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Alaska Oil and Gas: Energy Wealth or Vanishing Opportunity?

Final

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FOREWORD

This study of the oil and gas resources of arctic Alaska was conducted for the Office of Fossil Energy, U.S. Department of Energy, Washington DC. The study was jointly planned and directed by Office of the Deputy Assistant Secretary for Fossil Energy, U.S. Department of Energy and the State of Alaska to provide information to assess the importance to the Nation of the long term production potential of Alaskan oil and gas resources and to provide an inventory and analysis of this potential. It incorporates the cooperative efforts of the U. S. Department of Energy (DOE), the U. S. Department of Interior (DOI), the State of Alaska, the petroleum industry in Alaska, the University of Alaska, and EG&G Idaho, Inc.

The purpose of the study was to systematically identify and review (a) the known and undiscovered reserves and resources of arctic Alaska, (b) the economic factors controlling development, (c) the risks and environmental considerations involved in development, and (d) the impacts of a temporary shutdown of the Alaska North Slope Oil Delivery System (ANSODS).

The study was initiated by EG&G Idaho, Inc. on May 1, 1990 with a data collection phase in Alaska. The first complete draft of the report was delivered on August 4, 1990. Following review and comment by representatives of DOE, DOI, State of Alaska, ARCO Alaska Inc., and BP Exploration (Alaska), Inc. (BP), revisions were made and the final report issued September 30, 1990. Due to the rapidly changing events of the past few months that affect arctic Alaska operations, such as the recent developments on the Alaska North Slope causeway issue leading to the request by BP to suspend their permit application for development of Niakuk and the effects on oil prices of the Middle East crisis, it was not possible for the report to be completely up to date. However, it was determined that the report should issued and additional studies be performed in the future if necessary.

ACKNOWLEDGEMENTS

The support and cooperation received from all the parties involved and contacted during this study was tremendous. Data, guidance, and discussion was provided by the Division of Oil and Gas of the Department of Natural Resources of the State of Alaska, including working space during the data collection phase in Anchorage. Similar cooperation was received from the Department of Revenue, the Alaska Oil and Gas Conservation Commission, and the Governor's Office of the State of Alaska. We wish also to thank the Bureau of Land Management and Minerals Management Service offices in Anchorage, the U.S. Geological Survey of the Department of Interior and ARCO Alaska, Inc., BP Exploration (Alaska), Inc., Conoco, Inc., and Alyeska Pipeline Service Company.

Assistance, input, and guidance was provided by Mr. Guido DeHoratiis (DOE Project Manager) and Dr. Donald Juckett of the Office of Geoscience Research, Office of Fossil Energy, Washington, DC. DOE Idaho Operations Office project management was provided by Dr. Clay Nichols. Special thanks go to Dr. Henry Cole, Office of the Governor, State of Alaska, Juneau, Alaska for his support and for setting up contacts an Alaska and providing information for the study.

Special thanks go to Mr. T. C. Doughty and Mr. H. C. Jamison, retirees from Phillips and ARCO, respectively, who give up their planned summer activities to work on this project. Without their first hand knowledge of the history of North Slope development and extensive experience in operations of the oil industry on the North Slope of Alaska, it would not have been possible to complete such a comprehensive study in the time available.

The authors especially want to thank P. A. Howes, A. L. Kinghorn, and D. L. Thomas for their superior efforts in completing the report by the deadlines. Special thanks go to Diane for volunteering to work on the project and for her enthusiasm and support during the long hours throughout the project and to Peggy for graciously making the many changes requested by the authors in finalizing the report.

CONTENTS

ACRONYMS & ABBREVIATIONS

ACMP	Alaska Coastal Management Program
ACRS	Accelerated Cost Recovery System
ADEC	Alaska Department of Environmental Conservation
ADFG	Alaska Department of Fish and Game
ADNR	Alaska Department of Natural Resources
ANGTS	Alaska Natural Gas Transportation System
ANILCA	Alaska National Interest Lands Conservation Act
ANSODS	Alaska North Slope Oil Delivery System
ANWR	Arctic National Wildlife Range
AOGCC	Alaska Oil and Gas Conservation Commission
ARCO	Arco Alaska, Inc.
BBO	Billion Barrels of Oil
BACT	Best Available Control Technology
BCF	Billion Cubic Feet of Gas
BLM	Bureau of Land Management
BP	B.P. Exploration (Alaska), Inc.
BSTOIP	Barrels of Stock Tank Oil-In-Place
CAA	Clean Air Act
CERCLA	Comprehensive Environmental Response, Compensation, and Liability Act
COE	Army Corps of Engineers
CWA	Clean Water Act
CZMA	Coastal Zone Management Act
DCF	Discounted Cash Flow
DGC	Division of Governmental Coordination

DOE	Department of Energy
DOI	Department of Interior
DPS	Department of Public Safety
DRA	Drag Reducing Agent
EIA	Energy Information Administration
EIS	Environmental Impact Statement
ELF	Economic Limit Factor
EOR	Enhance Oil Recovery
EPA	Environmental Protection Agency
ESA	Endangered Species Act
EWE	Eileen West End
FASP	Fast Appraisal System For Petroleum
FONSI	Finding Of No Significant Impact
FWCA	Fish and Wildlife Coordination Act
FWPCA	Federal Water Pollution Control Act
FWS	Fish and Wildlife Service (US)
F5	5% Probability
F95	95% Probability
IDC	Intangible Development Cost
IRR	Internal Rate of Return
KGS	Known Geological Structure
KIC	Kaktovik Inupiat Corporation
LNG	Liquified Natural Gas
MARS	Minimum Area Resource Size
MBO	Thousand Barrels of Oil
MBPD	Thousand Barrels of Oil Per Day

MEFS	Minimum Economic Field Size
MM	Million
MMB	Million Barrels
MMBO	Million Barrels of Oil
MMBPD	Million Barrels of Oil Per Day
MMPA	Marine Mammal Protection Act
MMS	Minerals Management Service
MOA	Memorandum of Agreement
MONTLAR	Monte Carlo Sampling Program
MTG	Methane-to-Gasoline
NAAQS	National Ambient Air Quality Standards
NAS	National Academy Of Sciences
NEPA	National Environmental Policy Act
NES	National Energy Strategy
NESHAPS	National Emission Standards For Hazardous Air Pollutants
NGL	Natural Gas Liquids
NMFS	National Marine Fishries System
NPC	National Petroleum Council
NPDES	National Pollutant Discharge Elimination System
NPRA	National Petroleum Reserve-Alaska
NPR-4	Naval Petroleum Reserve No. 4
NSB	North Slope Borough
NSPS	Standards of Performance For New Stationary Sources
OCS	Outer Continental Shelf
OCSLA	Outer Continental Shelf Lands Act
OOIP	Original Oil-In-Place

PCB	Polychlorinated Biphenyls
PRESTO	Probabilitistic Resource Estimates Offshore
PSD	Prevention Of Significant Deterioration
RCRA	Resource Conservation and Recovery Act
SAG	Sagavanirktok River
SARA	Superfund Amendments and Reauthorization Act
SDWA	Safe Drinking Water Act
TAGS	Trans-Alaska Gas System
TAPS	Trans-Alaska Pipeline System
TCF	Trillion Cubic Feet of Gas
TSCA	Toxic Substances Control Act
UIC	Underground Injection Control
USDA	United States Department of Agriculture
USGS	United States Geological Survey
WAG	Water-Alternating-Gas (Injection)

OIL AND GAS RESOURCES OF ARCTIC ALASKA: PRESENT AND FUTURE

1. EXECUTIVE SUMMARY

1.1 Purpose, Objectives and Goals

The production of approximately 1.8 million barrels of oil per day (1.8 MMBPD) in January 1990 from the producing fields of arctic Alaska represents 25% of the Nation's domestically produced oil and contributes significantly to the energy security of the United States. This security is derived from the exceptional production capacity of the arctic Alaska fields and the associated transport system. The subject of this study is the area of Northern Alaska that is served or potentially served by the Alaska North Slope Oil Delivery System (ANSODS) which comprises the North Slope producing fields, gathering lines, processing facilities, and the Trans Alaska Pipeline System (TAPS) to the Valdez Terminal.

Production from the Prudhoe Bay oil field has begun to decline, with some estimates calling for a decline curve approaching 10% per year over the next 5 years. Such a dramatic downturn in production could have significant impacts upon the Nation's energy and economic security. It is possible that this decline can be slowed and producible reserves replaced over the years by utilizing advanced oil recovery techniques in existing fields coupled with compensating development of other fields in arctic Alaska. However, the regulatory, economic and environmental factors confronting efforts to further develop the oil fields of the North Slope of Alaska are formidable, and could preclude any real possibility of maintaining or regaining a level of production approximating that of today.

This study provides information useful for the National Energy Strategy being prepared by the Department of Energy and for long term federal and state of Alaska planning. It provides information to enhance the awareness of industry, Congress, and the general public to the importance of existing arctic Alaska reserves, the significance of potential discoveries, and support the need for a secure pipeline and distribution system.

Fields in Alaska that are considered "marginal" in an economic sense are believed to contain immense reserves in excess of those discovered in any onshore field in the Lower 48 states during the past few decades. Yet, because of the complex regulatory, economic and environmental factors relevant to activities on the North Slope, the decision to proceed with development is not an easy one, for industry, the state of Alaska, or the federal government. These decisions require unusually long lead times, and the process from the initial determination by industry that development of a field should be pursued to actual production may take 10 years or more, if development occurs at all.

1.2 Oil And Gas Resource Base

Remaining unexplored or under-explored North Slope areas, both on and offshore, offer the best opportunities in the U.S. for oil and gas discoveries in the giant and super-giant categories. The possibility for such discoveries is the primary motivating factor for industry programs. If they are successful, these activities will have a major impact on the nation's future energy needs.

Industry generally views the 1989 national assessment conducted by the United States Geological Society (USGS) and the Minerals Management Service (MMS), and the 1990 revision by the MMS for the Beaufort and Chukchi Sea as conservative representations of North Slope potential. Estimates of risked undiscovered economically recoverable oil in billions of barrels (BBO) are:

Province	95% Case	Mean	5% Case
Arctic Coastal Plain	0.00	3.36	10.93
Northern Foothills	0.00	0.72	2.64
Beaufort Shelf	----	0.38	----
Chukchi Sea	----	1.36	----

With the continuing decrease in oil and gas exploration in the U.S. and the transfer of interest and funding to foreign exploration, it is probable that interest in Alaska and North Slope exploration will decline. This condition is amplified when coupled with governmental decisions which effectively reduce federal lands available for leasing, exploration, and development.

Because of the extremely high exploration and development costs associated with exploration in the North Slope area, it is advisable for industry and government to work together to achieve cost-efficient results using environmentally sound practices.

The North Slope gas resources, both discovered and undiscovered, are dependent upon increased gas prices, market commitments, and delivery systems from the North Slope to markets. These are critical issues if resources are to be converted to reserves.

1.3 Development and Production: Present and Future

Production from North Slope oil fields was about 1.8 MMBPD in January 1990 and will decrease to about 1.0 MMBPD in 2000. Development of known undeveloped fields and application of advanced recovery techniques to existing fields and potential developments on the North Slope will only slow this decline. Discovery of another field similar in size to Prudhoe Bay or the combination of several large discoveries are necessary to stop or to reverse the decline.

The Most Likely Case forecasts developed in this study include producing North Slope fields and initiation of production from Point McIntyre and Niakuk in 1993. The economically recoverable reserves for this case are 8.6 billion barrels oil (8.6 BBO) using the National Energy Strategy (NES) Reference Case oil prices. Using a TAPS minimum throughput rate of 300 thousand barrels per day (MBPD), pipeline shutdown would occur about year-end 2009 and result in "lost" reserves of about 1.0 BBO.

Known undeveloped fields included in this study, in addition to Point McIntyre and Niakuk, are Gwydyr Bay, Seal Island/North Star, Sandpiper, and West Sak. The estimated reserves for these fields are 700 MMBO. The shutdown of TAPS at 300 MBPD would be delayed by only about 5 years by the development of these fields. The economics of developments similar to these in the TAPS pipeline corridor and close to shore in the Beaufort Sea, near the existing Prudhoe Bay infrastructure, indicates that small fields with about 60 MMBO of reserves can be developed provided the costs of environmental constraints are not significantly increased over historical costs.

Sensitivity evaluations show that oil price is the most critical of the economic variables to continued operation and to further development. Large increases in investments, such as $50 to $100 million (MM) to provide for a continuous bridge in place of breached, gravel causeways to offshore drilling islands, will make developments of smaller fields uneconomical. The request by BP Exploration (Alaska), Inc. (BP) to suspend the Niakuk permitting process as a result of the recent Corp of Engineers' announcement to not allow gravel causeways confirms this result.

Minimum economic field size (MEFS) for the Arctic National Wildlife Refuge (ANWR) is 400 MMBO reserves for a single field located on the West side and 600 MMBO for a field on the East side (Using NES Reference Case oil prices). Smaller fields will be economical if developed as a group connected by feeder pipelines to a main pipeline connecting to TAPS. A group of fields with reserves of 340, 215, and 145 MMBO could also be developed. Changes in oil prices to the low or the high oil price cases as well as major increases in the cost of development due to new environmental requirements change the required field sizes significantly.

The MEFS for the Chukchi Sea case is 2.6 BBO for the NES Reference Case oil prices. Given an existing pipeline constructed to connect a Chukchi Sea development to TAPS at Pump Station No. 2, a 300 MMBO field in the Meade Arch area and a 75 MMBO field in the foothills area of the National Petroleum Reserve - Alaska (NPRA) would be economical to develop.

To show the effect of larger field sizes on operations of then-producing fields and TAPS, four larger prospects in ANWR with a total of 6.25 BBO reserves were selected to illustrate the potential impact of exploration and development of ANWR. Such a development would extend the operating life of TAPS by about 10 years and increase reserves from existing fields and known undeveloped accumulations by about 575 MMBO. Also, with the possibility of a super giant discovery in the Chukchi Sea, a field with recoverable oil of 7.25 BBO was initially assumed for economic evaluation. The economically recoverable reserves for such a field are 6.93 BBO. The addition of such a field would extend the life of TAPS by 13 years and increase reserves from existing and known undeveloped fields by 700 MMBO.

Delayed exploration or development on the North Slope can be very critical to projects coming on in 2000 or later due to high pipeline tariffs or a potential shutdown of TAPS as a result of low throughput. A shutdown of TAPS followed by a restart at a later date may be feasible if sufficient reserves are discovered. However, the costs to maintain the pipeline would not cease during a shutdown and new fields would most likely have to pay normal tariff costs plus the fixed costs related to a shutdown.

1.4 Impact of a Shutdown of the Arctic North Slope Oil Delivery System

Short term shutdowns of TAPS and other field pipelines feeding TAPS do not cause significant problems. Main preparations consist of flushing and freeze protection of small flow lines in pump stations. Freeze protection of the 48 inch main pipeline is not required. Crude oil solidification is not anticipated from cooling of the oil. Security and maintenance of TAPS as well as field pipelines and field gathering systems would continue during any shutdown. Similar conditions would apply to intermittent operation of the pipeline. Thus, fixed costs would continue during down times making it unlikely that these alternatives would be economic.

Increasing the amount of condensate and natural gas liquids transported in TAPS would require construction of a separation plant and other major modifications at Valdez. A major study would be required to determine the feasibility of such expenditures.

North Slope oil production of 1.8 MMBPD will be 25% of the U. S. production in 1990. Using the Most Likely Case forecast of this study, North Slope production will decrease to 300 MBPD or 6% of U.S. production by 2010. Total U.S. production is expected to decrease from 7.7 MMBPD to between 4.1 and 5.6 MMBPD and imports are expected to increase to between 54 and 67% of U. S. requirements by 2010. The increased cost of imported oil due to a shutdown of ANSODS would be $11 billion in 1990, $15 billion in 2000, and $8 billion in 2010.

A permanent shutdown of ANSODS in 1995 would result in lost revenue to the federal government of $37 billion, to the state of Alaska of $54 billion, and to the oil industry of $70 billion, for a total of $161 billion. The impact on the state of Alaska is very significant since the revenue from the oil industry is currently about 85% of general fund revenues.

New discoveries and developments on the North Slope of Alaska will not only add to existing reserves but will allow the continued operation and development of known fields. This effect added to the potential for major discoveries can have a significant and long term benefit to the U.S. in terms of a secure oil supply and an improved balance of payments.

1.5 Environmental Issues

A number of environmental issues are tied inexorably to future oil development on the North Slope. Three of these issues can be viewed as being capable of precluding development of certain fields independent of other factors:

(1) The "no-net-loss" of wetlands policy, if strictly applied to Alaska, could prohibit the construction of virtually any on-shore facility, since virtually all land areas on the North Slope are considered wetlands;

(2) The construction of solid-fill causeways into the Chukchi and

Beaufort Seas, if not permitted, could prevent near-shore fields from being developed by significantly increasing the costs associated with bringing the produced oil to shore; and

(3) The construction of feeder pipelines connecting new fields with the TAPS, if prohibited, could significantly raise the cost of transporting produced oil to market, thereby making outlying fields uneconomic.

Other environmental issues, when viewed independently, would not be expected to prevent development. Compliance with restrictions associated with various combinations of these issues, however, could result in a significant cumulative negative impact on development.

2. OIL AND GAS RESOURCE BASE

2.1 Introduction

The North Slope of Alaska in common usage refers to the northerly slope of the Brooks Range drainage system and includes the northern foothills and the coastal plain. This is an area of 65,000 square miles and includes the 23-million acre National Petroleum Reserve-Alaska (NPRA) and the 19-million acre Arctic National Wildlife Refuge (ANWR). In this report, the offshore prospective petroleum area is also included which is comprised of the Chukchi Sea continental shelf and the Beaufort Sea continental shelf. The offshore area covers approximately 85,000 square miles from the shoreline to the shelf edge (Figure 2-1).

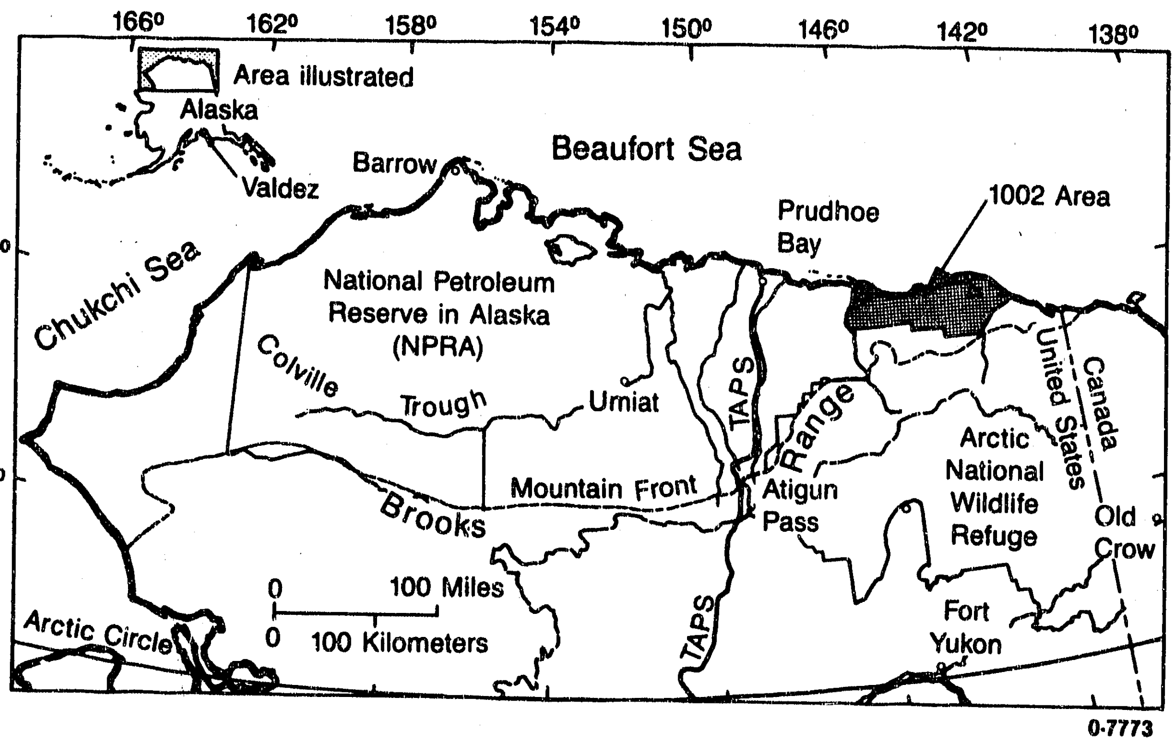


Figure 2-1. Map of northern Alaska showing major geographic features and locations of National Petroleum Reserve Alaska, Arctic National Wildlife Refuge, and the Trans Alaskan Pipeline System (TAPS)[2].

2.1.1 Geologic Framework and History of North Slope Exploration - Overview

For purposes of assessment of oil and gas resources the U.S. Geological Survey (USGS) and the Minerals Management Service (MMS) have divided the region into five geologic provinces (**Figure 2-2**). These include the Southern Foothills, Northern Foothills, and Arctic Coastal Plain onshore; and the Beaufort Shelf and Chukchi Sea offshore. Because they lie far to the north in the deeper waters of the Canada Basin, the Beaufort Basin and Chukchi Borderland are currently considered to have negligible potential by MMS and are not included in this report.

The entire region, comprised of the five provinces, is prospective for oil and gas resources and contains the largest oil field in North America, the Prudhoe Bay Field, which ranks first in production rate in the U.S. at 1.331 MMBPD. It also includes the second ranking producing field, Kuparuk River Field, at 300 MBPD. Total North Slope production was about 25% of the U.S. total and averaged 1.801 MMBPD in January 1990[1]. Although large resources of natural gas have also been discovered (28.5 trillion cubic feet (TCF) in the Prudhoe Bay Field, for example), they remain uneconomic because of the lack of a sufficient and stable price and the lack of a transportation system to market.

The region is the northwestern extension of the Rocky Mountains and Great Plains of the Lower 48 and Canada. It is a sedimentary basin composed of Paleozoic and Mesozoic continental platform and margin deposits derived from a northerly source (in present-day orientation) and Mesozoic and Cenozoic foreland basin deposits derived from a southerly source.[4] The petroleum reserves and resource (potential reserves) occur in both depositional sequences, the older Ellesmerian sequence of Mississippian to Lower Cretaceous Age clastic and carbonate rocks, and the younger Brookian sequence of Lower Cretaceous through Tertiary Age clastic sediments (**Figure 2-3**).

