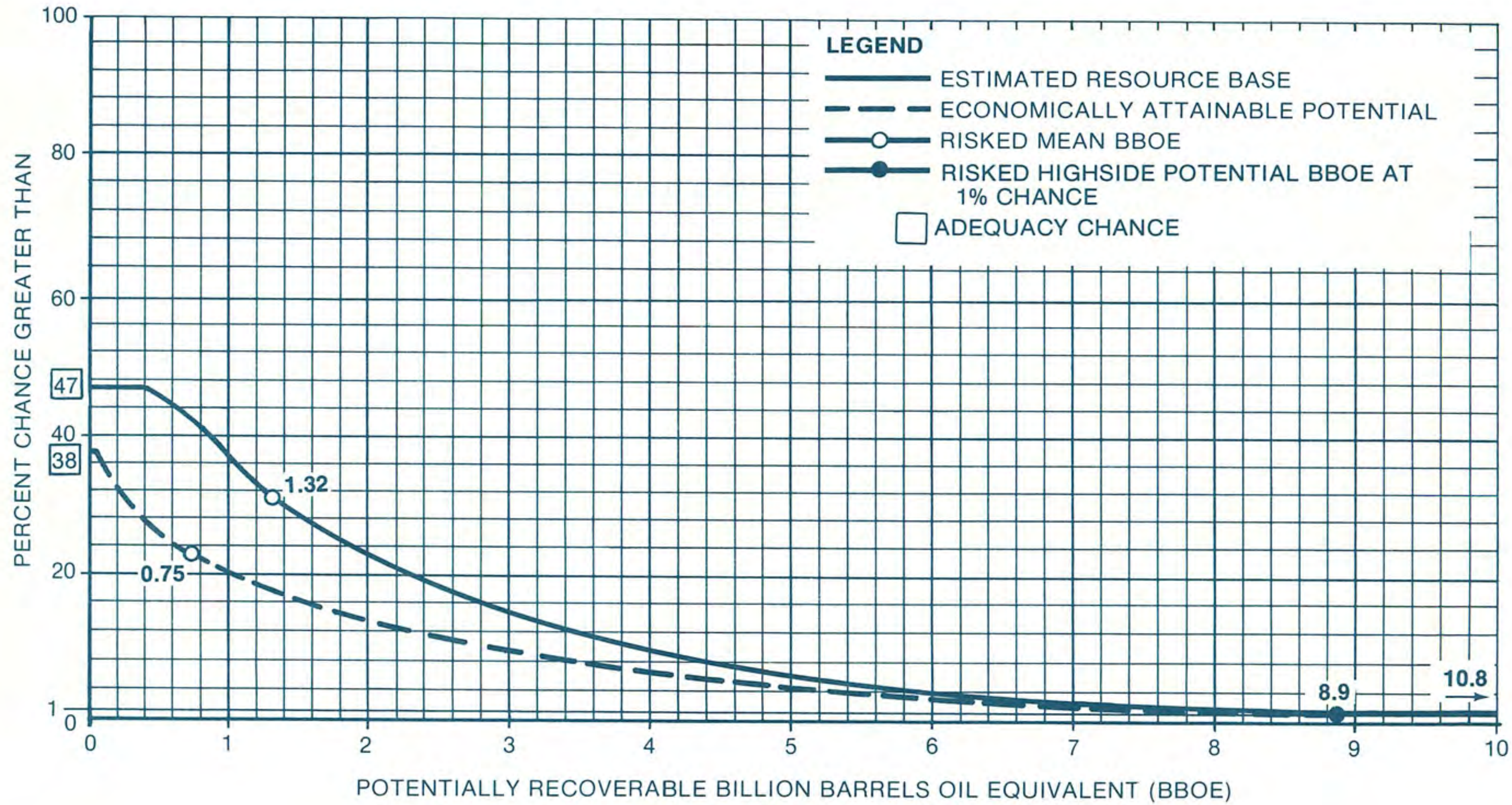


Figure C-8. Oil-Equivalent Risked Potential Recovery, Area 8—Bristol.

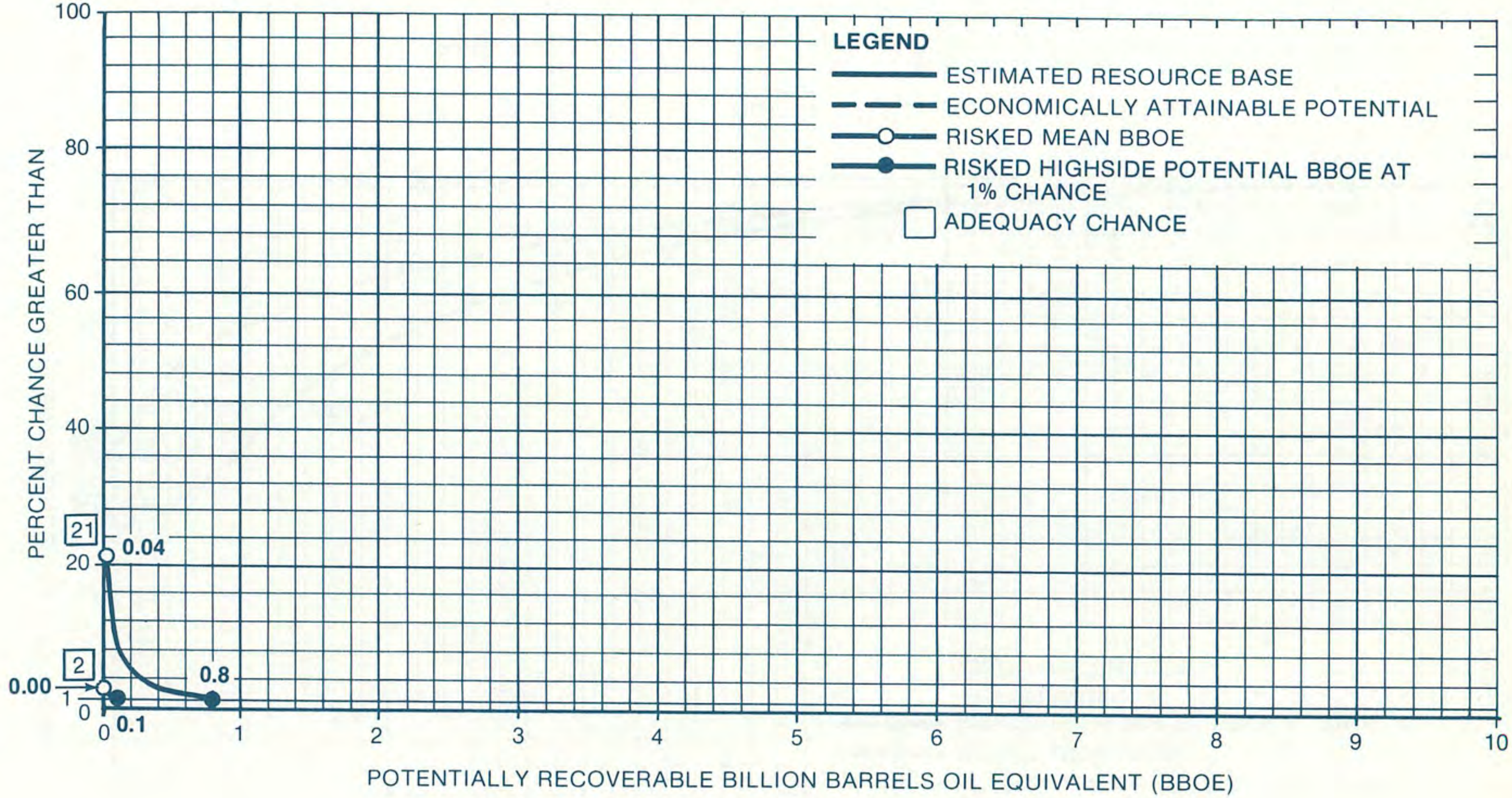


Figure C-9. Oil-Equivalent Risked Potential Recovery, Area 9—Umnak Plateau.

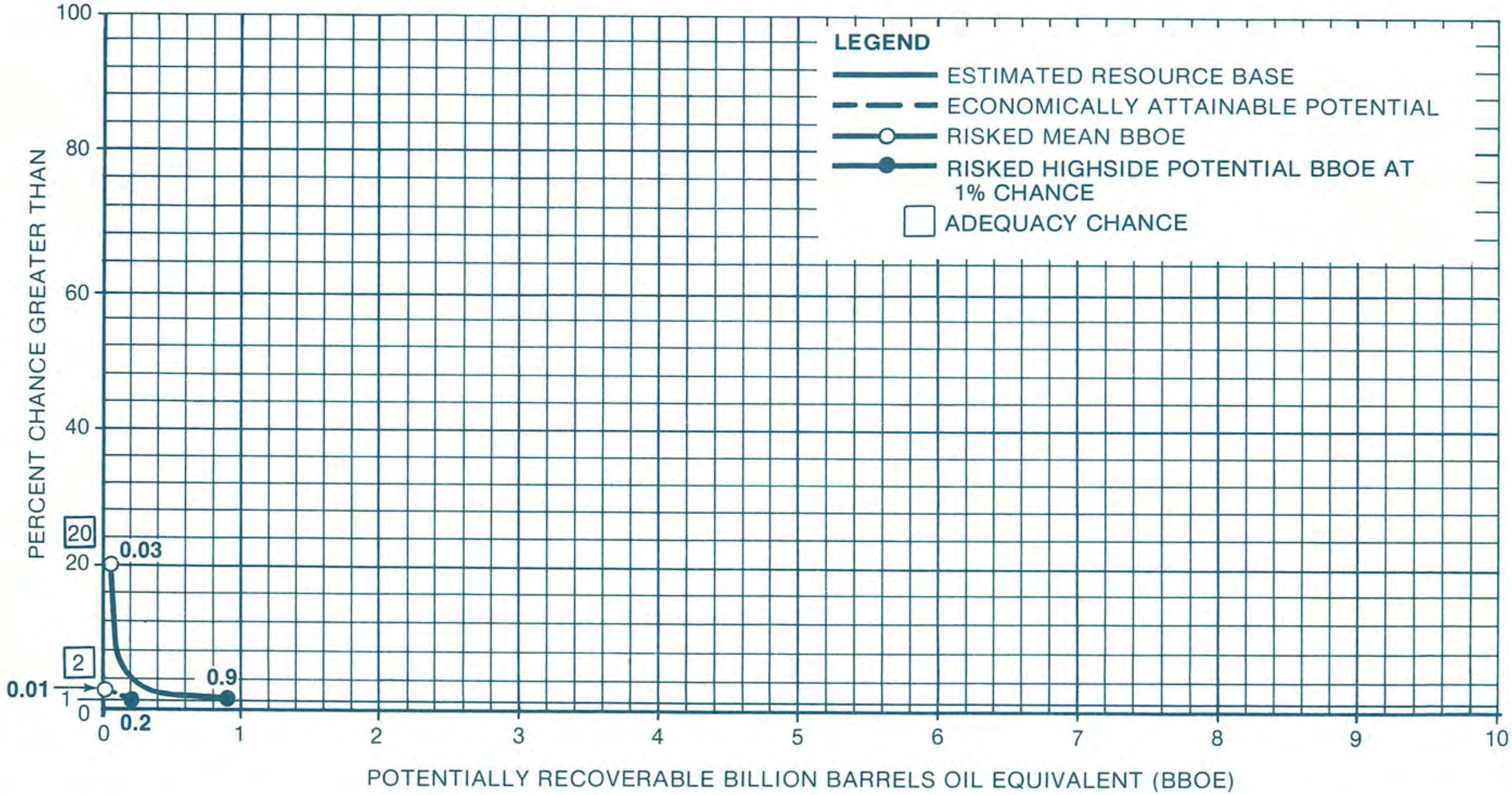


Figure C-10. Oil-Equivalent Risked Potential Recovery, Area 10—Aleutian Shelf.

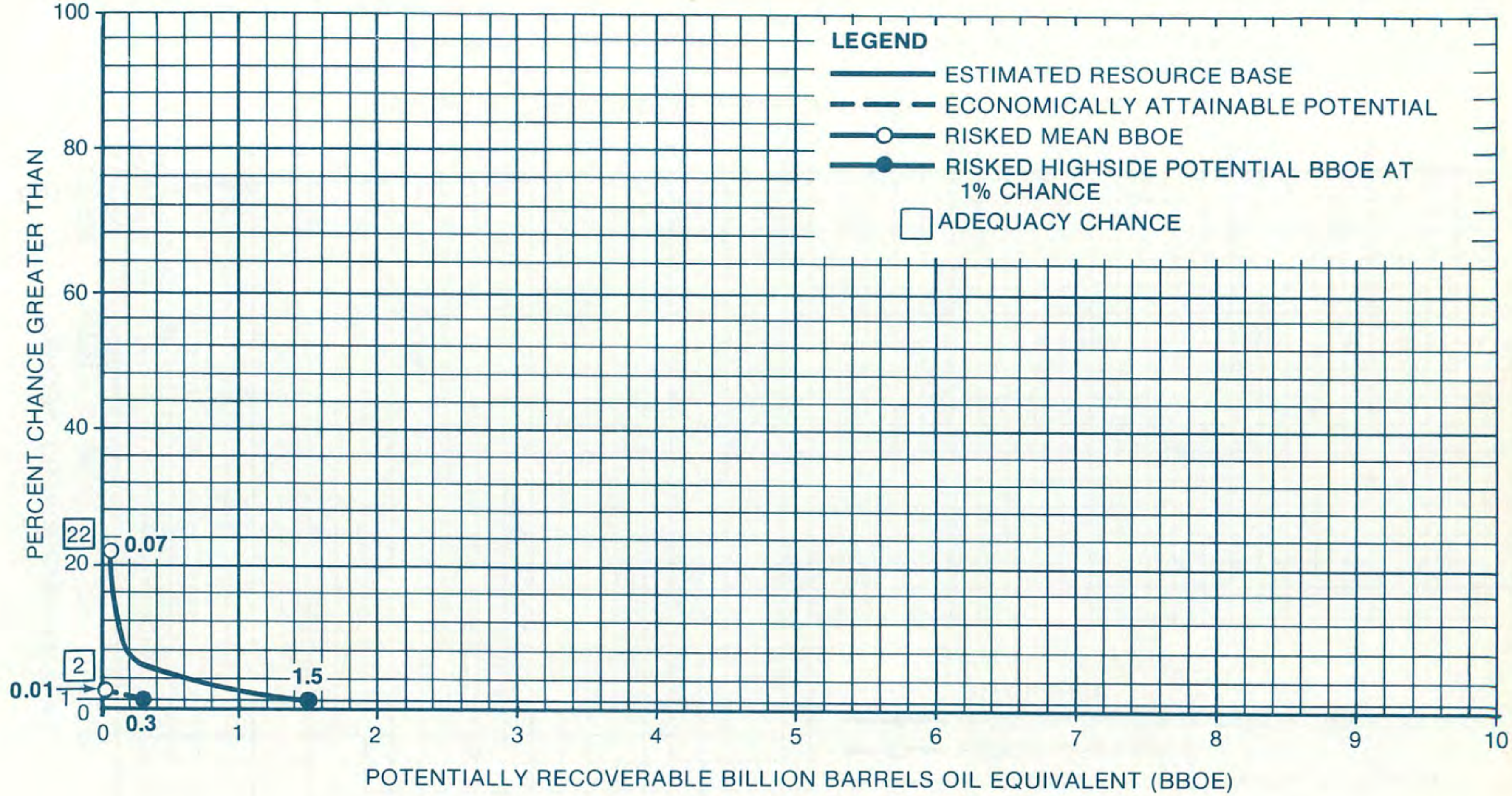


Figure C-11. Oil Equivalent Risked Potential Recovery, Area 11—Aleutian Slope.

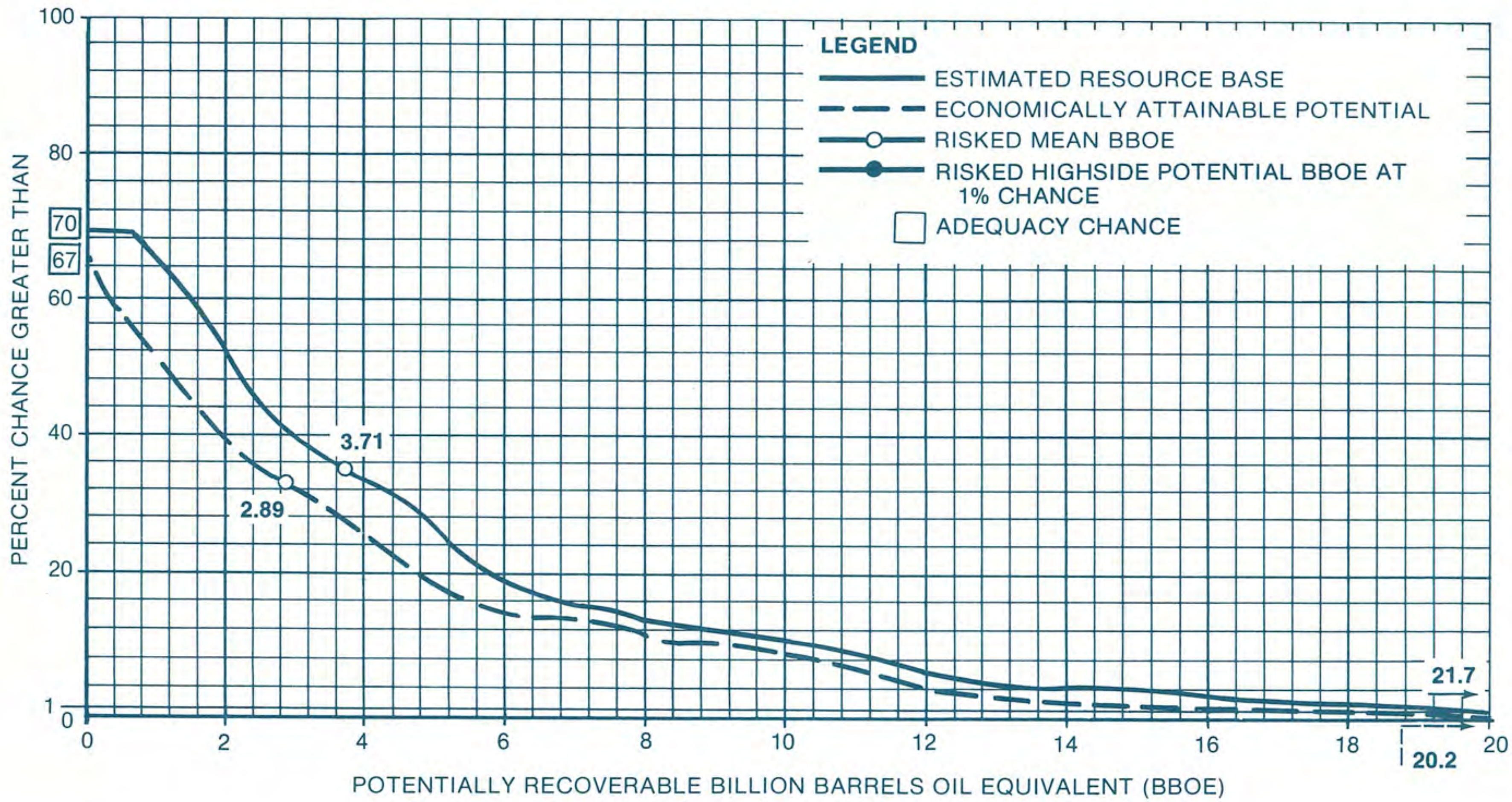


Figure C-12. Oil-Equivalent Risked Potential Recovery, Area 12—ANWR.

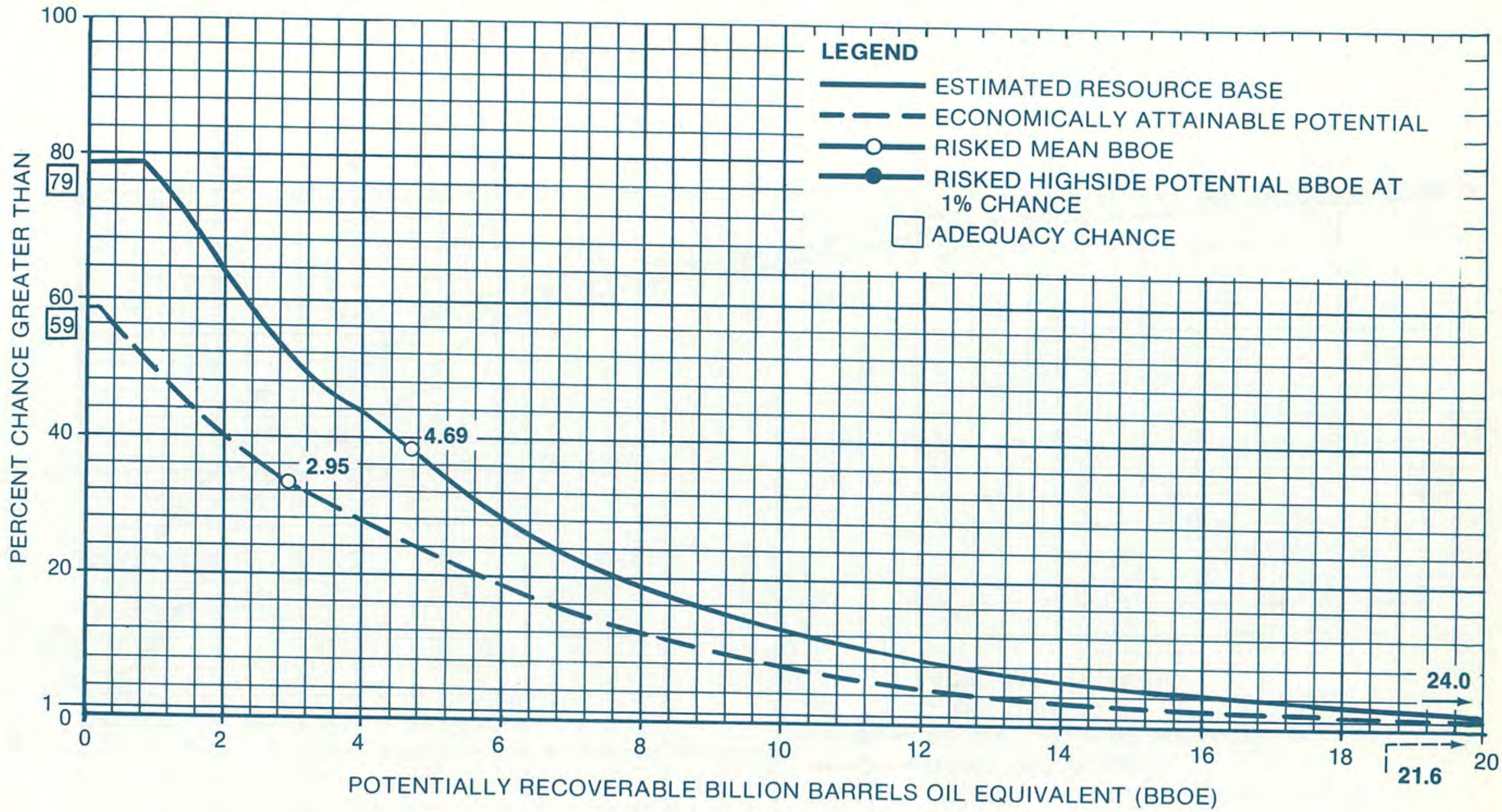


Figure C-13. Oil-Equivalent Risked Potential Recovery, Area 13—NPRA.

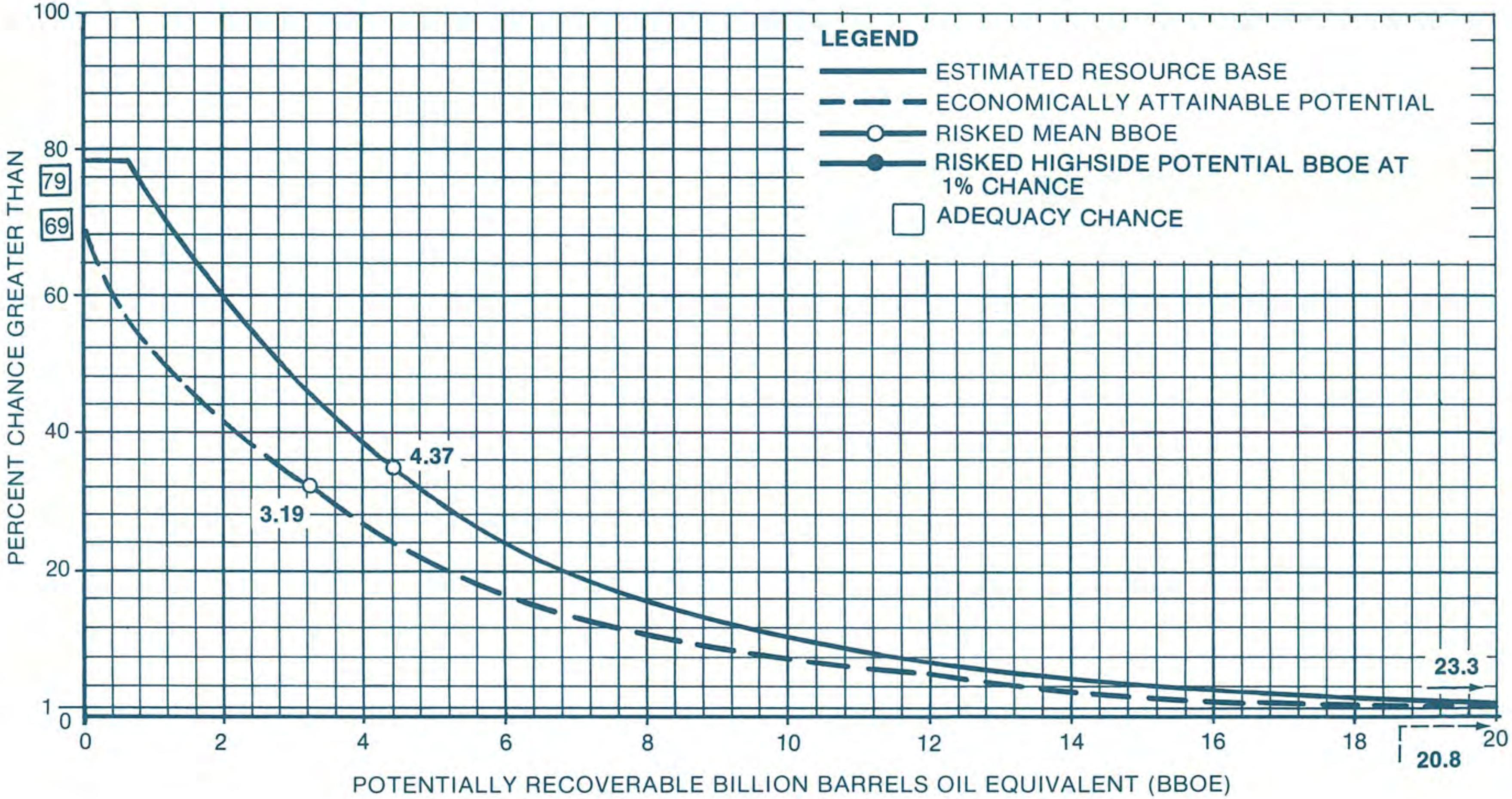


Figure C-14. Oil-Equivalent Risked Potential Recovery, Area 14—North Slope Onshore (Other).

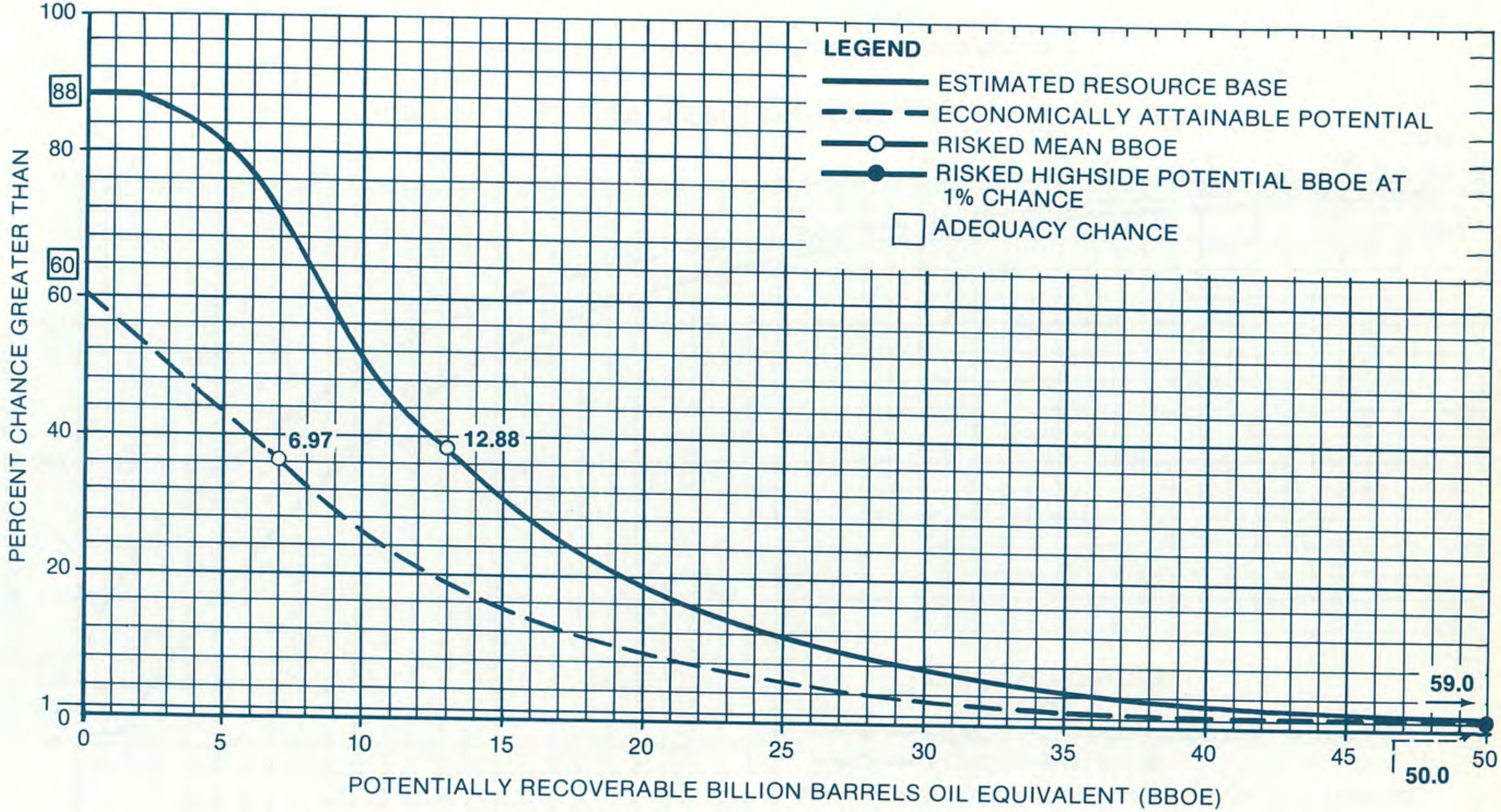


Figure C-15. Oil-Equivalent Risked Potential Recovery, Area 15—Beaufort Shelf.