Structural elements of the North Slope consist of the folded and thrusted Brooks Range, the Colville Trough, a foredeep basin lying north of and parallel to the mountain front, and the Barrow Arch which forms the northern

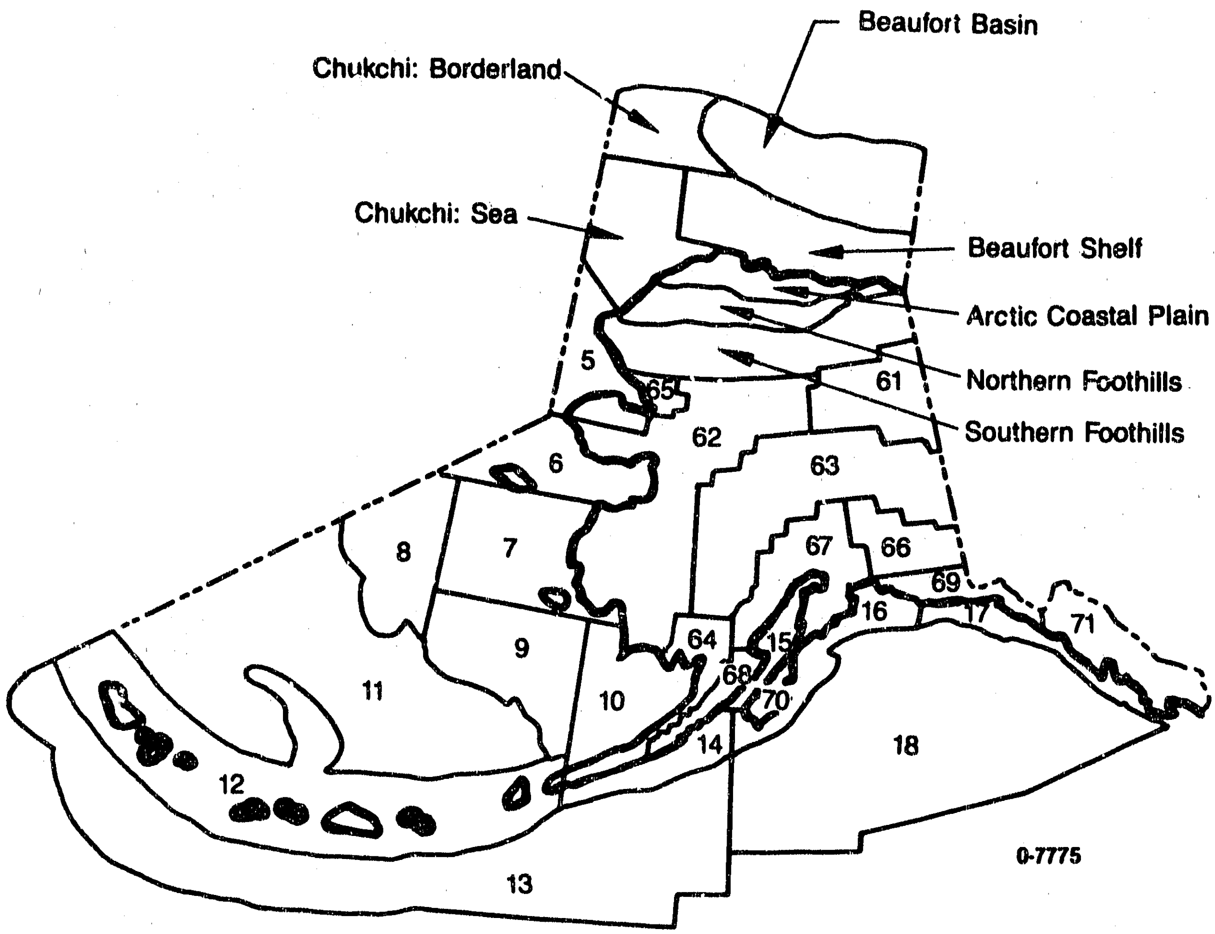


Figure 2-2. Onshore and offshore geologic provinces of Alaska[3].

flank of the basin. The east-plunging Barrow Arch extends some 375 miles northwest to southeast, offshore to onshore, parallel to the coast between Point Barrow and the northernmost point of the Canning River. All of the producing fields and the vast majority of oil and gas accumulations lie along or close to the Barrow Arch (Figures 2-4 and 2-5). North of the Barrow Arch lies a subparallel down-faulted hinge line, the rifted margin, which approximately marks the edge of the continental shelf. This Early Cretaceous rifting of the foreland (northern continental platform in present-day orientation) forms the northern passive continental margin to the foredeep basin bounded on the south by the convergent, compressional tectonic terrain of the Brooks Range, a feature unique to the North Slope region (Figure 2-6).[4]

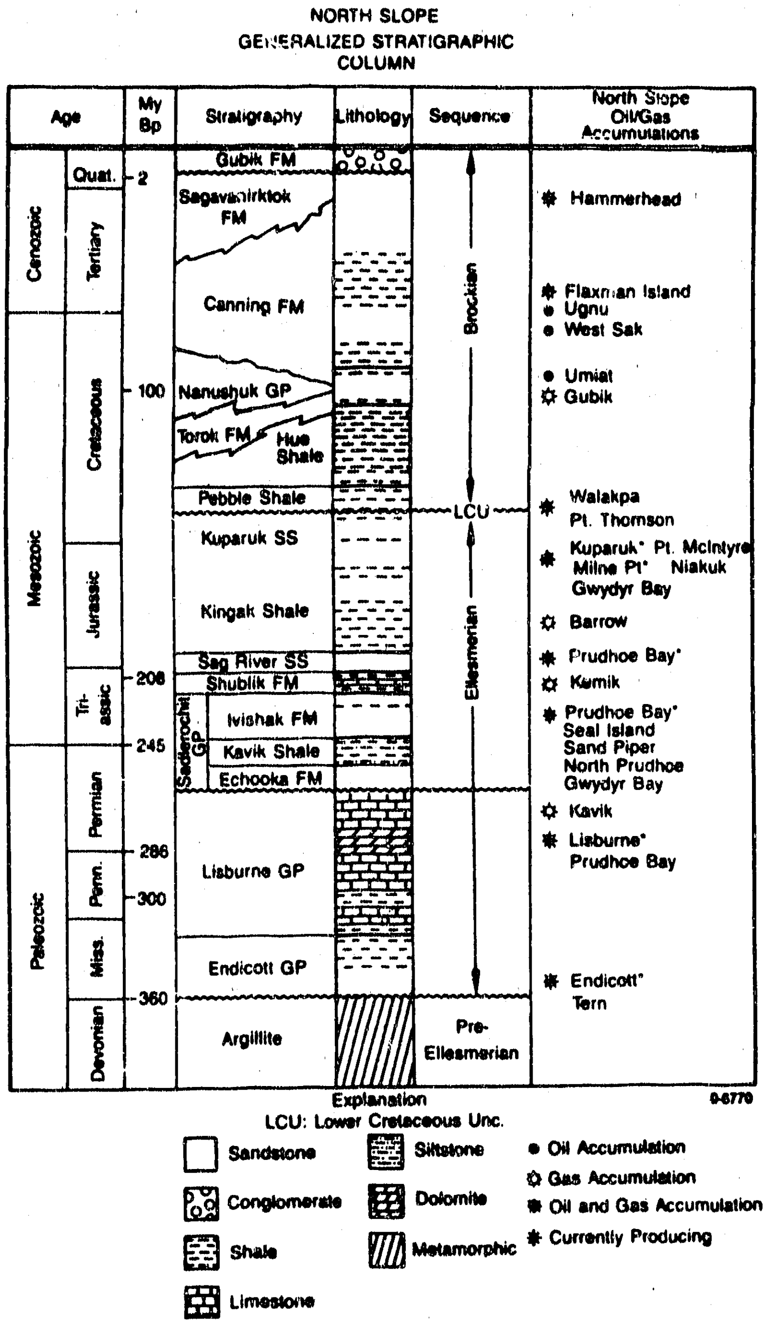


Figure 2-3. Generalized columnar section for the North Slope showing stratigraphic relations, age, lithology, and positions of known oil and gas accumulations.[4,5]

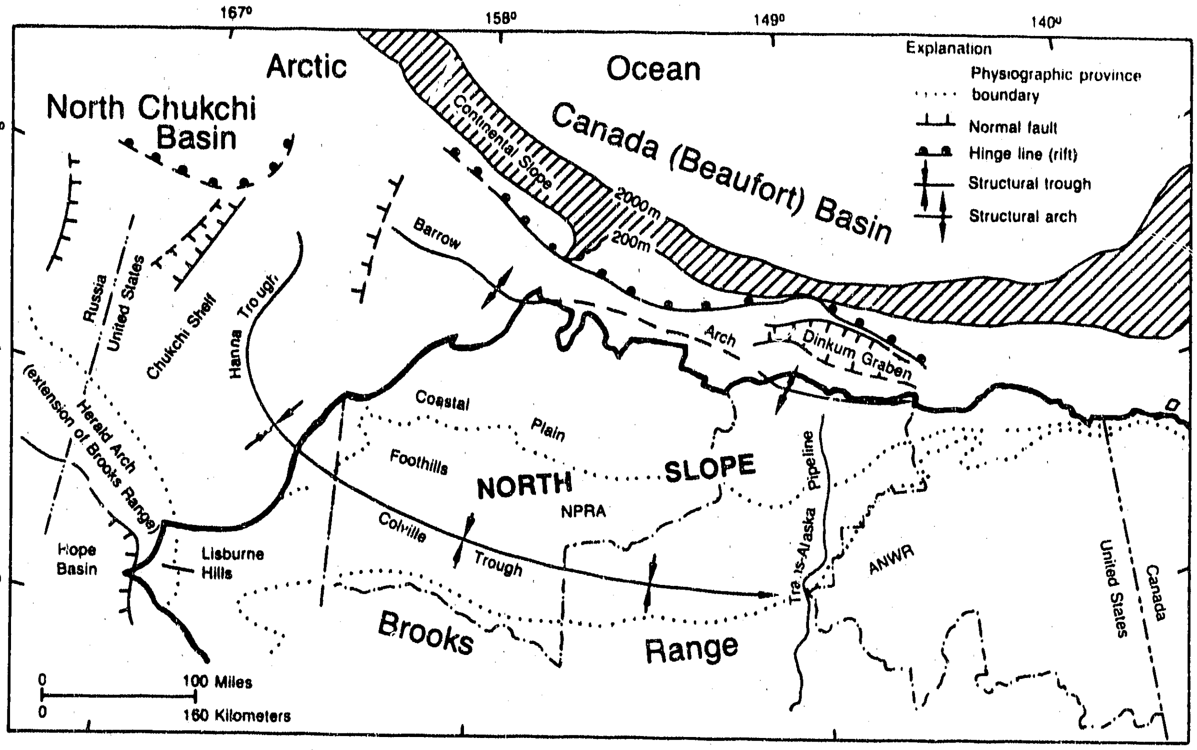


Figure 2-4. Generalized structural features and geologic framework of onshore and offshore northern Alaska.[2]

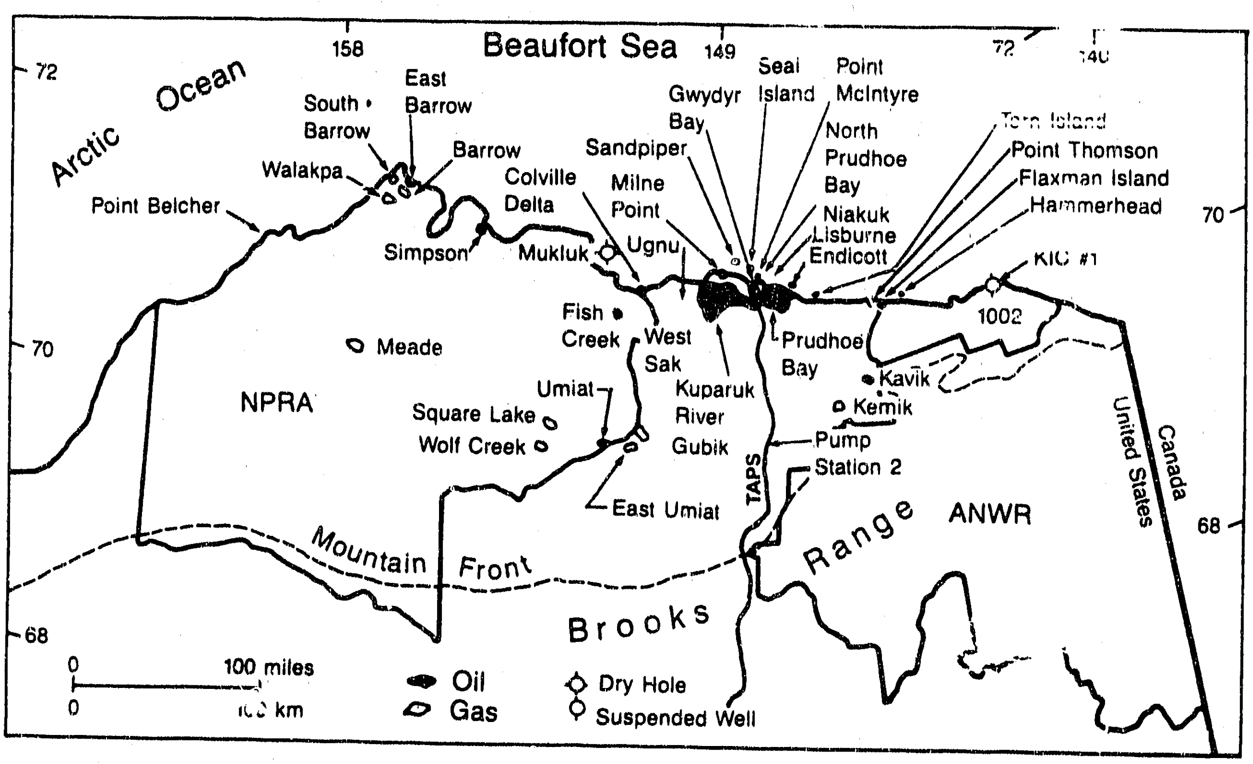


Figure 2-5. Known oil and gas accumulations, selected dry holes and suspended wells, and NPRA-ANWR boundaries, North Slope, Alaska.[6]

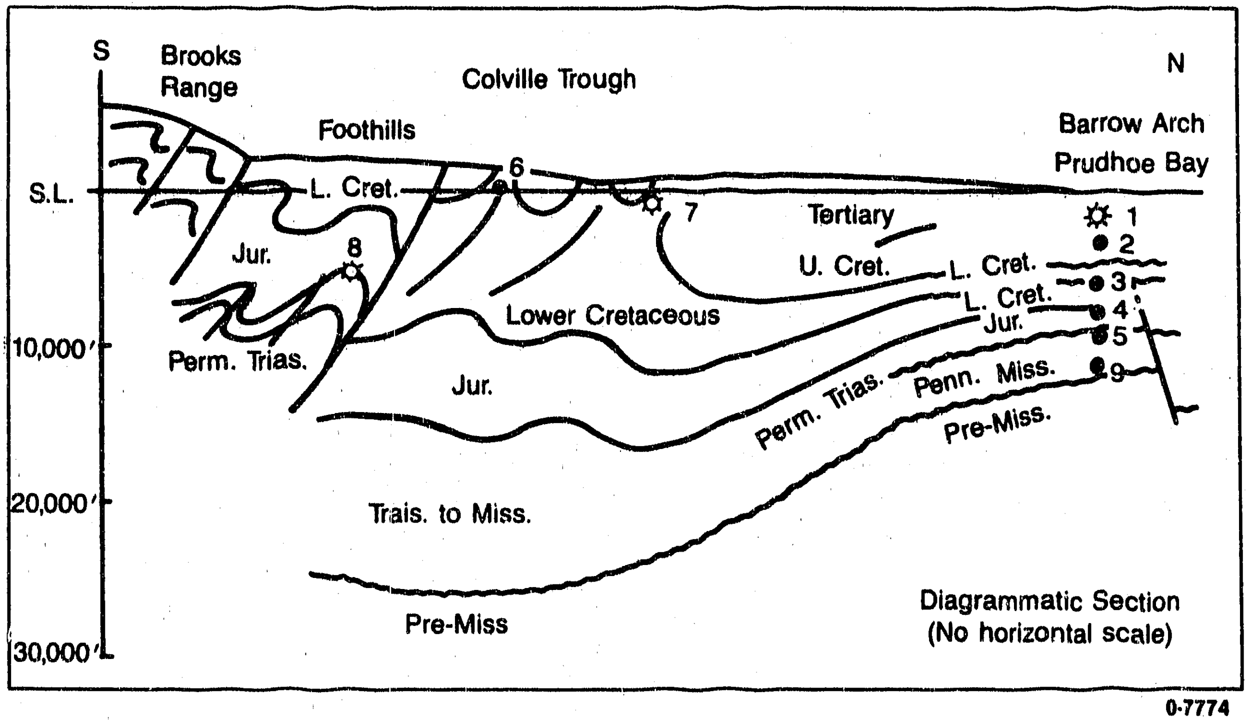


Figure 2-6. North-South cross section showing general structural and stratigraphic relationships from the Brooks Range to Prudhoe Bay. Stratigraphic position of accumulations in various locations indicated by symbols. Prudhoe Bay complex: (1) Tertiary gas, (2) West Sak sands, (3) Kuparuk River Formation, (4) Permo-Triassic, (5) Lisburne Group. *Umiat*: (6) Lower Cretaceous. *Gubik*: (7) Upper/Lower Cretaceous. *Kavik and Kemik*:(8) Permo-Triassic. *Endicott*: (9) Mississippian.[5]

The first commercial production in northern Alaska was established with the 1968 Prudhoe Bay discovery. Nine years elapsed between the discovery and first delivery of oil through TAPS in 1977. Exploration activity has been sporadic during the 22 years since the discovery owing to economic cycles in the petroleum industry, wide fluctuations in world oil prices, regulatory delays, environmental obstacles, and other economic and political effects.

To date, 32 oil and gas accumulations have been discovered and seven fields are productive. Exploration activity continues and wells are being planned and drilled both onshore and offshore.

2.1.2 Current Status of Known Reserves and Resources

On the North Slope of Alaska it is particularly important to distinguish between reserves and resources. Not only are our nation's two largest producing-rate oil fields located there, but also a significant proportion of our proved reserves, as well as discovered and undiscovered resources.

2.1.2.1 Reserves. Economic resources demonstrated with reasonable certainty to be recoverable from known accumulations under existing economic and operating conditions and are shown in Table 2-1.[7]

2.1.2.2 Discovered Resources. Accumulations known to exist but which cannot be produced with current economics and operating conditions. On the North Slope, many of the accumulations already discovered do not meet economic criteria because of the high cost of operations in remote areas. At least some of the accumulations shown in Table 2-2 will satisfy economic criteria and move from resource to reserve status. Both Niakuk and Point McIntyre are likely to be developed in the future, and West Sak is under intensive study and testing, and is the subject of experimental research designed to help produce heavier, more viscous oil. An example of recent developments not included in the data in Table 2-2, is Conoco's development of a portion of the northern end of the West Sak reservoir that lies within the Milne Point Unit. Production is expected to start in January 1991 and total about 6000 bpd from 16 wells. This area of the West Sak reservoir is deep enough and hot enough that waterflooding is expected to be a viable process for recovery.[8] Other areas of the reservoir are expected to require the use of thermal recovery methods such as hot waterflooding or steam flooding.

2.1.3 Summary of North Slope Onshore/Offshore Undiscovered Resource Estimates

Undiscovered resources are those believed to exist outside of known fields or accumulations based upon geologic knowledge and theory. Undiscovered recoverable resources are those which could be produced using current technology. Undiscovered economically recoverable resources could be produced under current economic conditions.

Table 2-1. North Slope Oil and Gas Fields[a] (As of January 1, 1990)

Field Name	Discovery Date	Estimated Original Recoverable Reserves	Production Start-up Date	Cumulative Production	Remaining[b] Reserves/Resource	Estimated Current Total Recoverable Reserves[b]
Prudhoe Bay	4/68	28,500 BCF 9590 MMBO	10/69 (Tests) 7/77(Pipeline)	1211 BCF[c] 6605 MMBO[d]	27,290 BCF 6266 MMBO[d]	28,500 BCF 12,900 MMBO
Kuparuk River	4/69	640 BCF 1600 MMBO	12/81 -----	697 BCF[e] 615 MMBO	520 BCF 1509 MMBO	> 640 BCF 2,124 MMBO
Prudhoe Bay (Lisburne Pool)	4/68	635 BCF 400 MMBO	11/83 (Tests) 3/85	275 BCF[e] 49 MMBO	888 BCF 157 MMBO	> 888 BCF 206 MMBO
Milne Point	10/69	0 100 MMBO	5/85-1/87 4/90	2.9 BCF[e] 9 MMBO	0 51 MMBO	0 BCF 60 MMBO
Endicott	3/78	731 BCF 375 MMBO	1987 ----	85 BCF[e] 82 MMBO	782 BCF 311 MMBO	782 BCF 393 MMBO
S. Barrow	4/49	25.2 BCF	8/49	20.2 BCF	5 BCF	25.2 BCF
E. Barrow	5/74	12.4 BCF	12/83	5.4 BCF	7 BCF	12.4 BCF
TOTALS		30,544 BCF 12,065 MMBO		2296 BCF[e] 7360 MMBO[d]	29,492 BCF 8294 MMBO[d]	>30,847 BCF 15,683 MMBO

a. After Alaska Department of Natural Resources[7]
b. A resource is changed to reserves when a field is developed for production and a transportation system is under development or in-place to move the product to market. Economically recoverable oil (reserves) from Most Likely Case, Table 3-10. The only gas volumes currently considered reserves are the volumes used as Fuel Gas for North Slope operations. Current gas reserves are not given in this table.
c. Production less reinjection.
d. Excludes NGL.
e. Portions of gas reinjected.

Table 2-2. North Slope Undeveloped Oil and Gas Accumulations[4] (As of January 1, 1990)

DISCOVERED RESOURCES

Location	Year	Amount
Umiat	1946	70 MMBO
Fish Creek	1949	Oil
Simpson	1950	12 MMBO
Meade	1950	20 BCF
Wolf Creek	1951	Gas
Gubik	1951	600 BCF
Square Lake	1952	58 BCF
E. Umiat	1963	4 BCF
Kavik	1969	Gas
West Sak	1969	0-1200 MMBO[a]
Ugnu	1969	Heavy Oil
Gwydyr Bay	1969	30-60 MMBO
No. Prudhoe	1970	75 (?) MMBO
Kemik	1972	Gas
Flaxman Island	1975	Oil
Point Thomson	1977	300 MMBO[b], 5000 BCF
Walakpa	1980	Gas
Niakuk	1981	58 MMBO,30 BCF
Tern Island	1982	Oil
Seal Island	1984	150 MMBO
Hammerhead	1985	Oil
Colville Delta	1985	Oil
Sandpiper	1986	Oil
Barrow	1988	Gas
Point McIntyre	1988	300 MMBO

a. Heavy Oil
b. Condensate

Although many resource assessments of parts or all of the North Slope petroleum province have been conducted, the most recent, exhaustive, and authoritative report was issued by the Department of Interior (DOI) in 1989.[3] The work was performed as part of the national assessment by the USGS and MMS with an effective date of January 1, 1987. Thus, as related to this discussion, the estimates are 3-1/2 years old. More recently, January 1990, the MMS revised the estimates for the Beaufort Sea and Chukchi Sea.[9]

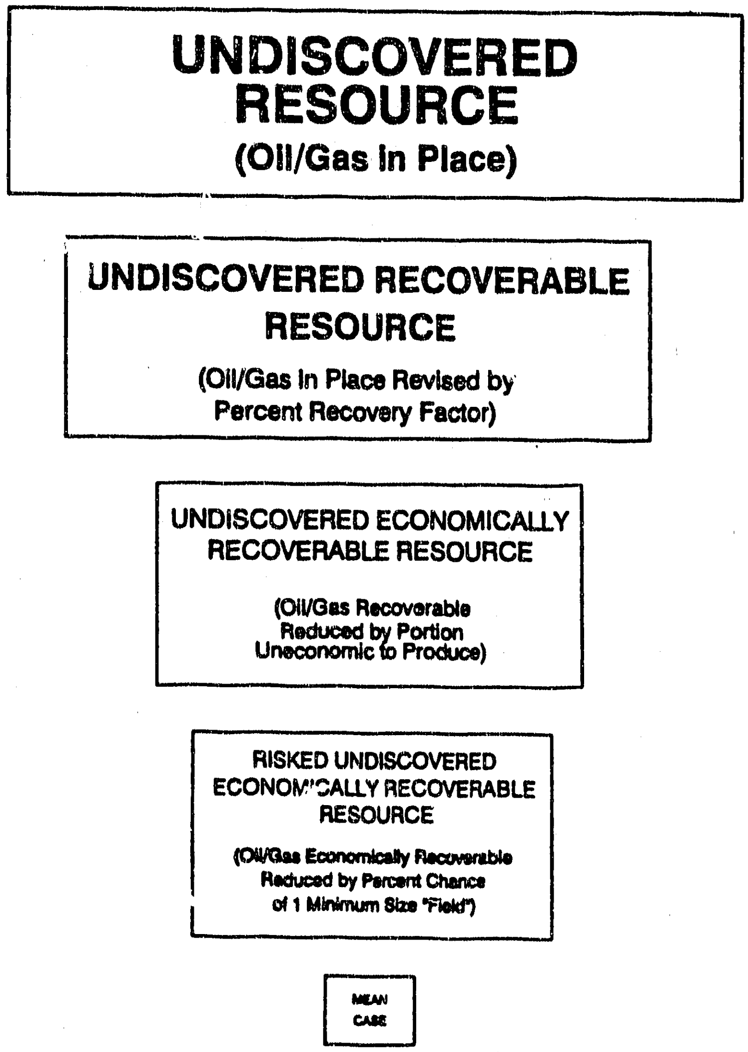
In order to summarize the latest estimates of undiscovered economically recoverable resources for the two offshore and three onshore North Slope Provinces, further description and definition are required.

Resource estimates are normally reported now as probability distributions (ranges) with low fractile (F95) and high fractile (F5) values. The F95 indicates a 19 in 20 chance that <u>at least</u> the amount tabulated will occur, or a 95% probability. The F5 represents a 1 in 20 chance, or a 5% probability. The mean is a single point of the distribution and is the arithmetic average of all values of the distribution.

<u>Conditional</u> resource estimates incorporate the condition that recoverable oil or gas actually occurs, and <u>conditional economically recoverable</u> resource estimates require the condition that at least one commercial hydrocarbon accumulation exists in the area.

<u>Risked</u> estimates are unconditional and include the chance of no oil or gas in the area.

Thus, in the hierarchy of descriptive terms, the resource estimates proceed from the largest numbers in a probability range to the smallest as more stringent limits are applied as shown diagrammatically in Figure 2-7.



Diagrammatic Chart of Resource Estimate Progression
(Not to Scale)

Figure 2-7. Hierarchy of resource estimates which ranges from the amount of oil/gas in-place (undiscovered resource) through the amounts recoverable under certain economic conditions and to the fully risked mean case. The top-to-bottom progression represents systematically increasing limits to recovery, economic, and risk criteria applied to resource estimates.

Table 2-3 is a summary of the risked economically recoverable resource as reported in 1989 by the DOI.[3] The USGS performed the onshore and adjacent state waters evaluation, and the MMS was responsible for the federal offshore estimate. The closing date for the evaluations for both agencies was the end of 1986.

In May of 1990 the Alaska Outer Continental (OCS) Region of the MMS published revised estimates for federal offshore waters including both the Beaufort and Chukchi Seas.[9] The conditional estimates of economically recoverable oil are presented in **Table 2-4**. The single value of the risked mean oil estimate is also given.

Comparing the Province Risked Mean Oil values of the most recent MMS estimates with the Province Risked Mean Oil values of the January 1987 estimates, it is apparent that the Beaufort Shelf (Sea) has shown a marked increase of 181% (0.21 BBO to 0.38 BBO) and the Chukchi Sea has increased a dramatic 231% (0.59 BBO to 1.36 BBO). Comparison of the conditional means for the Beaufort Shelf (Sea) and Chukchi Sea areas shows increases of 115% (1.44 BBO to 1.66 BBO) and 218% (2.73 BBO to 5.96 BBO), respectively. These changes result from new interpretations stemming from a considerable increase in the seismic data base, as well as more specific geologic knowledge applicable to the area.[3,9]

2.2 Discovered Oil/Gas Accumulations

Exploration in Alaska has resulted in the discovery of 32 oil and gas accumulations on the North Slope. Seven of the fields are currently productive. A chronological history of exploration leading to the discoveries and the current status of development is presented in this section.

Table 2-3. Estimates of Risked[a] Undiscovered Economically Recoverable Oil North Slope, Alaska[3] (1990 Revisions in Parentheses)[10] (BBO)

	ONSHORE AND ADJACENT STATE WATERS (USGS)		
PROVINCE	F95	F5	MEAN
058 Arctic Coastal Plain	0.00 (0.00)	10.930 (20.115)	3.360 (5.956)
059 Northern Foothills	0.00 (0.00)	2.640 (5.416)	0.720 (1.416)
060 Southern Foothills	0.00 (0.00)	12.640 (1.185)	3.590 (0.299)
	FEDERAL OFFSHORE WATERS (MMS)		
1 Beaufort Shelf	0.00	1.74	0.21
3 Chukchi Sea	0.00	3.59	0.59

a. Risked - include the chance of no oil in the area.

Table 2-4. Estimates of Conditional[a] Undiscovered Economically Recoverable Oil and Risked Mean Estimate, As of January 1990[9] (BBO)

	FEDERAL OFFSHORE WATERS (MMS)		
PROVINCE	95% Case	5% Case	Mean Case
Beaufort Sea	0.58	4.69	1.66
Chukchi Sea	1.19	13.10	5.96
	RISKED MEAN OIL		
Beaufort Sea	--	--	0.38
Chukchi Sea	--	--	1.36

a. Conditional - One or more undiscovered commercial accumulations of hydrocarbons exist in the area.

2.2.1 Exploration History

Successful hydrocarbon exploration in Alaska began in 1902 when oil was discovered at Katalla on the coast of the Gulf of Alaska. By the time the field was abandoned in 1933 the cumulative production was only 154 MBO.[11]

First commercial production in the modern era was established on the Kenai Peninsula by the Richfield Oil Corporation's Swanson River Unit 1 well in August 1957. This discovery set off a wave of intensive exploration throughout Alaska and was a major force in the successful effort to achieve statehood in 1959.[5]

One of the prime areas for exploration by the oil and gas industry was the North Slope where the potential for major petroleum reserves was known through the pioneering work of the USGS. The first account was published by Leffingwell in 1919 describing the geology of the Canning River region. In 1923, Naval Petroleum Reserve No. 4 (NPR-4) was established in a 23-million acre area lying north and west of the Colville River and extending from the Beaufort Sea on the north to the foothills of the Brooks Range on the south. From 1944 to 1953 the Navy and the USGS explored NPR-4 using extensive geological surface mapping, seismic, gravity and magnetic geophysical surveys, and 45 shallow core holes. They also drilled 37 test wells and found three oil accumulations at Umiat, Cape Simpson and Fish Creek as well as six gas accumulations at Gubik, South Barrow, Meade, Square Lake, Titaluk and Wolf Creek (Figure 2-5). None of these discoveries was commercial even though Umiat contains an estimated 30 to 100 MMB of recoverable oil and Gubik has 370 to 900 BCF of gas. Minor gas accumulations in the vicinity of Barrow, however, have been developed for use in the native village.[5]

Following the NPR-4 program, which was conducted for a total cost of $50 to $60 million, a 5-year (1953 to 58) hiatus ensued. After the Swanson River discovery, the Bureau of Land Management (BLM) announced the intention to make North Slope lands available for leasing, thus effectively removing the closure to entry which had been established under Public Land Order 82 in 1943. The BLM opened 14,727,116 acres to simultaneous filing and subsequent drawing in four "sales" (1958, 1964, 1965, and 1966) in blocks of 3 to 4 million acres each. These are shown on Figure 2-8. Also in 1958, the BLM offered 16,000 acres for competitive bidding in the Gubik Gas "Field" area which was classified as a Known Geological Structure (KGS).

The knowledge of available lands for leasing, exploration, drilling and possible development under the same basic conditions that had been established throughout the western Lower 48 states was the key incentive that drew the petroleum industry to the North Slope.[5]

Over the period of the next 10 years the industry was actively exploring throughout Alaska and established commercial production of oil and gas in the Cook Inlet region, both onshore and offshore. A total of 22 oil and gas fields have been discovered in this region with estimated original recoverable reserves of 1.173 BBO and 7.607 TCF of gas. Cumulative production totals 1.132 BBO and 3.907 TCF gas.[1]

No discoveries occurred in any of the other regions that were explored during the period. One of the most intensive and expensive exploration efforts in the entire state of Alaska took place on the North Slope. Industry surface geological field parties explored the region from the Brooks Range through the Northern Foothills and from the Canadian border to the Chukchi Sea. Geophysical surveys utilizing seismic crews began work in 1962. In 1960 the federal government had established the Arctic National Wildlife Range (ANWR) covering about nine million acres from the Canning River to the Canadian border and from the Beaufort Sea to the Brooks Range. Thus, industry entry and activity were restricted to the area between the Colville and Canning Rivers and a limited area west and south of NPR-4. In 1964 the State selected 1,616,745 acres under the Statehood Act comprising some 80 townships across the northern tier of lands between the Colville and Canning Rivers. Competitive sales were held in 1964, 1965 and 1967.[5]

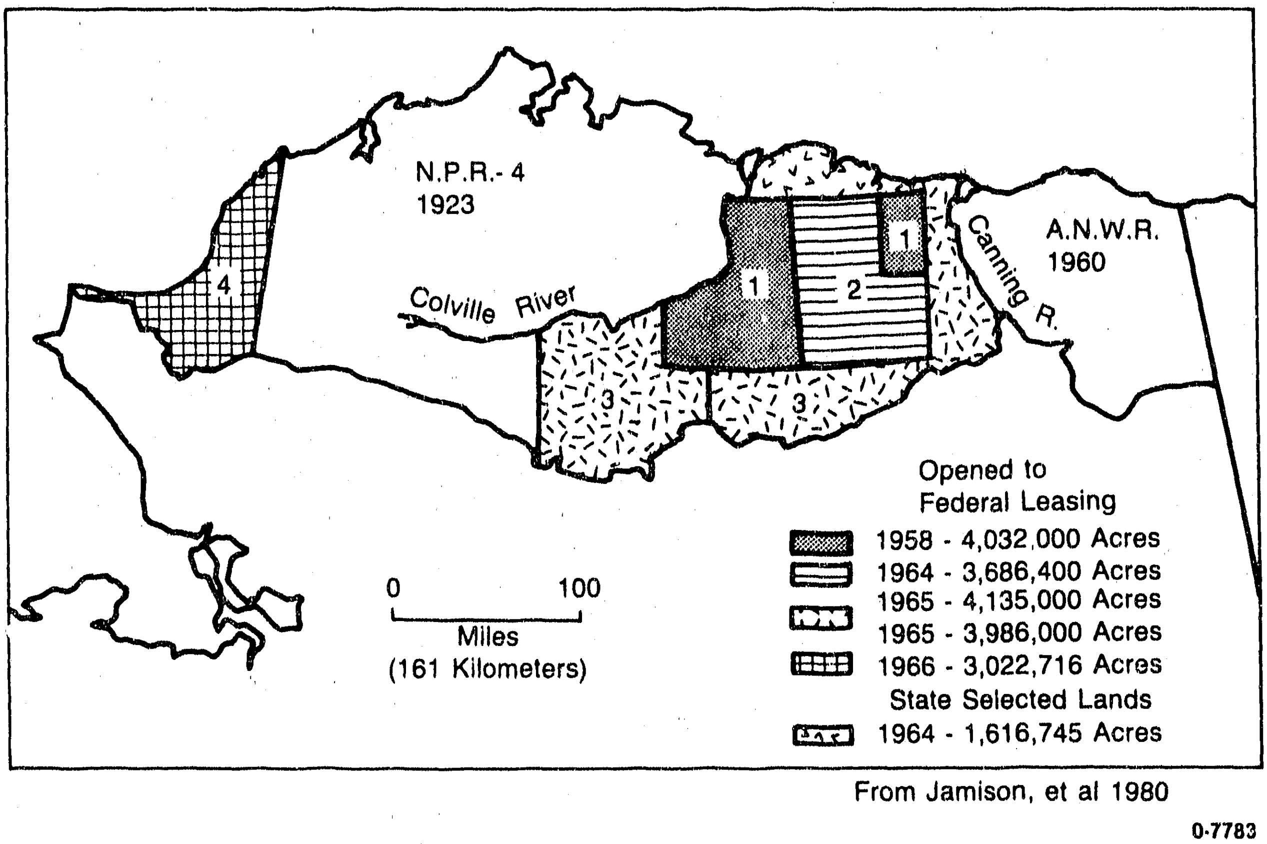


Figure 2-8. Map showing locations of areas opened to Federal leasing between 1958 and 1966, and State lands offered for leasing beginning in 1964.[5]

Also during this period, 10 dry holes were drilled by industry in the Northern Foothills for Cretaceous age objectives and on the Coastal Plain for Tertiary, Upper Cretaceous and older Mesozoic and Paleozoic objectives. It was at the end of this period of intensive activity when all surface geology, seismic exploration and drilling by other companies had ceased that ARCO-Humble (now Exxon) drilled the discovery well at Prudhoe Bay. The Prudhoe Bay State 1 was announced as a discovery in January, 1968 and completed in April. The 7-mile step-out confirmation well, the Sag River State 1, established the size of the field and the companies released the DeGolyer and McNaughton estimate that Prudhoe Bay ".... could develop into a field with recoverable reserves of some five to ten billion barrels of oil, which would rate it as one of the largest petroleum accumulations known to the world today."[5] With ultimate production estimated now to be 11.5 to 12.9 BBO, and with recoverable gas of 28.5 TCF, Prudhoe Bay remains the largest oil field discovered in North America. It produces from the Sadlerochit Group sands of Permo-Triassic age.

In 1969, industry drilled 33 exploratory wells in anticipation of the September State competitive lease sale in the Prudhoe Bay area. The sale drew over $900 million in bonus bids. In spite of this interest, it was the last one held on the North Slope until 1979 when the State and Federal governments held a joint sale. This long hiatus was the result of several obstacles to leasing, exploration, development and transportation of North Slope oil.

In 1966 a federal "land freeze" (a BLM moratorium on leasing) was instituted in response to Native Land Claims. Native Land Claims, imposition of stringent environmental stipulations, filing of several lawsuits, and vocal environmentalist objections served to delay construction of the 789 mile Trans Alaska Pipeline System (TAPS) until 1974. During the 1970 to 74 period only 34 exploratory wells were drilled, one more than the total drilled in the single year 1969. Construction of the pipeline was completed in 1977 for a total cost of $7.7 billion and oil began to flow from Prudhoe Bay on June 20, 1977.

Notwithstanding the negative aspects of the delay and freeze, over 100 wells were drilled from the discovery at Prudhoe Bay in 1968 through 1979. This drilling resulted in 19 discoveries and 12 significant accumulations (Table 2-5).[5,11,12]

In 1974, the federal government initiated a second major exploration program in NPRA (NPR-4 was renamed National Petroleum Reserve - Alaska) directed by the USGS, resulting in 27 exploratory wells being drilled. This effort found two minor gas fields at East Barrow and Walakpa, the former producing gas for the village. Total program cost was over one-half billion dollars.[11] Following the USGS program, NPRA was opened for industry leasing through BLM competitive sales. Industry interest was low and the third sale received no bids. One dry hole was drilled by industry.

Table 2-5. North Slope Oil and Gas Accumulation[12]

Accumulation Name	Discovery Date	Reservoir	Approximate Depth of Reservoir (ft)	In-Place Oil (BBO)	In-Place Gas (TCF)	Cumulative Production Oil (MMBO)	Cumulative Production Gas (BCF)	Reserves/Resource[a] Oil (MMBO)	Reserves/Resource[a] Gas (BCF)	API°	Test Rates (bpd or MMCF/d)	Distance to Pump Station #1 (mi)	Percent Recovery (%)	Estimated Original Reserves MMBO/BCF
Umiat	'46	Nanushuk	1,000	<1	<1	--	--	70	5	36-37	400 bpd	120	--	--
											6 MMCF/d	--	--	--
Fish Creek	'49	Nanushuk	3,000	<1	--	--	--	--	--	--	--	80	--	--
So. Barrow[b]	'49	Barrow	1,500	--	<1	--	20.2	--	5	--	--	210	--	--/25.2
Simpson	'50	Nanushuk	500	<1	<1	--	--	12	--	26	125 bpd	150	--	--
Meade	'50	Nanushuk	1,000	--	<1	--	--	--	20	--	--	220	--	--
Wolf Creek	'51	Nanushuk	1,500	--	<1	--	--	--	--	--	13MMCF/D	150	--	--
Gubik	'51	Colville	3,500	--	<1	--	--	--	600	--	2.5MMCF/D	100	--	--
Square Lake	'52	Colville	1,500	--	<1	--	--	--	58	--	--	150	--	--
E. Umiat	'63	Nanushuk		--	<1	--	--	--	4	--	--	115	--	--
Prudhoe Bay[b]	'68	Sadlerochit	8,000	23	27	6605	1,211[c]	6266	27,290	27	2025 bpd 25.6MMCF/D	0	42-50	9590/28,500
Lisburne[b]	'68	Lisburne	8,500	3	3	49	275[c]	157	888	27	1152 bpd 22MMCF/D	0	7-22	400/635
Kuparuk River[b]	'69	Kuparuk	6,000	5.3	2	615	697[c]	1509	520	25	1056 bpd	25	25-30	600/640
Kavik	'69	Sadlerochit	4,500	--	<1	--	--	--	--	--	44,000MMCF/D	60	--	--
West Sak	'69	Sagavanirktok	3,000	15-25	>1	--	--	0-1200	--	16-22	112 bpd	25	0-5	--
Ugnu	'69	Sagavanirktok	2,500	11-19	--	--	--	--	--	8-12	--	25	--	--
Milne Point[b]	'69	Kuparuk	7,000	<1	<1	9	2.9[c]	51	0	25	330 bpd	20	--	100/0
Gwydyr Bay	'69	Sadlerochit	10,000	<1	<1	--	--	30-60	--	--	2263 bpd	15	--	--
No. Prudhoe	'70	Sadlerochit	9,250	<1	<1	--	--	75(?)	--	--	2727 bpd 1.1MMCF/D	0	--	--
Kemik	'72	Shublik	8,500	--	<1	--	--	--	--	--	2 MMCF/D	60	--	--
E. Barrow[b]	'74	Barrow	--	--	<1	--	5.4	--	7	--	--	210	--	--/12.4
Flaxman Island	'75	Canning	12,500	--	--	--	--	--	--	23	2507 bpd 2165MMCF/D	70	--	--
Point Thomson	'77	Thomson	13,000	<1	6	--	--	300[d]	5000	18[e]	2283 bpd[e] 13,307MMCF/D	70	--	--
Endicott[b]	'78	Kekiktuk	9,500	1	<2	82	85[c]	311	782	23	2473 bpd	25	30-36	375/731
Walakpa	'80	Walakpa	2,500	--	<1	--	--	--	--	--	--	210	--	--
Niakuk	'81	Kuparuk	12,000	<1	<1	--	--	58	30	43	674 bpd	5	33%?	--
Tern Island	'82	Kekiktuk	12,000(M.D.)	--	--	--	--	--	--	--	1300 bpd	40	--	--
Seal Island	'84	Sadlerochit	12,000(M.D.)	<1	<1	--	--	150	--	40	5000 bpd	20	33%?	--
Hammerhead	'85	Sagavanirktok	5,500	--	--	--	--	--	--	--	1500 bpd	80	--	--
Colville Delta	'85	Kuparuk ?	6,000	--	--	--	--	--	--	25	414-1075 bpd	60	--	--

Table 2-5. (Continued)

Accumulation Name	Discovery Date	Reservoir	Approximate Depth of Reservoir (ft)	In-Place Oil (BBO)	In-Place Gas (TCF)	Cumulative Production Oil (MMBO)	Cumulative Production Gas (BCF)	Reserves/Resource[a] Oil (MMBO)	Reserves/Resource[a] Gas (BCF)	API°	Test Rates (bpd or MMCF/d)	Distance to Pump Station #1 (mi)	Percent Recovery (%)	Estimated Original Reserves (MMBO/BCF)
Sandpiper	'86	Sadlerochit	--	--	--	--	--	--	--	40-52	500-2500 bpd 18MMCF/D	25	--	--
Barrow	'88	Barrow	--	--	<1	--	--	--	--	--	--	210	--	--
Point McIntyre	'88	Kuparuk	8,500	1	--	--	--	300	--	--	5400 bpd 2500 bpd 1060 bpd	5	24-30	[illegible]00/--

a. A resource is changed to reserves when a field is developed for production and a transportation system is under development or in-place to move the product to market. Economically recoverable oil (reserves) from Most Likely Case, Table 3-10. The only gas volumes currently considered reserves are the volumes used as Fuel Gas for North Slope operations. Current gas reserves are not given in this table.
b. Producing Field.
c. Production Less reinjection.
d. Condensate.
e. Oil test from small oil rim.
M.D. Measured Depth.

After 1979, the federal government held three offshore OCS lease sales. Two of these were in the Beaufort Sea and one in the Chukchi Sea. The state held 17 sales in both onshore uplands and in offshore state waters. In this period nine accumulations were discovered. None are producing yet, but two are planned to be developed through the producing infrastructure at Prudhoe Bay. Niakuk, discovered in 1981, with reserves of 58 million barrels of oil (MMBO) and Point McIntyre, discovered in 1988, with reserves of 300 MMBO are still in the permit and delineation phases respectively.

From the inception of exploratory drilling in the NPR-4 program to the present, some 32 oil and gas accumulations have been discovered on the North Slope. Of these, 24 were onshore and eight offshore (Flaxman Island, Endicott, Niakuk, Tern Island, Seal Island, Hammerhead, Sandpiper and Point McIntyre). Endicott, discovered in 1978, began producing in 1987 with original reserves estimated at 375 MMBO (revised total recovery is now at 393 MMBO). It is the only offshore producing field in the Arctic Ocean (**Table 2-5 and Figure 2-9**).