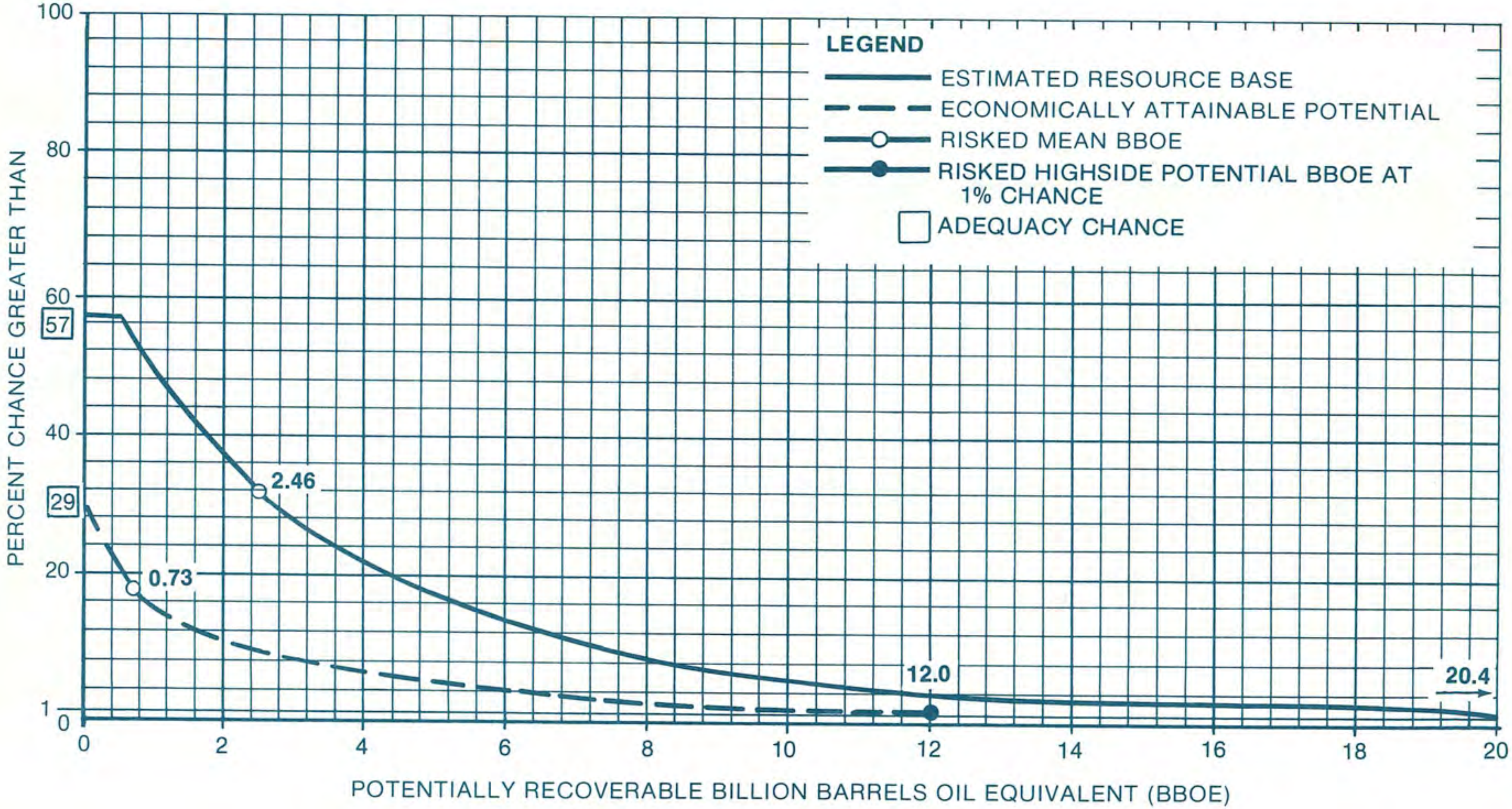


Figure C-16. Oil-Equivalent Risked Potential Recovery, Area 16—Beaufort Slope.

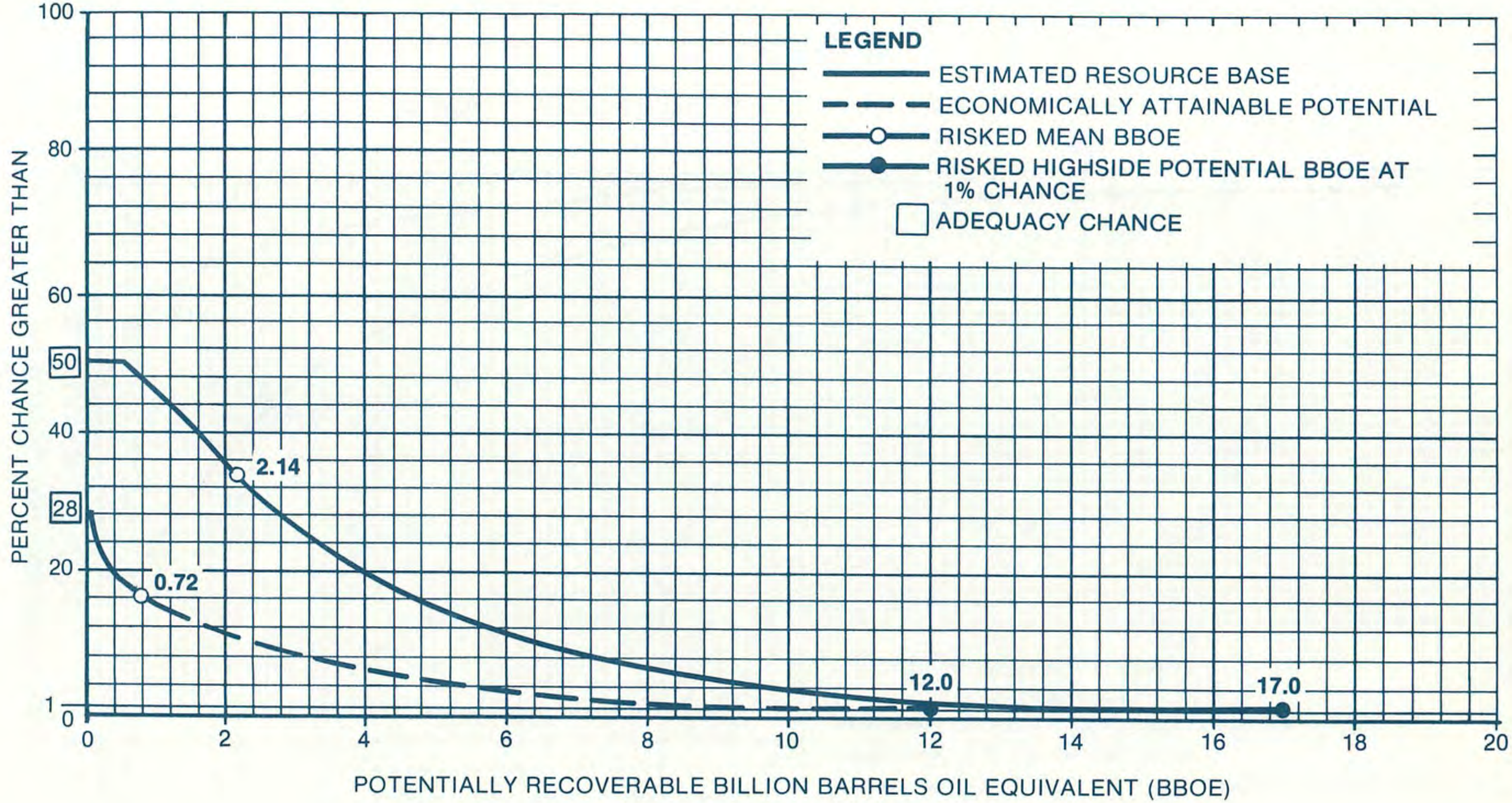


Figure C-17. Oil-Equivalent Risked Potential Recovery, Area 17—North Chukchi Shelf.

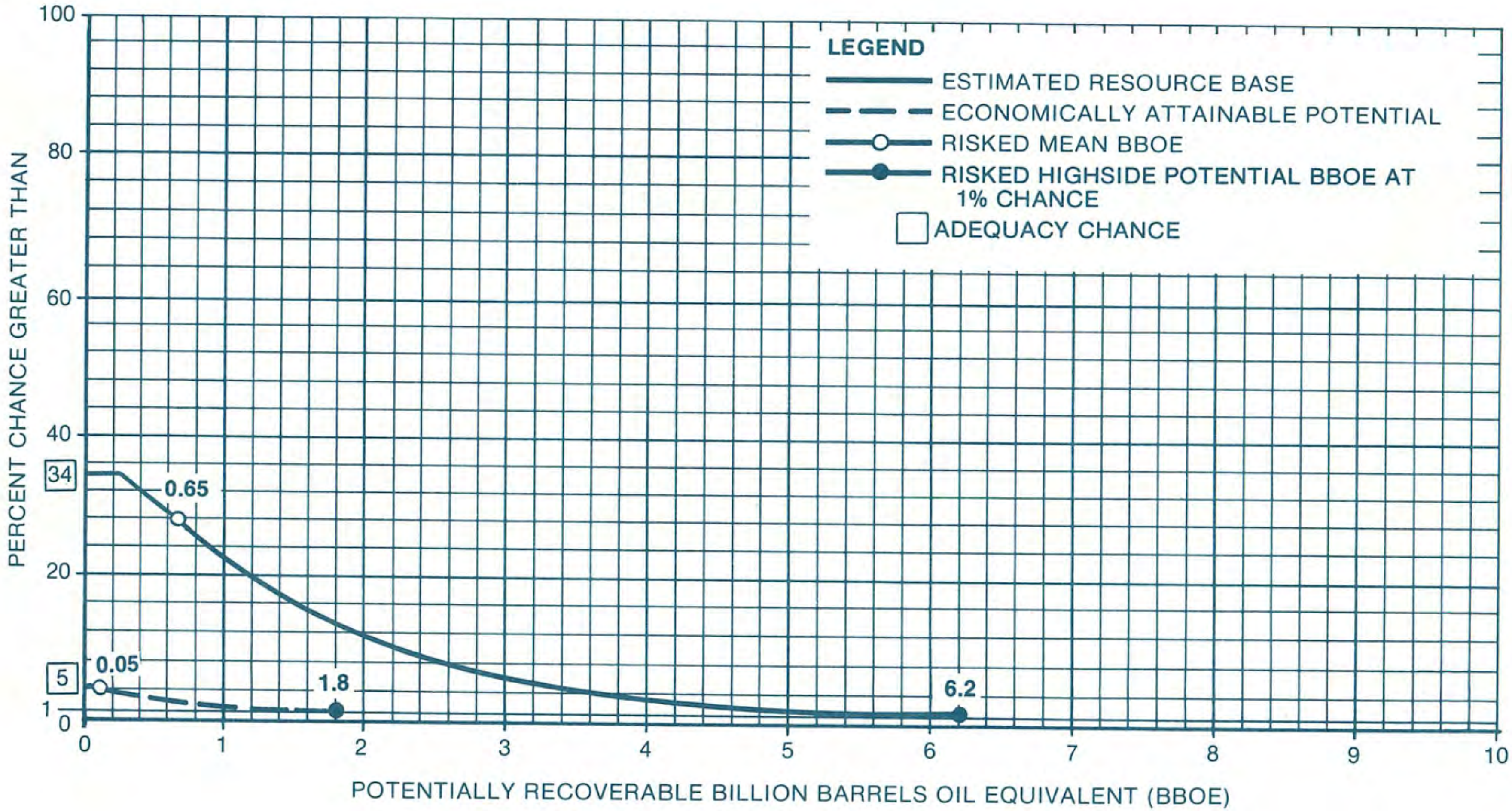


Figure C-18. Oil-Equivalent Risked Potential Recovery, Area 18—North Chukchi Slope.

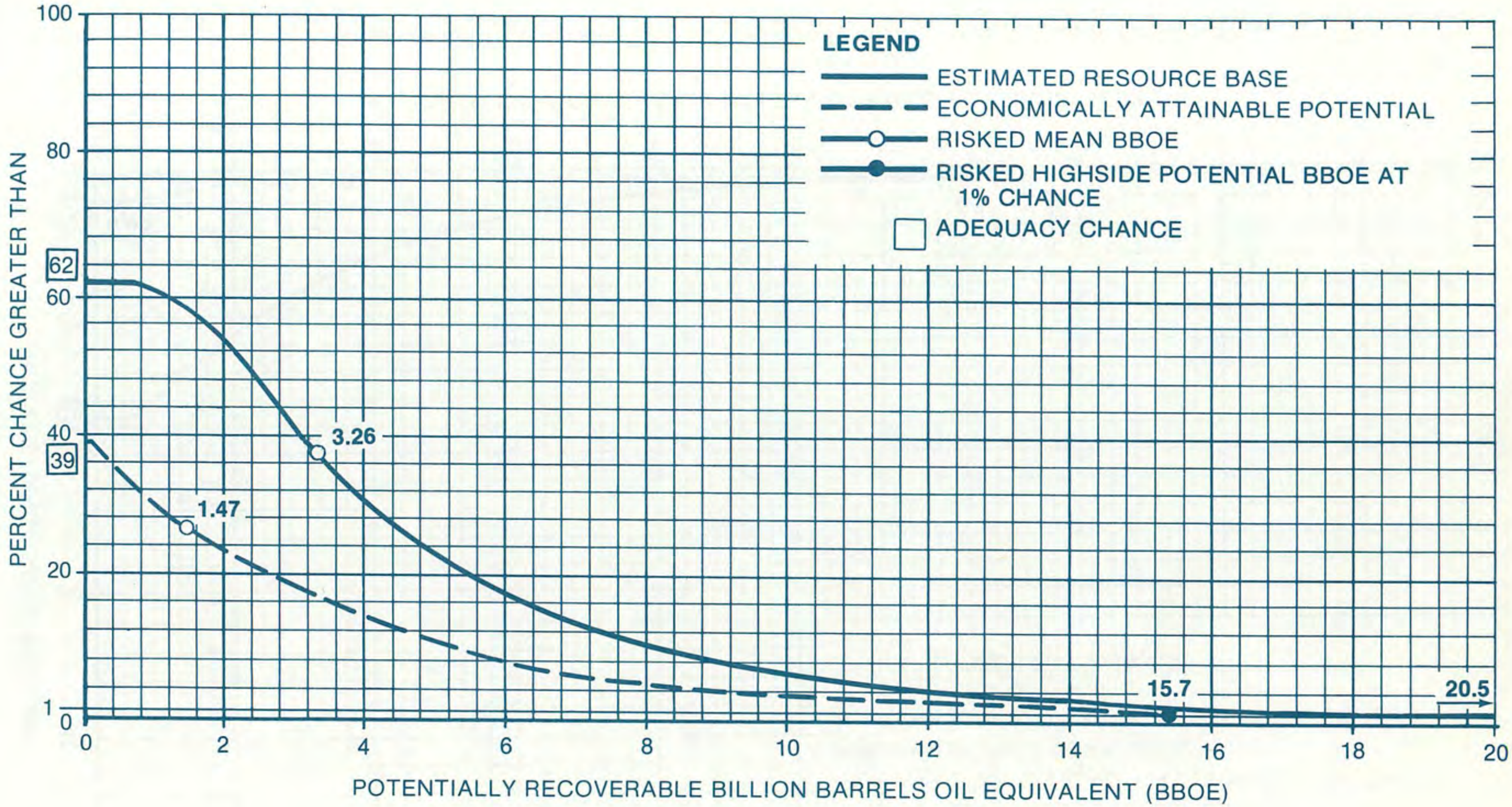


Figure C-19. Oil-Equivalent Risked Potential Recovery, Area 19—Central Chukchi.

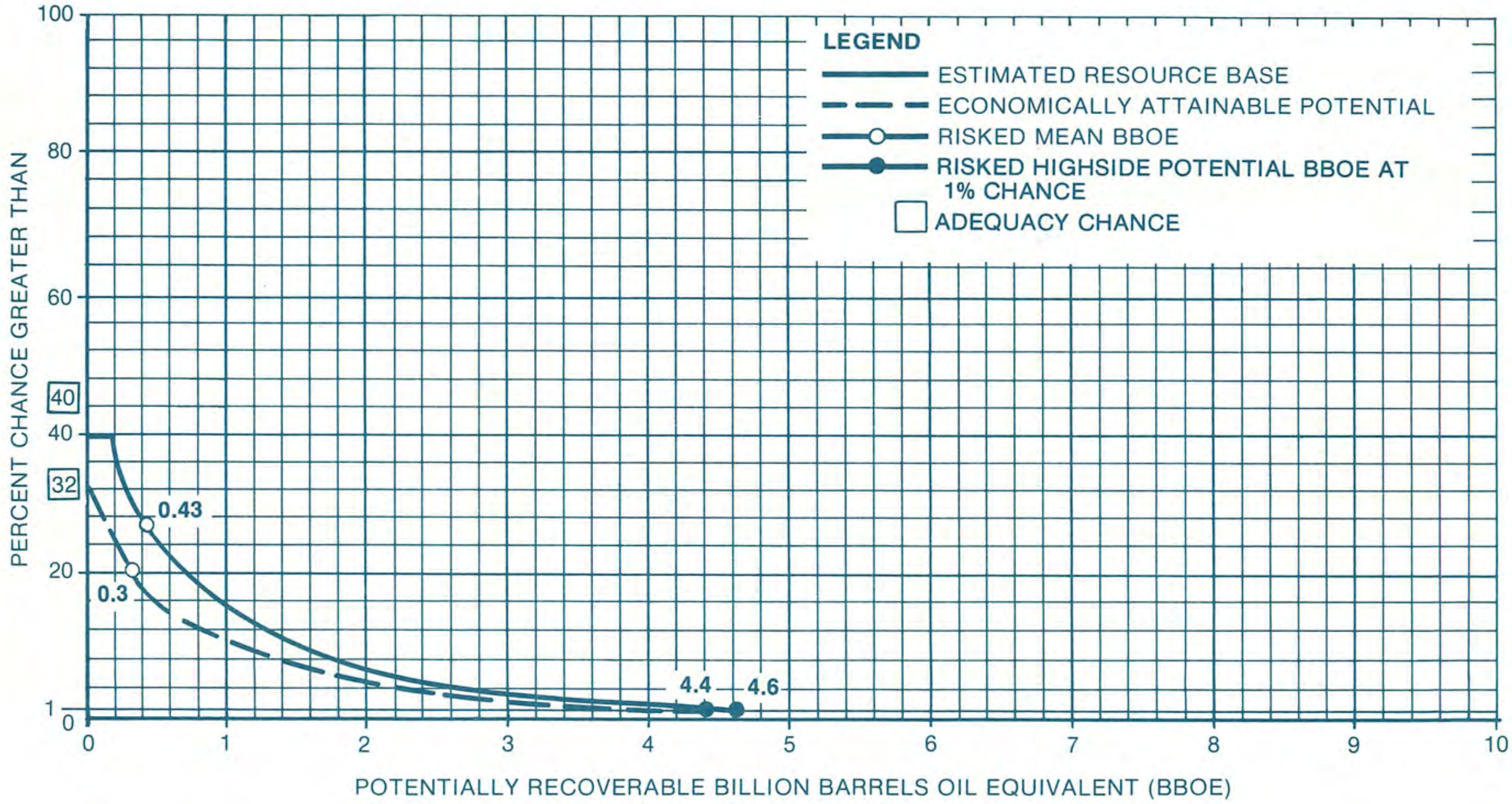


Figure C-20. Oil-Equivalent Risked Potential Recovery, Area 20—Hope.

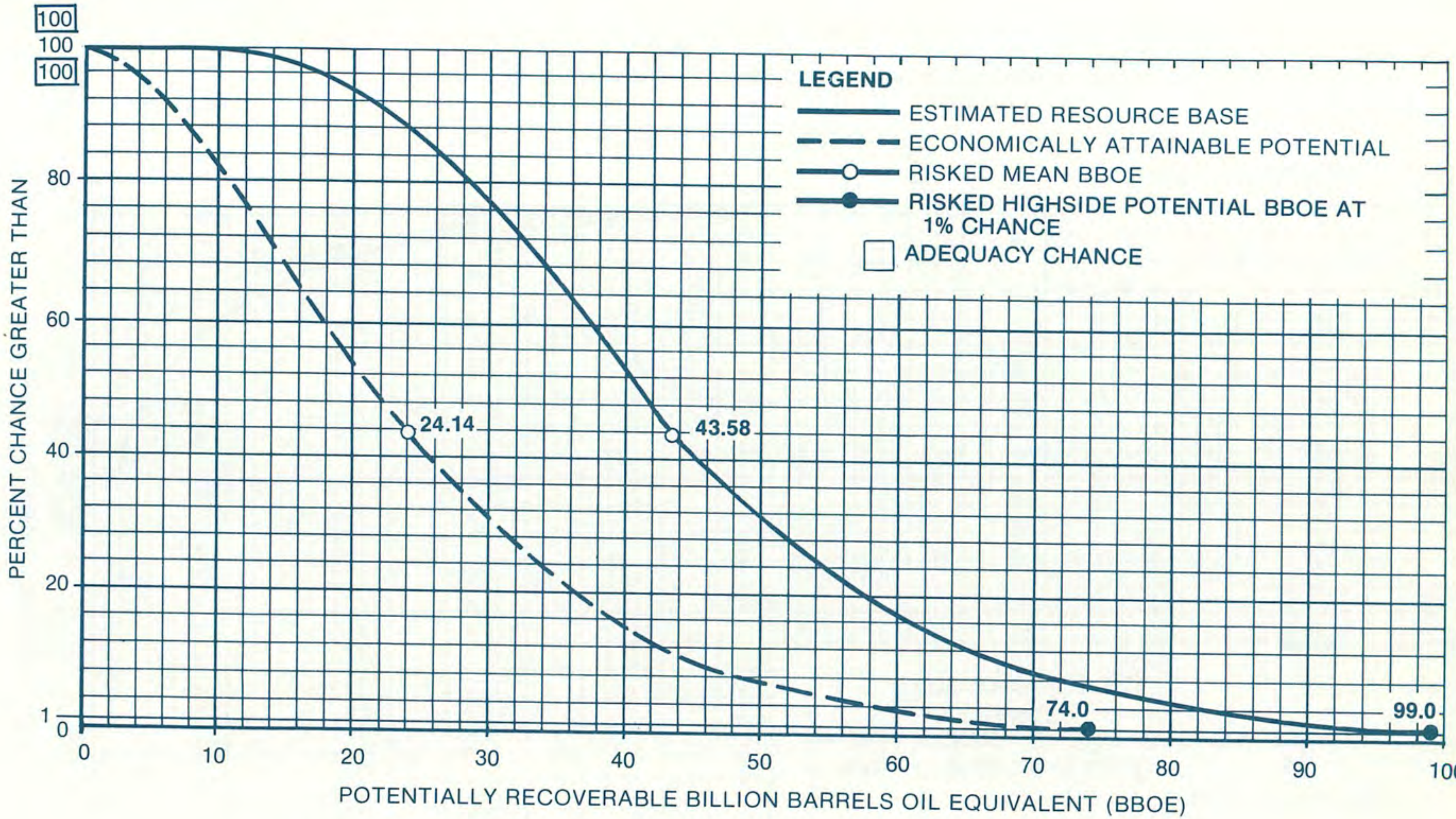


Figure C-21. Oil-Equivalent Risked Potential Recovery, Area 21—Arctic Grand Total.

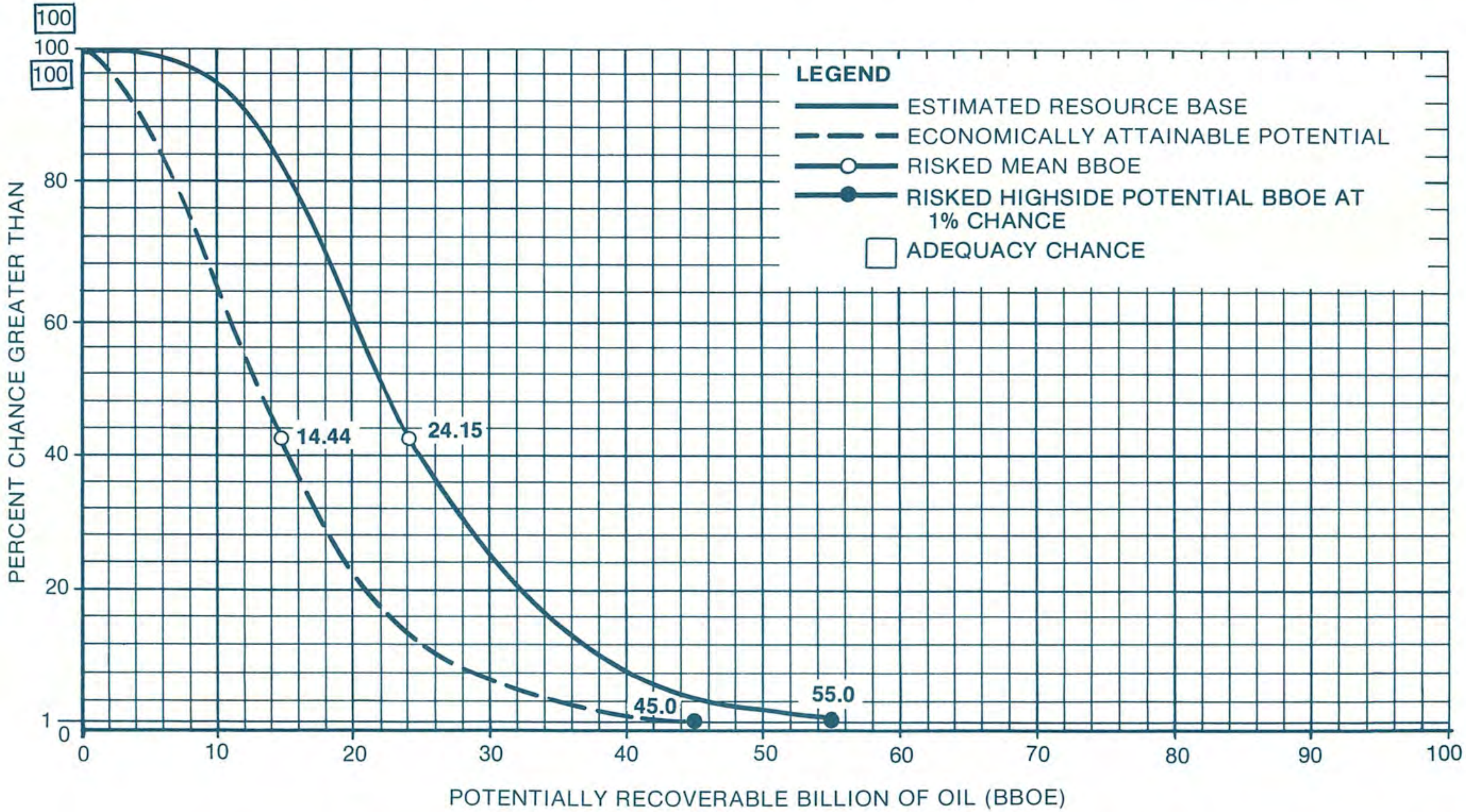


Figure C-22. Oil, Risked Potential Recovery, Area 22—Arctic Grand Total.

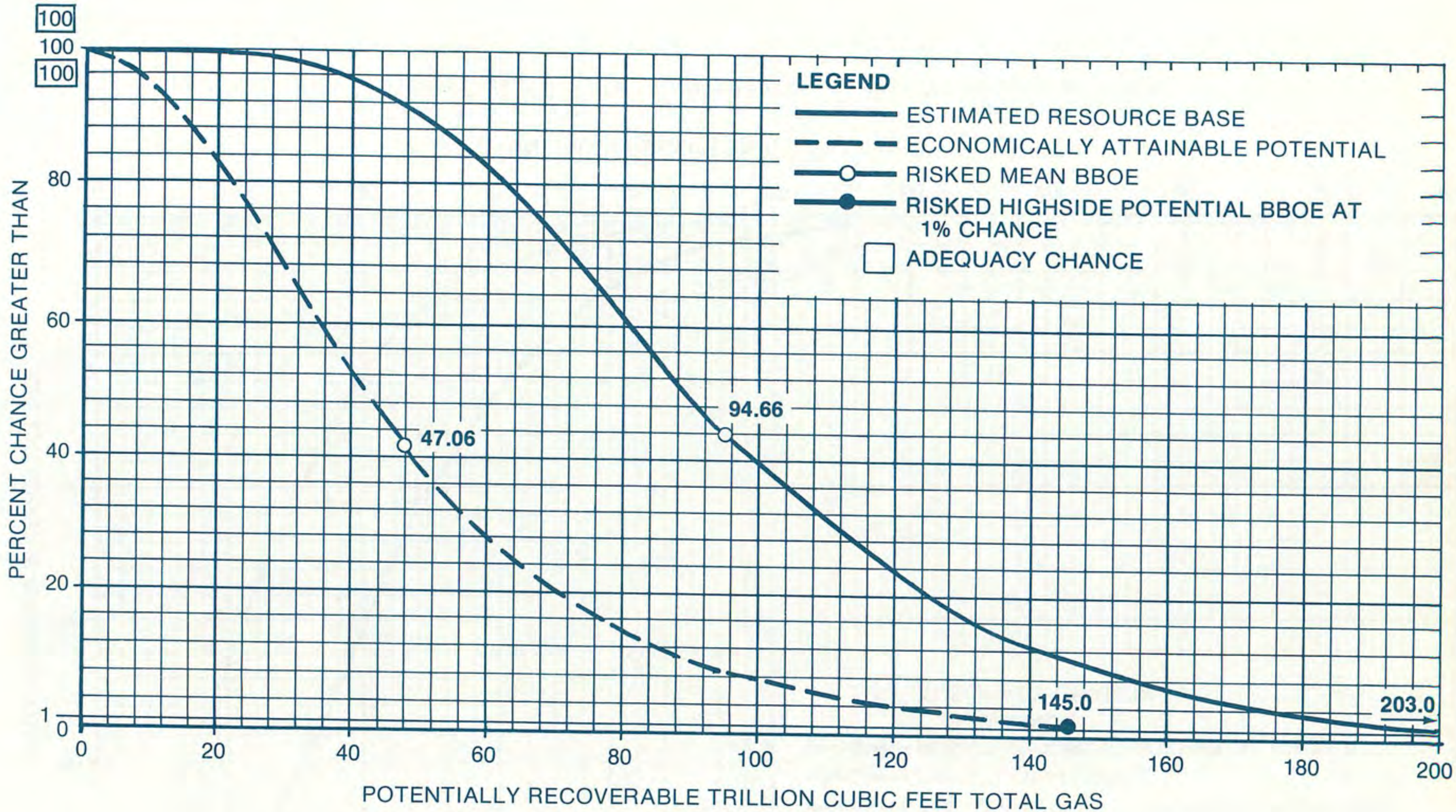


Figure C-23. Total Gas (TCF), Risked Potential Recovery, Area 23—Arctic Grand Total.

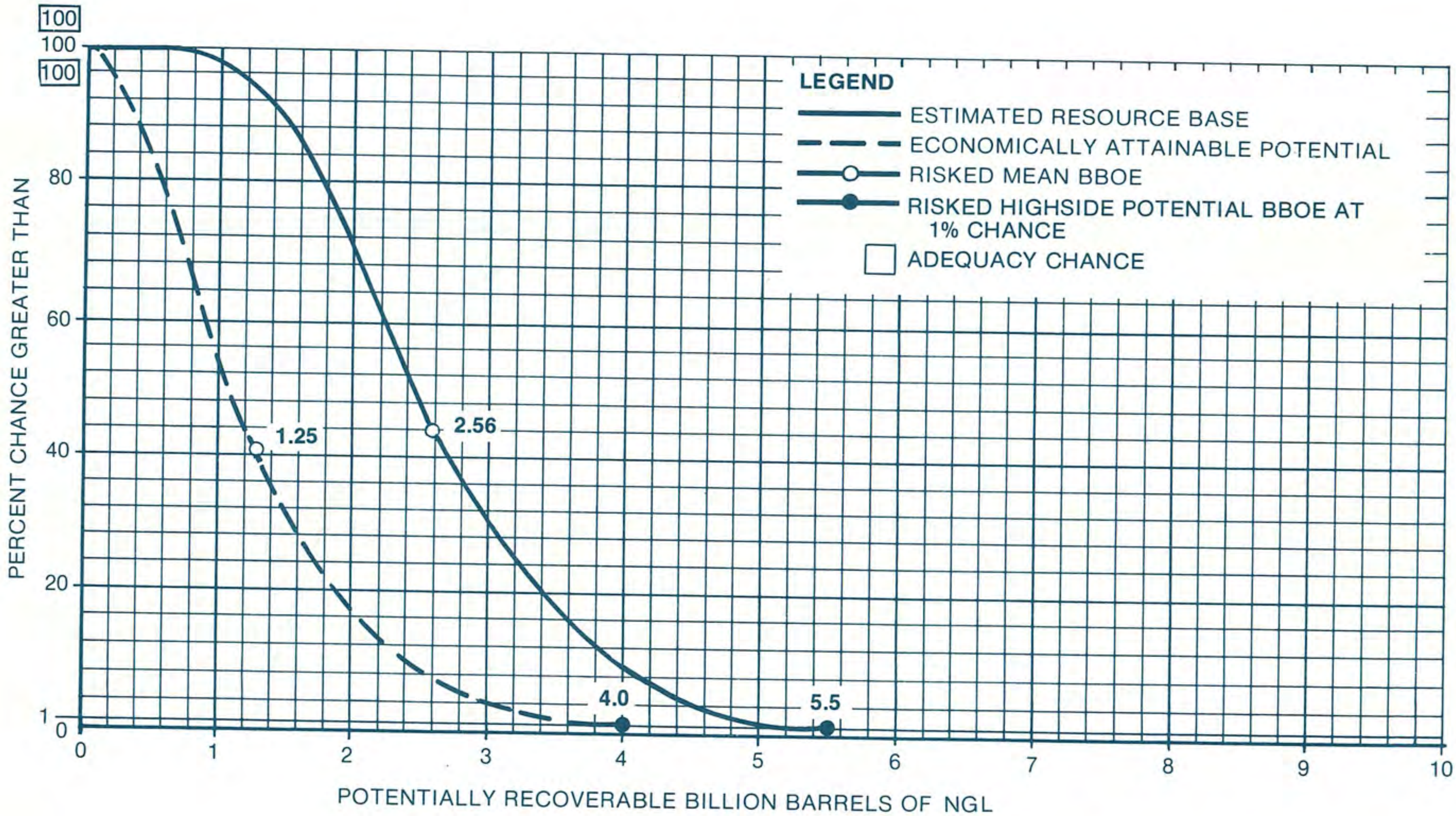


Figure C-24. NGL, Risked Potential Recovery, Area 24—Arctic Grand Total.