Six producing fields are located onshore. In addition to Prudhoe Bay, Kuparuk River Field was discovered in 1969, began production in 1981, and is the second ranking producing-rate field in the U.S. after Prudhoe Bay. Original reserve estimates of 1.6 BBO have been revised to 1.553 BBO. The Lisburne Field (underlying Prudhoe Bay Field) was also found in 1968 by the discovery well. Original estimated reserves were 400 MMBO but the total has been reduced to 206 MMBO. Milne Point was discovered in 1969, first produced in 1985, shut down in 1987 and started up again in April 1990. Original reserves were estimated at 100 MMBO. After 9 MMBO were produced, reserves were estimated to be 51 MMBO, making Milne Point the smallest economic field on the North Slope.[1]

The other two producing fields are minor gas fields supplying gas to the native village at Barrow. Original estimated reserves for both fields were 37.6 BCF, with cumulative production of 25.6 BCF.[1]

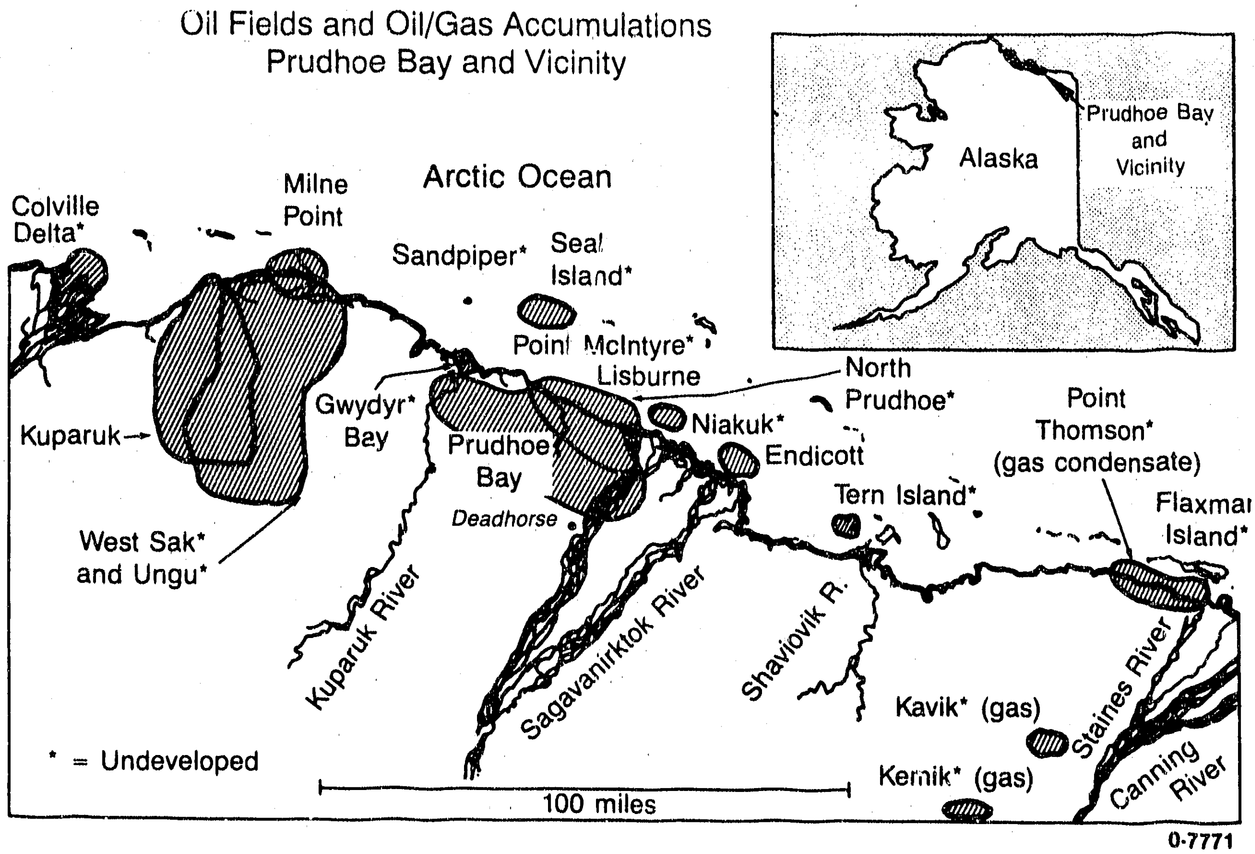


Figure 2-9. Location of North Slope oil and gas accumulations and fields.[13]

The seven fields listed above have produced a total of 7.366 BBO plus 60 MMB natural gas liquids (NGL) and 11.515 TCF of gas. Most of the gas has been reinjected. Remaining reserves are estimated at 6.330 BBO (including NGL) and 27.290 TCF of gas (**Table 2-1**).

The last area in the U.S. with known major petroleum potential to remain almost completely unexplored by industry lies in the Arctic National Wildlife Refuge which was established by the Alaska National Interest Lands Conservation Act (ANILCA) of 1980. Also ANILCA enlarged the original area of the Range from the 1960 total of 9 million acres to the 19 million acre total in 1980. Congress also set guidelines for study of the 1.55-million acre coastal plain area within ANWR in Section 1002. These lands known as the "1002 area" were to be evaluated by the Secretary of the Interior in order:

"To conduct a comprehensive continuing baseline study of the fish and wildlife resources of the Arctic Refuge 1002 area.

To develop guidelines for, initiate, and monitor an oil and gas exploration program; and to prepare a "Report to Congress" which describes the fish and wildlife resources of the 1002 area; identifies and estimates the volume and areal extent of potential hydrocarbon resources; assesses the potential impact of development; discusses transportation of oil and gas; discusses the national need for domestic sources of oil and gas; and recommend whether further exploration, development, and production of oil and gas should be allowed."

Under Section 1002, exploration was authorized to include surface geological and geophysical work, but not exploratory drilling. During the summers of 1983 through 1985 surface geological parties from 15 companies worked in the area. A helicopter gravity survey was done in 1983. More than 1300 line miles of seismic data were acquired during the winters of 1983/84 and 1984/85. The seismic program was funded and conducted by industry. The interpretation of all surface and subsurface data was performed by the USGS and BLM, and resultant analyses and hydrocarbon resource estimates are a product of their joint efforts. Results of this effort are summarized in Reference 14. Detailed descriptions of the results of exploration are presented in Reference 2.

As a result of the government-supervised exploration program in ANWR and of the environmental investigations coupled with the oil and gas assessments, Secretary of the Interior Hodel on April 21, 1987 recommended to Congress that the Secretary be directed "..... to conduct an orderly oil and gas leasing program for the entire 1.5 million-acre 1002 area ....."[14] Congress has not yet reached a final decision on the ultimate disposition of the 1002 area lands within ANWR.

It should be noted that one exploratory well has been drilled on the Arctic coastal plain adjacent to the 1002 area. This well was drilled on native lands near the village of Kaktovik in 1986 by Chevron and BP. The Chevron Jago River KIC 1 was drilled to 14,500 feet total depth (KIC refers to Kaktovik Inupiat Corporation). All results have been held confidential by the companies.

It should also be noted that significant resources of oil and gas have been discovered and, to some extent, delineated in the Mackenzie Delta region of the Yukon and Northwest Territories in Canada. This area is approximately 200 miles east of the eastern boundary of ANWR. Most of these 49 significant oil and gas discoveries are in Brookian sequence age rocks, which are younger than the major producing intervals in Alaska. At least 22 separate accumulations have been found.[6] Most of these discoveries are both oil and gas. Nevertheless, none have yet proved economic, either alone or combined. Much of the resource is located offshore in Mackenzie Bay, which adds significant cost for development and transportation. Total mean reserves are 1.7 BBO and 11.7 TCF. The potential endowment (recoverable resource) totals are 5.3 BBO and 56.2 TCF of gas.[15]

Finally, future North Slope exploration, both on and offshore is likely to depend on economics and political actions, to a much greater extent than on the probabilities for finding substantial hydrocarbon accumulations. Jamison summarized the perspective 10 years after the discovery of Prudhoe Bay as follows:[5]

> "Successful oil-finding on the North Slope depends on continuity and persistence of the overall exploration effort. This effort was, and is directly responsive to knowledge of a firm schedule of land availability.
>
> A stable and predictable investment climate is of utmost importance in North Slope exploration and production operations.
>
> The variety of accumulations found in the Prudhoe Bay Complex would indicate the probability of future sizable discoveries in other area of the North Slope, if exploration in such areas is not unduly restricted by federal, state and local regulatory procedures."

2.2.2. Current Status of Known Reserves and Resources

Table 2-5 summarizes available data on the 32 known oil and/or gas accumulations on the North Slope. They are listed chronologically from the time of discovery and include the seven currently-producing fields.[12]

2.2.3 Oil Resource

The difference between a petroleum resource and petroleum reserves is frequently misunderstood by the general public (see **Sections 2.1.2 and 2.1.3** of this report). A petroleum resource simply requires some measure of knowledge with respect to its possible presence. By comparison, reserves are considered in connection with specific technological and economic circumstances, i.e., producible with a profit to the operator. For example, the billions of barrels of oil that exist in tar sand deposits in Utah are considered a resource base. When the necessary technological and economic conditions exist so that the bitumen may be extracted at a profit to the operator, these deposits may become reserves. An oil accumulation of 25 million barrels may be a resource under given land, geology, geophysics, drilling, and tax costs. The same accumulation may be changed to reserves status if such costs are reduced to the point that allows an operator to produce the oil and receive a profit.

The closely-related factors of timing of technological developments and regulatory issues, economics, and world oil price play a critical role with respect to exploration activities in both the onshore and offshore areas of the North Slope. The size of the capital expenditures necessary to explore, lease, drill, and establish production facilities is such that delays related to both engineering and regulatory developments severely impact aggressive exploration efforts.

The time-cost of capital often precludes investment until reasonable forecasts concerning technology development can be made. For example, even a major discovery in an offshore area severely affected by pack ice may not be developed and brought onstream until cost effective technology to handle such problems as platform structural integrity or seabed ice scour becomes available.

Similar delays exist for permitting and regulatory processes. The three chronological schedules projected by the 1987 EIA (Energy Information Administration) report on scenarios for leasing, drilling, and establishing production in the 1002 area of ANWR show potential delays of up to 15 years.[16] **Table 2-6** shows the relative differences in the Accelerated, Normal, and Delayed Schedules for exploration and development activities in ANWR.

Table 2-6. Comparison of three projected schedules for drilling and development activities in ANWR.[16]

Activity	Time (in years) Accelerated	Normal	Delayed
Leasing	1	1	1
Discovery	3	5	9
Production	7	12	22

Because of the dynamic and volatile history of world oil prices, 7 years between leasing and establishing production in ANWR require large multi-year financial obligations with a great deal of profit-related uncertainty. Note that the 7-year case is minimum; the Delayed Schedule takes over three times as long to bring production onstream. An investor considering the huge fluctuations in world oil prices over the last 22 years might well entirely avoid the risks associated with such long-term exploration commitments. To offset these risks, industry must believe that the size of future discoveries will not lie at the low extreme of the probability curve (i.e., a 95 % probability that a relatively small total volume will be found), or even lie at the mean (i.e., the probability that an average total volume will be found). In order to justify the extreme risks associated with frontier areas, industry must assume that exploration will result in extremely large volumes, such as occur in super-giant discoveries (i.e., half billion barrel fields or larger) although there may be only a one or two percent probability of doing so.

Even in frontier areas with billions of barrels of potential reserves, economics and world oil price considerations strongly impact exploration activities. For example, tax structure, costs for production facilities and infrastructure, proximity to pipelines or transportation terminals, and widely fluctuating oil prices can all influence exploration programs, positively or negatively. The presence of vast quantities of oil and gas, which is geologically-controlled, may well describe a resource, but the transition from resource to reserves status depends on many other factors.

2.2.4 Gas Resource

Many of the preceding comments on the oil resource also apply to the North Slope gas resource. There are, however, specific considerations regarding transferring discovered and undiscovered gas resources into reserves. Currently, no viable market exists for North Slope gas because of lack of a sufficient and stable price for the product, and because of lack of a transportation system.

Since the discovery of Prudhoe Bay in 1968, with its potential reserves (resource) of 28.5 TCF of gas, various plans have been proposed for acquiring a market for North Slope gas and for constructing a delivery system to transport the gas to that market.

Two major efforts have been underway for several years. One is the Trans-Alaska Gas System (TAGS), a proposed $11 billion pipeline, 800 miles long. This 36-inch 2.3 BCF/day pipeline would extend from Prudhoe Bay to Valdez. This system would sell the gas to markets in the Far East. In 1989, TAGS acquired export permits to deliver up to 660 BCF/year to Japan, Taiwan, and South Korea, over a 25-year period.[17] The 2.3 BCF/day would produce 14 million ton of Liquified Natural Gas (LNG)/year, thus requiring 15 transport ships of 125,000 cubic meters LNG capacity each. The total system cost would be about $15 billion.

Another project is the Alaskan Natural Gas Transportation System (ANGTS) which would be designed as a 4,783 mile pipeline through Alaska and Canada to markets in the Lower 48 states. In Alaska, the 2.3 BCF/day pipeline would be a 746 mile, 42-inch line along the TAPS right-of-way from Prudhoe Bay to central Alaska and thence east to join with the proposed Foothills ANGTS project in western Canada. In 1988, ANGTS estimated costs for the 746 mile section in Alaska and the 1,356 mile Canadian link to Caroline, Alberta (where it would tie to the existing portion of the system that has been delivering Canadian gas to the U.S. midwest and northwest since 1981) to be $15 billion. This is a little more than one-half the 1982 figure.[17]

If one or the other of the systems is actually constructed, it may well offer the opportunity to market other North Slope gas resources, both discovered and undiscovered. Discovered resources are 37 TCF (see Tables 2-1 and 2-5). Undiscovered resources are estimated at about 70 TCF total, including approximately 15 TCF in federal OCS waters, using mean values.[3]

In much the same manner that TAPS has enabled smaller oil accumulations such as Kuparuk River, Milne Point, Lisburne, and Endicott to be produced after Prudhoe Bay came on stream, a TAGS or ANGTS could duplicate the process with respect to natural gas. Markets exist, but the transportation systems' high capital costs require greater and more predictable gas prices than those currently in existence or reasonably predictable.

2.3. Undiscovered Resource Base - Oil and Gas

In reviewing the estimates of the resource base for the North Slope, it is evident that a major component is entirely lacking in reference to <u>economically</u> recoverable resources. The preceding section of this report briefly describes the economics of natural gas production, the current lack of a viable market, and the resultant lack of a pipeline for North Slope gas. Therefore, the transfer from gas <u>resources</u> to <u>reserves</u> in both the discovered and undiscovered categories awaits future determination. Consequently, many of the assessment procedures and estimates focus upon oil, and in the economically recoverable categories, entirely upon oil.

2.3.1 Assessment Methods

It is not the purpose of this report to examine, in detail, the methods used currently, or in the past, to determine resource estimates. At the request of the Secretary of Interior, the National Academy of Sciences (NAS) has recently reviewed the entire process used by the USGS and MMS in the 1989 national assessment of undiscovered conventional oil and gas resources. A final report of the NAS is scheduled for mid-1990.[3] Nevertheless, methodology directly affects and determines the resulting estimates. Furthermore, assessments are frequently compared (**Figures 2-10 and 2-11**), and are used by many and varied audiences for different purposes. It is, therefore, incumbent upon the user to have a basic understanding of the methods used in order to interpret and apply resource estimates correctly.

In general, assessment methods applied to undiscovered oil and gas resources have developed through four stages of quantitative descriptive approaches. These include:[18]

- Volumetric or areal yield
- Performance extrapolation
- Delphi or modified Delphi
- Geological/statistical models.

The method used by both the USGS and MMS for the national assessment of 1989 and the prior NPRA and ANWR assessments was a play-based geological and statistical modeling approach, combined with group review and feedback by the expert estimators (modified Delphi). In this process, geologists and geophysicists who are experts in the area assess the resources of geologic "plays" in that area. A geologic play is "a group of geologically related known accumulations or undiscovered accumulations and/or prospects having similar hydrocarbon sources, reservoirs, traps, and geologic histories."[3]

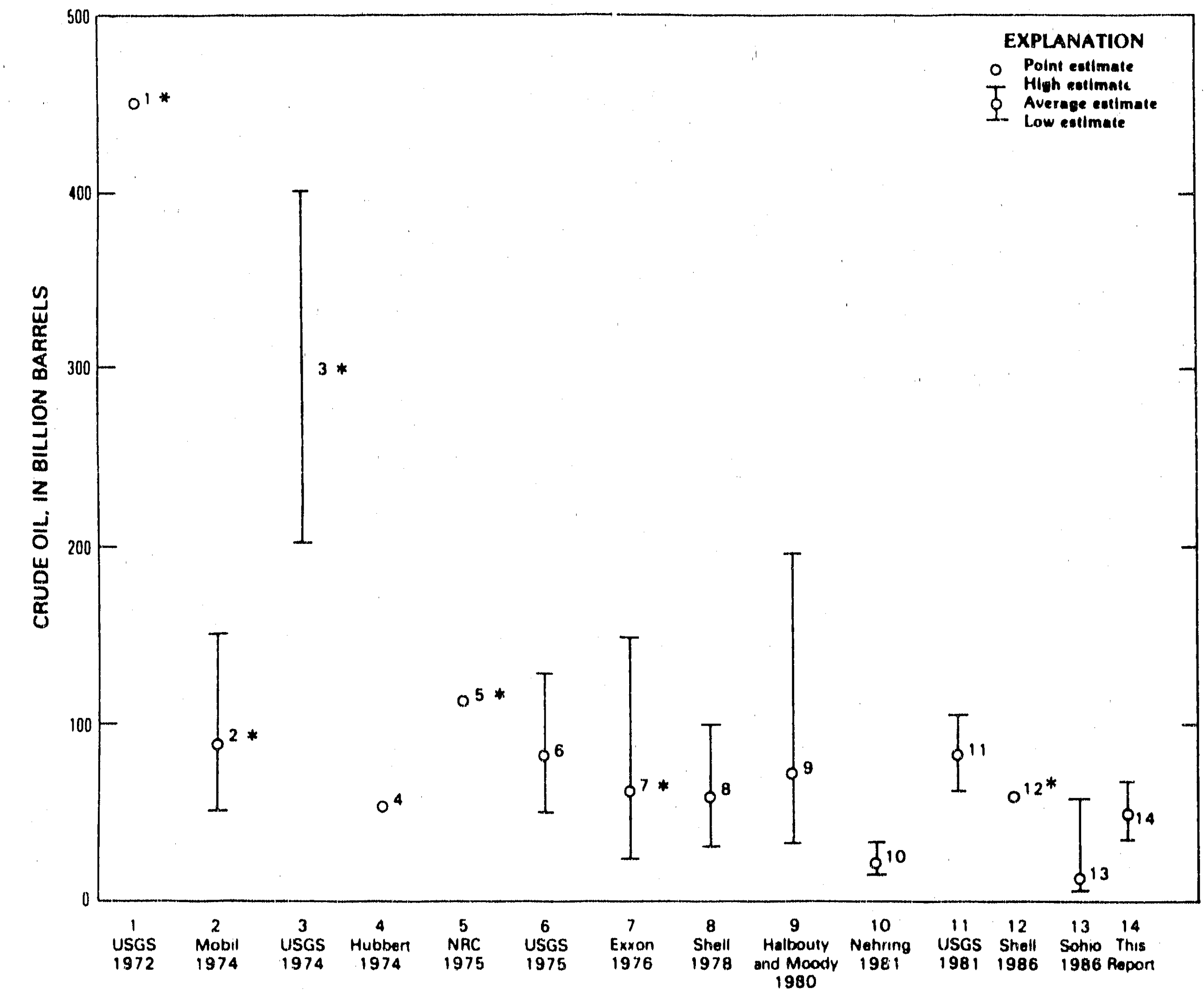


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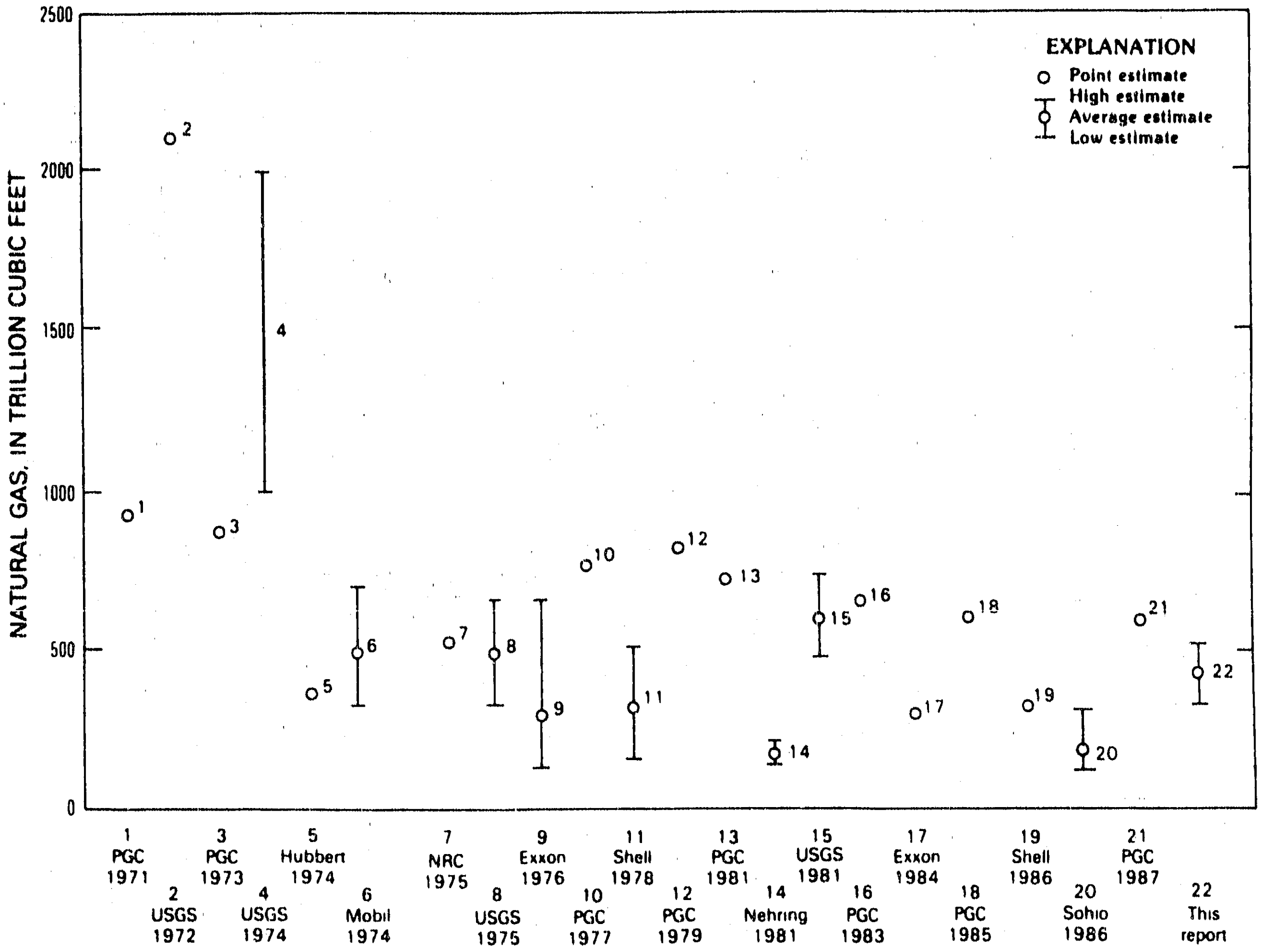
Figure 2-10. Ranges and single-point values from studies to estimate undiscovered oil potential of the United States. These investigations are the most pertinent ones in the public domain and span the 17-year period from 1972 to 1989.[3]



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21. Potential Gas Committee, 1987, Potential supply of natural gas in the United States (as of December 31, 1986): Golden, Colorado, Potential Gas Agency, Colorado School of Mines, 160 p.
22. This report.