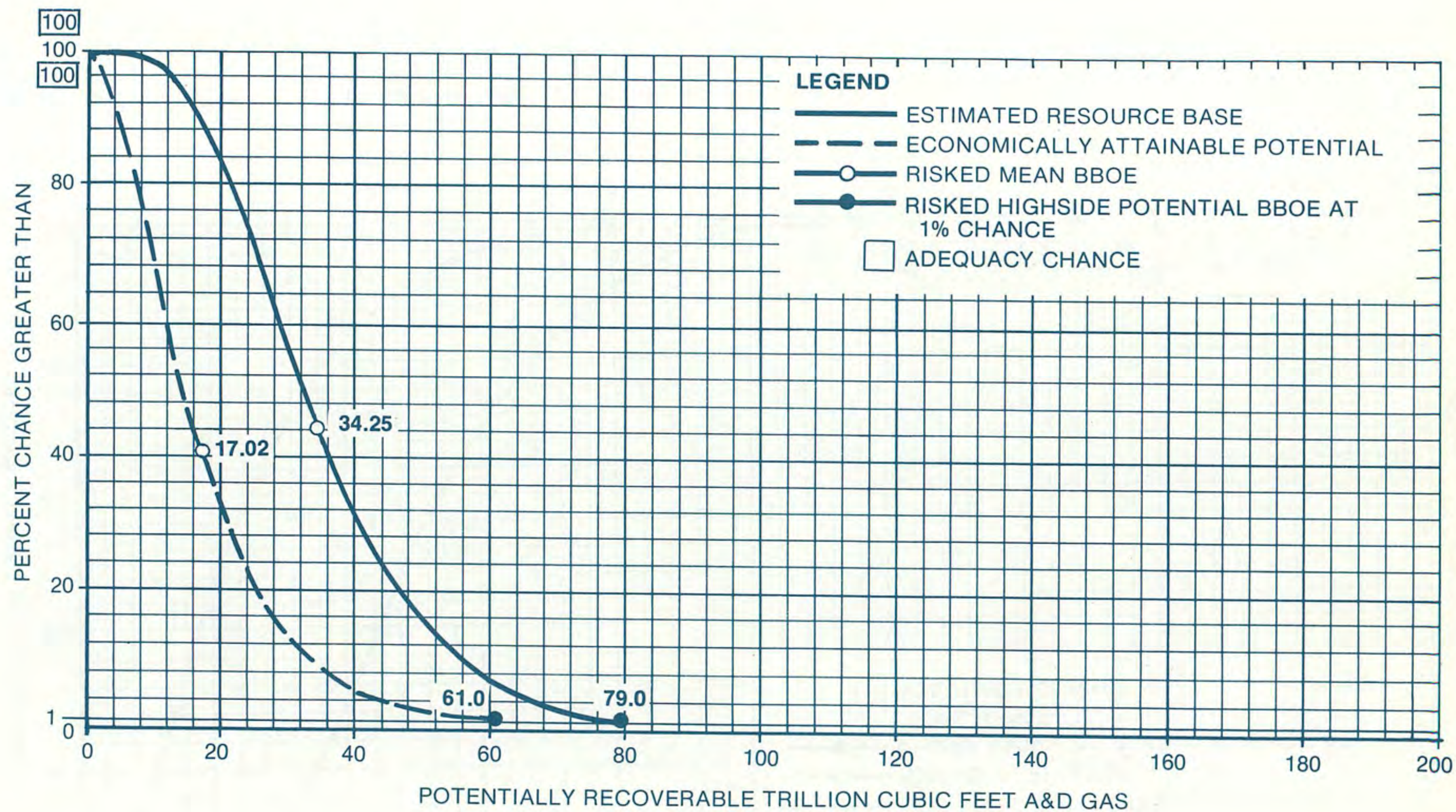


Figure C-25. Associated-Dissolved Gas (TCF), Risked Potential Recovery, Area 25—Arctic Grand Total.

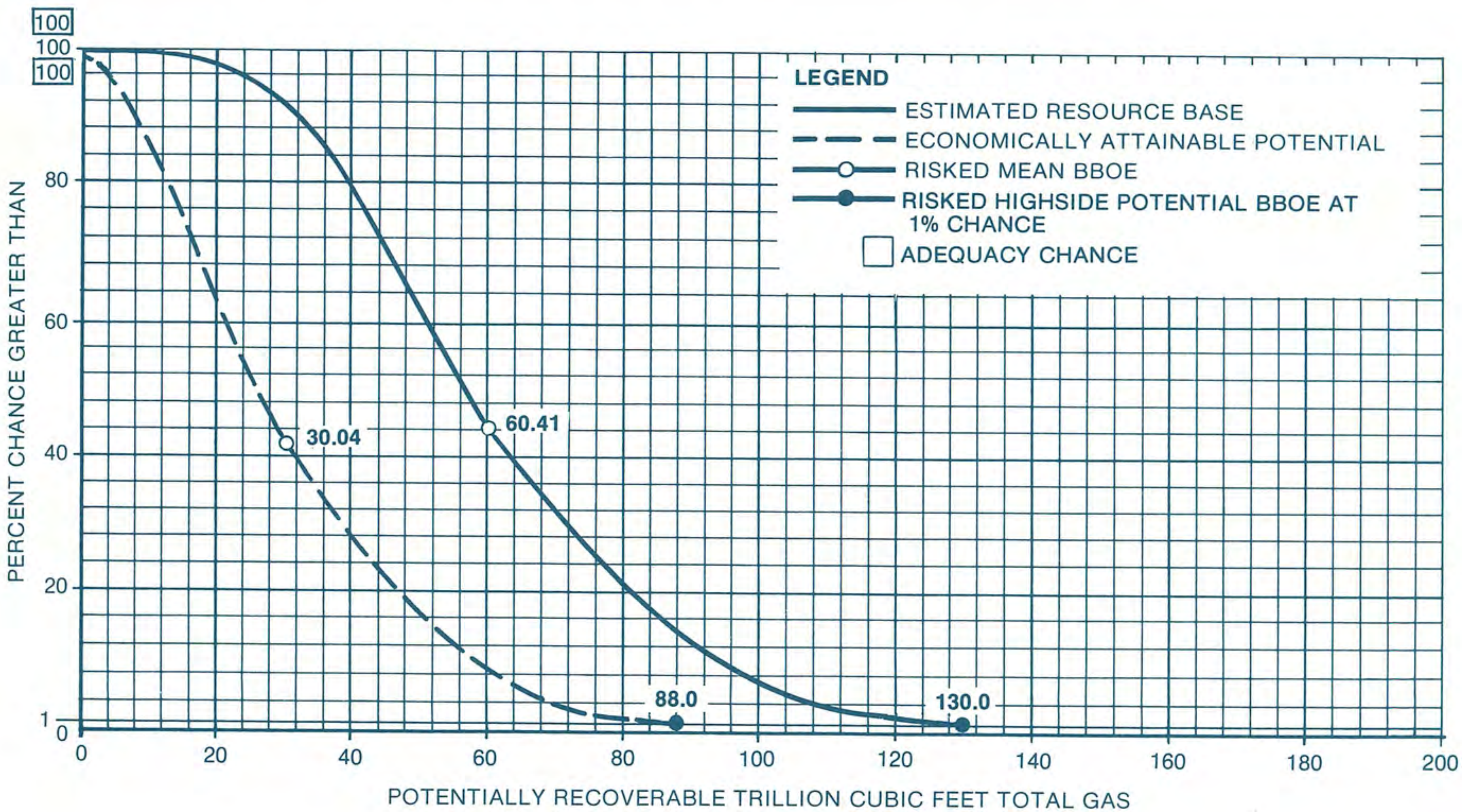


Figure C-26. Non-Associated Gas (TCF), Risked Potential Recovery, Area 26—Arctic Grand Total.

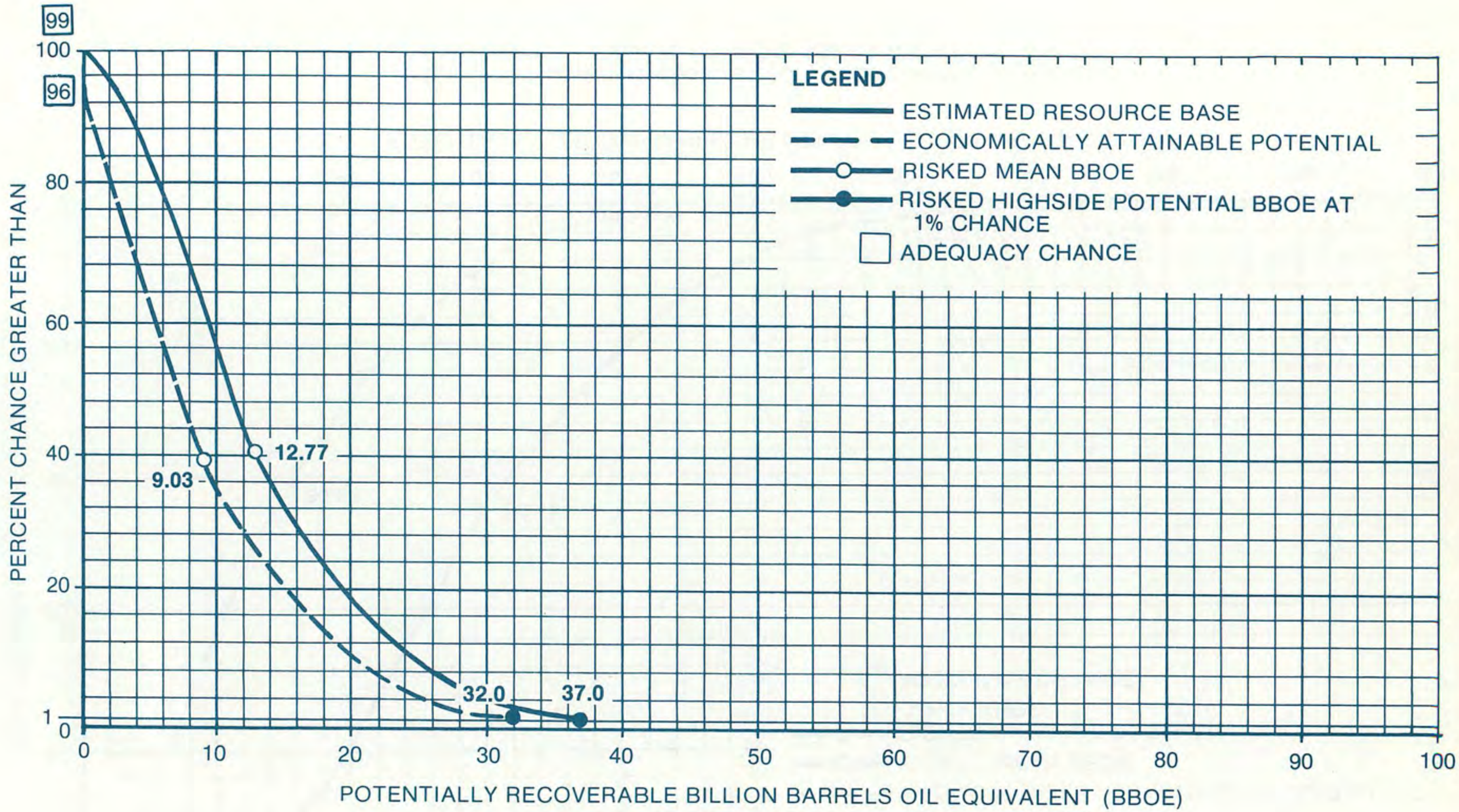


Figure C-27. Oil-Equivalent Risked Potential Recovery, Area 27—
Region 1—North Slope Onshore (Areas 12-14).

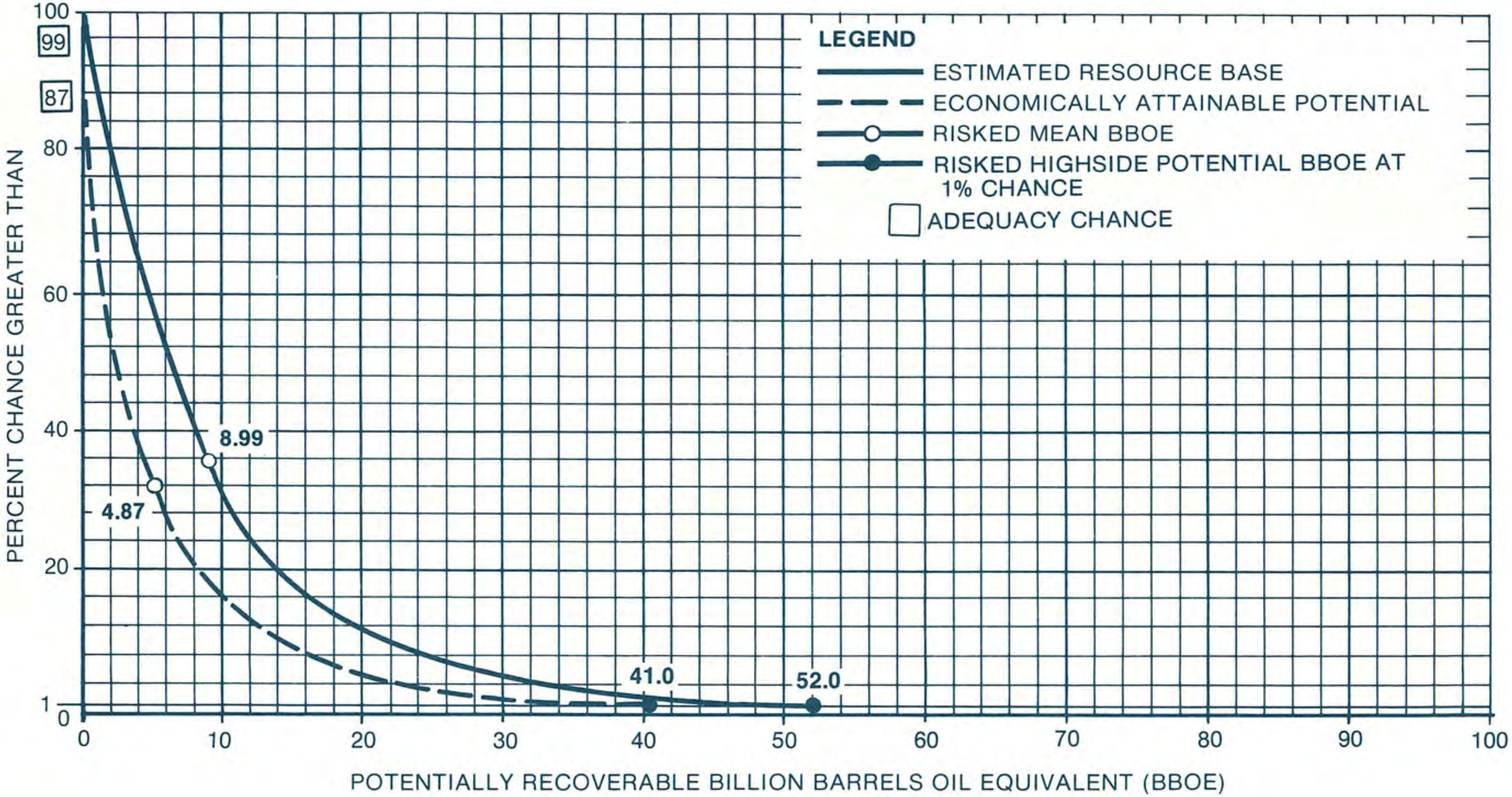


Figure C-28. Oil-Equivalent Risked Potential Recovery, Area 28—
Region II—Bering (Areas 1-11).

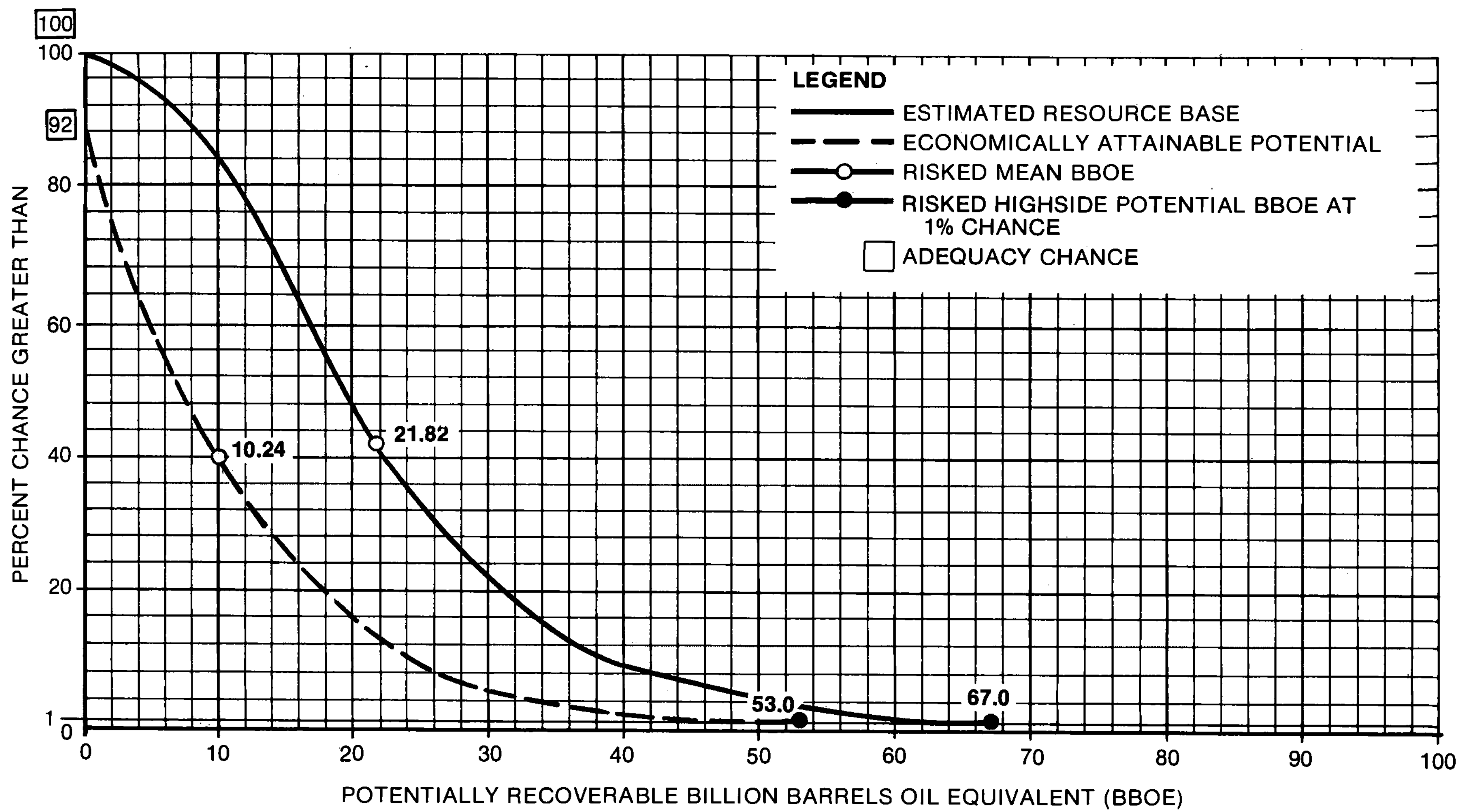


Figure C-29. Oil-Equivalent Risked Potential Recovery, Area 29—Region III—Beaufort and Chukchi (Areas 15-20).

APPENDIX D: OPERATING SCENARIOS

PART I: OIL SCENARIOS

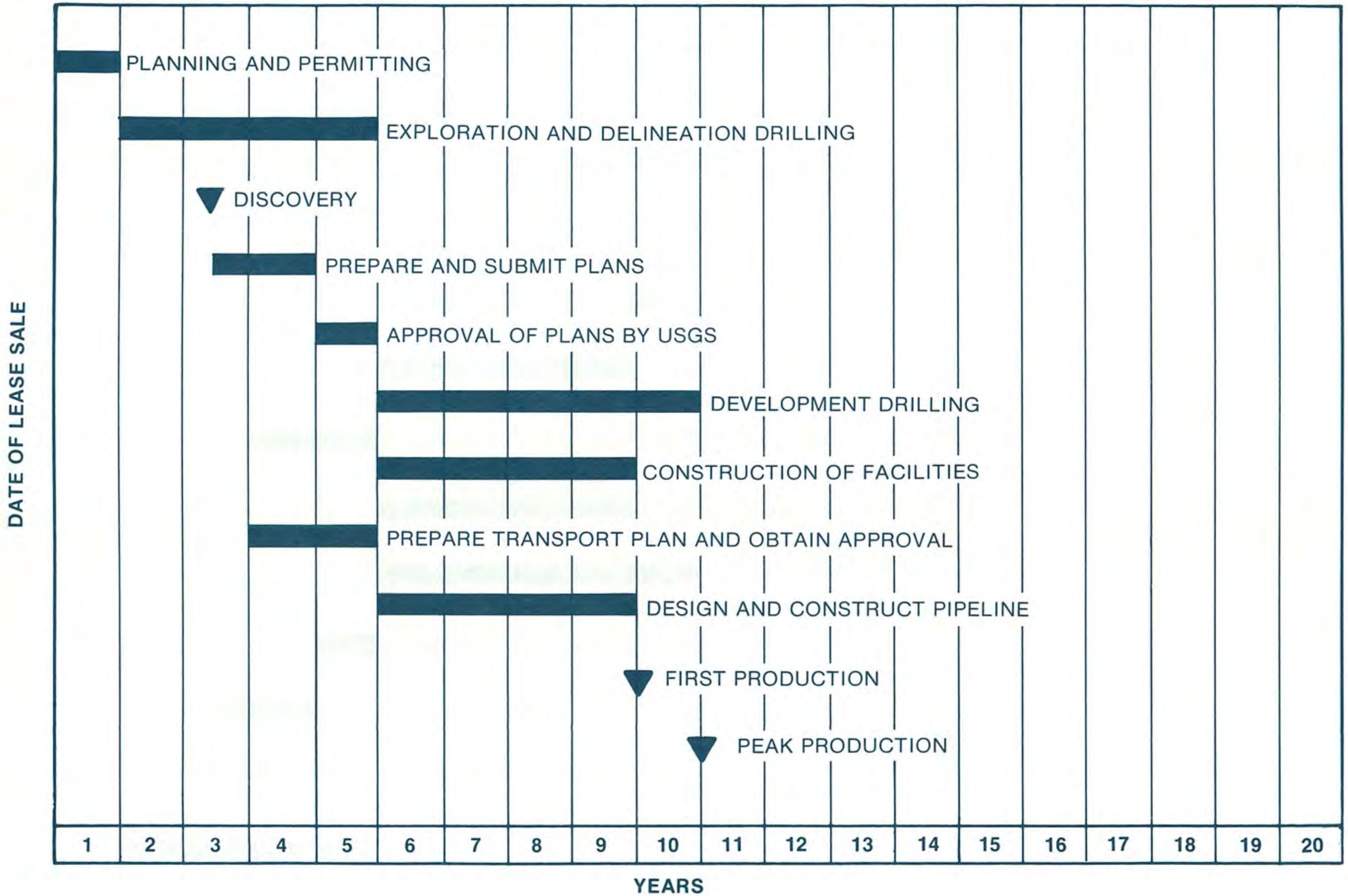


Figure D-1. ANWR (Oil Case—250,000 Barrels per Day).

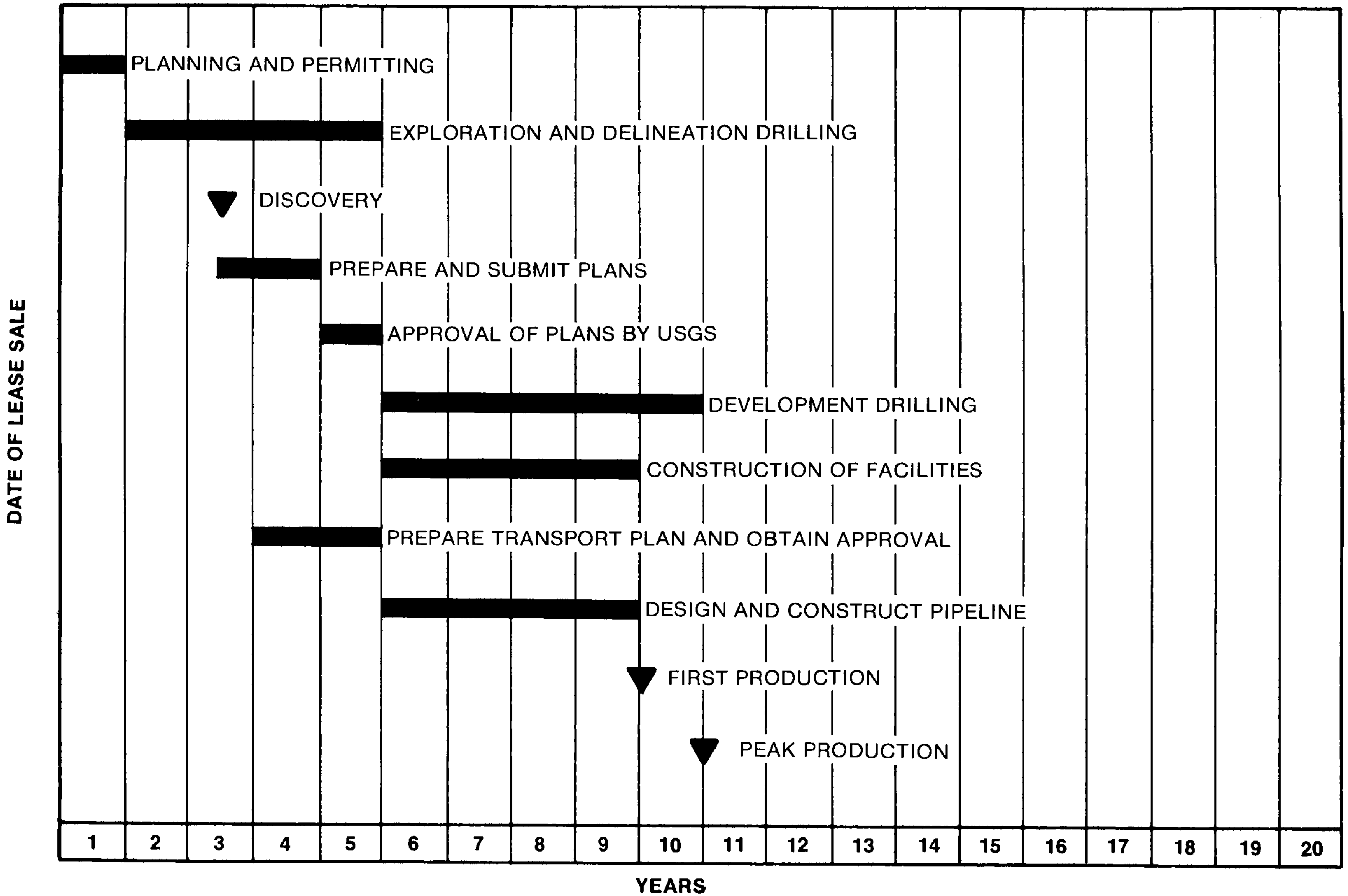


Figure D-2. NPRA (Oil Case—500,000 Barrels per Day).

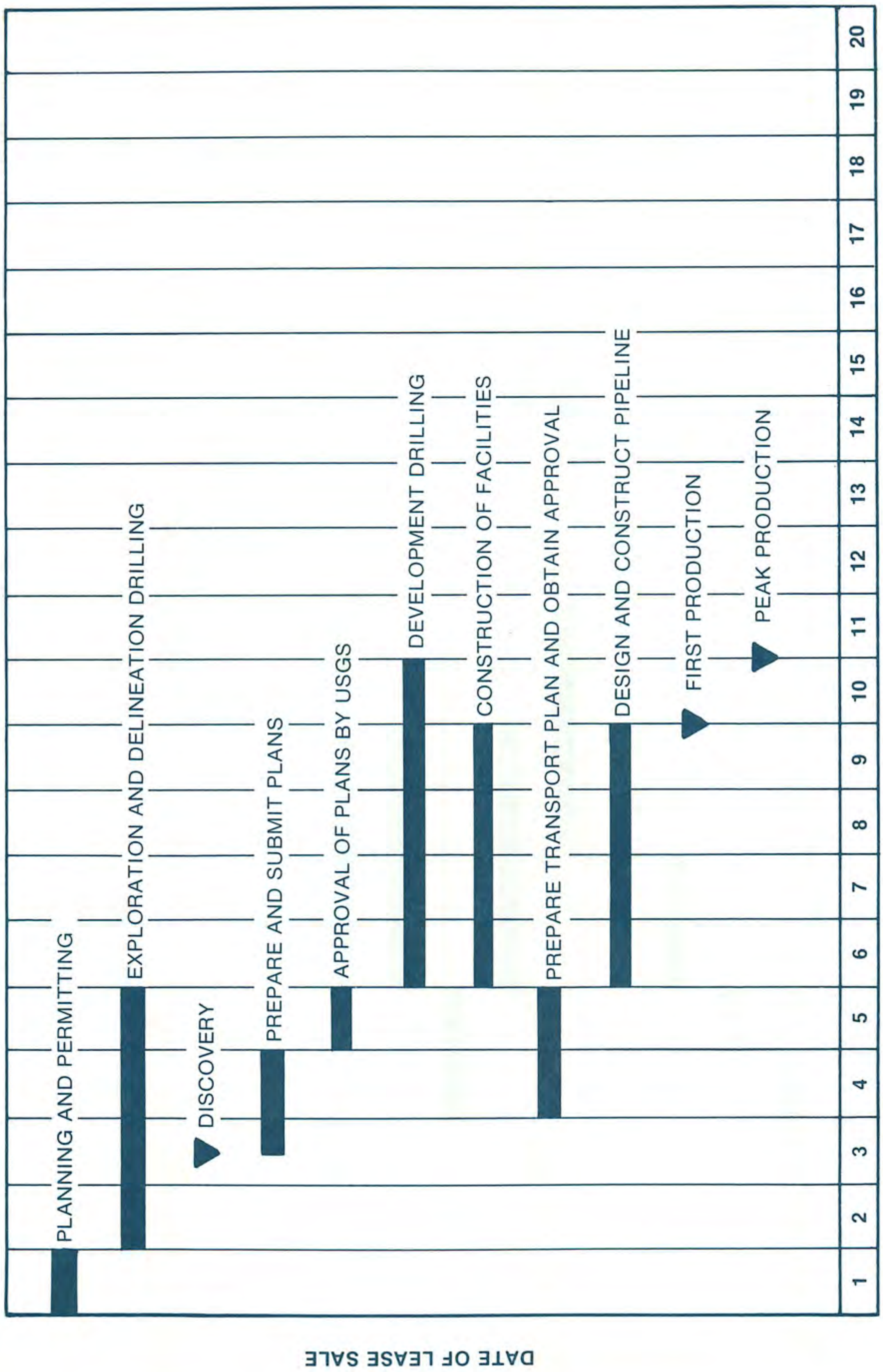


Figure D-3. North Slope Other (Oil Case--500,000 Barrels per Day).

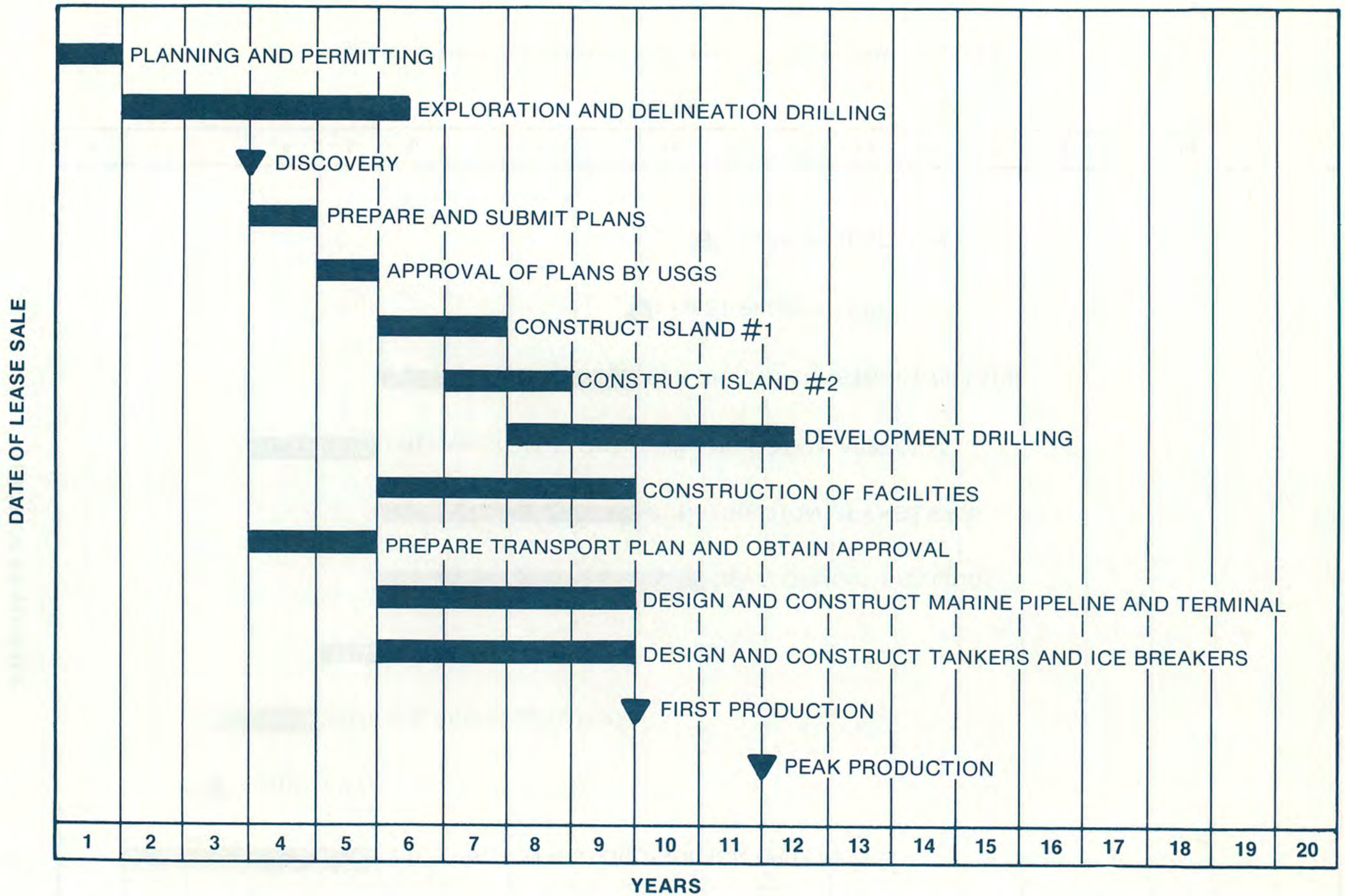


Figure D-4. Norton Basin (Oil Case—125,000 Barrels per Day).

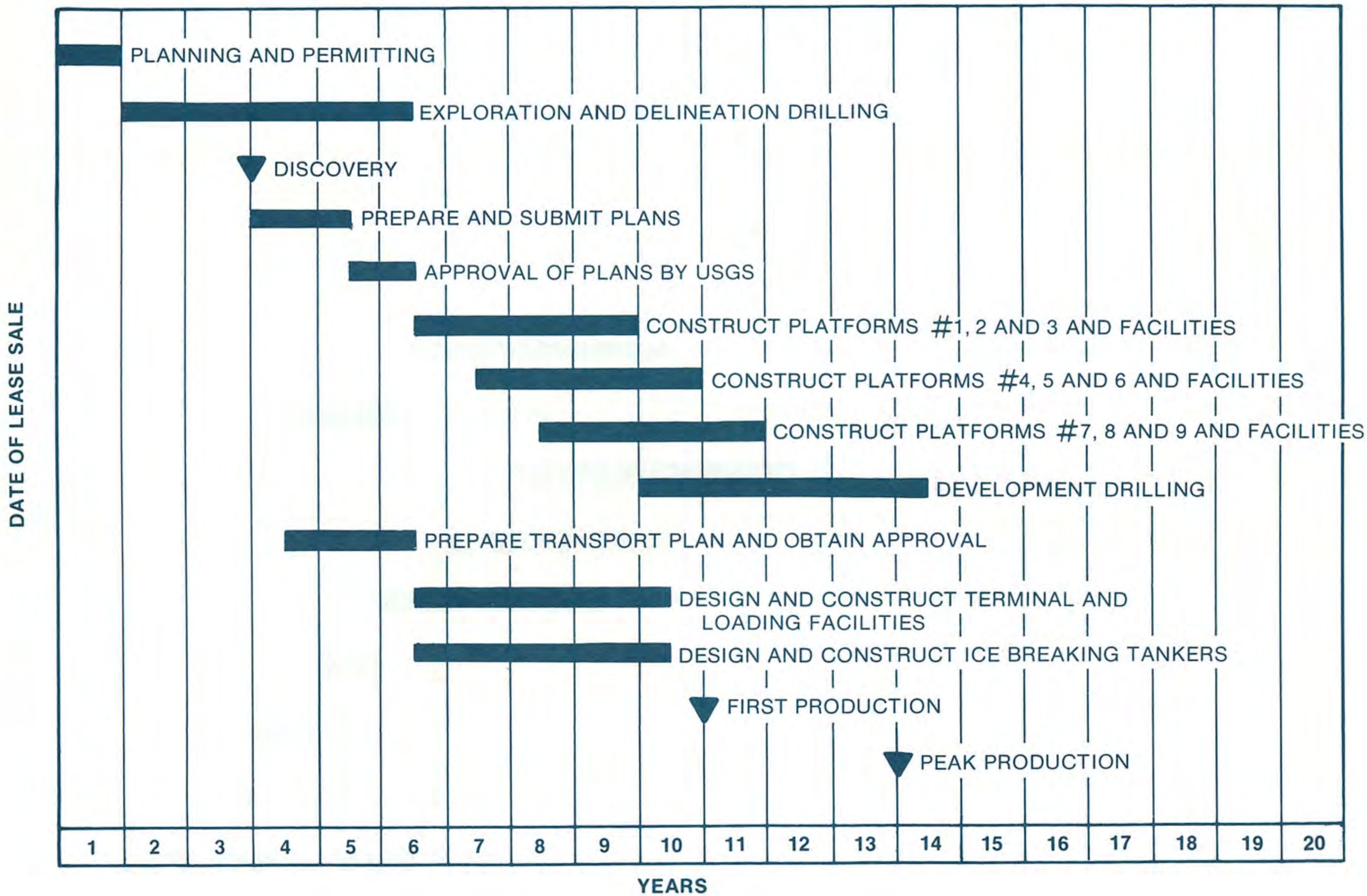


Figure D-5. Navarin Basin (Oil Case—500,000 Barrels per Day).

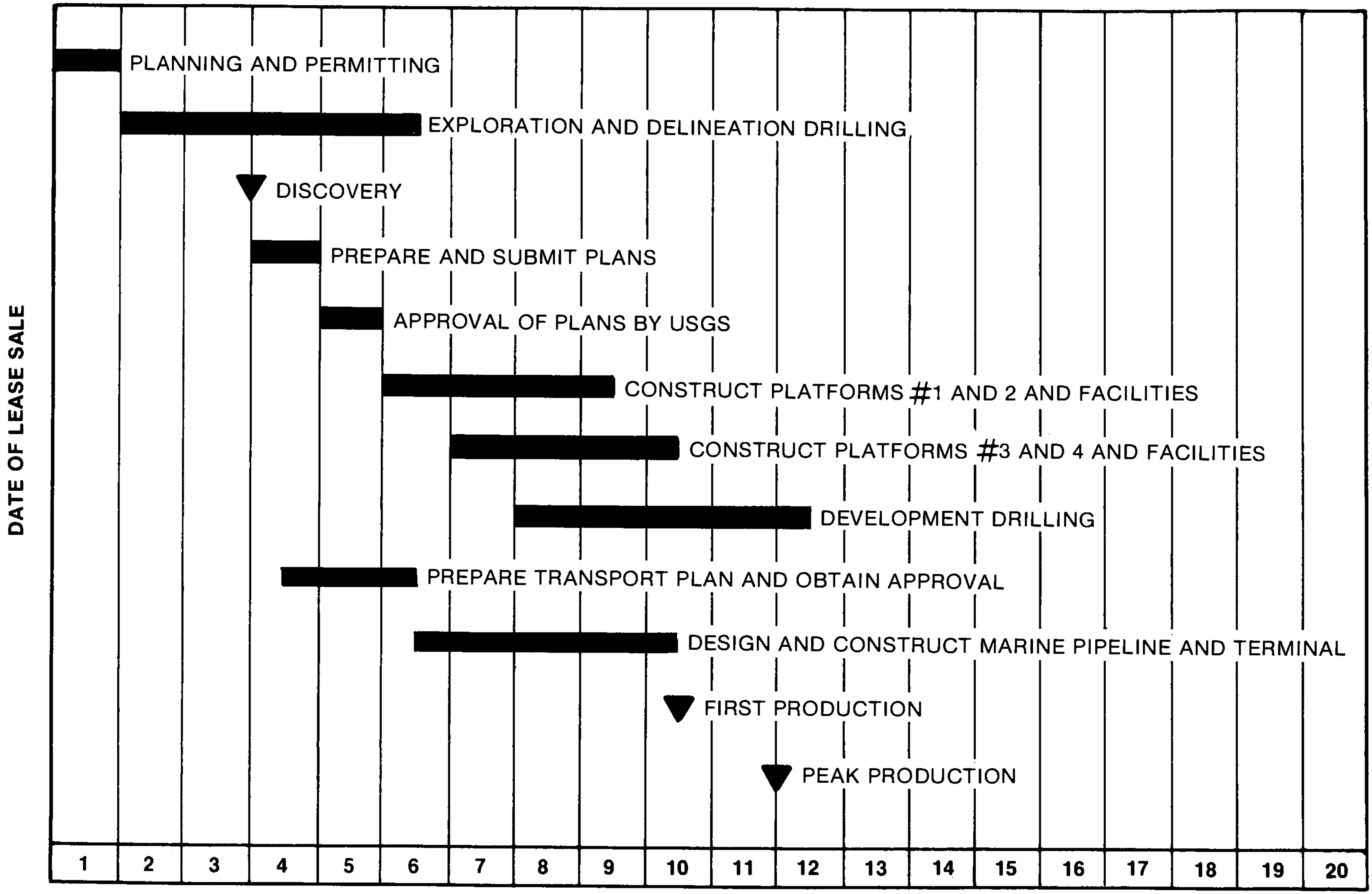


Figure D-6. St. George Basin (Oil Case—250,000 Barrels per Day).

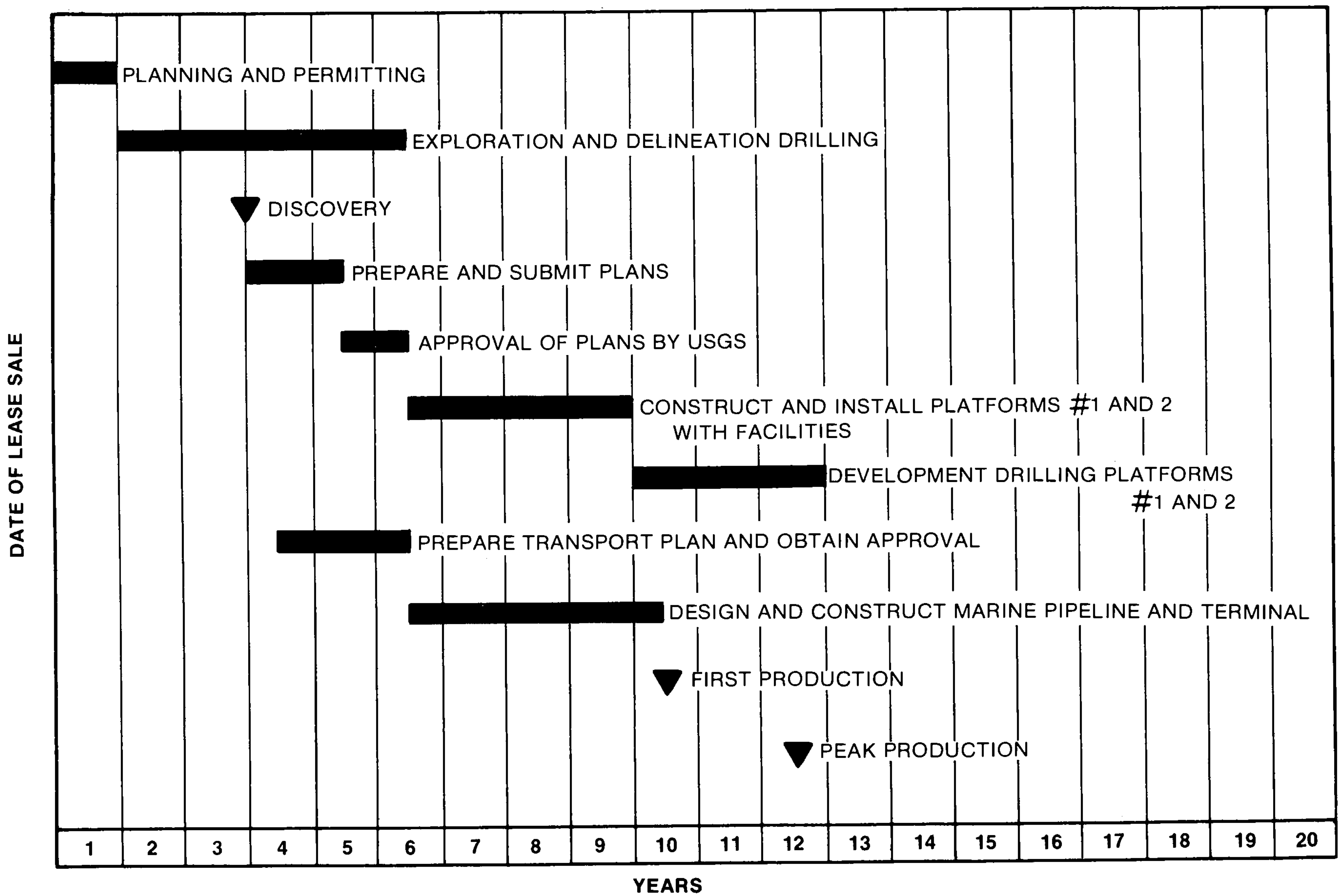


Figure D-7. Bristol Basin (Oil Case—250,000 Barrels per Day).

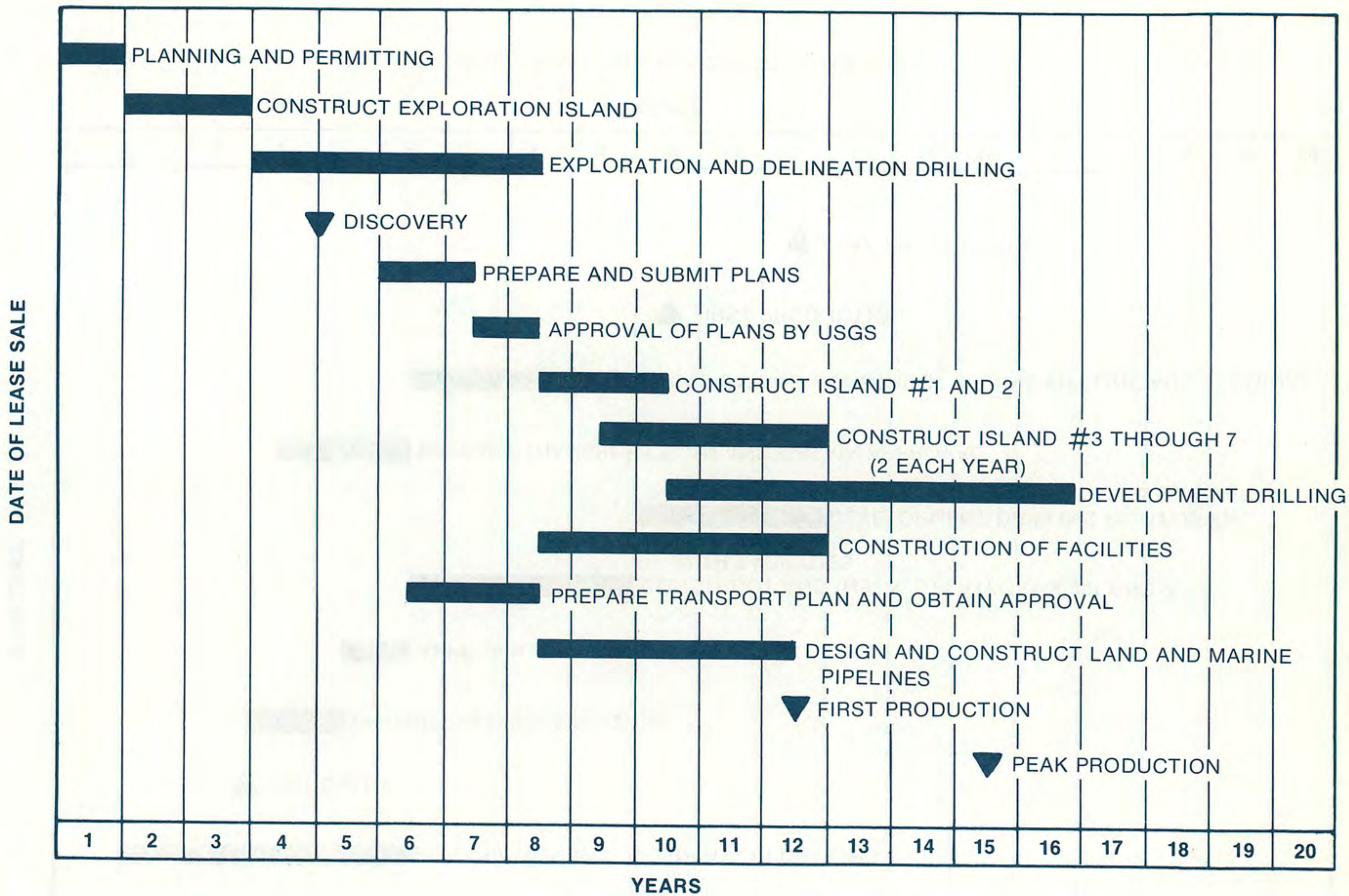


Figure D-8. Beaufort Shelf (Oil Case—500,000 Barrels per Day).

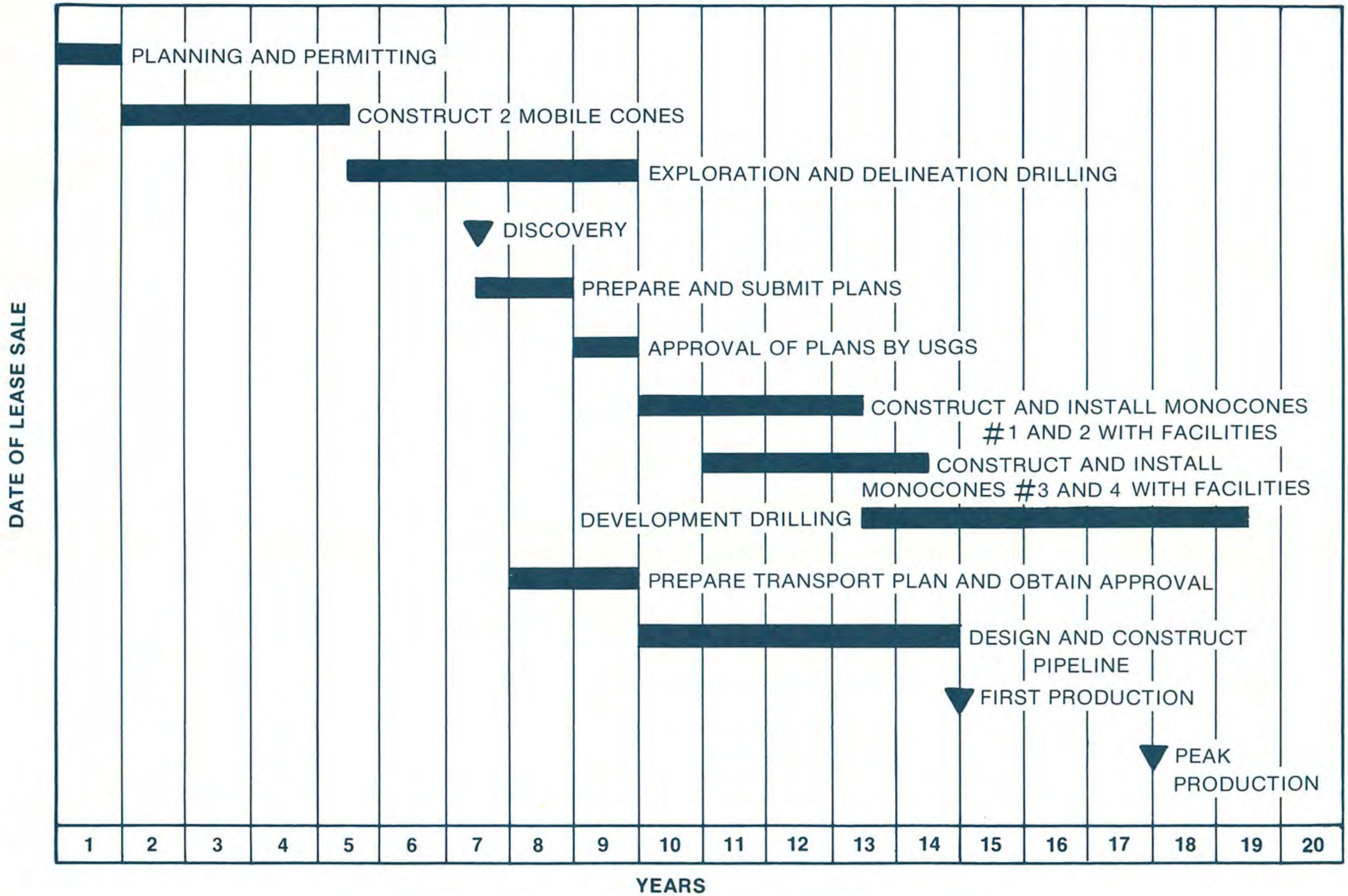


Figure D-9. Central Chukchi Shelf (Oil Case—250,000 Barrels per Day).

PART II:
GAS SCENARIOS

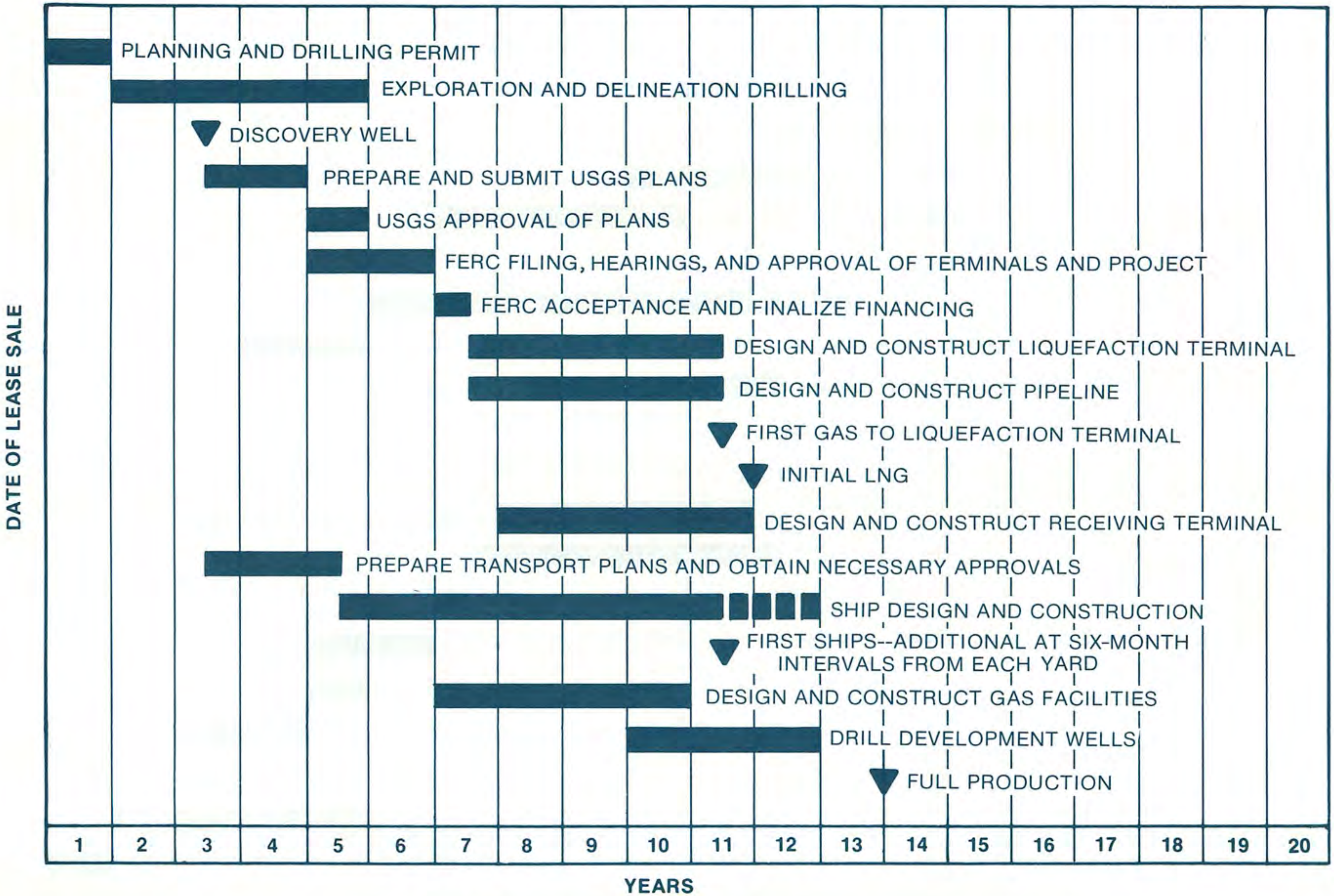


Figure D-10. NPRA Via TAPS to Valdez (Gas Case—1 BCF/D).

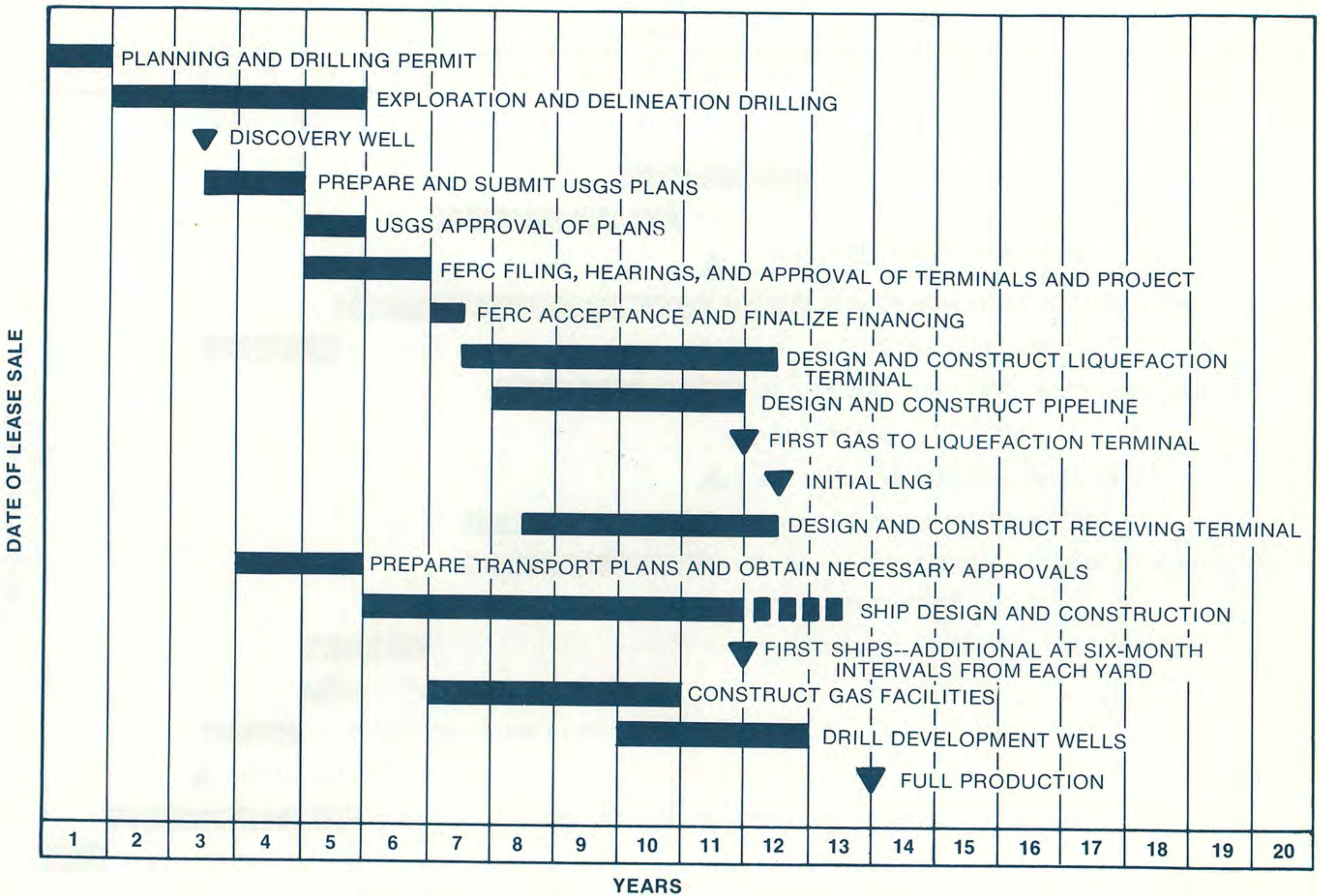


Figure D-11. NPRA Area to Wainwright (Gas Case—1 BCF/D).

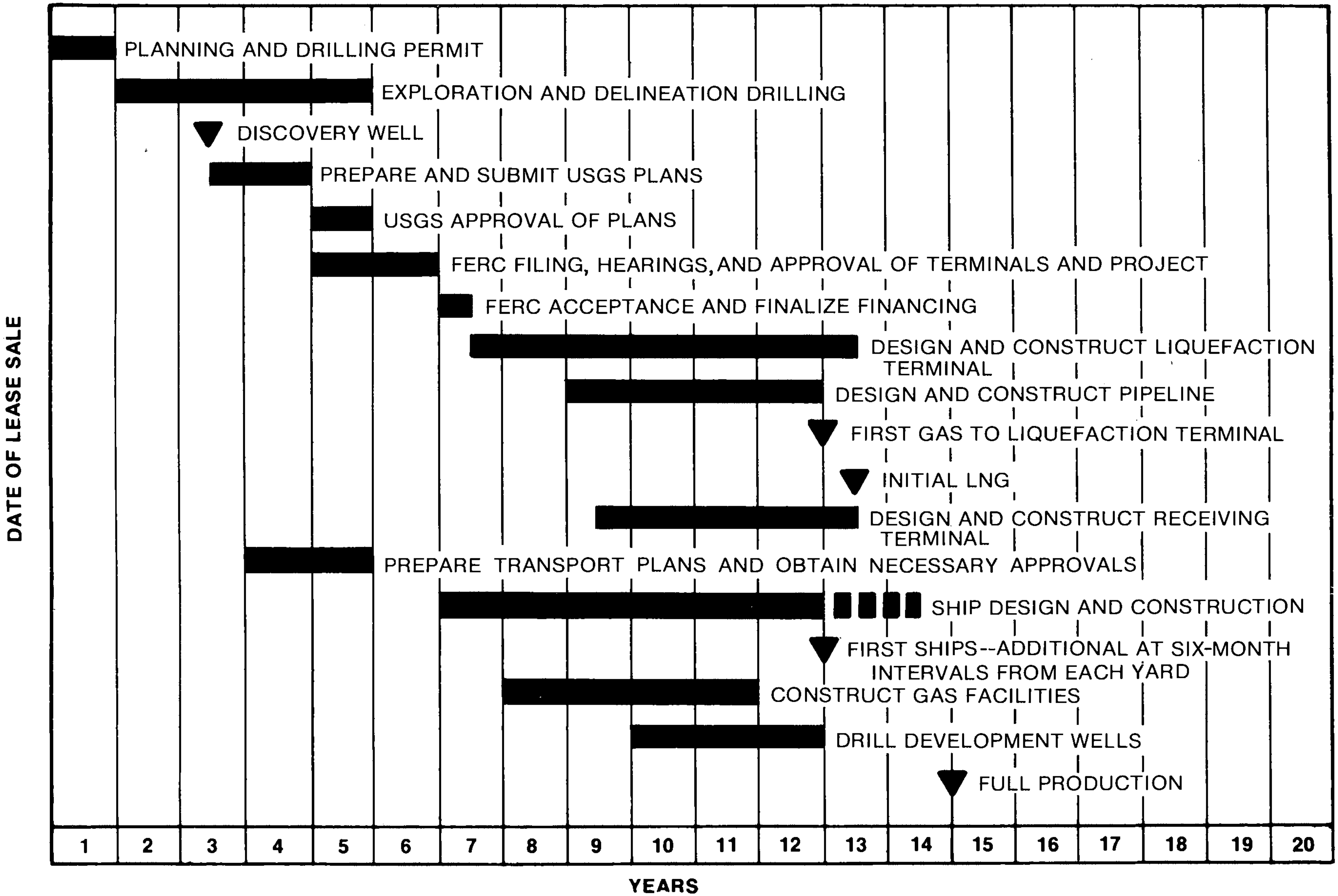


Figure D-12. NPRA Area to Nome (Gas Case—1 BCF/D).