Figure 2-11. Ranges and single-point value estimates from studies to estimate undiscovered gas potential of the United States. These investigations are the most pertinent ones in the public domain and span the 17-year period from 1972 to 1989.[3]

In order to assess resources in a play, the estimators must aggregate the resources of all prospects in the play or estimate the number and size of all potential fields in the play. The use of either approach, or a combination of the two, depends upon the amount and quality of data available.

MMS has an excellent data base throughout most of the Beaufort and Chukchi Seas founded upon an extensive seismic grid. The USGS has an excellent data base in NPRA and ANWR, similarly founded upon extensive seismic grids, but lacks seismic coverage in the remaining land and state waters areas on the North Slope. Consequently, although both agencies used play analysis as a fundamental approach, individual prospect identification and aggregation was used for the federal offshore assessment by MMS. The same approach was used for previous NPRA and ANWR assessments by USGS (and BLM). Field number and size estimation methods were used for the 1989 onshore and state waters assessment by USGS and incorporate the ANWR and NPRA results.

Regardless of the methods used, subjective judgement on the part of the estimators is an integral part of the process. Numerous decisions, estimates, assumptions, and even guesses are required of the estimators at every step from geological and geophysical evaluations, through engineering and production aspects, to economic factors and screens, and, thus, into the resulting estimates. In remote frontier regions such as the North Slope, the dependency upon expert judgement becomes even greater, owing to the lesser quantity of data as compared with mature producing areas. Although both MMS and USGS have excellent North Slope data bases, this is a relative circumstance. Many types of data, in several areas, are lacking in density or quantity required for more definitive results.

Therefore, the North Slope resource estimates, both onshore and offshore, are characterized by great uncertainty. An unfortunate tendency on the part of some users of the estimates is to focus upon a single number, usually the mean, in arriving at a conclusion. Understanding the <u>ranges</u> of probability distributions is fundamental to using the estimates to arrive at public or private decisions affecting, or affected by, North Slope oil and gas resources (see **Section 2.1.3** for resource assessment terminology). For a more expanded treatment of oil and gas resource estimation procedures and uncertainty, see Reference 18.

2.3.2 Previous Assessments

Figure 2-10 shows the historical succession of the most pertinent published studies on estimation of undiscovered recoverable conventional oil resources. These estimates are for the entire United States and thus cannot be related directly to North Slope resources. It is true, however, that North Slope resources form a significant portion of most or all of these estimates. In order to better appreciate the salient features of the evolutionary progression of the estimates, a few brief comments are warranted.

During the 17 years depicted in **Figure 2-10**, estimates of undiscovered oil resources in the U. S. have varied from the highs of the USGS, 1972 and 1974, to the lows of the Rand, 1981 and Sohio, 1986 studies. If the 1972 and 1974 USGS estimates are disregarded, there is general agreement that the undiscovered resource base in the U. S. is less than 100 BBO. With the exception of the 1974 Mobil and the 1986 Sohio estimates, industry estimates (points 7, 8, 9, and 12 in **Figure 2-10**) have been reasonably close to each other. This probably reflects the similarity of data sets available to industry and possibly an experience factor in working with such data sets. The most recent estimates by the USGS and the MMS are also reasonably close to the above-mentioned industry estimates.[3]

Figure 2-11 shows the historical succession of the most pertinent publications that estimate undiscovered recoverable conventional gas. The 1972 and 1974 USGS estimates are again the highest for the period between 1972 and 1989. Points 9, 11, 17, and 19 (Exxon and Shell) are reasonably close considering the fact that each company published their data eight years apart. Two other industry estimates (point 6, Mobil; point 20, Sohio) appear optimistically high and low, respectively.

The large quantities of gas resources available in the onshore and offshore of northern Alaska may constitute future targets for direct methane conversion technology. Fox describes such technology and indicate that an MTG (methane-to-gasoline) plant in New Zealand is yielding nearly 15 MBPD of high-octane unleaded gasoline.[19,20] Although this level of production is not currently economically feasible for northern Alaska, the fact that the New Zealand MTG operation is processing offshore gas at a rather remote location is encouraging for the future.

Previous North Slope oil and gas assessments have been conducted for both onshore and offshore areas. The focus of onshore assessments centered upon NPRA during the federal government's second intensive exploration program. At least six assessments were conducted from 1968 to 1980. Two separate assessments of ANWR have been conducted, the first in 1980 and the second in 1987, both mandated by Congress.

Two national assessments are notable for intensive review of North Slope potential, namely the 1980 and 1989 reviews previously discussed. In addition, biennial assessments of OCS regions are required by law, thus the MMS updates the Beaufort Shelf (Sea) and Chukchi Sea estimates every 2 years. The last update was discussed earlier in this report and is presented in **Table 2-4**.

2.3.3 Current Assessments

The national importance of the estimated undiscovered oil resource base in Alaska is apparent when compared with the same estimate for the Lower 48. **Figures 2-12 and 2-13** show estimates of undiscovered recoverable oil and undiscovered economically recoverable oil, respectively, for Alaska and the Lower 48.[3] Approximately one-third of the undiscovered recoverable oil resources in the United States are believed to exist in onshore and offshore Alaska. Data also suggest (**Figure 2-13**) that large discoveries are required in Alaska in order for them to be economical. The data shown in **Figures 2-12 and 2-13** do not include the 1990 MMS revisions for the Beaufort Sea and Chukchi Sea areas that have been previously discussed.[9]

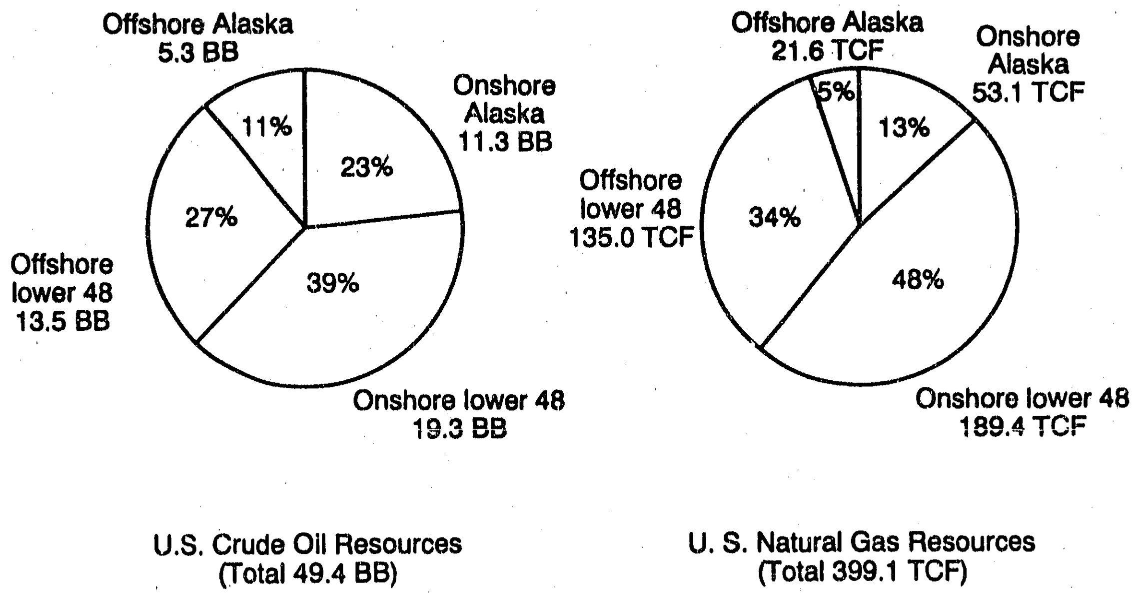


Figure 2-12. Distribution of risked undiscovered recoverable conventional oil and gas resources in the Lower 48 states and Alaska, based on mean estimates.[3] Offshore estimates include both federal and state waters.

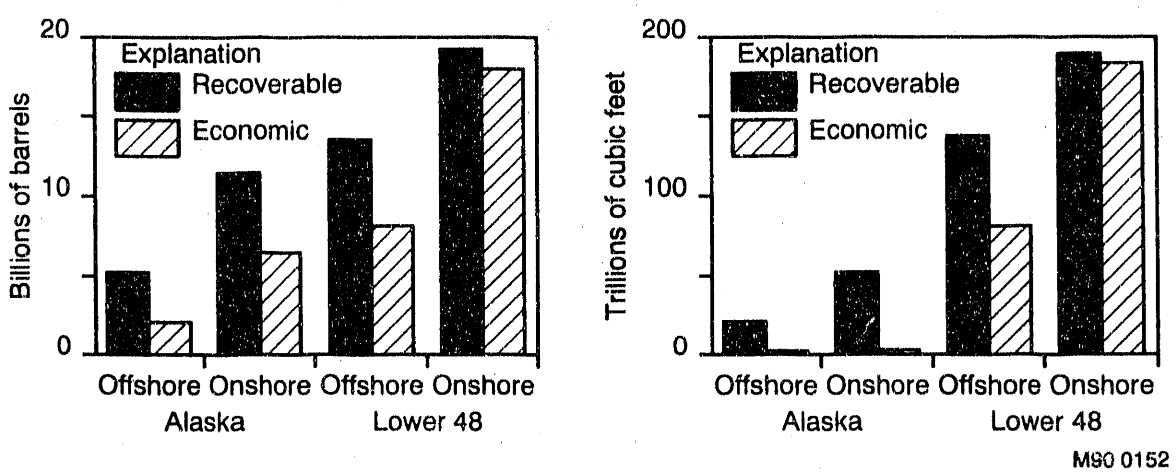


Figure 2-13. Comparison of risked mean estimates of undiscovered recoverable and undiscovered economically recoverable oil and gas in the Lower 48 states and Alaska.[3]

The contribution that onshore and offshore Alaska could make to the national resource base considering recoverable gas (**Figure 2-12**) and economically recoverable gas (**Figure 2-13**), respectively, is significant. The recoverable resource base for Alaska is estimated to be approximately 18% of the national total (**Figure 2-12**) but, because of the market proximity and pipeline issues considered earlier, a relatively insignificant amount is economically recoverable and none is from the North Slope.

The significance of Alaska to the 1989 totals is graphically shown in the two displays of undiscovered resources. It should be noted that the North Slope contributes over 90% of the undiscovered recoverable oil and almost 90% of the undiscovered recoverable gas for all of Alaska. For undiscovered economically recoverable oil, the proportionate share contributed by the North Slope to the Alaska total is even larger, more than 95%.

2.3.3.1 Onshore Summary. Earlier estimates for NPRA and ANWR are incorporated directly or indirectly in the current onshore estimates. Play analysis was utilized in the two areas, with 17 plays in NPRA and 10 in ANWR.[21] Six NPRA assessments were conducted in the period from 1968 to 1980.[22] The more recent 1987 ANWR study defined seven plays in ANWR, and the current assessment includes those resource estimates in the appropriate portions of the 12 plays now defined for the North Slope onshore provinces. These estimates are shown in **Tables 2-3 and 2-7** for the three onshore provinces. ANWR totals are shown separately in **Tables 2-8 and 2-9** and in **Figure 2-14**. Note that the numerical values are not comparable because the ANWR estimates are for undiscovered in-place resources and for conditional economically recoverable oil in the 1002 area (the condition being the occurrence of at least one economic-size oil accumulation in the area).

2.3.3.2 Offshore Summary. Estimates of economically recoverable oil for the two federal OCS provinces are shown in **Tables 2-3 and 2-4**. Other MMS estimates for the 1987 report are shown in **Tables 2-10, 2-11, and 2-12**.

2.3.3.3 Onshore provinces and plays. As stated earlier, 1989 USGS resource estimates were based upon analysis of 12 plays covering the North

Slope. These plays incorporated the seven plays utilized in the 1987 ANWR studies. It is beyond the scope of this report to attempt to review the details of the play definition and play analysis procedures utilized in either instance. It is important to realize, however, the expertise applied to the process and the subjective judgement exercised even in areas with good to excellent data bases.

Table 2-7. Estimates of Risked[a] Undiscovered Recoverable Oil and Gas Onshore and Adjacent State Waters (USGS) North Slope, Alaska[3] (1990 Revisions in Parentheses)[10]

Province	Crude Oil (BBO)			Gas (TCF)		
	F95	F5	Mean	F95	F5	Mean
058 Arctic Coastal Plain	1.500 (1.962)	14.800 (25.939)	6.000 (9.707)	4.660 (5.846)	58.240 (97.024)	22.110 (34.291)
059 Northern Foothills	0.670 (0.270)	5.120 (7.711)	2.240 (2.425)	4.030 (2.557)	24.310 (46.400)	11.490 (16.057)
060 Southern Foothills	0.580 (0.009)	13.180 (1.758)	4.350 (0.455)	2.850 (0.151)	61.560 (13.973)	20.490 (3.744)

a. Risked - includes chance of no oil or gas in area.

Note: Estimates of Undiscovered Economically Recoverable Oil are shown in Table 2-3.

Table 2-8. Estimates of Unrisked Undiscovered In-Place Oil and Gas Resources Arctic National Wildlife Refuge, 1002 Area North Slope, Alaska.[14]

Oil (BBO)			Gas (TCF)		
F95	F5	Mean	F95	F5	Mean
4.8	29.4	13.8	11.5	64.5	31.3

Table 2-9. Undiscovered, Conditional, Economically Recoverable Oil Resources in the 1002 Area.[14]

A. Conditional, economically recoverable oil

	Greater than(%)	Economic Scenario: Most likely case (BBO)	Economic Scenario: Most favorable case (BBO)
Probability	99	0.49	0.18
	95	0.59	0.23
	75	1.12	0.67
	50	2.21	1.49
	25	4.24	3.67
	5	9.24	7.83
	1	17.19	15.73
Maximum simulated oil (BBO)		22.34	22.34
Mean (arithmetic average) (BBO)		3.23	2.66
Marginal probability[a] (%)		19.0	26.0
Minimum economic field (BBO)		0.44	0.15

a. The marginal probability is the probability of occurrence of economically recoverable oil somewhere in the 1002 area.

B. Significant economic assumptions

Crude oil market price (1984 dollars/barrel in year 2000)	$33.00	$40.00
Annual inflation rate (%)	6.0	3.5
Discount rate:		
Real (%)	10.0	8.0
Nominal (%)	16.60	11.78
Federal royalty rate (%)	16.67	12.50
Development cost multiplier	1.0	0.75

After: U.S. Department of the Interior, "Arctic National Wildlife Refuge, Alaska, Coastal Plain Resource Assessment, Report and Recommendation to the Congress of the United States and Final Legislative Environmental Impact Statement," 1987.

Table 2-10. MMS Estimates of Risked[a] Undiscovered Recoverable Oil and Gas in Federal Offshore Waters[3]

Province	Crude Oil (BBO)			Gas (TCF)		
	F95	F5	Mean	F95	F5	Mean
Beaufort Shelf	0.49	3.74	1.27	2.14	12.81	8.26
Chukchi Sea	0.00	7.19	2.22	0.00	16.87	6.33

a. Risked - includes chance of no oil or gas in area.

Table 2-11. MMS Conditional Estimates of Undiscovered Recoverable Oil and Gas Federal Offshore Waters[3]

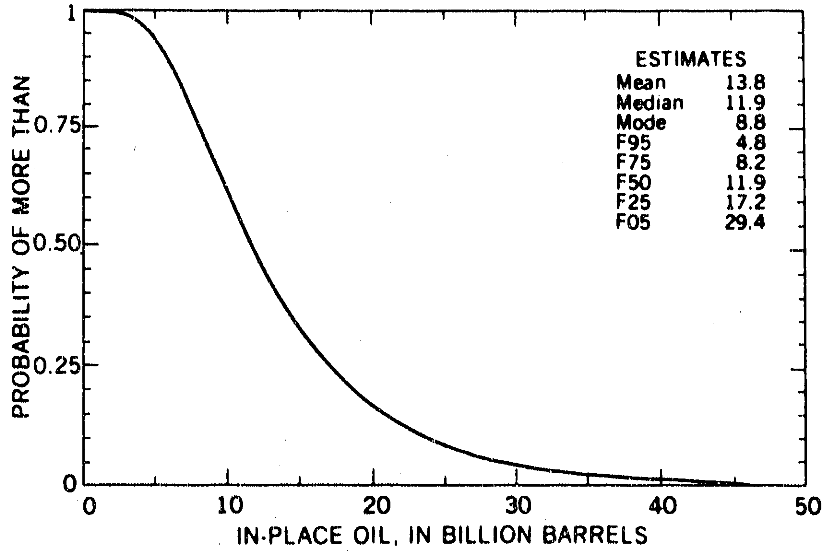
Province	Crude Oil (BBO)			Gas (TCF)		
	F95	F5	Mean	F95	F5	Mean
Beaufort Shelf[a]	0.49	3.74	1.27	2.14	12.81	8.26
Chukchi Sea[b]	1.27	8.25	4.44	6.73	17.83	12.66

a. Marginal probability[c] - 1.00.
b. Marginal probability - 0.50.
c. Chance that oil or gas exists in area in at least one accumulation of the minimum size assessed.

Table 2-12. MMS Conditional Estimates of Undiscovered Economically Recoverable Oil Federal Offshore waters[3]

Province	Crude Oil (BBO)		
	F95	F5	Mean
Beaufort Shelf[a]	0.55	4.02	1.44
Chukchi Sea[b]	1.03	5.41	2.73

a. Marginal probability[c] - 1.00
b. Marginal probability - 0.50
c. Chance that oil or gas exists in area in at least one accumulation in commercial quantities.



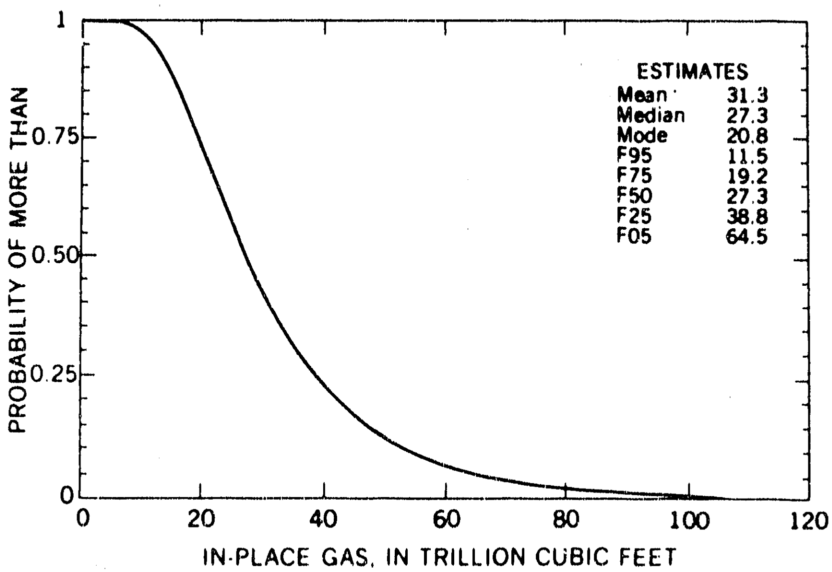


Figure 2-14. Probability curves showing the estimated in-place oil and gas resources for the 1002 area.[14]

2.3.3.3.1 Discussion of Methods and Results--As an example of how the USGS applied play analysis, a description from Bird and Magoon serves to describe the process as used in the 1987 ANWR evaluation (see **Appendix A**).[2]

In the ANWR evaluation, resources were calculated for individual plays by the FASP (Fast Appraisal System for Petroleum) computer program which uses probability theory to process geologic input. The play resource potentials were then aggregated with the other plays in the 1002 Area to determine the ranges of the total distributions of the in-place resources as shown in **Figure 2-14** and **Appendix A**.

Essentially, the same approach was used in the USGS 1989 national assessment procedure for the entire North Slope group of 12 plays. The geologic input form is somewhat different (see **Appendix A**), and, in this assessment, the FASP package calculated the distributions of the recoverable resources and also calculated the economically recoverable resources from the geologic, engineering, and economic input.