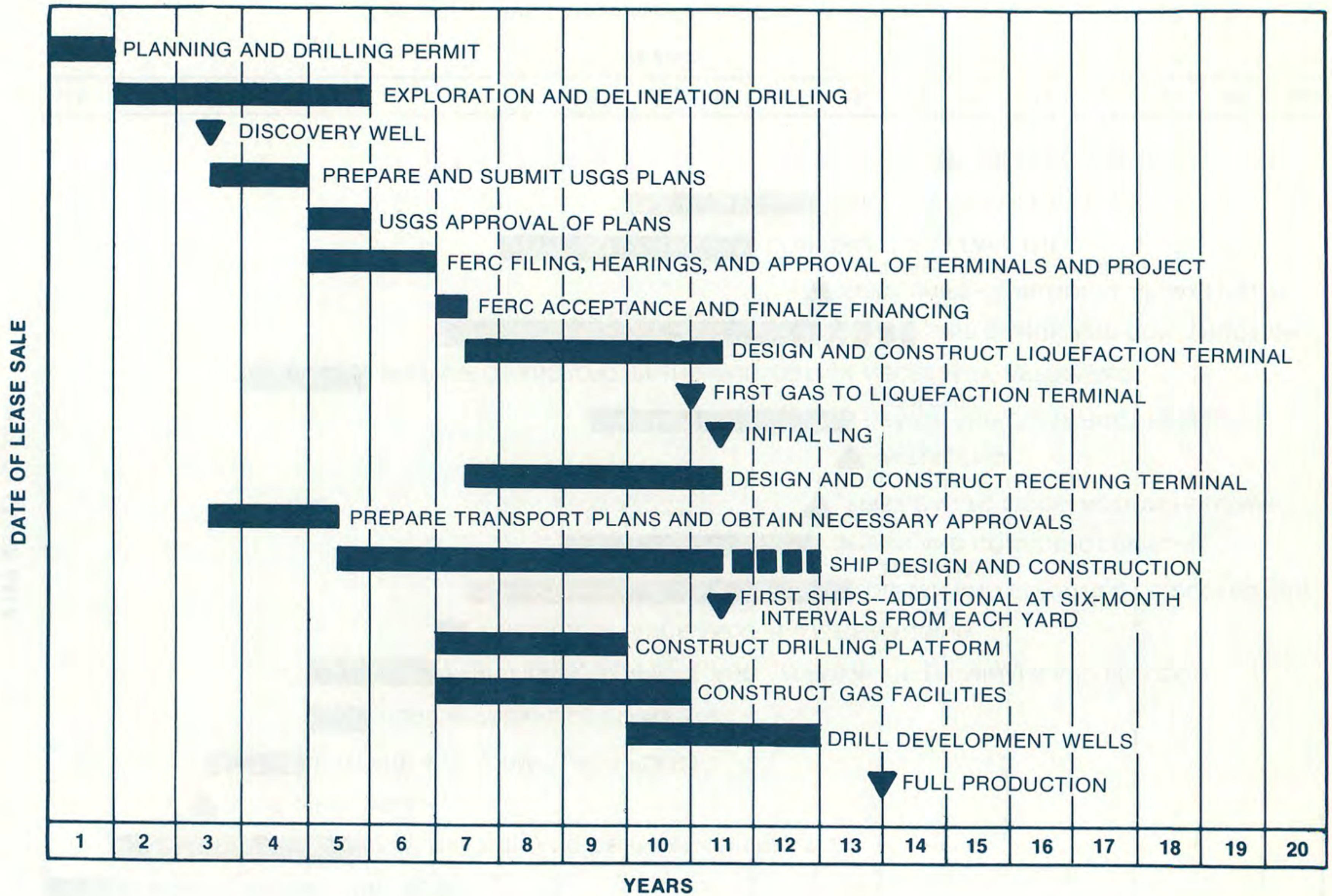


Figure D-13. Navarin Basin (Gas Case—1 BCF/D).

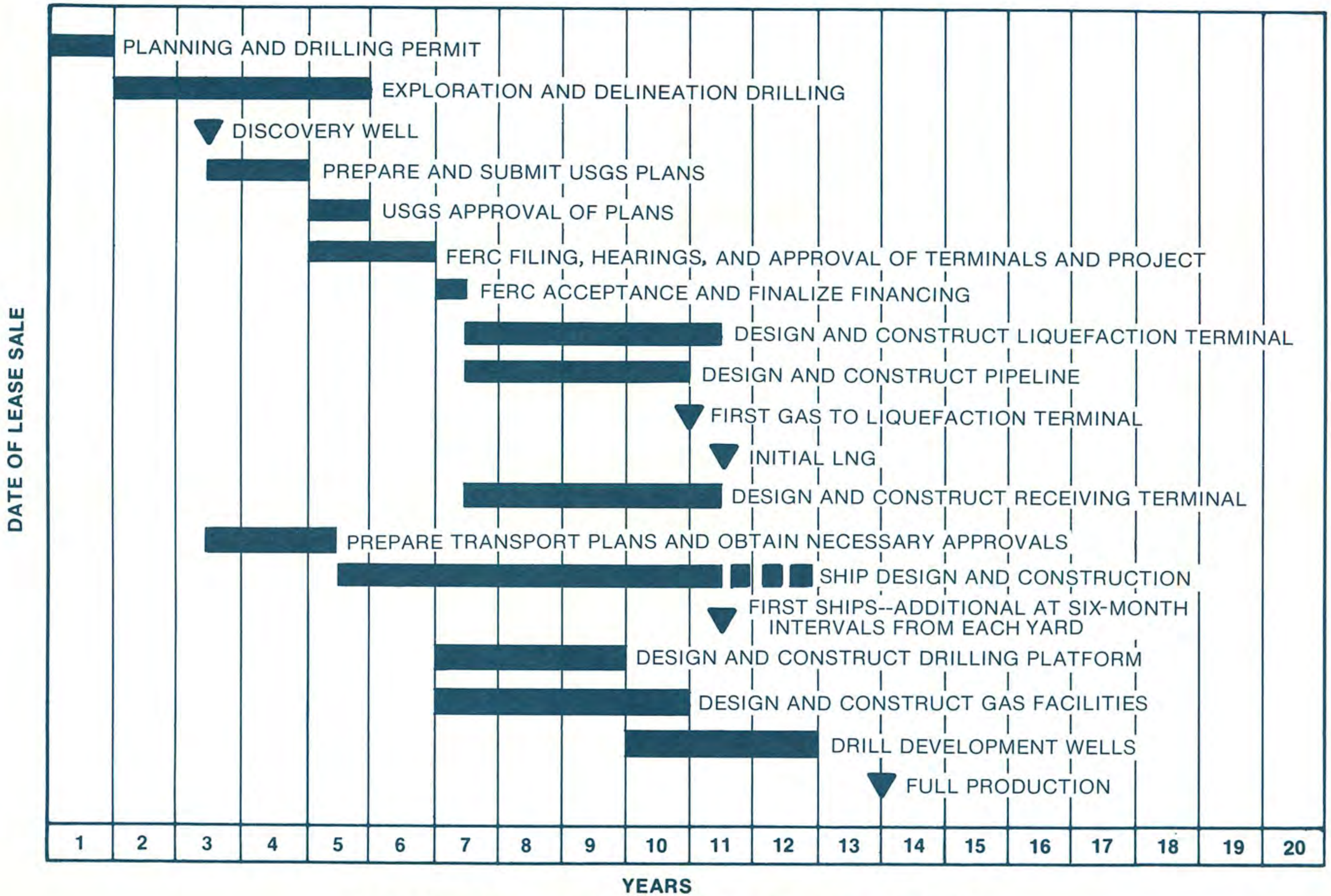


Figure D-14. St. George to Dutch Harbor (Gas Case—1 BCF/D).

APPENDIX E: COSTS

PART I: EXPLORATION COSTS

TABLE E-1

EXPLORATION WELL COSTS FOR A WELL 12,000 FEET DEEP (Costs in Millions of 1981 $)

Basin	Major Fixed Cost of Roads, Island Pads, Etc. (MM $)	Rig Day Rate (M $/Day)	Logistical Support (M $/Day)	Total Cost (M $/Day)	Downtime Factor	Drilling Time (Days)	Drilling Cost (MM $)	Total Well Cost (MM $)
ANWR	17	20	80	100	1.10	110	11	28.0
North Slope Other/NPRA	15	20	80	100	1.00	100	10	25.0
Bristol	—	120	185	305	1.05	105	32	32.0
St. George	—	120	185	305	1.05	105	32	32.0
Norton	—	60	180	240	1.00	100	24	24.0
Navarin	—	120	300	420	1.10	110	46	46.0
Chukchi	—	300	200	500	1.80†	180	90	90.0
Beaufort	50/Island 20/Well*	20	180	200	1.00	100	20	40.0

*Assumes 2.5 wells per island.
†Assumes mobile cone-type drilling rig can drill only two wells per year.

PART II: PRODUCTION COSTS

TABLE E-2
OIL PRODUCTION COST ESTIMATES—BASE CASE
(Costs in Millions of 1981 $)

	Region I		Region II				Region III	
	ANWR	North Slope Other/NPRA	Bristol Bay	St. George	Norton	Navarin	Chukchi	Beaufort
Exploratory Well Cost (6 Wells)	170	150	190	190	140	280	540	450
Field Size (BBO)	1	2	1	1	0.5	2	1	2
Field Peak Production Rate (B/D)	250,000	500,000	250,000	250,000	125,000	500,000	250,000	500,000
Initial Well Production Rate (B/D)	4,000	4,000	4,000	4,000	4,000	4,000	4,000	4,000
No. of Islands or Platforms Required	—	—	4	4	2	9†	4	7
Cost of Island or Platform (MM $)	—	—	120	400	210	480	380	190
Total Cost of Islands or Platforms (MM $)	—	—	480	1,600	420	4,300	1,520	1,330
Total No. of Wells*	136	271	128	136	68	271	136	271
Cost Per Dev. Well (MM $)	4.5	3.5	7.8	8.9	10.2	8.8	7.2	6.8
Total Cost of Dev. Wells (MM $)	610	950	1,000	1,210	690	2,400	980	1,840
Cost of Facilities (MM $)	2,600	4,500	1,200	1,200	620	2,400	1,200	2,100
Total Capital (MM $)	3,210	5,450	2,680	4,010	1,730	9,100	3,700	5,270
Operating Expenses (MM $/Yr)	80	140	110	110	85	200	140	140
Abandonment Cost (MM $)	320	550	140	400	170	910	370	530

*Includes 0.4 water injectors per producer plus gas injectors.
†7 drilling + 2 support/SPM platforms.

TABLE E-3
OIL PRODUCTION COST ESTIMATES—SMALL CASE
(Costs in Millions of 1981 $)

Item	Region I		Region II				Region III	
	ANWR	North Slope Other/NPRA	Bristol Bay	St. George	Norton	Navarin	Chukchi	Beaufort
Field Peak Production Rate (B/D)	125,000	250,000	125,000	125,000	50,000	250,000	125,000	250,000
Total Cost—Islands or Platforms (MM $)	—	—	240	800	210	2,900	760	760
Total Cost—Dev. Wells (MM $)	300	480	530	650	330	1,300	520	940
Cost of Facilities (MM $)	1,600	2,600	650	640	310	2,100	620	1,200
Total Capital (MM $)	1,900	3,080	1,420	2,090	850	6,300	1,900	2,900
Operating Expenses (MM $/Yr)	55	80	85	85	60	110	110	100

TABLE E-4
OIL PRODUCTION COST ESTIMATES—LARGE CASE
(Costs in Millions of 1981 $)

Item	Region I		Region II				Region III	
	ANWR	North Slope Other/NPRA	Bristol Bay	St. George	Norton	Navarin	Chukchi	Beaufort
Field Peak Production Rate (B/D)	500,000	1,000,000	500,000	500,000	250,000	1,000,000	500,000	1,000,000
Total Cost–Islands or Platforms (MM $)	—	—	560	2,800	840	7,700	2,700	2,500
Total Cost—Dev. Wells (MM $)	1,200	1,900	2,000	2,300	1,300	4,600	1,900	3,700
Cost of Facilities (MM $)	4,500	8,000	2,400	2,100	1,200	4,500	2,100	4,200
Total Capital (MM $)	5,700	9,900	4,960	7,200	3,340	16,800	6,700	10,400
Operating Expenses (MM $/Yr)	140	260	220	170	110	300	190	300

TABLE E-5

COSTS FOR GAS CASES
PROVED RESERVES: 5.5 TCF
AVERAGE FIELD PROD. RATE 1.0 BCF/D
(Costs in Millions of 1981 $)

Area:	NPRA			St. George	Navarin
Terminal:	Wainwright	Nome	Valdez	Dutch Harbor	Navarin
Exploratory Well Cost (6 Wells)	150.0	150.0	150.0	190.0	280.0
Total Cost of Islands or Platforms	—	—	—	800.0	960.0
Total Cost of Dev. Wells	152.0	152.0	152.0	368.0	364.0
Cost of Producing Facilities	200.0	200.0	200.0	200.0	252.0
Cost of Liquefaction Facilities	2,460.0	3,190.0	1,580.0	1,581.0	2,560.0
Cost of Receiving Terminal	590.0	590.0	590.0	592.0	590.0
Total Capital Cost (Ex. Transportation)	3,552.0	4,282.0	2,672.0	3,731.0	5,006.0
Operating Expenses (Ex. Transportation)	276.0	265.0	273.0	243.0	274.0

PART III:
TRANSPORTATION COSTS

COST AND TIMING ESTIMATES INDEX

	Title	Tables 1,000,000 B/D	Tables 500,000 B/D
Land Pipeline:	Wainwright to Nome Wainwright to New TAPS New TAPS to Valdez	E-6	E-15
Land Pipeline:	Kotzebue to Cook Inlet Kotzebue to Nome Kotzebue to New TAPS New TAPS to Valdez	E-7	E-16
Land Pipeline:	Nome to Cook Inlet Arctic Wildlife Range to New TAPS New TAPS to Valdez	E-8	E-17
Land Pipeline:	Nome to New TAPS New TAPS to Valdez Wainwright to Kotzebue Kotzebue to Cook Inlet	E-9	E-18
Land Pipeline:	New TAPS—Prudhoe to Valdez NPRA to Wainwright Nome New TAPS to Valdez	E-10	E-19
Marine Pipelines		E-11	E-20
Terminals		E-12	E-21
Tankers/Icebreakers		E-13	E-22
Support Logistics		E-14	E-23
		1 Billion SCF/D	1/2 Billion SCF/D
Land Pipeline:	NPRA to Wainwright Nome New TAPS to Valdez	E-24	E-25
LNG Tankers/Icebreakers		E-26	E-27

TABLE E-6

COST AND TIMING ESTIMATES
(Costs in Millions of 1981 $)

OIL
1 Million Barrels Per Day

Chukchi Basin

LAND PIPELINES (42-Inch Line)	Wainwright to Nome	Wainwright to Valdez: Wainwright to New TAPS—(PS-2)	Wainwright to Valdez: New TAPS PS-2 to Valdez
Capital			
Above-Ground Pipeline			
Cost Per Mile	12.0	12.0	12.0
Number of Miles	337	186	371
Cost	4,044.0	2,232.0	4,452.0
Below-Ground Pipeline			
Cost Per Mile	7.3	7.3	7.3
Number of Miles	338	186	371
Cost	2,467.4	1,357.8	2,708.3
Pump Stations	656.9	462.7	925.5
Terminals (New or Additions)	—	1,864.0	
Haul Road	845.9	467.4	Existing
Total Capital Cost	8,014.0	14,470.0	
Annual Operating Cost*	121.5	217.5	
Engineering and Construction Time (Years)	4	4	

*2 percent ad valorem taxes not included.

TABLE E-7

COST AND TIMING ESTIMATES
(Costs in Millions of 1981 $)

Hope Basin

OIL
1 Million Barrels Per Day

LAND PIPELINES (42-Inch Line)	Kotzebue to Cook Inlet	Kotzebue to Nome	Kotzebue to Valdez: Kotzebue to New TAPS	Kotzebue to Valdez: New TAPS Coldfoot to Valdez
Capital				
Above-Ground Pipeline				
Cost Per Mile	12.0	12.0	12.0	12.0
Number of Miles	397	187	185	270
Cost	4,764.0	2,244.0	2,220.0	3,240.0
Below-Ground Pipeline				
Cost Per Mile	7.3	7.3	7.3	7.3
Number of Miles	398	188	185	270
Cost	2,905.4	1,372.4	1,350.5	1,971.0
Pump Stations	902.7	365.6	479.9	731.3
Terminals (New or Additions)	1,864.0	—	1,864.0	
Haul Road	998.6	469.7	464.0	Existing
Total Capital Cost	11,435.0	4,452.0	12,321.0	
Annual Operating Cost*	171.0	67.5	—	184.5
Engineering and Construction Time (Years)	4	4	—	4

*2 percent ad valorem taxes not included.

TABLE E-8

COST AND TIMING ESTIMATES
(Costs in Millions of 1981 $)

OIL
1 Million Barrels Per Day

LAND PIPELINES (42-Inch Line)	Norton Basin Nome to Cook Inlet	ANWR to Valdez: ANWR to New TAPS	ANWR to Valdez	ANWR to Valdez: New TAPS to Valdez
Capital				
Above-Ground Pipeline				
Cost Per Mile	12.0	12.0		12.0
Number of Miles	350	77		396
Cost	4,200.0	924.0		4,752.0
Below-Ground Pipeline				
Cost Per Mile	7.3	7.3		7.3
Number of Miles	350	77		371
Cost	2,555.0	562.1		2,708.3
Pump Stations	902.7	268.5		925.5
Terminals (New or Additions)	1,864.0	—	1,864.0	
Haul Road	877.8	193.8		Existing
Total Capital Cost	10,400.0	—	12,200.0	—
Annual Operating Cost*	156.0		183.0	
Engineering and Construction Time (Years)	4		4	

*2 percent ad valorem taxes not included.

TABLE E-9

COST AND TIMING ESTIMATES
(Costs in Millions of 1981 $)

OIL
1 Million Barrels Per Day

LAND PIPELINES (42-Inch Line)	Nome to Valdez: Nome to Big Delta	Nome to Valdez: Big Delta to Valdez	Wainwright to Cook Inlet: Wainwright to Kotzebue	Wainwright to Cook Inlet: Kotzebue to Cook Inlet
Capital				
Above-Ground Pipeline				
Cost Per Mile	12.0	12.0	12.0	12.0
Number of Miles	340	135	150	397
Cost	4,080.0	1,620.0	1,800.0	4,764.0
Below-Ground Pipeline				
Cost Per Mile	7.3	7.3	7.3	7.3
Number of Miles	340	135	150	398
Cost	2,482.0	985.5	1,095.0	2,905.4
Pump Stations	788.4	211.4	365.6	902.7
Terminals (New or Additions)	1,864.0		1,864.0	
Haul Road	855.0	Existing	376.2	998.6
Total Cost	8,205.0	4,680.0	3,640.0	11,430.0
Total Capital Cost	12,886.0		15,062.0	
Annual Operating Cost*	193.5		226.5	
Engineering and Construction Time (Years)	4		4	

*2 percent ad valorem taxes not included.

TABLE E-10

COST AND TIMING ESTIMATES
(Costs in Millions of 1981 $)

OIL
1 Million Barrels Per Day

		NPRA			
				To Valdez	
LAND PIPELINES (42-Inch Line)	**New TAPS Line Prudhoe to Valdez**	**To Wainwright**	**To Nome**	**NPRA to New TAPS**	**New TAPS to Valdez**
Capital					
Above-Ground Pipeline					
Cost Per Mile	12.0	12.0	12.0	12.0	12.0
Number of Miles	412	57	330	128	371
Cost	4,944.0	684.0	3,960.0	1,536.0	4,452.0
Below-Ground Pipeline					
Cost Per Mile	7.3	7.3	7.3	7.3	7.3
Number of Miles	388	58	330	129	371
Cost	2,832.4	423.4	2,409.0	941.7	2,708.3
Pump Stations	1,097.0	171.4	659.9	268.5	925.5
Terminals (New or Additions)	1,864.0	—	—	1,864.0	
Haul Road	Existing	142.5	826.5	319.2	Existing
Total Capital Cost	10,737.0	1,421.0	7,855.0	13,015.0	
Annual Operating Cost*	160.5	22.5	118.5	195.3	
Engineering and Construction Time (Years)	4	4	4	4	

*2 percent ad valorem taxes not included.

TABLE E-11

COST AND TIMING ESTIMATES
(Cost in Millions of 1981 $)

OIL
1 Million Barrels Per Day

MARINE PIPELINES	North Aleutian Shelf	St. George	Navarin	Norton	Hope	Chukchi	Beaufort
Capital							
Cost Per Mile (36-Inch Diameter)	6.0	5.1	—	9.0	8.1	8.4	9.0
Number of Miles	50	200	—	50	100	75	50
Platform		330.0					
Total Capital Cost	300.0	1,320.0	—	450.0	825.0	650.0	450.0
Operating Cost Per Year							
Cost Per Mile	.09	.075	—	.135	.12	.12	.135
Total Operating Cost Per Year*	4.5	20.25	—	6.75	12.45	9.75	6.75
Engineering and Construction Time (Years)	1	2.5	—	4	4	4	4

*2 percent ad valorem taxes not included.

TABLE E-12

COST AND TIMING ESTIMATES
(Costs in Millions of 1981 $)

OIL
1 Million Barrels Per Day

TERMINALS	North Aleutian Shelf	St. George	Navarin	Norton	Hope	Chukchi	Beaufort
Capital							
Nearshore Terminal							
Cost Per Berth (Including Loading Lines)	460.0	460.0	—	460.0	460.0	460.0	—
Number of Berths	2	2	—	2	2	2	—
Cost	920.0	920.0	—	920.0	920.0	920.0	—
Onshore Facilities Cost	950.0	950.0	—	950.0	950.0	950.0	—
Transshipment Terminal Cost	None Required	None Required	2,330.0	2,330.0	2,330.0	2,330.0	—
Total Capital Cost	1,870.0	1,870.0	2,330.0	4,200.0	4,200.0	4,200.0	—
Operating Cost Per Year							
Nearshore Terminal	7.0	7.0	—	7.0	7.0	7.0	—
Onshore Facilities	26.0	26.0	—	26.0	26.0	26.0	—
Transshipment Terminal	—	—	37.0	37.0	37.0	37.0	—
Total Operating Cost Per Year	33.0	33.0	37.0	70.0	70.0	70.0	—
Engineering and Construction Time (Years)	4	4	4	4	5	5	—

TABLE E-13

COST AND TIMING ESTIMATES
(Costs in Millions of 1981 $)

OIL
1 Million Barrels Per Day

TANKERS/ICEBREAKERS	North Aleutian Shelf	St. George	Navarin	Norton	Hope	Chukchi	Beaufort
Capital							
Tankers							
Cost Per Tanker	—	—	190.0	330.0	380.0	380.0	—
Number of Tankers	—	—	3	5	8	13	—
Cost	—	—	570.0	1,650.0	3,040.0	4,940.0	—
Icebreakers/Sea Duty							
Cost Per Breaker	—	—	—	100.0	150.0	150.0	—
Number of Breakers	—	—	—	1	2	2	—
Cost	—	—	—	100.0	300.0	300.0	
Total Capital Costs	—	—	570.0	1,750.0	3,340.0	5,240.0	—
Operating Cost Per Year							
Tankers							
Cost Per Tanker	—	—	21.34	26.46	41.11	47.45	—
Cost Per Year	—	—	64.0	108.8*	305.9*	490.0*	—
Icebreakers/Sea Duty							
Cost Per Breaker	—	—	—	15.8	22.1	22.1	—
Cost Per Year	—	—	—	15.8	44.2	44.2	—
Total Operating Cost Per Year	—	—	64.0	124.6	350.1	534.2	
Engineering and Construction Time							
Years Per Tanker	—	—	4	4	4	4	—
Total Tankers	—	—	3	5	8	13	—
Total Years (Tankers)	—	—	4	4	6	8	—
Total Years (Breakers)	—	—	4	4	4	4	—

*Cost includes credit for non-Arctic voyages.

TABLE E-14

COST AND TIMING ESTIMATES
(Costs in Millions of 1981 $)

OIL
1 Million Barrels Per Day

SUPPORT LOGISTICS	North Aleutian Shelf	St. George	Navarin	Norton	Hope	Chukchi	Beaufort
Capital							
Basic Port Cost	20.0	20.0	—	20.0	25.0	30.0	—
Icebreakers (Port Duty)							
Cost Per Breaker	80.0	80.0	80.0	80.0	80.0	80.0	—
Number of Breakers	1	1	1	2	2	2	—
Cost	80.0	80.0	80.0	160.0	160.0	160.0	—
Support Vessels/Tugs	280.0	280.0	280.0	280.0	350.0	350.0	—
Total Capital Cost	380.0	380.0	360.0	460.0	535.0	540.0	—
Operating Cost Per Year							
Basic Port Cost	7.0	7.0	—	7.0	9.0	12.0	—
Icebreakers (Port Duty)	13.0	13.0	13.0	13.0	30.0	35.0	—
Support Vessels/Tugs	56.0	56.0	56.0	56.0	70.0	70.0	—
Total Operating Cost Per Year	76.0	76.0	69.0	76.0	109.0	117.0	—
Engineering and Construction Time							
Basic Port Years	2	2	—	2	3	3	—
Icebreakers/Port Duty (Years)	3.5	3.5	3.5	3.5	3.5	3.5	—
Support Vessels/Tugs (Years)	2	2	2	2	2	2	—

TABLE E-15

COST AND TIMING ESTIMATES
(Costs in Millions of 1981 $)

OIL
500 Thousand Barrels Per Day

Chukchi Basin

LAND PIPELINES (28-Inch Line)	Wainwright to Nome	Wainwright to Valdez: Wainwright to New TAPS—(PS-2)	Wainwright to Valdez: New TAPS PS-2 to Valdez
Capital			
Above-Ground Pipeline			
Cost Per Mile	9.6	9.6	9.6
Number of Miles	337	186	371
Cost	3,235.2	1,785.6	3,561.6
Below-Ground Pipeline			
Cost Per Mile	6.2	6.2	6.2
Number of Miles	338	186	371
Cost	2,095.6	1,153.2	2,300.2
Pump Stations	433.5	305.4	610.8
Terminals (New or Additions)	—	1,230	
Haul Road	845.9	467.4	Existing
Total Capital Cost	6,611.0	11,410.0	
Annual Operating Cost*	114.0	196.5	
Engineering and Construction Time (Years)	4	4	

*2 percent ad valorem taxes not included.

TABLE E-16

COST AND TIMING ESTIMATES
(Costs in millions of 1981 $)
Hope Basin

OIL
500 Thousand Barrels Per Day

LAND PIPELINES (28-Inch Line)	Kotzebue to Cook Inlet	Kotzebue to Nome	Kotzebue to Valdez: Kotzebue to New TAPS	Kotzebue to Valdez: New TAPS Coldfoot to Valdez
Capital				
Above-Ground Pipeline				
Cost Per Mile	9.6	9.6	9.6	9.6
Number of Miles	397	187	185	270
Cost	3,811.2	1,795.2	1,776.0	2,592.0
Below-Ground Pipeline				
Cost Per Mile	6.2	6.2	6.2	6.2
Number of Miles	398	188	185	270
Cost	2,467.6	1,165.6	1,147.0	1,674.0
Pump Stations	595.8	241.3	316.7	482.6
Terminals (New or Additions)	1,230.0	—	1,230.0 (Kotzebue to Valdez total)	
Haul Road	998.6	469.7	464.0	Existing
Total Capital Cost	9,103.0	3,672.0	9,682.0 (Kotzebue to Valdez total)	
Annual Operating Cost*	154.5	63.0	166.5 (Kotzebue to Valdez total)	
Engineering and Construction Time (Years)	4	4	4 (Kotzebue to Valdez total)	

*2 percent ad valorem taxes not included.

TABLE E-17

COST AND TIMING ESTIMATES
(Costs in Millions of 1981 $)

OIL
500 Thousand Barrels Per Day

LAND PIPELINES (28-Inch Line)	Norton Basin Nome to Cook Inlet	ANWR to Valdez To New TAPS	ANWR to Valdez New TAPS to Valdez
Capital			
Above-Ground Pipeline			
Cost Per Mile	9.6	9.6	9.6
Number of Miles	350	77	396
Cost	3,360.0	739.2	3,801.6
Below-Ground Pipeline			
Cost Per Mile	6.2	6.2	6.2
Number of Miles	350	77	371
Cost	2,170.0	477.4	2,300.2
Pump Stations	595.8	177.2	610.8
Terminals (New or Additions)	1,230.0	1,230.0	
Haul Road	877.8	193.8	Existing
Total Capital Cost	8,234.0	9,530.0	
Annual Operating Cost*	140.0	165.0	
Engineering and Construction Time (Years)	4	4	

*2 percent ad valorem taxes not included.

TABLE E-18

COST AND TIMING ESTIMATES
(Costs in Millions of 1981 $)

OIL
500 Thousand Barrels Per Day

LAND PIPELINES (28-Inch Line)	Nome to Valdez: Nome to Big Delta	Nome to Valdez: Big Delta to Valdez	Wainwright to Cook Inlet: Wainwright to Kotzebue	Wainwright to Cook Inlet: Kotzebue to Cook Inlet
Capital				
Above-Ground Pipeline				
Cost Per Mile	9.6	9.6	9.6	9.6
Number of Miles	340	135	150	397
Cost	3,264.0	1,296.0	1,440.0	3,811.2
Below-Ground Pipeline				
Cost Per Mile	6.2	6.2	6.2	6.2
Number of Miles	340	135	150	398
Cost	2,108.0	837.0	930.0	2,467.6
Pump Stations	520.3	139.5	241.2	595.8
Terminals (New or Additions)	1,230.0		1,230.0	
Haul Road	855.0	Existing	376.2	998.6
Total Capital Cost	10,250.0		12,091.0	
Annual Operating Cost*	174.0		204.0	
Engineering and Construction Time (Years)	4		4	

*2 percent ad valorem taxes not included.

TABLE E-19

COST AND TIMING ESTIMATES
(Costs in Millions of 1981 $)

OIL
500 Thousand Barrels Per Day

LAND PIPELINES (28-Inch Line)	New TAPS Line Prudhoe to Valdez	NPRA			
		To Wainwright	To Nome	To Valdez	
				NPRA to New TAPS	New TAPS to Valdez
Capital					
Above-Ground Pipeline					
Cost Per Mile	9.6	9.6	9.6	9.6	9.6
Number of Miles	412	57	330	128	371
Cost	3,955.2	547.2	3,168.0	1,228.8	3,561.6
Below-Ground Pipeline					
Cost Per Mile	6.2	6.2	6.2	6.2	6.2
Number of Miles	388	58	330	129	371
Cost	2,405.6	359.6	2,046.0	799.8	2,300.2
Pump Stations	724.0	113.1	433.6	177.2	610.8
Terminals (New or Additions)	1,230.0	—	—	1,230.0	
Haul Road	Existing	142.5	826.5	319.2	Existing
Total Capital Cost	8,315.0	1,162.0	6,474.0	10,228.0	
Annual Operating Cost*	145.5	37.5	111.0	175.8	
Engineering and Construction Time (Years)	4	4	4	4	

*2 percent ad valorem taxes not included.

TABLE E-20

COST AND TIMING ESTIMATES
(Costs in Millions of 1981 $)

OIL
500 Thousand Barrels Per Day

MARINE PIPELINES	North Aleutian Shelf	St. George	Navarin	Norton	Hope	Chukchi	Beaufort
Capital							
Cost Per Mile (24-Inch Diameter)	4.8	4.0	—	7.2	6.6	6.9	7.2
Number of Miles	50	200	—	50	100	75	50
Platform		300.0					
Total Capital Costs	240.0	1,100.0	—	360.0	660.0	520.0	360.0
Operating Cost Per Year							
Cost Per Mile	.075	.06	—	.105	.105	.105	.105
Total Operating Cost Per Year*	3.6	16.5	—	5.4	9.9	7.8	5.4
Engineering and Construction Time (Years)	1	2.5	—	4	4	4	4

*2 percent ad valorem taxes not included.