This process differs from the ANWR evaluation in that the BLM, which was responsible for economic evaluation, used a form of Probabilistic Resource Estimates Offshore (PRESTO), a computer program developed for MMS. The PRESTO II program used by BLM incorporated a Monte Carlo sampling approach to calculate aggregate risks and volume distributions. Economic input utilized minimum economic field size (MEFS) as a basic screen to determine whether an ANWR prospect would be economically successful. In the 1987 assessment, this screen (based on estimated development, production, and transportation costs and on estimated oil prices, inflation rates, and discount rates) resulted in a 440 MMBO MEFS for the "most likely case ($33/bbl in year 2000 in 1984 dollars)." For the 1989 national assessment, the MEFS was 384 MMBO, regardless of location or play using $18/bbl in 1987 constant dollars.[23]

The ANWR evaluation (and the earlier NPRA assessment) was unique to the North Slope because the seismic grid allowed the USGS and BLM to use prospect identification to aggregate play resources. This resulted in 26 identified prospects (**Figure 2-15**) that were based on structural closures defined by

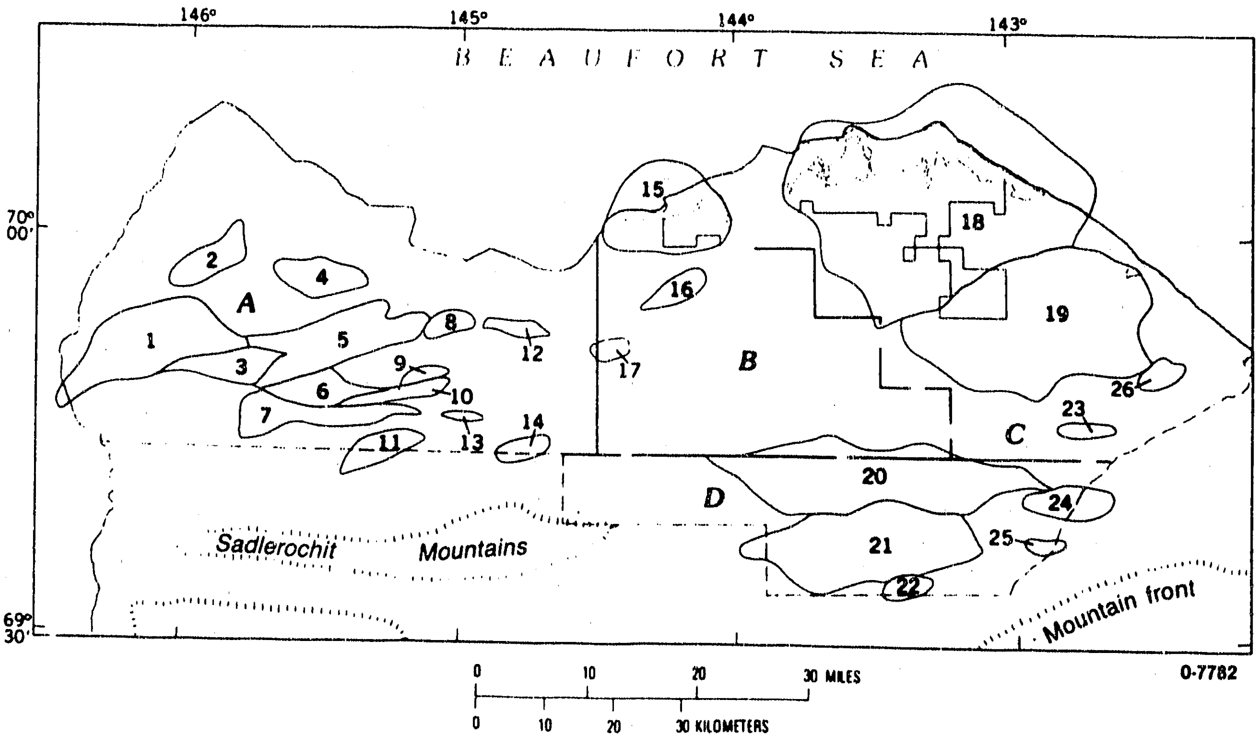


Figure 2-15. Distribution of the 26 seismically-mapped prospects in the 1002 area of ANWR, all of which exhibit structural closure.[2]

seismic interpretation. As stated in the 1987 DOI report, "...the 1002 area is expected to contain a very large additional volume of oil and gas in numerous smaller, structurally controlled accumulations (for example, the Imbricate Fold Belt play) and large stratigraphic accumulations (Topset play). The economically recoverable resource estimate should be viewed as an 'identifiable minimum' volume, which is constrained by economic and technical recoverability considerations."[14] PRESTO II program results are summarized in **Table 2-13**. For more detailed discussions of USGS and BLM play analysis in both the ANWR and national assessments, refer to EIA Service Report, 1989, pp. 11-33,[18] Bird and McGoon, 1989, pp. 279-307,[2] DOI, 1987, pp. 55-81,[14] and DOI, 1989, pp. 16-18.[3]

2.3.3.3.2 Discussion of Interpretation--To interpret the results of the ANWR and the national assessment, it is necessary to understand that the estimates reported as ranges of probability distributions are the product

Table 2-13. Comparison of DOI and EIA Estimates for 1002 Area[18]

"Table 1. Estimate of Undiscovered Crude Oil in the ANWR 1002 Area (Billion Barrels)

Probability	In-Place Oil	Recoverable Oil	
	DOI[a] (unconditional)	DOI[b] (conditional)	EIA[c] (unconditional)
95 percent	4.8	0.59	1.20
Mean	13.8	3.23	3.45
5 percent	29.4	9.24	7.35

[a]Arctic National Wildlife Refuge, Alaska, Coastal Plain Resource Assessment; by U.S. Department of the Interior (Fish and Wildlife Service, Geological Survey, Bureau of Land Management); draft report of 1986 and final report of April 1987.

[b]Conditional, economically recoverable oil; 19 percent marginal probability, "most likely economic case," area minimum economic field size of 0.44 billion barrels of oil.

[c]Products of DOI reported oil in place and 0.25 recovery efficiency; this represents the low, base, and high recoverable oil base rather than the 95 percent, mean, and 5 percent probability levels."

of groups of highly-qualified government experts working with generally excellent data bases, using sophisticated geologic/statistical/economic models and computer programs. The efforts put forth are generally judged as highly credible, although many other experts are critical of various steps in the process or portions of the results. (see **Appendix B**).

Regardless of the critiques of either the ANWR or national assessments involving various aspects of the methodologies used, it is apparent that no fundamental disagreements exist with either processes or results. Most of the public and published comments are expressions of degree of differences rather than orders of magnitude of differences.

Perhaps the greatest folly in usage occurs when the layman settles upon a single point of the distribution, usually the mean, and bases a decision on that single number. It is also true that frequent misuse of different reported types of resource estimates results from lack of understanding (i.e., confusing resources and reserves, mistaking recoverable resources for economically recoverable resources, not differentiating between risked and unrisked resources, and the like).

Unfortunately, the entire process is complex and no convenient solution is at hand to simplify it. It is incumbent upon the user to become familiar with the procedures in order to understand and apply the results correctly.

2.3.3.4 Offshore Provinces and Plays. MMS estimates of offshore resources in the Beaufort Shelf and Chukchi Sea for the 1989 national assessment were based upon play analysis for each area separately. Although MMS emphasis is placed upon lease sale evaluation procedures, biennial resource estimates are a legal requirement, so MMS engages in the process on an almost continuous basis. In these two OCS areas, several significant plays were defined and evaluated. Cooperative efforts with the USGS were instituted so that no major hiatus resulted from the progression from land to state waters to OCS waters.

2.3.3.4.1 Discussion of Methods and Results--MMS play analysis differs from the USGS approach, at least in some areas, by virtue of the relatively dense and extensive seismic grid available by federal law to MMS on a purchase basis. Combined with similar availability of all OCS drilling and production data, MMS seismic and geologic interpretations enable the agency to develop detailed maps and thus to identify specific structural and stratigraphic traps for all horizons of interest.

Therefore, MMS has the ability to simulate drilling specific prospects in order to calculate recoverable resources and to apply prospect play and area cutoffs in order to aggregate economically recoverable province estimates. During lease sale evaluations, tract economic values are assessed by a similar process using the MONTCAR computer program. In the 1989 assessment, MMS used the latest development of the PRESTO III computer program. The geologic model for PRESTO incorporates zone, prospect, play, and province risk analyses, together with geologic and engineering parameters, as shown in **Appendix C** and **Figures C-1** and **C-2**.

The PRESTO III program uses the geologic model to calculate aggregate risks and aggregate volume distributions. The program applies an economic screen based upon a MEFS. It makes these calculations by a Monte Carlo sampling device, the Latin hypercube system, which assures a representative sampling throughout the distribution. Thus, MEFS are aggregated to play, province, and eventually basin minimum economic resource size. The MEFS are calculated separately through other programs such as MONTCAR.

With infrastructure in place, in the Chukchi and Beaufort Seas, the MEFS varied from a low of 208 MMBO to a high of 278 MMBO, using $18/bbl in constant 1987 dollars and dependent upon geographic location and operational parameters in the base case economic scenario, but regardless of water depth.[23] The minimum area resource size (MARS) needed to support the infrastructure, however, was 810 MMBO for the Chukchi Sea and 517 MMBO for the Beaufort Sea. For a more detailed discussion of MMS methodologies, refer to EIA Service Report, 1989, pp. 35-56,[18] DOI, 1989, p. 18,[3] and DOI, 1988, 88-373, pp. 104-115.[23]

It should be noted once again that the resulting estimates of resources in the 1989 assessment (effective as of January 1, 1987) were substantially increased by the 1990 revisions for both the Beaufort and Chukchi Sea area, based upon additions to the data base.[9] Since these increases were more than double the earlier estimates in some cases, they serve to illustrate the uncertainties in the process. Usually, more data serve to reduce uncertainty and provide a more reliable estimate.

2.3.3.4.2 Discussion of Interpretation--As in the previous discussion concerning USGS/BLM estimates, the observations of other informed reviewers tends to support the conclusions reached by the MMS experts in the area. Critiques are even more limited by confidentiality of the MMS data base and are therefore more qualitative in scope (see **Appendix D**).

Because of the recent (1990) revision of resource values in the two OCS provinces, it is apparent that the increased data base has had a significant effect on input parameters.[9] Without access to the confidential seismic and exploratory well data recently acquired in the Chukchi Sea, it is premature to speculate on the eventual outcomes which can only be determined by drilling.

2.4 Summary of Resource Potential and Status of North Slope Exploration

Because three of the five provinces comprising the onshore and offshore North Slope are being explored on a continuing basis by the oil industry, it is probable that oil and/or gas discoveries will eventually result. The onshore Arctic Coastal Plain, the Beaufort Shelf, and Chukchi Sea are the locations for exploratory drilling activities currently operating or planned for the next drilling season. The promise for future giant to super-giant oil discoveries lies within these provinces or within the confines of the ANWR 1002 area in the eyes of explorationists familiar with North Slope petroleum geology.

2.4.1 Probabilities for Discoveries and Impact of a Major Find

The likelihood of a major discovery, however, cannot be predicted. The pace of activity is generally slow, limited to the summer drilling season offshore and the winter drilling season onshore.

Exploratory drilling by Shell is expected to resume in July 1990 in the Chukchi Sea. Shell drilled and abandoned the first test on the Klondike prospect in 1989. The second test, Burger, was drilled to about 5,500 feet and the third test, Popcorn, to 545 feet before being suspended last year. Shell intends to reenter these two wells and has permitted a last year. Shell intends to reenter these two wells and has permitted a fourth prospect, Crackerjack.[24]

Texaco has submitted plans to MMS for up to 51 locations on 13 prospects in the Chukchi Sea with drill depths from 9,000 to 15,000 feet. The first prospect, Diamond, is scheduled for July 1991 and is 50 miles offshore. A second prospect, Tourmaline, would also start in 1991 if time permits. It would be located between Shell's Popcorn and Klondike wells, Texaco estimates costs for the two 15,000 foot wells at $50-70 million each.[24]

ARCO plans to drill two exploratory wells on the Fireweed prospect, 15 miles offshore from NPRA in the Beaufort Shelf. The location is north of Exxon's abandoned Antares well drilled over 5 years ago.[24]

If any of these wells should prove to be a commercial discovery, the impact would be significant because of the size field required to proceed with development and production. Although MMS estimated MEFS at 208 to 278 MMBO, the MARS ranged from 517 to 810 MMBO. The MEFS for the Chukchi Sea is 2,600 MMBO in this report (see **Section 3.5.6**). The time lag before production could begin would be similar to, or probably longer than, the 7 to 22 year delay estimated for ANWR. In **Section 3** of this report, engineering and economic evaluations of hypothetical potential prospects, onshore and offshore, help to define the parameters of size and the impact of discoveries.

In addition to current and planned exploratory drilling offshore, the oil industry maintains its presence on the North Slope by continuing efforts to maximize recovery from producing fields and by attempting to add production from known discoveries such as Niakuk, Point McIntyre, and West Sak. Potential reserves from the accumulations, especially when aggregated, are positive increments, but, as shown in **Section 3**, are not expected to significantly affect the magnitude of the long term production decline from Prudhoe Bay.

Industry is vitally interested in the proposals before Congress to initiate leasing procedures in the coastal plain 1002 area of ANWR. Although various bills dealing with ANWR were being circulated in Congress early in 1989, the public reaction to the Valdez oil spill effectively halted all efforts toward enacting legislation.

General consensus exists that ANWR offers the best opportunity for a major onshore oil discovery in the U.S. Nowhere else can industry look toward onshore exploration targets large enough to make a significant contribution toward reversing the continuing decline in U.S. crude production and offset our ever-increasing import level which recently reached 52% of demand.[25]

The EIA in the 1987 Service Report on ANWR made the following comments on potential size and impact of an ANWR resource distribution range:[16]

> "The EIA has developed a base-case estimate of 3.4 billion barrels of economically recoverable oil within the Area, but it brackets this with a low-case estimate of 1.2 billion barrels and a high-case estimate of 7.4 billion barrels.
>
> This range of estimates on total resources led to corresponding variations in EIA's estimates of peak production for the low, base, and high cases, respectively--namely 286 thousand, 789 thousand, and 1.4 million barrels per day. These production peaks for a totally new source of domestic oil would augment the annual U.S. oil production now projected for the year 2005 by 6 percent, 16 percent, or--in the high case--up to 28 percent."

In testimony before Congress on June 23, 1987, James Eason, the Director of the Alaska Division of Oil and Gas observed:[11]

> "First, I believe oil and gas leasing and development in Alaska is extremely important to both the state and the nation, and second, I am convinced that the coastal plain (or 1002 area) of the Arctic National

Wildlife Refuge (ANWR) is the most prospective unexplored petroleum province remaining in North America.

As a result of the field work and geophysical surveys conducted over the past twenty years, it has been clearly demonstrated by federal, state, and independent investigators that the 1002 area could yield Prudhoe Bay-size quantities of petroleum. To put this conclusion in proper perspective, the Prudhoe Bay field on Alaska's North Slope, is the largest oil field in North America, with original reserves of nearly 10 billion barrels of recoverable oil. Production from the Prudhoe Bay field and the adjacent Kuparuk River field currently accounts for over 20% of the total daily domestic crude production.

Situated on trend between the prolific North Slope oil fields to the west and the petroleum-rich Canadian MacKenzie Delta province to the east, the 1002 area has all the key geologic elements requisite for major hydrocarbon accumulations."

He further commented:

"It is clear to the state of Alaska that the high prospectivity of the coastal plain of ANWR, and its potential to supplement the projected domestic production decline, thereby reducing our oil imports, justifies an early and thorough assessment of the area by exploratory drilling."

In a recent memorandum, the BLM Staff Economist in Alaska, James Borkoski,[26] commented on the impact of postulated volumes of reserves and timing of initial production from ANWR using the 1987 BLM mean and high-level cases for illustrative purposes.

"The portion of ANWR being considered for development is the 1002 area. This area consists of 1.5 million acres of the total of 19 million acres within ANWR. The mean or average estimate of recoverable resources is 3.2 billion barrels. At this level of production, actual federal revenues are estimated at 38.9 billion dollars, and state and local revenues are expected to total 16.1 billion dollars over the life of the field (undiscounted for time)."

The memorandum also states:

"The graph on Attachment 5 [Figure 2-16 of the present report] shows the net result of the on-line ANWR impact on North Slope oil production. The first full year of production has been estimated at year 2005, or 15 years into the future. The peak years of production using the mean case of 3.2 BBO increases daily production up to approximately 1.1 million bbls/day and puts production about 10 years back in time to the anticipated level in 1995. This level, unfortun- ately though, is still only 58 percent of the actual North Slope production in 1989 of 1.881 million bbls/day." (See **Figure 2-16**).

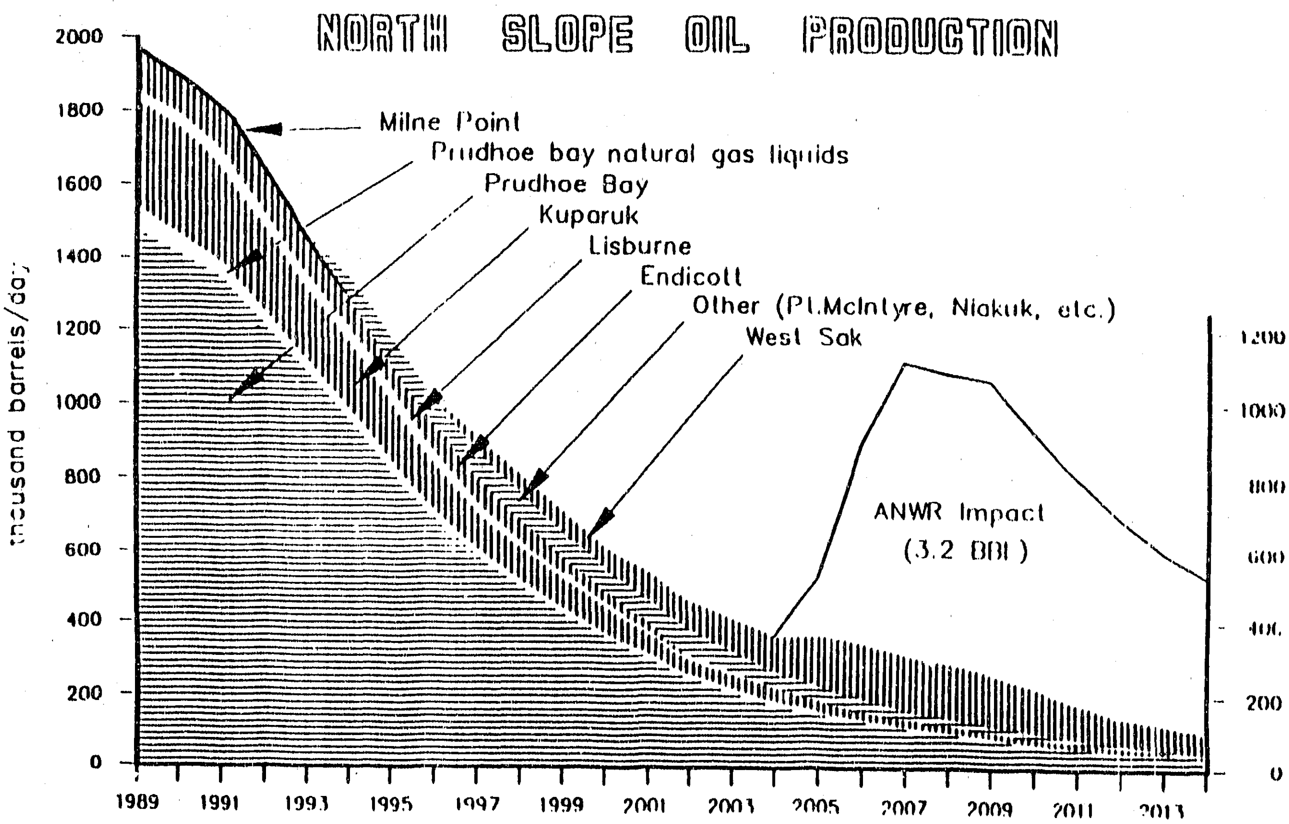


Figure 2-16. Attachment 5 from Eason (1987) testimony to Congress showing possible impact of 3.2 billions of barrels of oil from ANWR on North Slope oil production.[11]

In relating the impact of the high level case, he indicated:

"The ANWR potential as shown by ARCO in Attachment 6 is correct but possibly misleading. The BLM assessment indicated that the high level case was 9.2 billion barrels, but the conditional probability of obtaining this production level was only 5 percent compared to a conditional probability of 35 percent at the mean level of 3.2 billion barrels. A graph illustrating the 9.2 billion barrel potential is illustrated on Attachment 7," **(Figure 2-17** of the present report).

And finally, he commented on the impact of Alaska's revenue stream:

"The anticipated increase in revenue to the state of Alaska would be expected to reach almost 1.5 billion dollars annually during the peak years of production if the mean level of 3.2 billion barrel level is achieved (attachment 4). This is equivalent to almost two-thirds of the current general fund of 2.3 billion dollars."

It is, therefore, evident that the stakes are huge for industry, for the state of Alaska, and for the nation as the future of ANWR is debated in Congress.

Alone, or combined with the resource potential of the remainder of the North Slope onshore and offshore area, ANWR could be a vital part of U.S. energy supply, if Congress were to permit leasing, exploration, and development.

2.4.2 Industry Attitudes, Targets, and Investment Rationale

It is undoubtedly necessary that governmental policy makers at the local, state, and national level understand at least the basic applications of resource assessment estimates. Much of the foregoing discussion in this section is directed toward that end.

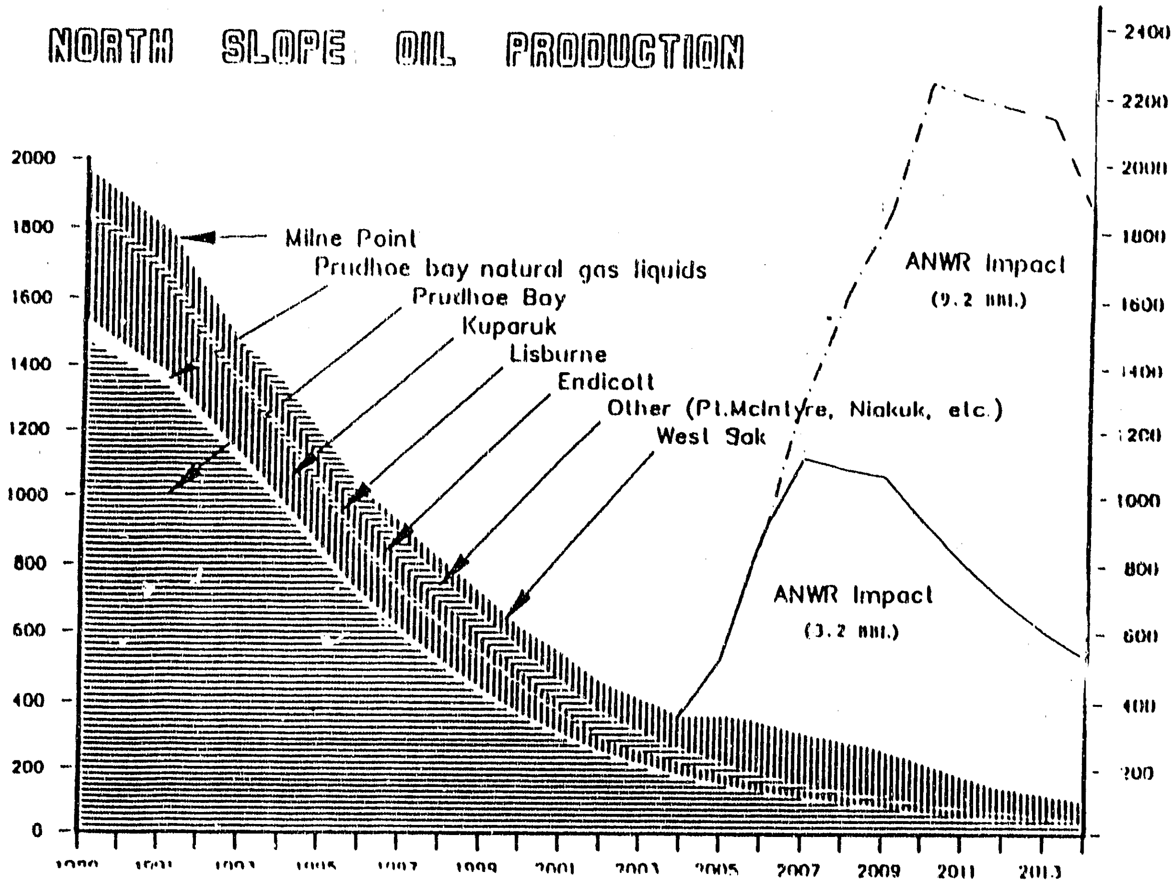


Figure 2-17. Attachment 7 from Eason's testimony to Congress showing possible impact of 9.2 billions of barrels of oil from ANWR on North Slope oil production.[11]

It is equally important, or even more important for that group to realize that resource assessments, while valuable for planning purposes for government and industry alike, have a limited degree of significance to industry in making exploration investment decisions. This is especially true in remote frontier areas where expenditures are extremely high and exploration targets must be commensurately large.