TABLE E-21

COST AND TIMING ESTIMATES
(Costs in Millions of 1981 $)

OIL
500 Thousand Barrels Per Day

TERMINALS	North Aleutian Shelf	St. George	Navarin	Norton	Hope	Chukchi	Beaufort
Capital							
Nearshore Terminal							
Cost Per Berth	460.0	460.0	—	460.0	460.0	460.0	—
Number of Berths	2	2	—	2	2	2	—
Cost	920.0	920.0	—	920.0	920.0	920.0	—
Onshore Facilities Cost	590.0	590.0	—	590.0	590.0	590.0	—
Transshipment Terminal Cost	None Required	None Required	1,510.0	1,510.0	1,510.0	1,510.0	—
Total Capital Cost	1,510.0	1,510.0	1,510.0	3,020.0	3,020.0	3,020.0	—
Operating Cost Per Year							
Nearshore Terminal	7.0	7.0	—	7.0	7.0	7.0	—
Onshore Facilities	24.0	24.0	—	24.0	24.0	24.0	—
Transshipment Terminal			31.0	31.0	31.0	31.0	—
Total Operating Cost Per Year	31.0	31.0	31.0	62.0	62.0	62.0	—
Engineering and Construction Time (Years)	4	4	4	4	4	4	—

TABLE E-22

COST AND TIMING ESTIMATES
(Costs in Millions of 1981 $)

OIL
500 Thousand Barrels Per Day

TANKERS/ICEBREAKERS	North Aleutian Shelf	St. George	Navarin	Norton	Hope	Chukchi	Beaufort
Capital							
Tankers							
Cost Per Tanker	—	—	190.0	330.0	380.0	380.0	—
Number of Tankers	—	—	1.5	2.5	4	6.5	—
Cost	—	—	285.0	825.0	1,520.0	2,470.0	—
Icebreakers/Sea Duty							
Cost Per Breaker	—	—	—	100.0	150.0	150.0	—
Number of Breakers	—	—	—	1	2	2	—
Cost	—	—	—	100.0	300.0	300.0	—
Total Capital Cost	—	—	285.0	925.0	1,820.0	2,770.0	—
Operating Cost Per Year							
Tankers							
Cost Per Tanker	—	—	21.34	26.46	41.11	47.45	—
Cost Per Year	—	—	32.01	54.4*	152.95*	245.0*	—
Icebreakers/Sea Duty							
Cost Per Breaker	—	—	—	15.8	22.1	22.1	—
Cost Per Year	—	—	—	15.8	44.2	44.2	—
Total Operating Cost Per Year	—	—	32.0	70.2	197.15	289.2	—
Engineering and Construction Time							
Years Per Tanker or Breaker	—	—	4	4	4	4	—
Total Tankers	—	—	1.5	2	4	6.5	—
Total Years (Tankers)	—	—	4	4	4	6	—
Total Years (Breakers)	—	—	4	4	4	4	—

*Cost includes credit for non-Arctic voyages.

TABLE E-23

COST AND TIMING ESTIMATES
(Costs in Millions of 1981 $)

OIL
500 Thousand Barrels Per Day

SUPPORT LOGISTICS	North Aleutian Shelf	St. George	Navarin	Norton	Hope	Chukchi	Beaufort
Capital							
Basic Port Cost	20.0	20.0	—	20.0	25.0	30.0	—
Icebreakers (Port Duty)							
Cost Per Breaker	80.0	80.0	80.0	80.0	80.0	80.0	—
Number of Breakers	1	1	1	1	1	1	—
Cost	80.0	80.0	80.0	80.0	80.0	80.0	—
Support Vessels/Tugs	210.0	210.0	210.0	210.0	280.0	280.0	—
Total Capital Costs	310.0	310.0	290.0	310.0	385.0	390.0	—
Operating Cost Per Year							
Basic Port Cost	5.0	5.0	—	5.0	7.0	9.0	
Icebreakers (Port Duty)	13.0	13.0	13.0	13.0	30.0	35.0	—
Support Vessels/Tugs	42.0	42.0	42.0	42.0	56.0	56.0	
Total Operating Cost Per Year	60.0	60.0	55.0	60.0	93.0	100.0	—
Engineering and Construction Time							
Basic Port (Years)	2	2	—	2	3	3	—
Icebreakers (Port Duty) (Years)	3.5	3.5	3.5	3.5	3.5	3.5	—
Support Vessels/Tugs (Years)	2	2	2	2	2	2	—

TABLE E-24

COST AND TIMING ESTIMATES
(Costs in Millions of 1981 $)

GAS
1 Billion Standard Cubic Feet Per Day

LAND PIPELINES (36-Inch Line)	National Petroleum Reserve-Alaska		To Valdez	
	To Wainwright	To Nome	NPRA to New TAPS	New TAPS to Valdez
Capital				
Below-Ground Pipeline				
Cost Per Mile*	10.6	10.6	10.6	10.6
Number of Miles	115	660	257	742
Cost	1,219.0	6,996.0	2,724.2	7,865.2
Pump Stations	—	—	—	—
Terminals (New or Additions)	—	—	—	—
Haul Road	142.5	826.5	319.2	Existing
Total Capital Cost	1,362.0	7,823.0	10,909.0	
Annual Operating Cost†	13.6	78.2	109.1	
Engineering and Construction Time (Years)	4	4	4	

*Includes pipeline and compressor stations at 100-mile intervals, headquarters operation and maintenance, communications system, temporary facilities (camps, etc.), and project management costs. No gas conditioning plant or shipping terminal is included.

†2 percent ad valorem taxes not included.

TABLE E-25

COST AND TIMING ESTIMATES
(Costs in Millions of 1981 $)

GAS
500 Million Standard Cubic Feet Per Day

National Petroleum Reserve-Alaska

LAND PIPELINES (24-Inch Line)	To Wainwright	To Nome	To Valdez: NPRA to New TAPS	To Valdez: New TAPS to Valdez
Capital				
Below-Ground Pipeline				
Cost Per Mile*	9.0	9.0	9.0	9.0
Number of Miles	115	660	257	742
Cost	1,035.0	5,940.0	2,313.0	6,678.0
Pump Stations	—	—	—	—
Terminals (New or Additions)	—	—	—	—
Haul Road	142.5	826.5	319.2	Existing
Total Capital Cost	1,178.0	6,767.0	9,310.0	
Annual Operating Cost†	12.2	70.4	93.1	
Engineering and Construction Time (Years)	4	4	4	

*Includes pipeline and compressor stations at 100-mile intervals, headquarters operation and maintenance, communications system, temporary facilities (camps, etc.), and project management costs. No gas conditioning plant or shipping terminal is included.

†2 percent ad valorem taxes not included.

TABLE E-26

COST AND TIMING ESTIMATES
(Costs in Millions of 1981 $)

GAS
1 Billion Standard Cubic Feet Per Day

LNG TANKERS/ICEBREAKERS	Area: St. George Terminal: Dutch Harbor	Navarin Navarin	NPRA Wainwright	NPRA Nome	NPRA Valdez
Capital					
Tankers					
Cost Per Tanker	300.0	310.0	510.0	460.0	300.0
Number of Tankers	6	7	10	7	6
Cost	1,800.0	2,170.0	5,100.0	3,220.0	1,880.0
Icebreakers/Sea Duty					
Cost Per Breaker	—	—	150.0	100.0	—
Number of Breakers	—	—	2	1	—
Cost	—	—	300.0	100.0	—
Total Capital Costs	1,800.0	2,170.0	5,400.0	3,320.0	1,800.0
Operating Cost Per Year					
Tankers					
Cost Per Tanker	23.54	24.04	39.48	32.20	23.54
Cost Per Year	141.0	188.0	395.0	225.0	141.0
Icebreakers/Sea Duty					
Cost Per Breaker	—	—	22.1	15.8	—
Cost Per Year	—	—	44.2	15.8	—
Total Operating Cost Per Year	141.0	188.0	439.2	240.8	141.0
Engineering and Construction Time					
Years Per Tanker	6	6	6	6	6
Years Per Breaker	—	—	4	4	—

TABLE E-27

COST AND TIMING ESTIMATES
(Costs in Millions of 1981 $)

GAS
500 Million Standard Cubic Feet Per Day

LNG TANKERS/ICEBREAKERS	Area: St. George Terminal: Dutch Harbor	Navarin Navarin	NPRA Wainwright	NPRA Nome	NPRA Valdez
Capital					
Tankers	300.0	310.0	510.0	460.0	300.0
Cost Per Tanker	3	3.5	5	3.5	3
Number of Tankers	900.0	1,085.0	2,550.0	1,610.0	900
Cost					
Icebreakers/Sea Duty					
Cost Per Breaker	—	—	150.0	100.0	—
Number of Breakers	—	—	2	1	—
Cost	—	—	300.0	100.0	—
Total Capital Costs	900.0	1,085.0	2,850.0	1,710.0	900.0
Operating Per Year					
Tankers					
Cost Per Tanker	23.4	24.04	39.4	32.2	23.54
Cost Per Year	70.5	94.0	197.5	112.5	70.5
Icebreakers/Sea Duty					
Cost Per Breaker	—	—	22.1	15.8	—
Cost Per Year	—	—	44.2	15.8	—
Total Operating Costs Per Year	70.5	94.0	241.7	128.3	70.5
Engineering and Construction Time					
Years Per Tanker	6	6	6	6	6
Years Per Breaker	—	—	4	4	—

APPENDIX F: ECONOMIC ASSESSMENT

PART I: OIL CASE ASSUMPTIONS

Oil Case Assumptions

The following assumptions were used in preparing the oil case economics:

1. Production rates are based on analogy with expected and actual production rates of 17 fields recently developed in the North Sea. Although the actual performance in an area will depend on reservoir characteristics, productivity of wells, drilling schedules, and transportation mode, the following performance has been assumed for each of the basins evaluated:
   a) Peak rate of 9.1 percent of reserves per year.
   b) Building up of peak rate from production startup is 20 percent in year 1, 70 percent in year 2.
   c) Peak rate occurs in years 3, 4, and 5.
   d) Starting in year 6, decline is 12 percent per year.
   e) All reserves are produced. There is no automatic cutoff because of high costs in later years.
   f) Associated gas/oil ratio is 1,000 SCF per barrel.
   g) All associated gas is reinjected or used for fuel.
   h) In a few cases, the buildup of production described in (b) above is extended.
   i) Water injection is the primary pressure-maintenance mode and begins in adequate time to avoid pressure depletion. Increasing gas/oil ratio or decreasing wellhead pressures requires artificial lift.
   j) No additional reduction in efficiency is made for the cases where tankers are used, as fleet size and journey times account for any weather-related downtime.
2. An oil price of $36.50 per barrel delivered to the Gulf Coast is used as the base price. The tariff from the Gulf Coast to the ice-free port at Valdez or the Aleutians is $5.00 per barrel, giving a net back to an Alaskan port of $31.50 per barrel, which is the price used.
3. No lease acquisition costs are included in these analyses and bonus calculations cannot be made using these economics, as the cases are too generalized and exclude the effect of risk.
4. Year 1 of the economic runs is the first year after lease sale. As the lease sales are staggered in time, year 1 does not indicate the same calendar year.
5. Constant, unescalated 1981 costs and prices are used throughout this report for capital, operating costs, and oil prices. No attempt has been made to forecast either inflationary trends in expenditures or real growth or decline in oil pricing.
6. For simplicity a royalty of 1/6 was used for all offshore areas and a 20 percent royalty was used for NPRA, North Slope other, and ANWR.

7. Income tax calculations include the following assumptions:
   a) Windfall profits tax is not levied against properties considered in this report.
   b) Depletion allowance is 0 percent.
   c) Investment tax credit equals 10 percent of all tangible investments.
   d) All intangibles are expensed in the year spent. All tangibles are written off using the unit-of-production method.
   e) Onshore leases have a combined federal and state taxation rate of 52 percent. Offshore OCS leases have a 46 percent federal tax rate applied.
   f) Income tax credits that occur in a field development as investment tax credits and operating losses are assumed to offset the operators' taxable income elsewhere.
   g) State and local taxes other than income taxes are applied as currently imposed. These include a state severance tax of 11 percent of wellhead value applied to all onshore production and a state ad valorem tax of 2 percent per year applied to the tangible capital value of all onshore facilities.
8. Financing—all capital is assumed to be 100 percent equity with no financial leverage.
9. Geological and geophysical (G&G) costs for each successful development in a basin are set at $6 MM. Allocation of total industry expenditures to the successful individual cases was considered to be unrealistic. An arbitrary allocation of $3 MM, $2 MM, and $1 MM for years 1, 2, and 3, respectively, was made. This means that only the G&G costs for successful prospects are included in these economic analyses and any unsuccessful G&G costs are excluded.
10. Unit costs used for exploration and development are shown in Figures F-1 and F-2 as a function of reserves. Net transportation costs used are defined by Figures F-3 through F-5.
11. Combining the production from several areas into a group transportation system requires allocation of capital and operating costs for shared facilities. In each use, the reserve chosen for the case is ratioed to the group's economic resource base to develop a cost allocation factor. This calculation is an iterative procedure.
12. In order to assess the impact of various parameters on the economics, the following sensitivities were run on all cases:
   a) Capital expenditures increased by 50 percent.
   b) Capital expenditures reduced by 50 percent.
   c) Price variation of $5/bbl, $10/bbl, -$5/bbl.

   On selected cases—Central Chukchi Shelf, ANWR, and Navarin Basin Shelf—the following additional sensitivities were run:
   d) Zero royalty.
   e) Increase investment tax credit to 30 percent.
   f) Impose one year production delay.

The range of oil prices used in the sensitivity runs is intended to be sufficiently broad to allow future users of the report to correct the then current prices to 1981 constant dollar prices and to find results in the report that encompass these new constant dollar prices. The price sensitivity also allows the reader to consider the economic effect of factors such as different prices for sweet versus sour crudes, or for sales in different markets.

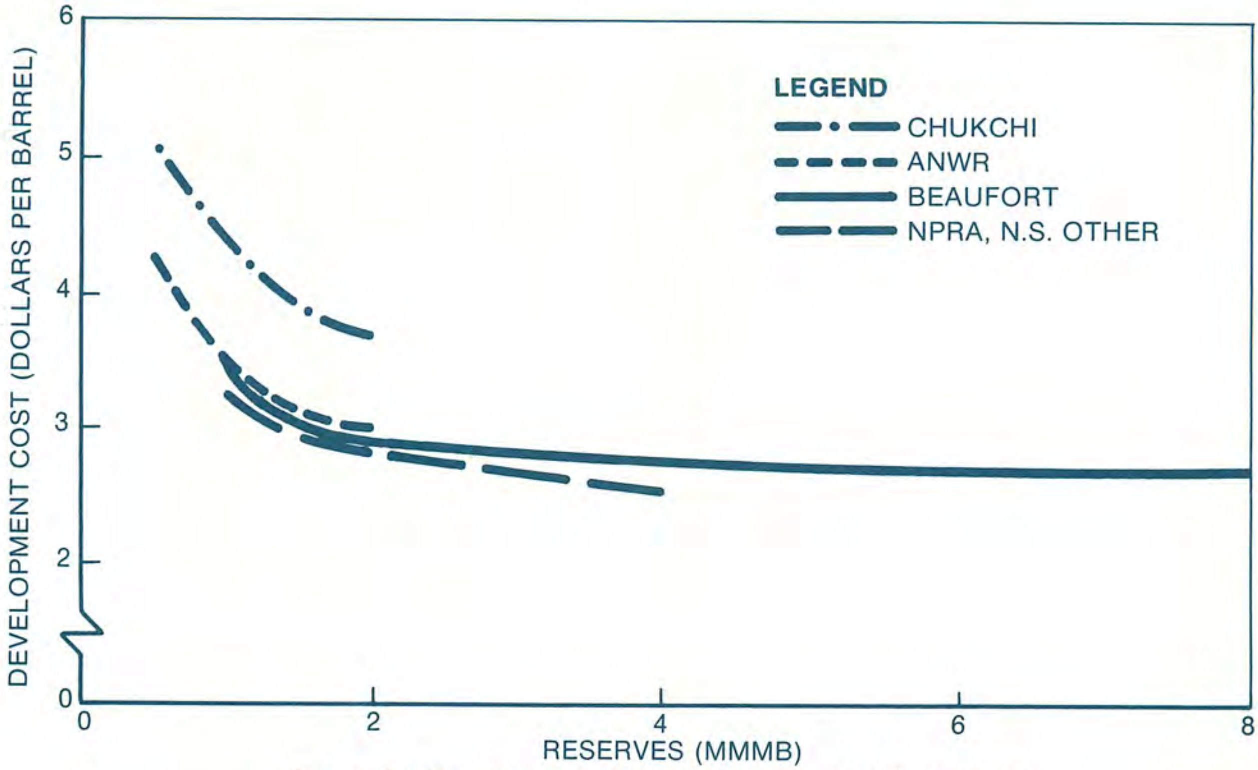


Figure F-l. Development Cost vs. Reserve—Northern Group.

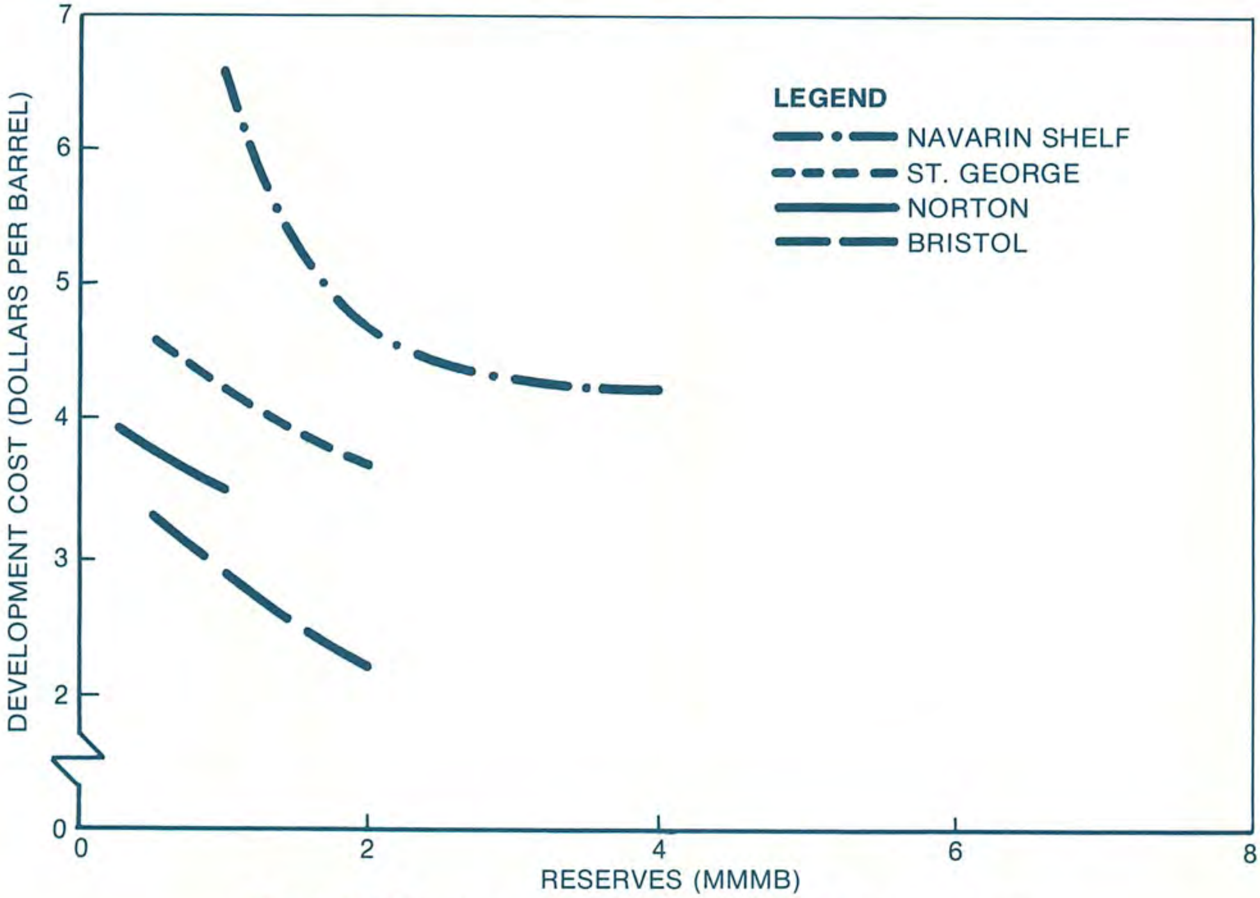


Figure F-2. Development Cost vs. Reserve—Bering Sea Group.

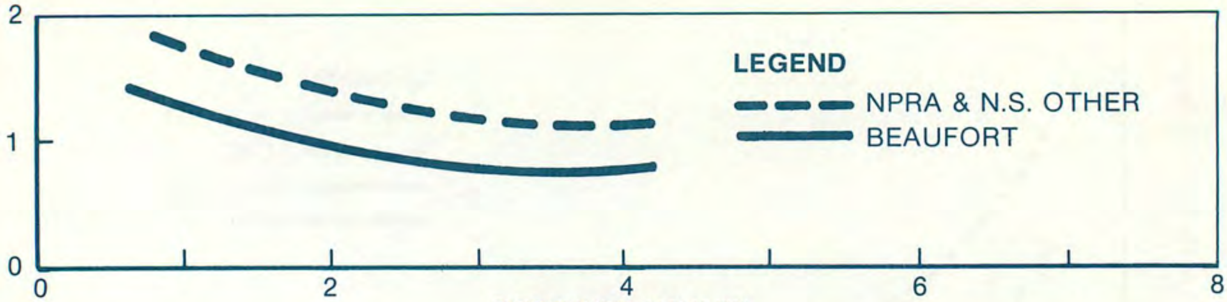


Figure F-3. Net Transportation Cost vs. Reserve—Stand-Alone Cases.

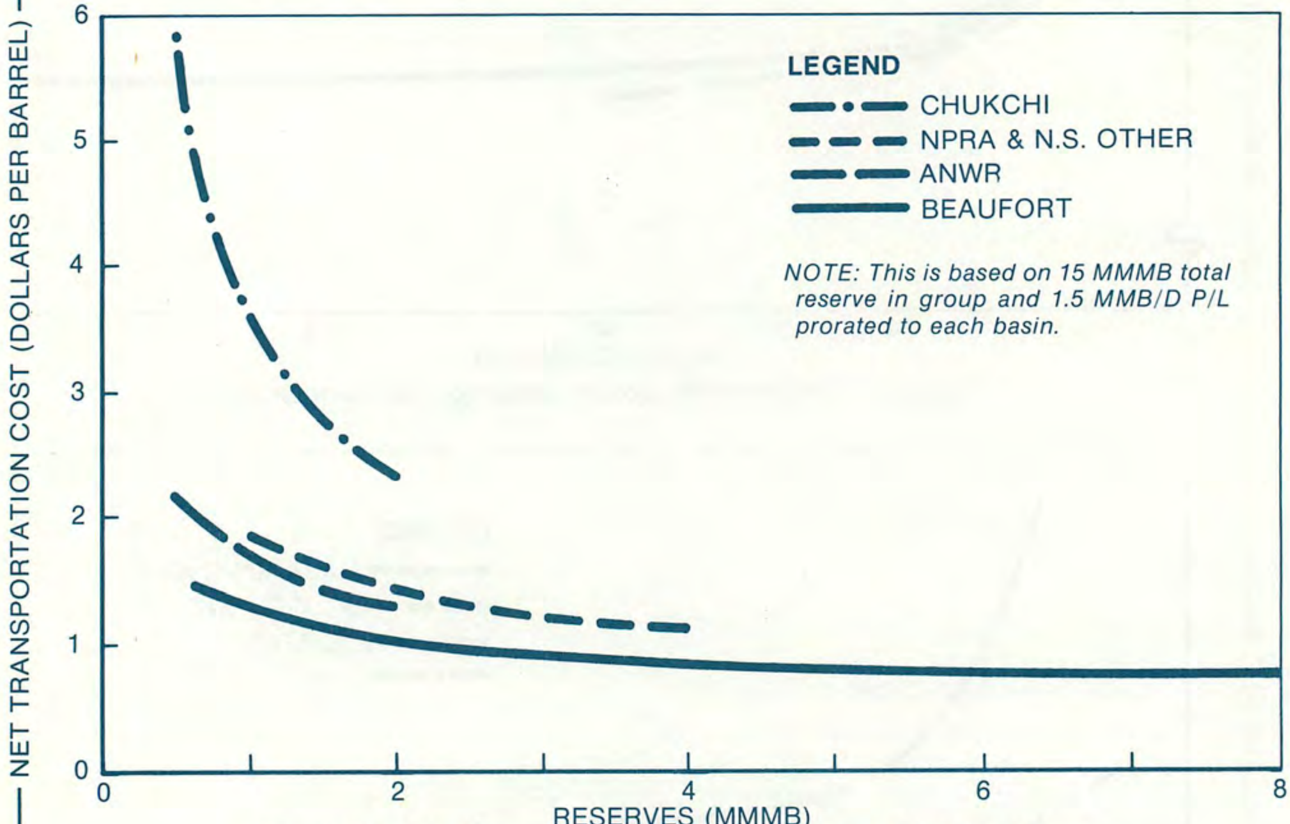


Figure F-4. Net Transportation Cost vs. Reserve—Northern Group.

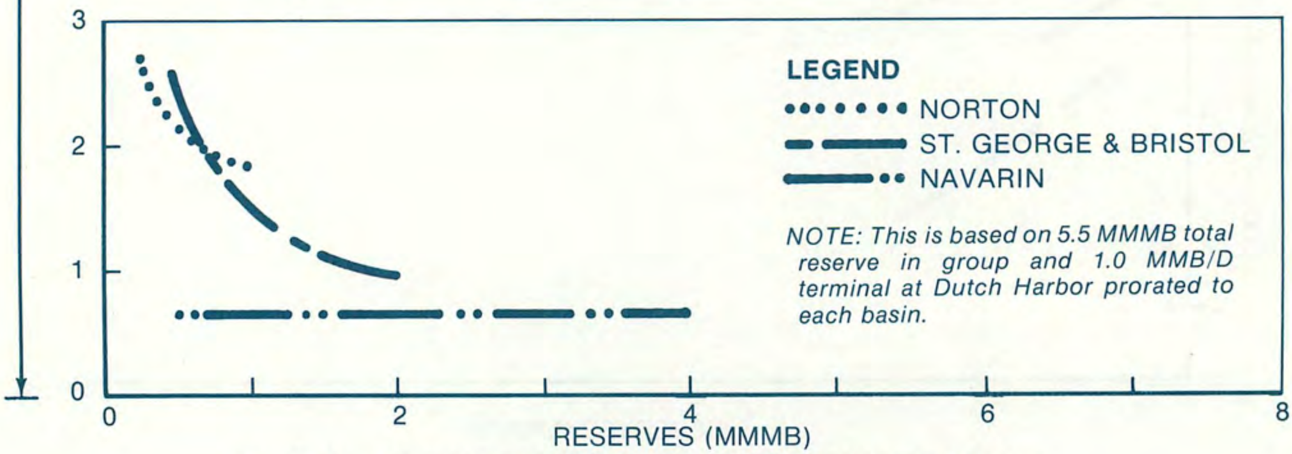


Figure F-5. Transportation Cost vs. Reserve—Bering Sea Group.

PART II: GAS CASE ASSUMPTIONS

Gas Case Assumptions

The following assumptions were used in preparing the natural gas case economics:

1. Natural gas is discovered in sufficiently large quantities to fill the transportation system from a basin for a period of 20 years. Production is maintained by additional drilling and field compression. Produced condensate is re-injected into the reservoir and not sold.
2. No reduction in efficiency is made for tanker downtime resulting from operations in ice-covered areas. The size and the journey time of tankers are adjusted to give 100 percent efficiency.
3. Gas price on the West Coast has been assumed to be $6.48 per MCF ($6.29 per MMBtu). This reflects equivalency with crude oil price, assuming a landed crude oil price of $36.50 per barrel on the West Coast.
4. Natural gas price sensitivity runs were made to allow future use of the study when 1981 constant dollar prices may be somewhat different than they are today. The range of gas prices used in the sensitivity runs is intended to be sufficiently broad to allow future users of the report to correct the then current prices to 1981 constant dollar prices and to find results in the report that encompass these new constant dollar prices.

   The prices selected for sensitivity are:

$6.48 per MCF	Base Case
$7.52 per MCF	+1.04
$8.55 per MCF	+2.07
$5.44 per MCF	−1.04

5. Other assumptions are identical to 3 through 9 of the oil cases.

Note: An acceptable DCF rate of return for the natural gas industry is generally about 1-1/2 percentage points less than the DCF rate of return for the crude oil industry. This difference between the DCF rate of return for natural gas and crude oil is due to the regulated elements (i.e., pipeline and plant) of the natural gas chain. It is generally accepted that the cost of capital for a regulated utility is less than that for companies that face the threat of competition. The monopoly status offered natural gas pipelines by the FERC reduces both topside potential and bottomside risks by limiting the amount of return that can be collected from the customer to an established range of allowable returns, which is generally based on past precedent, and by allowing the regulated entities to pass on certain expenses to the customers. Also, a regulated pipeline venture can generally be more highly leveraged than an oil venture.

PART III:
OIL CASE RESULTS

TABLE F-1

ECONOMIC RESULTS—OIL CASES
(Northern Grouping)

BEAUFORT BASIN	Gross Reserve					
	1,000 MMB		2,000 MMB		4,000 MMB	
	(MM $)	($/B)	(MM $)	($/B)	(MM $)	($/B)
Investment						
Exploration/Production	3,358.0	3.36	5,690.0	2.85	10,851.0	2.71
Transportation	1,286.0	1.29	1,939.0	0.96	3,389.0	0.85
Abandonment	250.0	0.25	500.0	0.25	1,000.0	0.25
Total	4,894.0	4.89	8,129.0	4.06	15,240.0	3.81
Operating Cost						
Direct	2,990.0	2.99	4,238.0	2.12	8,840.0	2.21
Taxes	283.0	0.28	427.0	0.21	744.0	0.19
Total	3,273.0	3.27	4,665.0	2.33	9,584.0	2.4
Cash Flow						
Gross Revenue	31,500.0	31.50	63,000.0	31.50	126,000.0	31.50
Royalty	5,355.0	5.36	10,710.0	5.36	21,420.0	5.36
Operating Cost	3,273.0	3.27	4,665.0	2.33	9,584.0	2.40
Investment	4,894.0	4.90	8,129.0	4.06	15,240.0	3.81
Cash Flow (BFIT)	17,978.0	17.98	39,496.0	19.75	79,756.0	19.94
Income Tax	7,956.0	7.96	17,646.0	8.82	35,702.0	8.93
Cash Flow (AFIT)	10,022.0	10.02	21,850.0	10.93	44,054.0	11.01
Present Value (AFIT) @ 15%	3.0		463.0		1,284.0	
Payout Years	14.81		14.32		14.09	
DCF ROR AFIT Constant 1981 Dollars (%)	15.4		18.4		20.2	

ANWR	Gross Reserve					
	500 MMB		1,000 MMB		2,000 MMB	
	(MM $)	($/B)	(MM $)	($/B)	(MM $)	($/B)
Investment						
Exploration/Production	2,082.0	4.16	3,386.0	3.39	5,512.0	2.76
Transportation	1,082.0	2.16	1,629.0	1.63	2,526.0	1.26
Abandonment	160.0	0.32	320.0	0.32	640.0	0.32
Total	3,324.0	6.65	5,335.0	5.34	8,678.0	4.34
Operating Cost						
Direct	1,863.0	3.73	2,727.0	2.73	4,671.0	2.34
Taxes	1,562.0	3.12	2,916.0	2.92	5,782.0	2.89
Total	3,425.0	6.85	5,643.0	5.64	10,453.0	5.23
Cash Flow						
Gross Revenue	15,750.0	31.50	31,500.0	31.50	63,000.0	31.50
Royalty	3,150.0	6.30	6,300.0	6.30	12,600.0	6.30
Operating Cost	3,425.0	6.85	5,643.0	5.64	10,453.0	5.23
Investment	3,324.0	6.65	5,335.0	5.34	8,678.0	4.34
Cash Flow (BFIT)	5,851.0	11.70	14,222.0	14.22	31,269.0	15.63
Income Tax	2,795.0	5.59	7,005.0	7.01	15,639.0	7.82
Cash Flow (AFIT)	3,053.0	6.11	7,217.0	7.22	15,630.0	7.82
Present Value (AFIT) @ 15%	−273.0		−164.0		210.0	
Payout Years	13.62		12.67		12.01	
DCF ROR AFIT Constant 1981 Dollars (%)	10.1		13.3		16.3	

TABLE F-1 (Continued)

NPRA AND NORTH SLOPE OTHER BASIN

	Gross Reserve					
	1,000 MMB		2,000 MMB		4,000 MMB	
	(MM $)	($/B)	(MM $)	($/B)	(MM $)	($/B)
Investment						
Exploration/Production	3,243.0	3.24	5,610.0	2.81	10,054.0	2.51
Transportation	1,774.0	1.77	2,674.0	1.34	4,342.0	1.09
Abandonment	275.0	0.28	550.0	0.28	1,100.0	0.28
Total	5,292.0	5.29	8,834.0	4.42	15,496.0	3.87
Operating Cost						
Direct	2,652.0	2.65	4,671.0	2.34	8,478.0	2.12
Taxes	2,933.0	2.93	5,665.0	2.83	11,445.0	2.86
Total	5,585.0	5.69	10,336.0	5.17	19,923.0	4.98
Cash Flow						
Gross Revenue	31,500.0	31.50	63,000.0	31.50	126,000.0	31.50
Royalty	6,300.0	6.30	12,600.0	6.30	25,200.0	6.30
Operating Cost	5,585.0	5.59	10,336.0	5.17	19,923.0	4.98
Investment	5,292.0	5.29	8,834.0	4.42	15,496.0	3.87
Cash Flow (BFIT)	14,323.0	14.32	31,230.0	15.62	65,381.0	16.35
Income Tax	7,050.0	7.05	15,582.0	7.79	32,855.0	8.21
Cash Flow (AFIT)	7,273.0	7.27	15,649.0	7.85	32,527.0	8.13
Present Value (AFIT) @ 15%	−164.0		132.0		836.0	
Payout Years	12.66		12.11		11.75	
DCF ROR AFIT Constant 1981 Dollars (%)	13.3		15.8		17.7	

CHUKCHI BASIN

	Gross Reserve					
	500 MMB		1,000 MMB		2,000 MMB	
	(MM $)	($/B)	(MM $)	($/B)	(MM $)	($/B)
Investment						
Exploration/Production	2,505.0	5.01	4,285.0	4.29	7,306.0	3.65
Transportation	2,916.0	5.83	3,578.0	3.57	4,540.0	2.27
Abandonment	650.0	1.30	1,300.0	1.30	2,600.0	1.30
Total	6,071.0	12.14	9,163.0	9.16	14,446.0	7.22
Operating Cost						
Direct	3,480.0	6.96	4,416.0	4.42	6,024.0	3.01
Taxes	639.0	1.28	789.0	0.79	996.0	0.50
Total	4,119.0	8.24	5,205.0	5.21	7,020.0	3.51
Cash Flow						
Gross Revenue	15,750.0	31.50	31,500.0	31.50	63,000.0	31.50
Royalty	2,677.0	5.35	5,355.0	5.35	10,710.0	5.35
Operating Cost	4,119.0	8.4	5,205.0	5.21	7,020.0	3.51
Investment	6,071.0	12.14	9,163.0	9.16	14,446.0	7.22
Cash Flow (BFIT)	2,882.0	5.76	11,778.0	11.78	30,824.0	15.41
Income Tax	856.0	1.71	4,715.0	4.72	13,085.0	6.54
Cash Flow (AFIT)	2,026.0	4.05	7,062.0	7.06	17,739.0	8.87
Present Value (AFIT) @ 15%	−636.0		−648.0		−469.0	
Payout Years	22.33		19.82		18.59	
DCF ROR AFIT Constant 1981 Dollars (%)	3.7		7.6		11.5	

TABLE F-2

ECONOMIC RESULTS—OIL CASES
(Bering Sea Grouping)

NORTON BASIN	Gross Reserve					
	190 MMB		500 MMB		1,000 MMB	
	(MM $)	($/B)	(MM $)	($/B)	(MM $)	($/B)
Investment						
Exploration/Production	996.0	5.24	1,876.0	3.75	3,486.0	3.49
Transportation	799.0	4.21	1,247.0	2.49	2,241.0	2.24
Abandonment	83.0	0.44	166.0	0.33	166.0	0.17
Total	1,878.0	9.88	3,289.0	6.58	5,893.0	5.89
Operating Cost						
Direct	2,116.0	11.14	3,780.0	7.56	5,600.0	5.60
Taxes	17.0	0.09	46.0	0.09	91.0	0.09
Total	2,133.0	11.23	3,826.0	7.65	5,691.0	5.69
Cash Flow						
Gross Revenue	5,985.0	31.50	15,750.0	31.50	31,500.0	31.50
Royalty	1,029.0	5.42	2,677.0	5.35	5,355.0	5.36
Operating Cost	2,133.0	11.23	3,826.0	7.65	5,691.0	5.69
Investment	1,878.0	9.88	3,289.0	6.58	5,893.0	5.89
Cash Flow (BFIT)	945.0	4.97	5,958.0	11.92	14,561.0	14.56
Income Tax	302.0	1.59	2,511.0	5.02	6,287.0	6.29
Cash Flow (AFIT)	643.0	3.38	3,447.0	6.89	8,274.0	8.27
Present Value (AFIT) @ 15%	−268.0		−273.0		−279.0	
Payout Years	15.6		13.9		13.5	
DCF ROR AFIT Constant 1981 Dollars (%)	5.1		10.5		12.5	

BRISTOL BASIN	Gross Reserve					
	500 MMB		1,000 MMB		2,000 MMB	
	(MM $)	($/B)	(MM $)	($/B)	(MM $)	($/B)
Investment						
Exploration/Production	1,351.0	2.70	2,578.0	2.58	3,863.0	1.94
Transportation	1,560.0	3.12	1,771.0	1.77	2,289.0	1.14
Abandonment	135.0	0.27	270.0	0.27	540.0	0.27
Total	3,046.0	6.09	4,619.0	4.62	6,692.0	3.35
Operating Cost						
Direct	1,809.0	3.62	2,750.0	2.75	6,588.0	3.29
Taxes	46.0	0.09	91.0	0.09	183.0	0.09
Total	1,855.0	3.71	2,841.0	2.84	6,771.0	3.39
Cash Flow						
Gross Revenue	15,750.0	31.50	31,500.0	31.50	63,000.0	31.50
Royalty	2,678.0	5.35	5,335.0	5.36	10,710.0	5.36
Operating Cost	1,855.0	3.71	2,841.0	2.84	6,771.0	3.39
Investment	3,046.0	6.09	4,619.0	4.62	6,692.0	3.35
Cash Flow (BFIT)	8,172.0	16.30	18,685.0	18.69	38,827.0	19.41
Income Tax	3,541.0	7.08	8,405.0	8.41	17,430.0	8.72
Cash Flow (AFIT)	4,631.0	9.26	10,279.0	10.28	21,398.0	10.70
Present Value (AFIT) @ 15%	−187.0		258.0		914.0	
Payout Years	14.49		13.53		12.96	
DCF ROR AFIT Constant 1981 Dollars (%)	11.8		18.1		22.1	

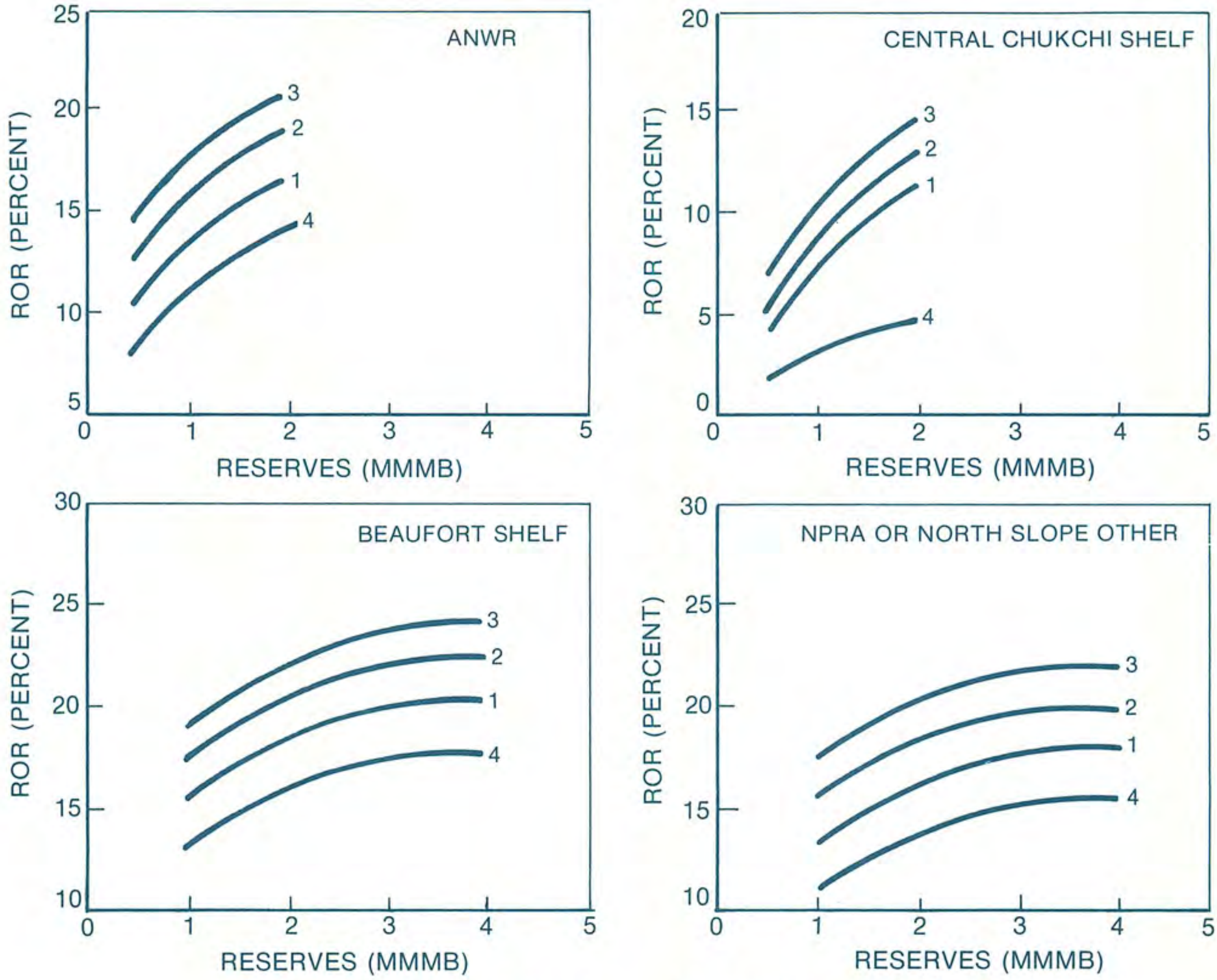
TABLE F-2 (Continued)

NAVARIN SHELF BASIN

	Gross Reserve					
	1,000 MMB		2,000 MMB		4,000 MMB	
	(MM $)	($/B)	(MM $)	($/B)	(MM $)	($/B)
Investment						
Exploration/Production	6,582.0	6.58	9,386.0	4.69	17,080.0	4.27
Transportation	580.0	0.58	1,160.0	0.58	2,319.0	0.58
Abandonment	455.0	0.46	910.0	0.46	1,820.0	0.46
Total	7,617.0	7.62	11,456.0	5.73	21,219.0	5.30
Operating Cost						
Direct	3,996.0	3.99	7,452.0	3.73	9,497.0	2.37
Taxes	75.0	0.075	149.0	0.75	299.0	0.07
Total	4,071.0	4.07	7,601.0	3.80	9,796.0	2.45
Cash Flow						
Gross Revenue	31,500.0	31.50	63,000.0	31.50	126,000.0	31.50
Royalty	5,355.0	5.36	10,710.0	5.36	21,420.0	5.36
Operating Cost	4,071.0	4.07	7,601.0	3.80	9,796.0	2.45
Investment	7,615.0	7.62	11,457.0	5.73	21,219.0	5.30
Cash Flow (BFIT)	14,460.0	14.46	33,232.0	16.62	73,565.0	18.39
Income Tax	6,170.0	6.17	14,560.0	7.28	32,477.0	8.12
Cash Flow (AFIT)	8,290.0	8.29	18,672.0	9.34	41,088.0	10.27
Present Value (AFIT) @ 15%	−490.0		−311.0		−54.0	
Payout Years	15.10		15.19		14.99	
DCF ROR AFIT Constant 1981 Dollars (%)	10.7		13.3		14.9	

ST. GEORGE BASIN

	Gross Reserve					
	500 MMB		1,000 MMB		2,000 MMB	
	(MM $)	($/B)	(MM $)	($/B)	(MM $)	($/B)
Investment						
Exploration/Production	2,286	4.59	4,226	4.23	7,396	3.69
Transportation	1,296	2.59	1,472	1.47	1,907	0.95
Abandonment	180	0.36	360	0.36	720	0.36
Total	3,762	7.52	6,058	6.06	10,023	5.01
Operating Cost						
Direct	4,340	8.68	5,040	5.04	6,748	3.37
Taxes	46	0.09	77	0.08	186	0.09
Total	4,386	8.77	5,117	5.12	6,934	3.47
Cash Flow						
Gross Revenue	15,750	31.50	31,500	31.50	63,000	31.50
Royalty	2,677	5.35	5,355	5.36	10,710	5.34
Operating Cost	4,386	8.77	5,117	5.12	6,934	3.47
Investment	3,762	7.52	6,058	6.08	10,023	5.01
Cash Flow (BFIT)	4,924	9.85	14,970	14.97	35,333	17.67
Income Tax	2,002	4.00	6,479	6.48	15,600	7.80
Cash Flow (AFIT)	2,992	5.98	8,491	8.49	19,733	9.87
Present Value (AFIT) @ 15%	-378		-217		510	
Payout Years	14.6		13.5		12.8	
DCF ROR AFIT Constant 1981 Dollars (%)	8.9		13.0		18.0	



1 = BASE CASE 2 = +$5/BBL 3 = +$10/BBL 4 = -$5/BBL

Figure F-6. Price Sensitivity—Northern Group.

NOTE: This is based on 15 MMMB total reserve in group and 1.5 MMB/D P/L prorated to each basin.

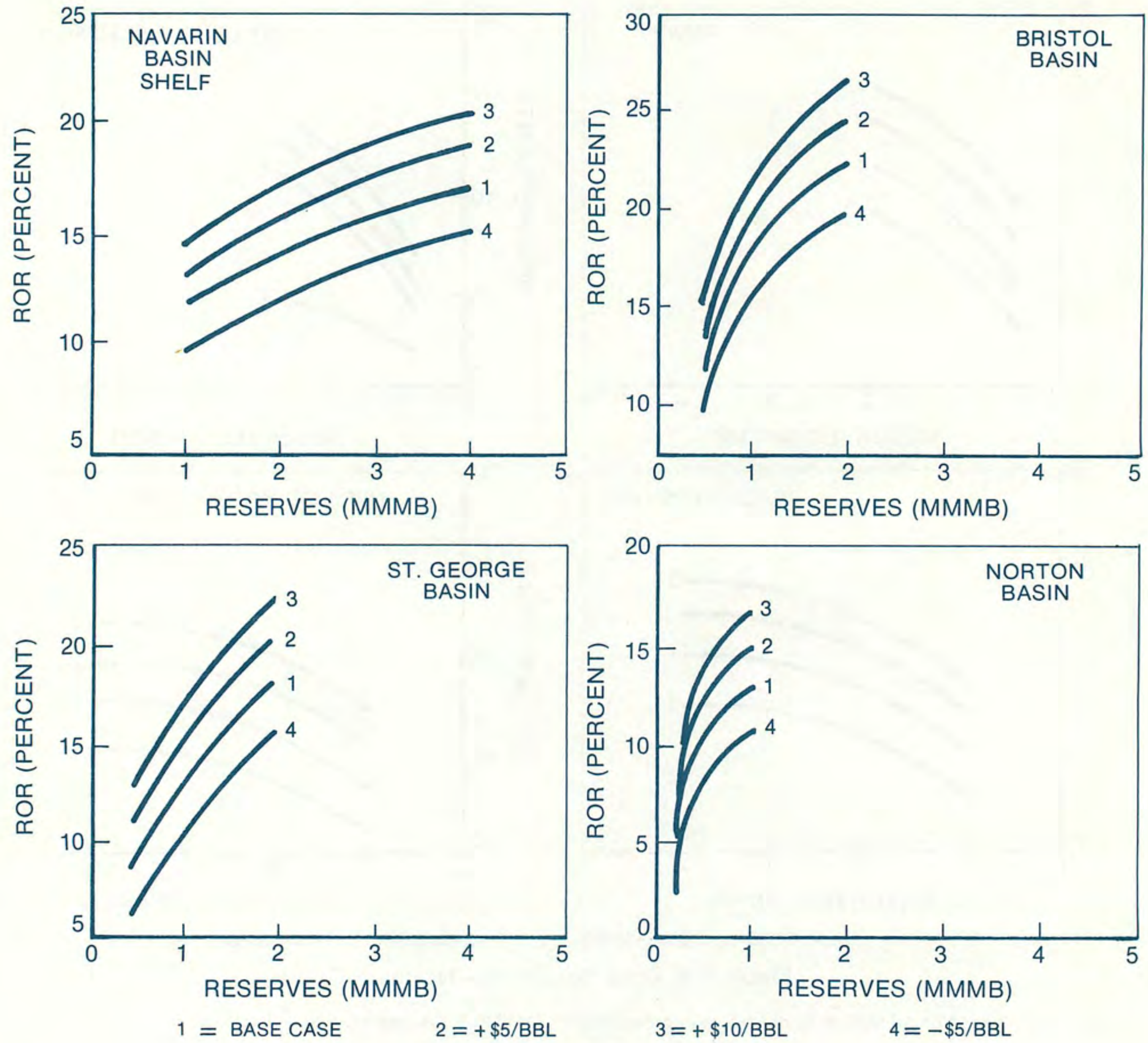


Figure F-7. Price Sensitivity—Bering Sea Group.

NOTE: This is based on 5.5 MMMB total reserve in group and 1.0 MMB/D terminal at Dutch Harbor prorated to each basin.

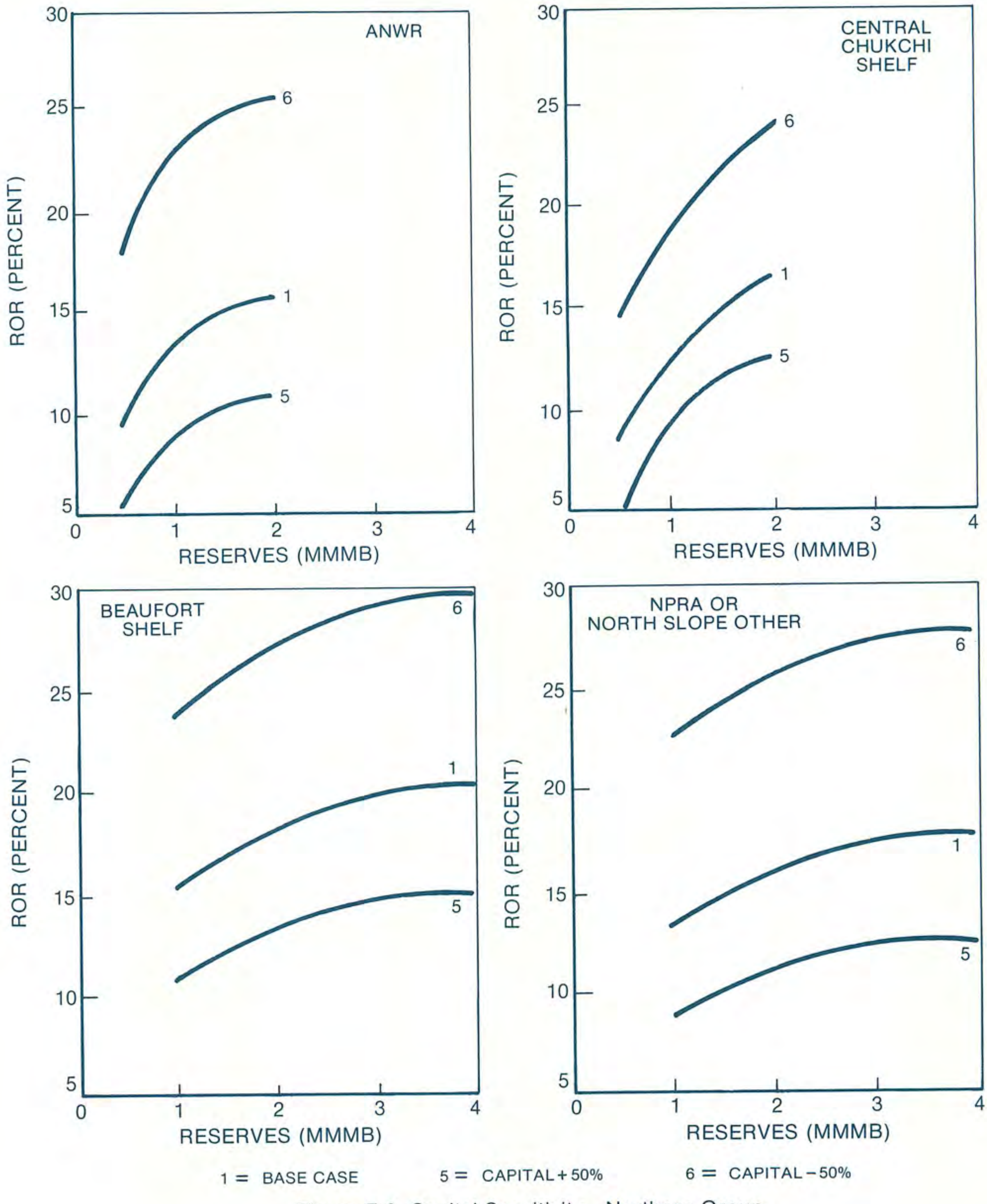


Figure F-8. Capital Sensitivity—Northern Group.

NOTE: This is based on 15 MMMB total reserves in group and 1.5 MMB/D P/L prorated to each basin.

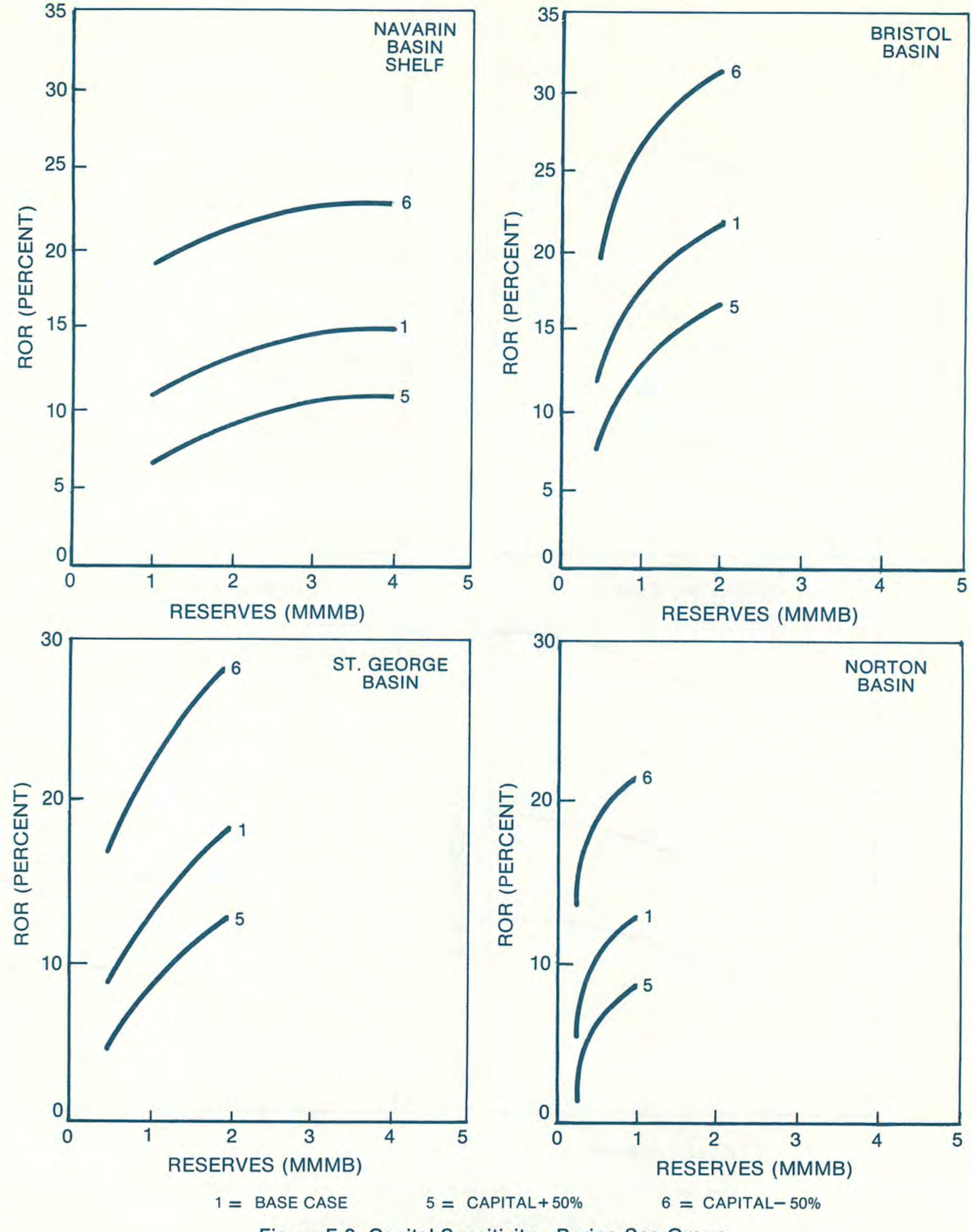


Figure F-9. Capital Sensitivity—Bering Sea Group.

NOTE: This is based on 5.5 MMMB total reserve in group and 1.0 MMB/D terminal at Dutch Harbor prorated to each basin.

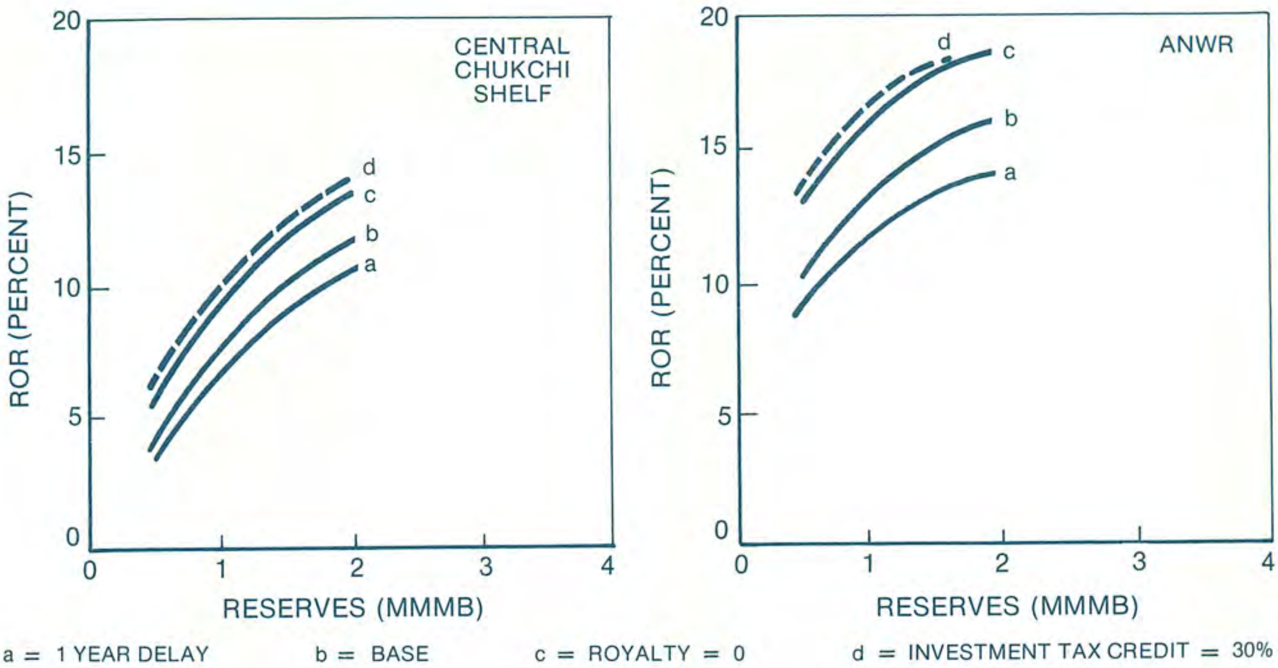


Figure F-10. Other Sensitivity Cases—Northern Group.

NOTE: This is based on 15 MMMB total reserve in group and 1.5 MMB/D P/L prorated to each basin.

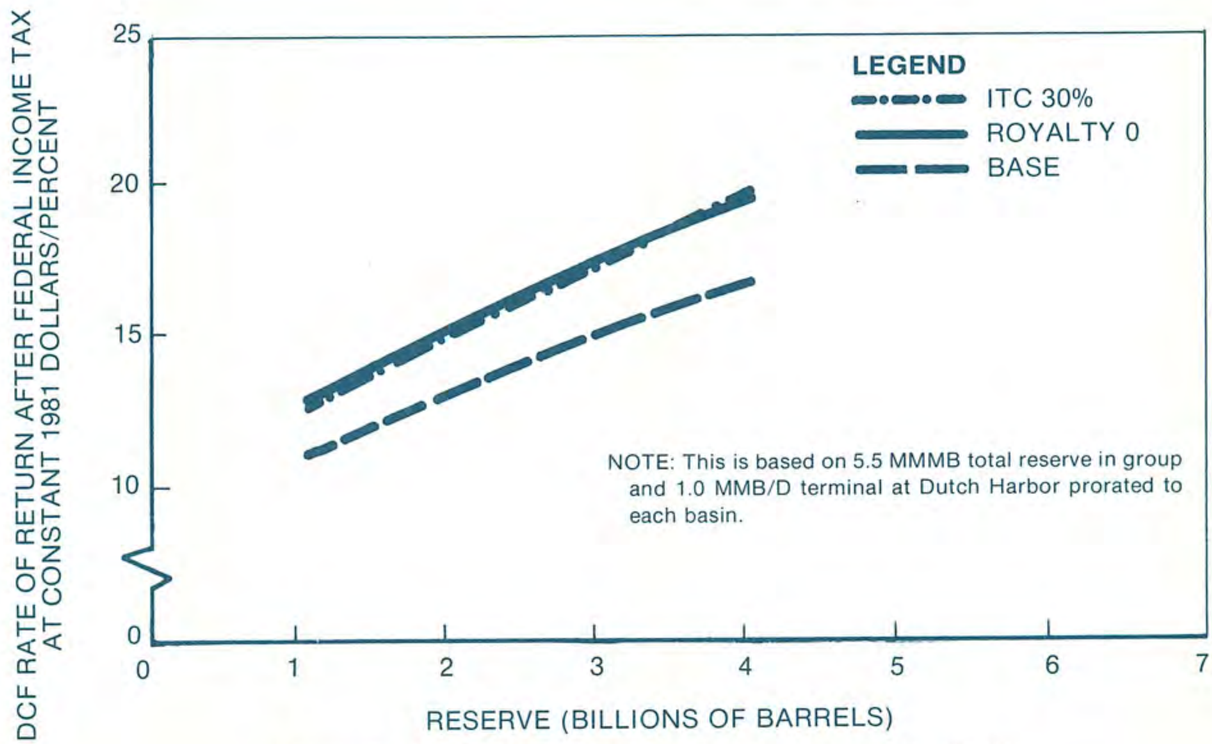


Figure F-11. Other Sensitivity Cases—Navarin Basin Shelf.