Several factors cause the oil industry to assess potential resources from a different perspective than do various State and Federal agencies. One of the critical factors lies in the experience and background of the professional explorationist. Another concerns the use of different databases and, thereby, the resultant variation in interpretations.

Other factors are as fundamental as a company's history, culture, and local presence in a particular exploration province. Another may be the concern about being excluded from the competitors' success. Changes in corporate financial status, positive or negative, tend to create departures from a plan, i.e., decisions to enter or depart from an exploration program or area.

Certainly another major factor, or chain of circumstances, lies in the current political and economic climate facing the domestic oil industry. The oil price slide of several years ago has drastically changed the fundamental structure of the industry. Today there are fewer major and independent companies with fewer dollars to spend on fewer and smaller exploration targets in the U.S. today. Consequently, the smaller amounts of exploration capital are directed more and more to foreign ventures where opportunities (i.e., different tax, environmental, and regulatory circumstances) seem brighter.

A major cause of diversion of exploration financing away from areas like the North Slope is that no other areas like the North Slope are available for industry to lease and explore in the U.S., onshore or offshore. The Oil and Gas Journal reporting on problems of industry access to federal lands, noted the following in a section entitled, "Industry's lament."[27]

> Oil companies note the OCS supplies the nation with 10% of its domestic crude oil and 24% of its natural gas....
>
> Geologists estimate half of the nation's future oil and a third of its natural gas could be found on the OCS....
>
> "U.S. dependence on foreign oil is increasing rapidly and dangerously as a result of decreasing domestic production," says Stephen Chamberlain, American Petroleum Institute's exploration director.
>
> He further states, "current government policy is making the problem worse. Although federal lands offer some of the best prospects for

major new petroleum discoveries, those prospects are off-limits to exploration and production."

He cites DOE estimates that federal lands might contain as much as 85% of the country's remaining oil and 40% of its natural gas. Yet only about 13% of the federal land onshore and 2% of federal acreage offshore are under lease for petroleum operations.

"Moratoriums or deferrals of leasing have already placed off-limits almost half of all federal offshore lands and 40% of those onshore," Chamberlain says. "And proposals currently before Congress would further reduce the acreage available for leasing, either temporarily or permanently."

In reference to ANWR, the article stated:

"Chamberlain says the coastal plain of Alaska's Arctic National Wildlife Refuge may contain, 'vast petroleum resources,' that might replace declining flow from Prudhoe Bay oil field. But Congress has not approved exploration there.

'If the U.S. is to regain control over its energy security, a sensible, balanced government lands policy is essential,' Chamberlain says. 'That policy must encourage environmentally responsible development of America's still plentiful energy resources.' "

Another commonly overlooked or misunderstood reason why industry geoscientists look at resource estimates from a different perspective is their tolerance for risk in appraising the high-level values of resource distribution ranges. During interviews and discussions with several exploration managers (all of whom have current programs in both onshore and offshore areas on the North Slope) it was repeatedly stated that the federal resource estimates were too low. These managers indicated that their companies were not exploring for targets of the size depicted as the mean of resource ranges for areas like ANWR or the various North Slope onshore and offshore provinces. In their opinion, such targets are too small to warrant serious consideration.

This proclivity to assume large target sizes for prospects, areas, and provinces or basins is not a psychological bent toward over-optimism, but rather a willingness to deal with higher risk levels and, thus, bigger targets. This can best be illustrated by examining a typical volumetric oil distribution range plotted against the probability of occurrence. In order to deal with the most basic case, excluding risk and economic screens, the 1987 ANWR oil-in-place estimate is used (**Figure 2-18**).

The various fractile values, as well as the mean, median, and mode values, calculated from the curve, are tabulated in the upper right-hand corner. It can easily be seen that the F05 fractile value (a 1 in 20, or 5% chance) is almost 30 BBO. That is, a 5% probability exists that a 29.4 BBO in-place, *or larger*, resource exists in the 1002 area of ANWR.

The mean value, or average of all values on the curve, occurs at approximately the 0.40 probability point on the curve, thus indicating a 40% chance of 13.8 BBO, *or greater*, in-place resource.

An oil company geologist or exploration manager might compare the Prudhoe Bay oil in-place value of 23.3 BBO to the probability distribution and conclude that an approximate 10% chance exists of discovering that size, or larger, volume.

Considering even higher risk levels, the conclusion could be reached, from the curve, that a 2% chance of about 35 BBO or more, exists in the area. Looking at a 1%, or 1 in 100 chance to find accumulations that meet, or exceed, 40 BBO in-place may well be the type of risk and target size required to make the investment level decision for North Slope exploration.

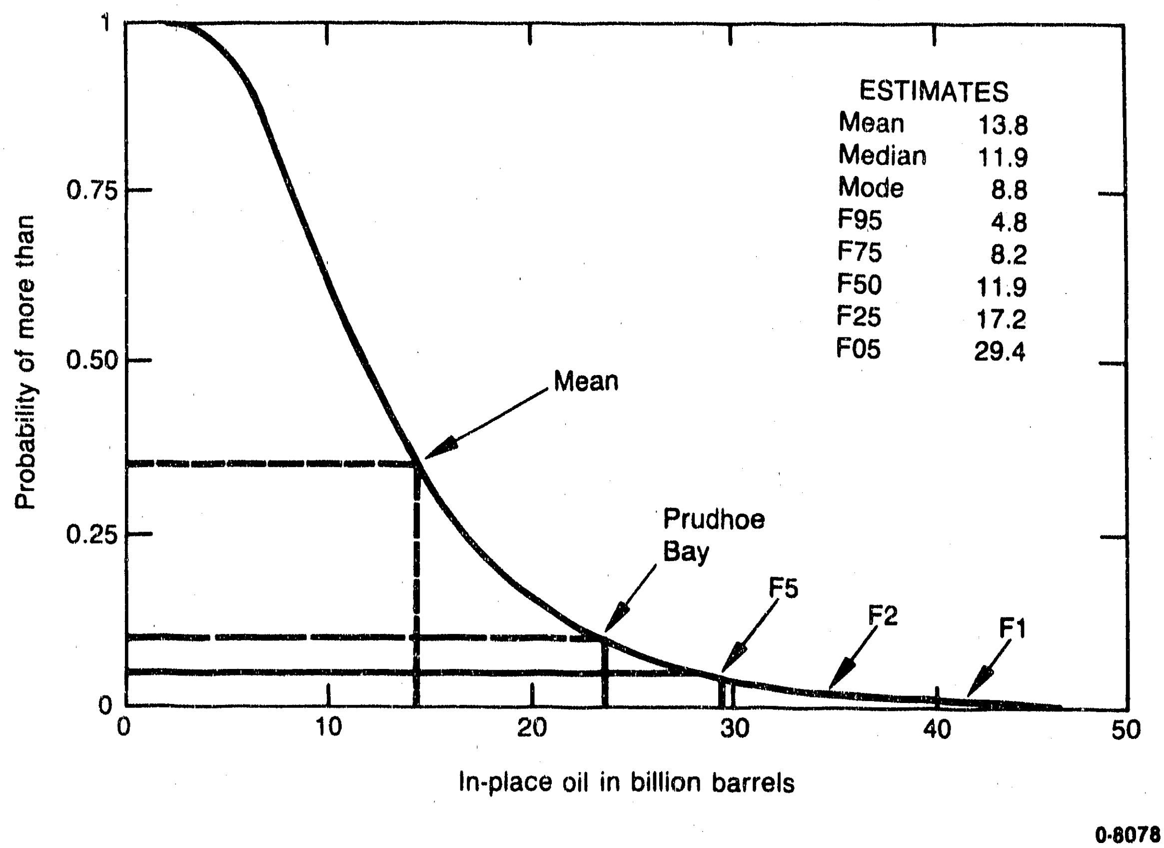


Figure 2-18. Probability curve shown on **Figure 2-14** showing unrisked possible in place oil at the F05, F02, and F01 fractile values and the same relation for Prudhoe Bay.

2.4.3 Economic effects

Exploration activities on the North Slope contend with the same climatic, logistic, terrain and remote operations factors that affect all human endeavors in the area. Because exploration programs involve such diverse activities as seismic geophysical surveys and drilling exploratory wells which are usually scheduled in the winter months when the tundra is frozen, and because they normally occur in remote locations away from the infrastructure, operational problems are greatly magnified. As a consequence, exploration costs are greatly increased relative to those of the Lower 48. Obviously, offshore work exacerbates the operational difficulties, thus increasing costs even more.

Although current cost data are not easily available, a few general comments may serve as illustrations of the burdens carried in exploratory efforts. **Table 2-14** compares North Slope costs of the pre-discovery era in the 60s to the peak cost period in the early 80s.

Table 2-14. Comparison of Mid-60s and 1982 Exploration Costs for North Slope Activities.[28]

Activity	Mid-60s	1982
13,500 foot wildcat	$4.5 million	$20 to 25 million
Geologic Field work (3 months)	$125,000	$750,000
Seismic crew (4 months)	$1.06 million	$8.0 million

Comparable costs today are not available from verifiable published sources, but some generalizations apply. Seismic costs on the North Slope, for instance, vary from about $13,000 to $27,000/mile for a 4-month (winter) season. Thus, for a 100 mile/month average, costs might range from $5.2 million to $10.8 million.

Although no drilling cost averages are available from recent onshore wildcat wells, a 1987 exploratory well was drilled to a total depth of 10,500 feet, plugged back and redrilled as a deviated hole to a specific target at similar depth for $2.5 million. The Kup Delta No. 1 well was drilled by two Dallas independents, Vaughn Petroleum, Inc. and CMOG, in the Gwydyr Bay area some 10 miles northwest of Prudhoe Bay.[29] Drilling costs generally have declined substantially because the peak levels of the early 1980s no longer prevail.

Offshore drilling generates some seemingly astronomical costs, but the record high for a wildcat well in the U.S. is certainly the Mukluk well. The total cost was $150 million for a Beaufort Sea dry hole that tested the Mukluk structure on leases acquired in 1982 for about $1.4 billion.[11]

Texaco recently estimated drilling costs for two proposed Chukchi Sea 15,000 foot wildcats at $50 to $70 million each.[24]

In considering the economics of exploration and the requirements for success, a critical factor is the previously mentioned (MEFS) necessary for a potential resource to become a viable reserve. It has been noted earlier in this report that MEFS usually refers to a "stand-alone" accumulation that can support the entire production and transportation infrastructure. Such is the case for Prudhoe Bay with its multi-billion dollar field installations plus TAPS (including the Valdez Terminal and the necessary fleet of tankers to get oil to the refineries). That same infrastructure however, allows development of other, and smaller, "satellite" fields such as Kuparuk River, Milne Point, Endicott, Lisburne, and hopefully, Niakuk and Point McIntyre.

A similar approach may well allow smaller satellite accumulations to become economic in areas remote from Prudhoe Bay and TAPS.

In the EIA review of 1987, the following observation was stated:[16]

> "A basic MEFS consideration concerns the potential sharing of the infrastructure, especially the transportation network. Since the DOI analysis assumes a "stand-alone" MEFS, any discovery would need to financially support the total expenses of all necessary support items. This constitutes, in essence, a worst case basis for ANWR 1002 Area development. Sharing facilities among fields would allow the development of groups of smaller, economically marginal fields that individually do not meet a "stand-alone" MEFS threshold. If sharing of the infrastructure were allowed in the analysis, the resulting smaller MEFS would undoubtedly have produced a larger estimate of expected resources."

Similar conclusions about the MEFS onshore criteria can be drawn, particularly in view of the 384 MMBO threshold which was universally applied throughout the North Slope. MMS used a different approach and calculated minimum economic sizes not only on a field basis, but also on an area basis. The MEFS varies from 208 MMBOE in the Chukchi Sea to 278 MMBOE in the Beaufort Sea and the MARS from 517 to 810 MMBO.[23] Both agencies used the $18/bbl 1987 constant dollar assumption.

Obviously, different economic and operating parameters have various effects on decisions affecting North Slope exploration. Companies exploring in the area normally operate with highly competent and experienced personnel, using "cutting-edge" technology and applying sophisticated evaluation models of each step in the exploration/production sequence. A final quote from the 1987 ANWR evaluation accurately expresses the viewpoint of the industry explorer:[16]

"In the end, the decision whether or not to drill will not be based on perceptions formed from either DOI or EIA assessments. That decision will be based on the assessments of those individuals or corporations that, after incurring considerable exploration expenditures, will form their own perceptions. At best, this or any other probabilistic assessment is an approximate guide (of considerable importance, to be sure) in the political decision-making process; it is of fairly little value to the entrepreneur prepared to make this choice, it means that he may be betting on something that others have not seen, and he is risking sizeable amounts of money on the accuracy of his bet."

2.4.4 Environmental Effects

Because a thorough evaluation of environmental concerns is documented in **Section 5** of this report, the following brief discussion is limited to comments about effects on the exploration process. The process includes only actual physical operations involved in surface geological work, geophysical surveys, and exploratory drilling operations.

Surface geology usually involves helicopter and fixed wing air support for summer field parties in a camp environment. Primary operational concerns are entry permits in areas such as ANWR, caches for food, fuel and other supplies, waste and garbage disposal, water supply and prevention of contamination, and avoiding interference with fish and wildlife. Normal field party activities have minor impact on the environment, and therefore are not hindered significantly by regulatory procedures.

The most limiting restrictions are those related to entry into sensitive areas such as wildlife refuges, parks and preserves, wetlands, native corporation lands and the like. Complete and free access to all lands of geologic significance is a necessity for thorough definition of the petroleum potential of the North Slope, and should apply to all those with professional scientific credentials.

Geophysical operations involve larger field parties for seismic surveys, normally carried out during a 3 to 4 month winter season when the tundra is frozen. This also applies to near-shore surveys operating on the sea ice. Similar concerns affect geophysical parties with respect to camp operations, but are more complex due to constant moves, the required heavy equipment, and greater numbers of people. Seismic permitting is somewhat complex and time-consuming because of the potential impacts. Seismic surveys now usually involve vibrators as an energy source rather than the use of explosives detonated in drilled shot-holes, thus greatly minimizing surface disruption.

Obviously, exploratory drilling operations have the largest environmental impacts. Onshore remote wildcats are normally one-season winter operations using ice roads and pads, rather than gravel islands which are used for multi-season drilling. Water and gravel supply become critical planning and permitting problems.

Roads, culverts, bridges and pads must be carefully engineered in order to properly perform their functions under adverse terrain and climatic conditions. Drilling operations necessitate water sources; drilling mud, fluid and cuttings containment; reserve pit drilling fluid, test production and flaring containment and protection; subsurface permafrost and aquifer protection; as well as safety and oil spill contingency plans and equipment. Camp operations require stringent safeguards in regard to waste, garbage, water supply, transport, safety, fire prevention, permafrost protection, and conduct of personnel regarding fish and wildlife. Offshore operations intensify all the concerns involved with onshore wildcats, plus adding new ones such as drilling shut-down periods during bowhead whale migration.

Even with the various permitting steps and regulations exploration activities can be carried out successfully with adequate planning and operating skills. Environmental impacts are transitory and can be accommodated within current guidelines.

2.5 Conclusions

In order to consider sources for the nation's future domestic energy supply, a clear understanding of the oil and natural gas resource potential of the North Slope of Alaska is vital. Discovered and undiscovered resources will not be quickly, easily, or cheaply converted to reserves and thus be readily available to meet increasing demand. The following conclusions have developed from the body of information contained in this section of the report.

- The North Slope resource endowment is a substantial portion of the total estimated resource base of the U.S. Alaska is estimated to provide almost 25% of the undiscovered economically recoverable oil, and the North Slope contributes more than 95% of the Alaska total. Similarly, Alaska's natural gas recoverable resource is estimated to be 18% of the U.S. total and the North Slope provinces make up 90% of the total for Alaska.

- Discovered, but undeveloped, oil resources on the North Slope continue to be converted to reserves (along with reserve growth from currently producing fields), but these additions will not be sufficient to significantly affect the decline caused by long term decreasing production from Prudhoe Bay.

- The 1989 (effectively January 1, 1987) national assessment conducted by the USGS and MMS was an adequate representation of the North Slope potential, but revisions and clarifications can be made, particularly with regard to economic judgments incorporated in the process.[3] This also applies to the 1987 ANWR evaluation. The 1990 MMS dramatic upward revisions of estimated resources for the Beaufort and Chukchi Sea areas emphasizes the need for regularly scheduled reviews of both onshore and offshore provinces in the region.[9]

- The undiscovered oil resource for the North Slope onshore and offshore provinces is viewed by industry from a different perspective than that commonly perceived by governmental bodies and agencies, or as reported by news media. Industry personnel view the estimates as a general guide to potential, but normally see the targets much higher on the distribution curves at the upper end of resource ranges and, therefore, with higher risk factors.

- The North Slope gas resources, both discovered and undiscovered, are dependent upon increased gas prices, market commitments, and delivery systems from the North Slope to markets. These are critical issues if resources are to be converted to reserves.

- Remaining unexplored or under-explored North Slope areas, both on and offshore, offer the best opportunities in the U.S. for oil and/or gas discoveries in the giant and super-giant categories.

- With the continuing decrease in oil and gas exploration in the U.S. and the transfer of interest and funding to foreign exploration, it is probable that interest in Alaska and North Slope exploration will decline. This condition is amplified when coupled with governmental decisions which effectively reduce federal lands available for leasing, exploration, and development.

- Impacts on the oil and gas supplies of the U.S. should not be judged from single number (mean or average) estimates, but should be considered from the perspective of the full range of opportunities, including the high risk - high potential values. The possibility for such discoveries is the primary motivating factor for industry programs. If they are successful, these activities will be very significant to the nation's future energy supply.

- Because of the extremely high exploration and development costs associated with exploration in the North Slope area, it is advisable for industry and government to work together to achieve cost-efficient results and environmentally sound practices.

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Appendix A

"**ASSESSMENT MODEL**--The play-analysis method attempts to describe the natural occurrence of oil and gas and therefore is described as a model. The model divides the geologic characteristics and attributes of potential hydrocarbon accumulations into three classes: (1) play attributes, (2) prospect attributes, and (3) number of prospects and their reservoir and trap characteristics. Play and prospect attributes, which determine the presence of hydrocarbons, are assessed as to their probability of occurrence. Reservoir and trap characteristics, which determine hydrocarbon volumes, are assessed in terms of ranges of values (sizes). The number of prospects in a play is likewise assessed in terms of a range of values.

The geologist's judgments of these characteristics are recorded on a data form. An example of this form is annotated in figure 22.9 to show how this method addresses the two fundamental questions asked in any assessment: (1) are there oil or gas accumulations in the area, and (2) if so, how much oil and gas is present."[1] (See **Figure A-1**).

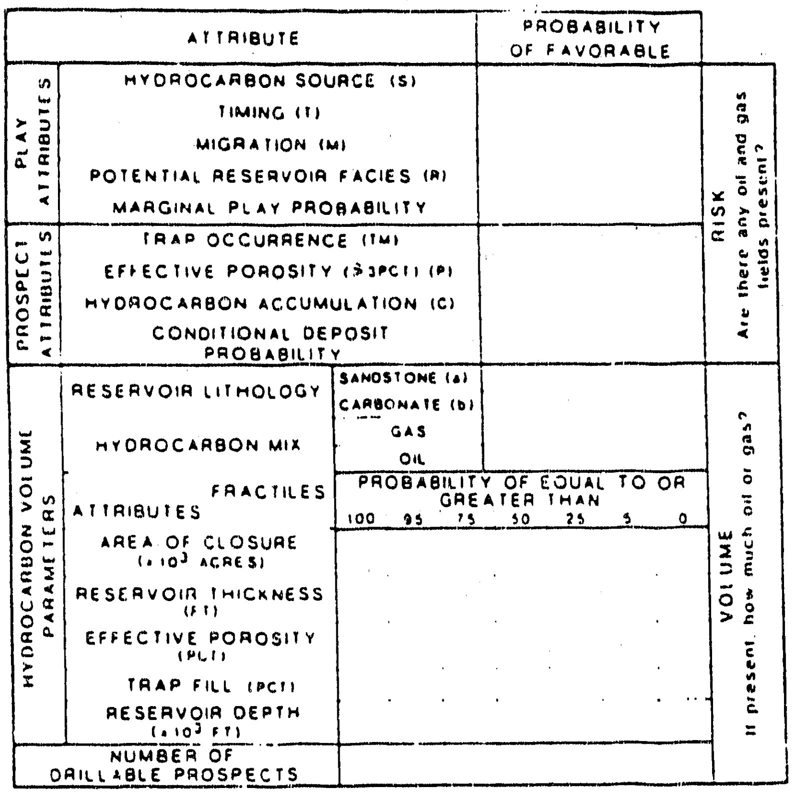

Figure A-1. Example of play analysis data sheet designed to consider fundamental aspects of petroleum assessment.[1]

USGS National Assessment Oil and Gas Appraisal Data Form (FASPFS)

Evaluator ____________ Play Name: ____________
Date ____________ Province ____________ No. ______

	Attribute	Probability Favorable or Present	Comments
Play Attributes	Hydrocarbon Source (S)		
	Timing (T)		
	Migration (M)		
	Potential Reservoir Facies (R)		
	Marginal Play Probability $S \times T \times M \times R = MP$		
Accumulation Attribute	Conditional Probability of at least one undisc. accumulation in play.		
	Minimum accumulation size assessed: — $\times 10^6$ BBL: — $\times 10^9$ CF.		

Hydrocarbon Accumulation Parameters (Undisc. accum's)										
Reservoir Lithology	Sandstone									
	Carbonate									
	Other									
Hydrocarbon type	Gas									
	Oil									
Attribute \ Fractiles		100	95	75	50	25	5	0		
Accumulation Size	Oil (10^6 BBL)									
	Gas (10^9 CF)									
Reservoir Depth ($\times 10^3$ Ft)	Oil									
	NA Gas									
Conditional: No. of accumulations										

Average ratio of associated-dissolved gas to oil ______ CF/barrel

Average ratio of NGL to gas, NA GAS ____ BBL/10^6 CFG, Assoc-Dis Gas ____ BBL/10^6 CFG

Est. % resource on Federal land ___%, Indian (native) land ___%, Non-Federal offshore ___%

Play area ______ mi^2

Discovered resources.