PART IV:
GAS CASE RESULTS

TABLE F-3
ECONOMIC RESULTS—NATURAL GAS CASES

NPRA TO VALDEZ

	Gross Reserve			
	5.5 TCF		10 TCF	
	(MM $)	($MCF)	(MM $)	($/MCF)
Investment				
Exploration	156	0.03	156	0.02
Transportation/Production	13,149	2.39	18,164	1.82
Abandonment	185	0.04	275	0.03
Total	13,490	2.45	18,595	1.86
Operating Cost				
Direct	8,641	1.6	12,465	1.3
Taxes	0	0	0	0
Total	8,641	1.6	12,465	1.3
Cash Flow				
Gross Revenue	35,640	6.5	64,800	6.5
Royalty	7,128	1.3	12,960	1.3
Operating Cost	8,641	1.6	8,641	0.9
Investment	13,490	2.5	13,490	1.4
Cash Flow (BFIT)	6,381	1.2	20,780	2.1
Income Tax	1,704	0.3	7,873	0.8
Cash Flow (AFIT)	4,677	0.9	12,907	1.3
Present Value (AFIT) @ 15%	-2,312		-2,573	
Payout Years	21.7		18.7	
DCF ROR AFIT Constant 1981 Dollars (%)	3.3		6.3	

NPRA TO WAINWRIGHT

	Gross Reserve			
	5.5 TCF		10 TCF	
	(MM $)	($MCF)	(MM $)	($/MCF)
Investment				
Exploration	156	0.03	156	0.02
Transportation/Production	10,203	2.39	17,163	1.72
Abandonment	185	0.03	273	0.03
Total	10,544	1.92	17,592	1.76
Operating Cost				
Direct	12,228	2.2	18,825	1.9
Taxes	0	0	0	0
Total	12,228	2.2	18,825	1.9
Cash Flow				
Gross Revenue	35,640	6.5	64,800	6.5
Royalty	7,128	1.3	12,960	1.3
Operating Cost	12,228	2.2	18,825	1.9
Investment	10,544	1.9	17,592	1.7
Cash Flow (BFIT)	5,740	1.0	15,423	1.5
Income Tax	1,704	0.3	5,509	0.6
Cash Flow (AFIT)	4,034	0.7	9,914	1.0
Present Value (AFIT) @ 15%	-1,816		-2,781	
Payout Years	22.3		20.4	
DCF ROR AFIT Constant 1981 Dollars (%)	3.4		4.9	

TABLE F-3 (Continued)

NPRA TO NOME	Gross Reserve			
	5.5 TCF		10 TCF	
	(MM $)	($MCF)	(MM $)	($/MCF)
Investment				
Exploration	156	0.04	156	0.02
Transportation/Production	11,741	2.13	19,155	1.96
Abandonment	207	0.04	292	0.02
Total	12,104	2.2	19,999	2.00
Operating Cost				
Direct	12,054	2.2	14,295	1.4
Taxes	0	0	0	0
Total	12,054	2.2	14,295	1.4
Cash Flow				
Gross Revenue	35,640	6.5	64,800	6.5
Royalty	7,128	1.3	12,960	1.3
Operating Cost	12,054	2.2	14,295	1.4
Investment	12,104	2.2	19,999	2.0
Cash Flow (BFIT)	4,354	0.8	17,546	1.8
Income Tax	920	0.2	6,254	0.6
Cash Flow (AFIT)	3,434	0.6	11,292	1.1
Present Value (AFIT) @ 15%	-1,647		-2,362	
Payout Years	22.4		20.5	
DCF ROR AFIT Constant 1981 Dollars (%)	3.1		5.5	

TABLE F-4
ECONOMIC RESULTS—NATURAL GAS CASES

ST. GEORGE BASIN

	Gross Reserve			
	5.5 TCF		10 TCF	
	(MM $)	($MCF)	(MM $)	($/MCF)
Investment				
Exploration	196	0.04	196	0.02
Transportation/Production	6,584	1.19	10,789	1.08
Abandonment	230	0.04	402	0.04
Total	7,010	1.27	11,387	1.14
Operating Cost				
Direct	6,516	1.2	10,215	1.0
Taxes	0	0	0	0
Total	6,516	1.2	10,215	1.0
Cash Flow				
Gross Revenue	35,640	6.5	64,800	6.5
Royalty	6,059	1.1	11,016	1.1
Operating Cost	6,516	1.2	10,251	1.0
Investment	7,010	1.3	11,387	1.1
Cash Flow (BFIT)	16,055	2.9	32,182	3.2
Income Tax	6,868	1.3	13,973	1.4
Cash Fow (AFIT)	9,188	1.7	18,209	1.8
Present Value (AFIT) @ 15%	-763		-893	
Payout Years	17.8		16.9	
DCF ROR AFIT Constant 1981 Dollars (%)	9.0		10.9	

NAVARIN BASIN

	Gross Reserve			
	5.5 TCF		10 TCF	
	(MM $)	($MCF)	(MM $)	($/MCF)
Investment				
Exploration	286	0.05	286	0.03
Transportation/Production	6,423	1.17	7,603	7.60
Abandonment	262	0.05	420	0.04
Total	6,971	1.27	11,307	1.13
Operating Cost				
Direct	8,522	1.5	13,155	1.3
Taxes	0	0	0	0
Total	8,522	1.5	13,155	1.3
Cash Flow				
Gross Revenue	35,640	6.5	64,800	6.5
Royalty	6,059	1.1	11,016	1.1
Operating Cost	8,522	1.5	13,155	1.3
Investment	6,971	1.27	11,307	1.13
Cash Flow (BFIT)	14,088	2.6	29,322	2.9
Income Tax	6,601	1.2	12,703	1.3
Cash Flow (AFIT)	7,487	1.4	16,619	1.7
Present Value (AFIT) @ 15%	1,004		-986	
Payout Years	18.8		17.0	
DCF ROR AFIT Constant 1981 Dollars (%)	7.4		10.4	

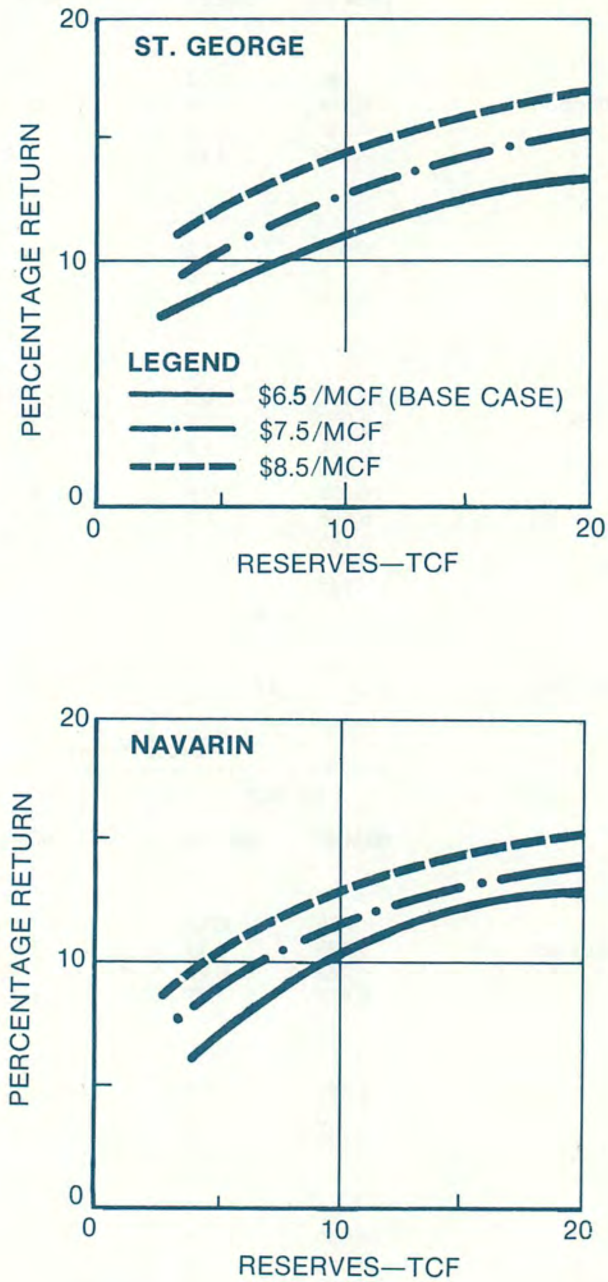


Figure F-12. Price Sensitivity—Gas.

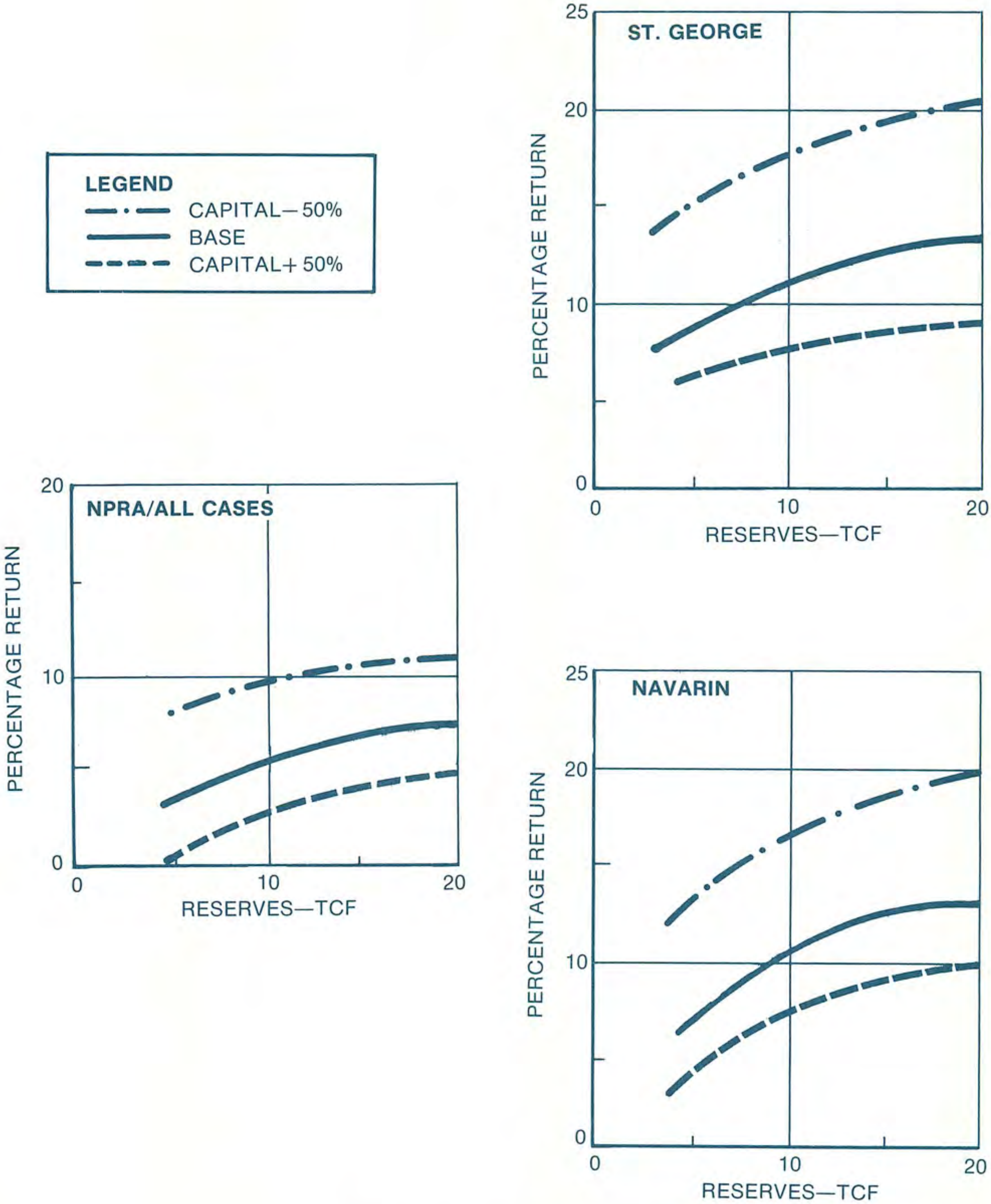


Figure F-13. Capital Sensitivity—Gas.

PART V: ECONOMIC RESOURCE BASE CALCULATION METHODOLOGY

Economic Resource Base Calculation Methodology

The economic resource base (ERB) of each basin is the risked mean potentially recoverable resource that can be economically developed under a selected rate of return criterion. The ERB is determined by combining the probability distribution for risked potentially recoverable resources, as provided in Appendix C, with the economic assessment of the minimum reserve that can be economically developed under selected rate of return criteria, as provided in Chapter Six.

The methodology used in calculating the ERB can best be explained by an example calculation. In the following steps, the Arctic National Wildlife Refuge is used, for illustrative purposes, as a typical basin.

Step 1

The basin's minimum economic reserve for a selected after-tax DCF rate of return of 15 percent is determined, from a graph of reserve vs. DCF rate of return for the basin in Figure 23, to be 1.6 billion barrels of oil.

Step 2

Since the graph of probability distribution of risked potentially recoverable resources on Figure C-12 is on an oil-equivalent basis that combines oil and gas, the minimum economic reserve must be scaled up to use the potential resource curve. The ratio used in scaling up the minimum economic reserve is the risked mean total resource base expressed in billion barrels of oil equivalent (BBOE) divided by the risked mean oil resource base expressed as billion barrels of oil [OIL(BB)]. From Table C-3, the ratio is calculated as 3.71/2.34 =1.59. Multiplying the minimum economic reserve for oil by this ratio gives a minimum economic reserve, on an oil-equivalent basis, of 2.54 billion barrels.

Step 3

Entering the graph of probability distribution of risked potentially recoverable resources (Figure C-12) at 2.54 billion barrels oil equivalent, the chance of discovering at least the minimum economic reserve is determined to be 44 percent.

Step 4

Since the ERB is the risked mean of the reserves greater than the minimum economic reserve, it is determined by integrating the area remaining under the probability distribution curve after the uneconomic resources have been rejected. This economic area is that illustrated in Figure F-14. For the ANWR, the risked mean economic reserve is determined, by integration, to be 3.28 billion barrels on an oil-equivalent basis.

Step 5

To reconvert to an oil basis, the calculated ERB, on an oil-equivalent basis, is divided by the scaling factor of 1.59, as determined in Step 2. This gives an ERB of 2.1 billion barrels of oil.

The ERB for each basin was calculated for both 10 and 15 percent rates of return, and for both gas and oil, using the above methodology and the curves provided in Appendix C.

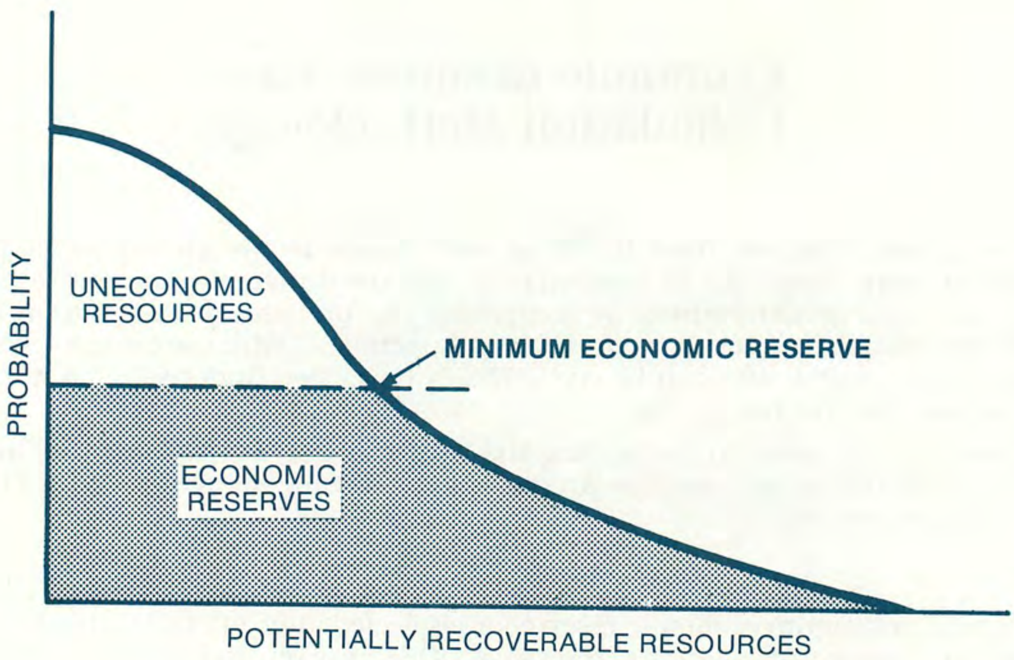


Figure F-14. Economic Resource Base.

APPENDIX G: WORKING PAPERS

Working Papers Supporting the U.S. Arctic Oil and Gas Report

Abstract Number		Number of Pages
Jurisdictional Issues Task Group Papers		
1	Jurisdictional Issues Task Group Report	14
Resource Assessment Task Group Papers		
2	Resource Assessment Task Group Report	57
Exploration Task Group Papers		
3	Exploration Task Group Report (Sections I and II)	37
4	Exploration Task Group Report (Sections III-VII)	41
5	Review of Tract Evaluation by USGS and Role of U.S. Government in Data Acquisition	9
6	Procedures for Arctic Exploration	10
7	Environmental and Operational Considerations for Arctic Exploration	41
Production Task Group Papers		
8	Production Task Group Report—Preface, Summary and Conclusions, Recommendations	27
9	Arctic Provinces and Their Physical Environments	17
10	Environment/Structure Interactions	15
11	Exploration Drilling Systems	6
12	Offshore Development Structures	24
13	Development Wells	10
14	Crude Oil and Gas Production Facilities	28
15	Field Production Operations	7
16	Gas Processing Facilities	15
17	Construction Methods and Equipment	20
18	Field Development and Production	15
19	Exploration and Production Scenarios	23
20	Production Bibliography and Glossary of Terminology and Abbreviations	9
21	Physical Environment of Alaska	137

Abstract Number		Number of Pages

Transportation Task Group Papers

22	Transportation Task Group Report—Summary	42
23	Land Pipelines	43
24	Marine Pipelines	35
25	Arctic Marine Terminals (Nearshore)	78
26	Tankers and Icebreakers	90
27	Support Logistics	68
28	Transportation Bibliography	305

Environmental Protection Task Group Papers

29	Environmental Protection Task Group Report—Executive Summary	49
30	Introduction and Background Information	17
31	Description of the Arctic Physical and Biological Environment	110
32	Fate and Effects of Spilled Oil in the Arctic Environment	49
33	Socio-Economic Impacts	52
34	Socio-Economic Data and Exhibits	59
35	Regional, Community, and Regional Corporation Profile	201
36	Legislative and Regulatory Recommendations	87
37	Legislative and Regulatory Examples, Statute Summaries, and Exhibits	84
38	Key Environmental Resources	67

Economics Task Group Papers

39	Economics Task Group Report	365

Abstracts of Working Papers

These working papers were developed and submitted by the Task Groups of the Committee on Arctic Oil and Gas Resources for the use of the National Petroleum Council (NPC) in preparing its December 1981 report, *U.S. Arctic Oil and Gas*. The sections of the NPC report were based wholly or in part on the work of the Task Groups. These working papers, however, are not a report of the NPC and do not constitute the advice and recommendations of the NPC. The detailed data and conclusions of the Task Groups contained in these papers are being reproduced in the public interest. Publication of these papers was approved by the NPC at its December 3, 1981 meeting. Photocopies of the working papers may be purchased by using the order form that is attached inside the back cover of this report.

Jurisdictional Issues Task Group Papers

1. Jurisdictional Issues Task Group Report (14 pages)

   International boundaries are defined and illustrated by two maps. State/federal jurisdictional issues concerning the Beaufort Sea are discussed and illustrated by a map. The status of onshore federal lands north of latitude 68°N is described.

Resource Assessment Task Group Papers

2. Resource Assessment Task Group Report (57 pages)

   The regions assessed are defined, the data base noted, definitions given, and the assessment methodology described. Assessment results for 20 areas, three composite regions, and the total U.S. Arctic are given in terms of oil equivalents, oil, total gas, natural gas liquids, associated and dissolved gas, and non-associated gas. Major conclusions and recommendations are presented. Task Group report appendices are presented as Appendix C.

Exploration Task Group Papers

3. Exploration Task Group Report—Sections I and II (37 pages)

   The objectives of the Exploration Task Group are defined as a comprehensive review of all factors related to Arctic exploration and as recommendations that would improve Arctic exploratory efforts. Eight recommendations relating to permits and regulations and 17 relating to leasing are presented. A discussion of future technology requirements leads to six specific recommendations and five general recommendations regarding to the U.S. govenment's role in exploration.

4. Exploration Task Group Report—Sections III-VII (41 pages)

   Significant factors affecting exploration are noted and optimal exploration programs for three Arctic areas with differing environments are described. An historical review of U.S. Arctic exploration includes a list of all past exploration activities as well as a proposal for exploration of the Arctic National Wildlife Refuge. Costs for geological and geophysical surveys and for exploratory drilling as applied to the various Arctic environments are reported.

5. Review of Tract Evaluation by USGS and Role of U.S. Government in Data Acquisition (9 pages)

   Presale evaluation of lease tracts, as related to various bidding systems and "fair market value," is discussed. Profit realized from past leasing is reviewed and it is concluded that present procedures inhibit development of OCS resources. The government's role in Arctic data acquisition is reviewed and the consequences of inadequate funding are discussed.

6. Procedures for Arctic Exploration (10 pages)

   Exploration procedures used prior to exploratory drilling are described. Topics discussed include geologic field studies, photographic surveys, geophysical surveys, and geochemical techniques.

7. Environmental and Operational Considerations for Arctic Exploration (41 pages)

   The Arctic environment is described with regard to weather, topography, and animal life for both onshore and offshore regions. The special operational considerations that must be recognized in order to carry out exploratory activities in these regions are detailed. Emphasis is on activities that are usually conducted prior to exploration drilling.

Production Task Group Papers

8. Production Task Group Report—Preface, Summary and Conclusions, Recommendations (27 pages)

   The findings of the Task Group summarize the state-of-the-art of drilling and production technology in Arctic regions and the need for more advanced technology, in order to optimize operations. Typical scenarios for cost and timing of field development are presented. Existing and potential problems caused by legislative and regulatory actions are reviewed and recommendations are made that would help to alleviate these problems. Recommendations are also made in regard to acquiring future data.

9. Arctic Provinces and Their Physical Environments (17 pages)

   This summary describes the physical environment of the individual Arctic regions covered by this report, with particular emphasis on ice. The detailed description is presented in Working Paper No. 21, which is Appendix B in the Production Task Group Report.

10. Environment/Structure Interactions (15 pages)

    Forces that affect offshore structures are discussed with emphasis on those caused by sea ice. Ice forces on fixed structures that result from sheet ice or pressure ridges are analyzed, as are the failure modes encountered. The reaction of compliant floating structures to ice forces is examined along with a discussion of superstructure icing. Wave and earthquake loads are also reviewed.

11. Exploration Drilling Systems (6 pages)

    Exploration drilling systems suitable for each of the three U.S. Arctic regions are described and cost estimates for exploratory drilling in different areas are presented.

12. Offshore Development Structures (24 pages)

    Structures that may be used for offshore development platforms, as well as their costs and selection criteria, are described. Types of platforms reviewed include manmade islands, pile-founded steel structures, gravity structures, and floating platforms.

13. Development Wells (10 pages)

    The drilling and completion of development wells in the Arctic regions is described, with particular emphasis on methods for coping with permafrost. Costs and timing for development drilling in various Arctic areas are presented.

14. Crude Oil and Gas Production Facilities (28 pages)

    Facilities required for both onshore and offshore production are described and typical costs are presented. Particular emphasis is placed on deck concepts for offshore structures. Offshore loading and storage terminal systems are reviewed. Systems for subsea production are also discussed and typical costs are given.

15. Field Production Operations (7 pages)

    Production operations in Arctic regions and their organization are described, with both onshore and offshore considerations noted. Typical manpower and cost data are presented.

16. Gas Processing Facilities (15 pages)

    Alternatives for disposition of natural gas produced in the Arctic are discussed. Reinjection may be employed when economic transportation is unavailable. Transportation may be by pipeline, or by tanker after the gas is either liquefied or converted to other products. Facilities for processing gas into liquefied natural gas (LNG) or methanol are described as they would be constructed in Arctic regions. Costs and yield data for LNG and methanol process plants are presented, including storage, loading, and receiving facilities.

17. Construction Methods and Equipment (20 pages)

    Construction methods and particular Arctic considerations for both onshore and offshore production facilities are discussed. Typical field data for several offshore locations are presented and various types of marine construction equipment and their availability are described. Personnel requirements and availability for Arctic construction projects are reviewed.

18. Field Development and Production (15 pages)

    An historical review is made of field development in the North Sea to serve as a model for timing of offshore U.S. Arctic development. Leasing, exploration, and development times leading to peak production are reviewed, and costs, manpower, physical environment, and delaying factors are discussed.

19. Exploration and Production Scenarios (23 pages)

Some of the figures from this paper are included in Appendix D. Scenarios are presented for both oil and gas production in the U.S. Arctic regions showing timing on a minimum delay basis from lease sale to peak production. These scenarios consolidate timing developed by the Exploration, Production, and Transportation Task Groups and provide a basis for developing economic assessment cases.

20. Production Bibliography and Glossary of Terminology and Abbreviations (9 pages)

An extensive bibliography supporting the papers developed by the Production Task Group and glossary are presented.

21. Physical Environment of Alaska (137 pages)

A detailed description of the physical environment of Arctic Alaska that includes discussions of non-area-specific ice properties and pressure ridges and area-specific meteorology, oceanography, ice conditions, and Arctic soils. Numerous charts, maps, and graphs are used to quantify the descriptions.

Transportation Task Group Papers

22. Transportation Task Group Report—Summary (42 pages)

Various ways of moving oil and gas from representative Arctic producing areas to ice-free ports are summarized on a scenario basis. This discussion provides additional background for the costs that are included in Appendix E. Summaries and recommendations developed by the Task Group teams covering land pipelines, marine pipelines, nearshore terminals, tankers and icebreakers, and support logistics are included.

23. Land Pipelines (43 pages)

Alternative potential land pipelines suitable to transport oil and gas from northern Alaska to various possible ports via several representative pipeline corridors are discussed. It is concluded that present technology is adequate. Representative pipeline corridors are indicated in sufficient detail to define route elevations and hydraulic gradients for pump station design. Construction feasibility, land requirements, mining requirements, cost, and schedule for the various lines are discussed.

24. Marine Pipelines (35 pages)

Potential oil and gas pipelines that would bring production to shore from six geologic basins in the offshore U.S. Arctic are proposed and discussed. It is concluded that the basic technology is available but installation will be difficult and costly. Costs and schedules are estimated, particular problems are identified, and construction techniques are described. Recommendations for research and development in this field are included.

25. Arctic Marine Terminals (Nearshore) (78 pages)

A representative tanker terminal design for Arctic ports is defined and the required facilities are described. Appropriate site requirements are detailed and design and cost-estimate procedures are presented. Construction methods, schedules, and construction manpower requirements are developed. Cost estimates for a typical terminal south of the Bering Strait are presented and further studies needed to optimize the design of such terminals are defined.

26. Tankers and Icebreakers (90 pages)

An extensive discussion of sea and atmospheric conditions in the offshore area addressed is presented for factors that relate to the selection of shipping routes. Ice conditions, ice reconnaissance and forecasting, and wind conditions are discussed in detail, and numerous charts and tables are included. A possible icebreaking tanker design is presented, and manning requirements, costs, and reliability are estimated. Needs for icebreaker assistance are discussed, and designs are suggested for various types of service along with cost estimates.

27. Support Logistics (68 pages)

Requirements for logistical support of offshore oil and gas exploration and development are defined and the limited support potential of existing Alaskan communities is noted. The relation of support requirements to the various phases of offshore oil operations is developed and desirable characteristics for support base locations are detailed. Materials and service requirements, land and labor requirements, and harbor management techniques are detailed, and overall costs are estimated.

28. Transportation Bibliography (305 pages)

An extensive bibliography supporting the papers developed by the Transportation Task Group is presented.

Environmental Protection Task Group Papers

29. Environmental Protection Task Group Report—
Executive Summary (49 pages)

Environmental considerations for both onshore and offshore ecosystems are discussed and data gaps are identified. Waste disposal practices are reviewed and oil spill technology and response capabilities are described. Social and economic factors relating to the native population that will be affected by oil and gas development are discussed. Legislative and regulatory factors that constrain oil and gas operations are noted. Detailed recommendations are listed that are designed to expedite oil and gas development while providing adequate protection of the Arctic environment.

30. Introduction and Background Information (17 pages)

The history of oil and gas operations in the U.S. Arctic is presented, with emphasis on legislative actions affecting exploration. Included is a brief summary of the types of facilities and operations that are associated with oil and gas development.

31. Description of the Arctic Physical
and Biological Environment (110 pages)

An extensive description of both the onshore and offshore physical and biological environment is given, with particular emphasis on the caribou herds, fish resources of representative pipeline corridors, and the fauna of the ice edge community. Potential environmental risks and concerns are addressed, with considerable attention to the potential impact of tanker terminals and the associated tanker routes. Risk avoidance techniques are reviewed with stress on procedures for minimizing fish resource disturbance. Data needs for both onshore and offshore environmental information are discussed.

32. Fate and Effects of Spilled Oil in the Arctic Environment (49 pages)

The disposal of solid and liquid wastes is reviewed with considerable emphasis on the disposal of waste drilling fluids and cuttings. The fate and effects of oil in the Arctic marine environment is addressed, and there is an extensive review of oil spill countermeasures that may be employed under Arctic conditions.

33. Socio-Economic Impacts (52 pages)

    The social and economic environment as it relates to the Alaskan natives is described, with emphasis on the governmental structure. Potential environmental risks are reviewed and particular attention is given to factors affecting relationships between the natives and industrial developers. Significant issues are discussed and recommendations for improved planning and better communication are presented.

34. Socio-Economic Data and Exhibits (59 pages)

    Regional maps showing native land selections and population data are presented. Data on wage and employment, subsistence, and commercial fishing are given. Charts are included showing state government organization and municipal options. This paper constitutes a portion of the appendix to Working Paper No. 33.

35. Regional, Community, and Regional Corporation Profile (201 pages)

    Profiles of regional community centers and regional corporations are given in considerable detail. This paper is the remainder of the appendix to Working Paper No. 33.

36. Legislative and Regulatory Recommendations (87 pages)

    Specific regulatory constraint problem areas are addressed to establish if relief may be obtained through legislative, regulatory, or policy revisions. Each of the key statutes that have a significant impact on Arctic oil and gas activity are reviewed, examples of specific impacts are given, and recommendations are made that could relieve the constraining impacts without detriment to the environment.

37. Legislative and Regulatory Examples, Statute Summaries, and Exhibits (84 pages)

    Examples of the impact of regulatory constraints on specific oil industry projects are presented along with appropriate exhibits. Key statutes that cause regulatory constraints are summarized. This paper constitutes the appendices to Working Paper No. 36.

38. Key Environmental Resources (67 pages)

    The key environmental resources that are known to exist in the western and northern Alaskan coastal zone are identified, located, and discussed. Details are given for birds, fish, and marine mammals. Protected areas including wilderness areas and refuges, and zones of concern are identified.

Economics Task Group Papers

39. Economics Task Group Report (365 pages)

    Details of the economic assessment discussed in Chapter Six are presented as developed from information supplied by other task groups. Methodology and data base information are detailed along with the computed results for both the natural gas and crude oil scenarios.

ACRONYMS AND ABBREVIATIONS

A & D Gas—Associated and dissolved gas

ABSORB—Alaskan Beaufort Sea Oilspill Response Body

ACMP—Alaska Coastal Management Program

AFIT—After federal income tax

ANCSA—Alaska Native Claims Settlement Act

ANGTS—Alaska Natural Gas Transportation System

ANILCA—Alaska National Interest Lands Conservation Act

ANWR—Arctic National Wildlife Refuge

B—Barrels

BB—Billion barrels

BBO—Billion barrels of oil

BBOE—Billion barrels of oil equivalent

B/D—Barrels per day

BFIT—Before federal income tax

BLM—Bureau of Land Management

BOP—Blowout preventer

CEIP—Coastal Energy Impact Program

CIRO—Cook Inlet Response Organization

COE—Corps of Engineers (U.S. Army)

COST—Continental Offshore Stratigraphic Test

CRREL—Cold Region Research and Engineering Laboratory

CRSA—Coastal Resource Service Area

CZM—Coastal Zone Management

CZMA—Coastal Zone Management Act

DCF—Discounted cash flow

DCRA—Department of Community and Regional Affairs (State of Alaska)

DOE—U.S. Department of Energy

EIS—Environmental Impact Statement

EPA—U.S. Environmental Protection Agency

ERB—Economic resource base

GOACO—Gulf of Alaska Cleanup Organization

LNG—Liquefied natural gas

M—Thousand

MB/D—Thousands of barrels of oil per day

MCF—Thousand cubic feet

MM—Million

MMM—Billion

NA Gas—Non-associated gas

N/A—Not applicable

NEPA—National Environmental Policy Act

NGL—Natural gas liquids

NPC—National Petroleum Council

NPDES—National Pollution Discharge Elimination System

NPR-4—Naval Petroleum Reserve Number 4

NPRA—National Petroleum Reserve-Alaska

NSB—North Slope Borough

OCS—Outer Continental Shelf

OCSEAP—Outer Continental Shelf Environmental Assessment Program

PSD—Prevention of Significant Deterioration

REAA—Rural Education Attendance Area

ROR—Rate of return

TAPS—Trans-Alaska Pipeline System

TCF—Trillion cubic feet

UIC—Underground injection control

USGS—U.S. Geological Survey

$—1981 U.S. dollars