	OIL (10^6 BBL)	GAS (10^9 CF)	NGL (10^6 BBL)
IN ACCUM'S > CUT-OFF	______	______	______
TOTAL	______	______	______

Source: USGS

Figure A-2. Sample data sheet for the FASPFS (Fast Appraisal System for Petroleum) appraisal method used by the U.S. Geological Survey for the 1987 national assessment of undiscovered oil and gas in the U.S.[2]

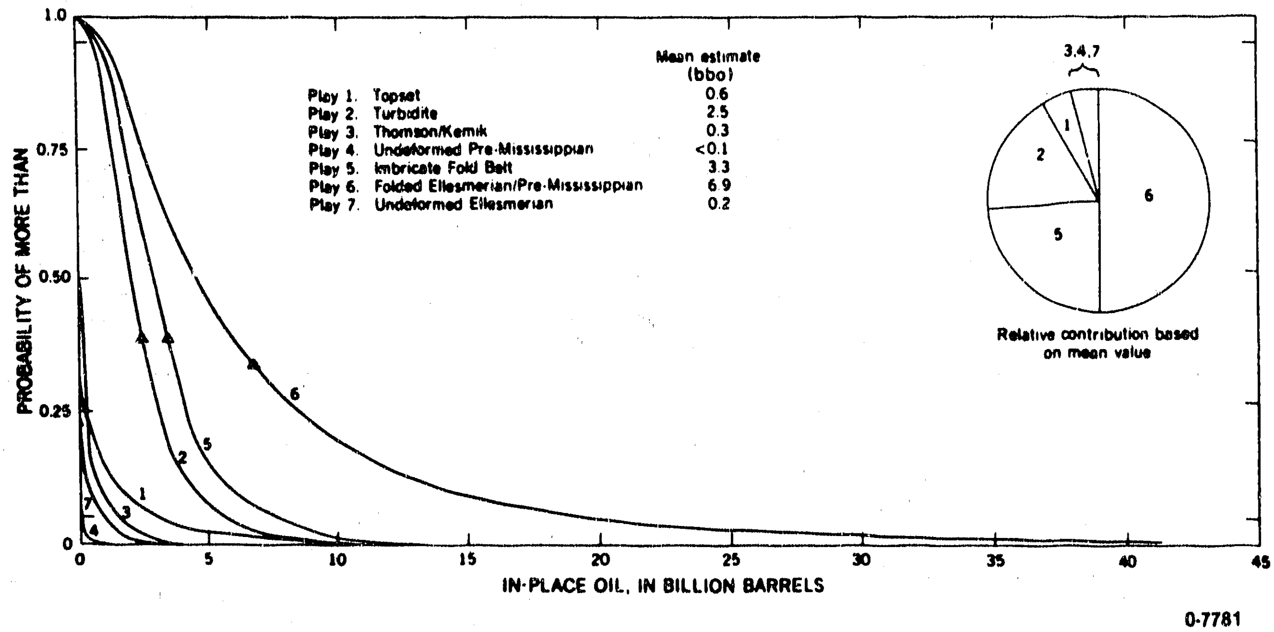

Figure A-3. Estimated in-place oil resource for the seven plays in the 1002 area, and individual probability curves and relative contributions of plays.[1]

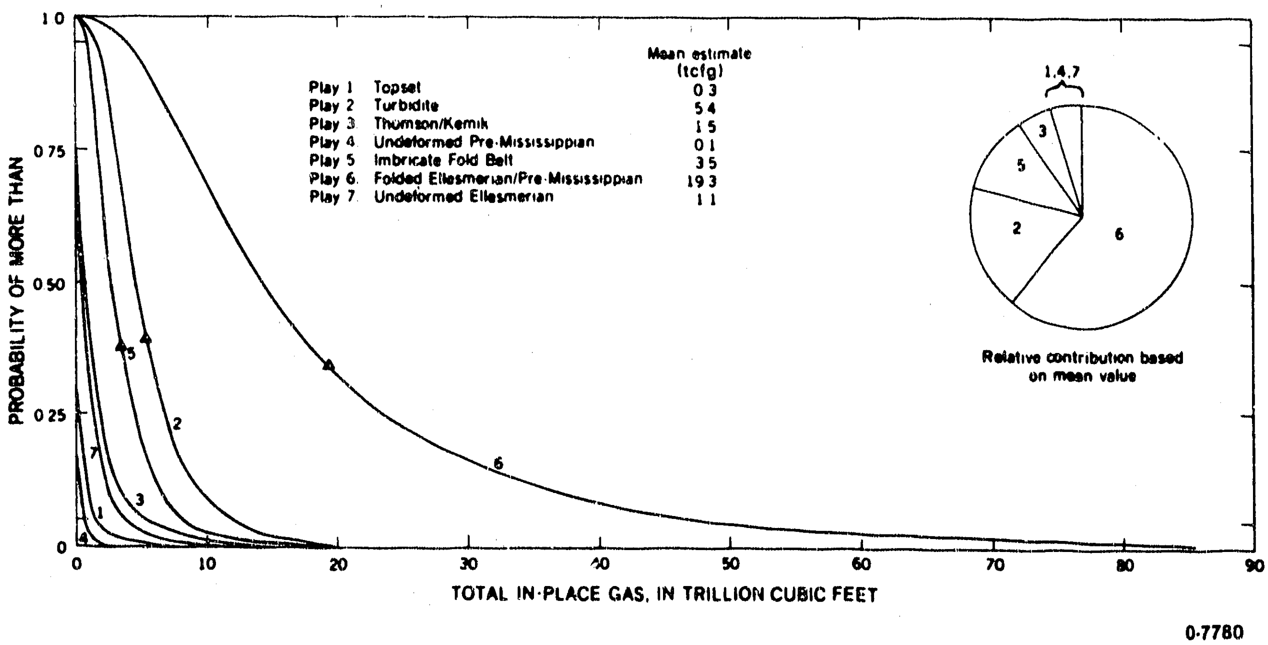

Figure A-4. Estimated in-place gas resource for the seven plays in the 1002 area, and individual probability curves and relative contributions of plays.[1]

References - Appendix A

1. K. J. Bird and L. Magoon, Petroleum Geology of the Northern Part of the Arctic National Wildlife Refuge, Northeastern Alaska, USGS Bulletin No. 1778, 1987.

2. Potential Oil Production from the Coastal Plain of the Arctic National Wildlife Refuge, Energy Information Administration, SR/RNGD/87-01, October 1987.

Appendix B

The State of Alaska in 1986 evaluated the early 1980 ANWR estimates as follows:[1]

"In summary, the results of this evaluation indicate that the ANWR coastal plain may contain large petroleum deposits. On the basis of current data, large quantities of resources and large individual deposit sizes may occur within the coastal plain of ANWR. There is a 1-percent chance that the requisite parameters of source rock, timing, migration, reservoir rock, and trapping mechanisms have combined to generate up to 45.78 BBO and 6.24 TCF gas in place in ANWR (Tables 1 and 2). Assuming a recovery factor of 35 percent for oil, up to 16 billion barrels of recoverable oil may be present. This compares favorably with the original recoverable oil reserves of about 10 billion barrels in the Prudhoe Bay field."

In 1987, the EIA instituted a review of the ANWR Coastal Plain as mandated by Congress as part of their annual charge to prepare a long-term energy outlook. The EIA was also asked to review the DOI assessment and make a projection of crude oil production over time. The results were presented in an informative document, EIA Service Report SR/RNGD/87-01.[2] Significant comments and conclusions from the report are as follows:

"More than 1,300 linear miles of seismic profiles were surveyed across the 1002 Area during 1983-85 to determine its general geologic structure. Other exploratory investigations (including geochemical and gravity surveys) have also been going on for years. Although no test wells have been drilled within the 1002 Area itself, data are available from wells to the immediate west. In sum, one would be hard-put to deny the high crude oil potential of the ANWR 1002 Area when observing that: (a) the largest oil field in North America lies only 60 miles west of it; (b) a 600 million barrel oil and gas condensate field adjoins the 1002 Area on the immediate west; (c) commercial (sic) fields in the Canadian Beaufort Sea and McKenzie Delta are about 150 miles to the east; (d) the sedimentary section, containing both oil source rocks and reservoir rocks, extends to depths of about 25,000 feet; (e) potential oil or gas bearing structures have been identified through seismic work; and (f) several oil seeps are present. The petroleum industry has shown its high interest in the ANWR 1002 Area too, through: (a) funding of the previously-mentioned seismic survey by twenty-two energy companies; (b) drilling by Chevron Corporation and partners of the expensive 14,500-foot exploratory well on Kaktovic (sic) Inupiat Corporation lands, just north of the 1002 Area; and (c) competitive bidding for offshore tracts in the State of Alaska's Lease Sale 50 (Camden Bay, adjacent to the northwest part of the 1002 Area)."

"The DOI mean conditional estimate of economically recoverable oil is 3.23 billion barrels. This is the volume of recoverable oil to be expected if any economic field at all is found--an event for which DOI has concluded there is a marginal probability of 19 percent. Put another way, the DOI conditional resource estimate and the associated marginal probability mean that there is about one chance in five of finding a field with at least 440 million barrels of economically recoverable oil (the MEFS), but that if such commercial oil deposits are found, 3.23 billion barrels of oil are expected to be recovered.

For several reasons, the EIA considers this conditional mean estimate for the ANWR 1002 Area somewhat conservative. First, the model considered only the 26 prospects identified on a relatively coarse seismic grid (3 by 6 miles). The ANWR 1002 Area can be expected reasonably to contain other stratigraphic oil accumulations besides these, as well as numerous smaller structurally-controlled accumulations. Such accumulations, which could become economic once a basic infrastructure and pipeline connection were in place, might well appear on a more closely-spaced seismic grid and would certainly not be a surprise as a result of exploratory and development drilling.

Beyond the number of structures included in the analysis, however, the ANWR results yielded by PRESTO II may be low because of the way area risk is treated. In this particular application, the chances of success were considered for only the five largest of the 26 identified structures in determining the area risk, even though it is routine to base the geologic area risk on the probability that at least one prospect (out of all those in any given area) will contain an accumulation of hydrocarbons as modeled (Cooke, 1985). In addition, the area risk in this instance included the restriction that any deposits in the 5 prospects considered must be economic in order to be counted--i.e., they must exceed Minimum Economic Field Size (MEFS). Normally, economic considerations are introduced later in the PRESTO II model by applying the MEFS test proper; and, in fact, all fields in the analysis were also tested subsequently against the MEFS threshold in order to be accepted in the overall recoverable resource estimate. The DOI explained this approach with the rationale that "there must be at least one field in the area large enough to bear the cost of a regional transportation infrastructure in order for commercial development to occur."

Additional comments on area risk:

"Limiting the area risk determination to only 5 prospects--even though this group consists of the largest and, therefore, the most promising structures, ignores *a priori* the geologic potential of the other structures. Ignoring these structures completely constitutes a definite conclusion about the geologic and economic potential whose justification is somewhat unclear, given the uncertainty about the geologic characteristics of any of the structures."

With respect to DOI assessment methods and results, the EIA determined:

"In conclusion, EIA considers the DOI estimate of 3.23 billion barrels of economically recoverable oil as a conditional value to be somewhat conservative for the ANWR 1002 Area. First, the PRESTO II methodology is inherently conservative by limiting itself only to the large, seismically identified structures in the area, thereby ignoring the potential contribution of both stratigraphic traps and smaller structures. Second, the area geologic risk assumed in the DOI study is high in our judgment. Finally, EIA believes that the MEFS used should be smaller. A lower MEFS threshold would have a twofold effect--including additional recoverable resources in the results and lowering the area economic risk."

Conclusions and comparisons reached by EIA:

"Table 1 [Table 2-13 of present report] presents the unconditional oil-in-place estimates made by DOI and the resultant unconditional EIA estimates of undiscovered economically recoverable oil in the ANWR 1002 Area. The conditional DOI estimates of economically recoverable oil are also shown for comparison. The DOI economically recoverable estimates are conditional upon the occurrence of at least one economic-size oil accumulation in the area--the probability of which is about 19 percent, according to DOI. In contrast, the unconditional EIA estimates listed in Table 13 suggest a much higher probability that the ANWR 1002 Area contains economically recoverable oil accumulations. The EIA low recovery case--an estimate with a high confidence level--is 1.20 billion barrels of economically recoverable oil, or about double the conditional DOI value. The base case EIA estimate for economically recoverable oil is 3.45 billion barrels, which is about the same as the conditional DOI mean estimate. In the high recovery case--involving a low confidence level--the EIA estimate of 7.35 billion barrels is lower than the conditional DOI estimate."

As a final comment on the general process of assessment, the EIA stated:

"It should also be understood that any probabilistic assessment of recoverable crude oil reserves is basically judgmental--in spite of the scientific appearance of complex computer models that may have been used in deriving it. Furthermore, this reserve assessment is subject to asymmetrical adjustments as the exploratory process proceeds. Suppose the first wildcat well discovered a super-giant field--perhaps the size of Prudhoe Bay. A single such well would significantly shift the recoverable reserve estimates and boost the production potential of that region far beyond the probabilistic assessment of this report. On the other hand, if the first wildcat drilled is dry, the ANWR reserve estimate and production potential would be reduced somewhat--but not wiped out--because other large structures remain to be explored."

Mr. Charles Mull of the State of Alaska Department of Natural Resources Division of Geological and Geophysical Surveys had these comments in a December 9 (1988) letter with regard to the Alaska portion of the national assessment:[3]

"**Arctic Coastal Plain**--I am sorry that this area was not divided into two sub areas, because the geology of the coastal plain of the Arctic National Refuge is quite different than the coastal plain of the rest of the North Slope. It is therefore a little difficult to evaluate the estimates for this area. Overall, I have no big quarrel with the estimate.

Northern Foothills--same concern as above. The boundary as drawn on the map appears to place most of the area of greater ANWR potential (based on the separate ANWR assessment published last year) in the northern foothills province. If this is the case, it is impossible for me to know how much of the potential of this province the potential given in this assessment may come from the area of ANWR, and if so, then the estimate given may be unrealistically low because of underestimation of the potential of the western part of the northern foothills.

Southern Foothills--based upon my experience mapping and evaluating the geology of the Brooks Range thrust belt, I feel rather strongly that the 5% fractile estimate of 12.64 billion barrels of economically recoverable oil from this belt is unrealistically high. Most of this area--area 60 on the map--is within the Brooks Range proper, and most of the remainder is in the very complex thrust belt. The belt is much more likely to be mostly a gas province, and I personally think that when a Trans-Alaska gas pipeline is built, there is a fair likelihood that gas resources in the foothills province will be economic.

On balance, it is possible that what I think may be an overestimation of the oil potential of the Southern Foothills may be counterbalanced by what

I think is an underestimation of the potential of the western part of the Northern Foothills."

Comments from Mr. Garnett Pessel of the same State of Alaska agency in a November 17, 1988 letter are as follows:[3]

"After attending the meeting in Anchorage on the appraisal of Alaskan oil an gas resources, I have the following comments, for your use:
In general, the background work that went into the appraisal was good to excellent, at least from the point of view of the geology used.

The onshore geology, as presented by the U.S. Geological Survey, was somewhat uneven. This was apparently due to the fact that the appraisal was done almost unilaterally by their oil and gas people, and information from other branches of the USGS and other Federal and State agencies was not solicited. Perhaps future appraisals should attempt to rectify this weakness. However, the best geology, as presented, was for the North Slope, and that is where the bulk of the resources are located. In areas where the geology was not as well understood, I do not believe that better data would have appreciably affected the resource appraisal."

Both sets of comments were in response to public presentations by USGS geologists held under the auspices of the American Association of State Geologists at the request of the Department of the Interior. This was after issuance of the national assessment Open File Report 88-373 and prior to issuance of the final 1989 DOI national assessment.[4,5]

In a memorandum to the Commissioner of Natural Resources of the State of Alaska, dated November 1, 1989, the Resource Evaluation Section of that agency comments in a review of the 1989 national assessment Alaskan estimates that:

"We caution that estimates of undiscovered oil are derived from complex regional resource modelling and, as such, are highly uncertain and suitable for only limited application. We have included an appendix that discusses the methodology used for this type of study and why the numbers should be taken with 'a grain of salt'."

And that:

"Estimates for onshore Alaska are too optimistic. This is due to inflated estimates in all three North Slope onshore provinces (see map). The estimates for the Southern Foothills Province are especially unreasonable." (It should be noted that recent revisions of province resource estimates by the USGS have corrected this problem.[6])

"Estimates for offshore Alaska are reasonable, but may be overly pessimistic in two provinces. The oil potential of the Beaufort Sea and the oil and gas potential of Cook Inlet may be understated and should be slightly increased."

In a final section on Usage of Results, the following comments illustrate the strengths and weaknesses of oil and gas resource estimates and the caveats that should be applied to their use:

"Undiscovered resources are just that; they are unknown. The estimated values resulting from a study are 'reliable' only until additional data becomes available. The methodology to assess undiscovered resources was developed primarily as a planning tool for petroleum industry managers, as well as government planners. The estimates provide a relative ranking of overall prospectiveness for vastly different and distant areas, and can be an effective management decision tool.

However, a glance at the large standard deviations associated with the ranges of resource estimates in frontier areas immediately tells us that a very high degree of uncertainty is attached to the given values. Although the mean estimate represents the average of all the possible values, it also is a number that should be viewed with much skepticism.

Past federal estimates for Alaska's OCS basins such as Gulf of Alaska, S. George, Navarin, Lower Cook Inlet and Norton Sound have one thing in common--they were wrong. Even the ranges of values between the F95 and F5 fractiles failed to capture the reality that these areas are apparently devoid of recoverable resources.

Certainly, in areas where detailed data are available, greater reliability in the estimates may result. However, the Resource Evaluation Section is unaware of any studies which show other than a random correspondence between the estimates of undiscovered resources and what ultimately becomes the discovered resources, or reserves."

References - Appendix B

1. J. J. Hansen and R. W. Kornbrath, "Resource Appraisal Simulation for Petroleum in the Arctic National Wildlife Refuge, Alaska," State of Alaska Department of Natural Resources Professional Report 90, 1986.

2. Potential Oil Production from the Coastal Plain of the Arctic National Wildlife Refuge, Energy Information Administration, SR/RNGD/87-01, October 1987.

3. C. G. Groat, Robert Jordan, and Perry Wigley, "Review of Geological Information Utilized by U. S. Geological Survey and Mineral Management Service in Their Assessment of U. S. Undiscovered, Conventionally Recoverable Oil and Gas Resources," Oil and Gas Assessment Review Committee, American Association of State Geologists, December 1988.

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5. "National Assessment of Undiscovered Conventional Oil & Gas Reserves, (preliminary)," U.S. Department of Interior, U.S. Geological Survey/Minerals Management Service, USGS-MMS working paper, Open File Report No. 88-373, 1988.

6. K. J. Bird, Personal Communication, USGS, Menlo Park, California, September 19, 1990.

Appendix C

Samples of the forms used with the PRESTO program are shown in Figures C-1 and C-2.

MMS Alaska Region Prospect Assessment Form

FORM A

PROSPECT PROBABILITY OF SUCCESS
for
PRESTO PROGRAM
NATIONAL RESOURCE ASSESSMENT

Your Name(s)________________________________Date__________

Name of Province____

Name of Play____

Prospect Number____

For each of the following probabilities, assign a number zero to one, where zero indicates no confidence, and one indicates absolute certainty.

1. Province: What is the probability that at least one prospect in the province contains hydrocarbons as described by the distributions of area, net pay and recovery?

   Probability of Success = ______________________

2. PLAY: What is the probability that at least one prospect in the play contains hydrocarbons as described by the distributions of area, net pay and recovery?______________________

   Probability of Success = __________(Must be ≤ Province Probability)

3. Prospect: Assign probabilities for trap, reservoir, and geologic history.

   A. TRAP: Consider what kind of trap is this prospect, what is the probability that it exists as mapped, and what is the quality of the seal.

Trap Type	Probability of Success =
Simple Anticline	(max. 1.0)
Faulted/Truncated Anticline	(max. .75)
Fault Trap	(max. .50)
Strat Trap	(max. .25)

   B. RESERVOIR: What is the probability that the estimated minimum recovery factor and the minimum net pay exists within this prospect?

   Probability of Success = ______________________

   C. GEOLOGIC HISTORY: What is the probability that the geologic history of this prospect is favorable toward the sourcing and migration of hydrocarbons into this trap and reservoir?

   Probability of Success = ______________________

PROSPECT PROBABILITY OF SUCCESS = A x B x C = ______________________ (Must be ≤ Play Probability)

Figure C-1. Sample of a PRESTO form used in the MMS national resource assessment program (from Alaska Region MMS).[1]

FORM B

PRESTO RESOURCE ESTIMATE REPORT FORMAT

Your Name(s)____________________ Date________
Name of Province____________________ Sale Number________
Name of this Play____________________
This Play Probability of Success (from Form A)__________
This Prospect Number______ Prospect Probability of Success (from Form A)________
Water Depth for this Prospect (Feet)__________
Distance from Shore for this Prospect (Statute Miles)__________

		G/G - Supplied Distributions		
		Zone 1	Zone 2	Zone 3
Depth to Top of Zone (Feet)				
Zone Probability of Success*				
Total Closure at Spill Contour, Acres				
OPROB** ______ GPROB** ______		//////////	//////////	//////////
Proportional Gas Pay	Minimum			
(Fraction of Net Pay)	Most Likely			
	Maximum			
Productive Acres	Minimum			
(Defines Fill-Up)	Most Likely			
	Maximum			
Pay Thickness	Minimum			
(Net Feet)	Most Likely			
	Maximum			
Oil Recovery Factor	Minimum			
(Bbls/Acre-Foot)	Most Likely			
	Maximum			
Gas-To-Oil Ratio	Minimum			
(CF/Bbl for Dissolved	Most Likely			
Gas)	Maximum			
Gas Recovery Factor	Minimum			
(MCF/Acre-Foot for Gas	Most Likely			
Cap & Nonassociated Gas)	Maximum			
Natural Gas Liquids	Minimum			
(Bbls/MMCF for Gas Cap	Most Likely			
& Nonassociated Gas)	Maximum			

* Zone Probability of Success must be ≤ Prospect Probability of Success. For a single zone, Zone Probability = Prospect Probability.

** OPROB = Probability of all Oil; GPROB = Probability of all Gas. OPROB + GPROB must be ≤ 1.00. The computer generates a random number on the interval 0 to 1. If the number falls between 0 and OPROB, the zone contains oil only. If the number falls between 1-GPROB and 1, the zone contains gas only. Otherwise, both are present. In case the zone contains both oil and gas, the proportion of the gas pay is determined by sampling the G/G-supplied distribution.

All Oil	Oil and Gas	All Gas
Example: OPROB = 0.40	Gas Fraction Developed By PRESTO	Example: GPROB = 0.30

0.00 — 1.00

Source MMS

Figure C-2. Sample of a PRESTO form used in the MMS national resource assessment program (from Alaska Region MMS).[1]

Reference - Appendix C

1. Potential Oil Production from the Coastal Plain of the Arctic National Wildlife Refuge, Energy Information Administration, SR/RNGD/87-01, October 1987.

Appendix D

Mr. Mull of the Alaska Department of Natural Resources, Division of Geological and Geophysical Surveys had these observations in his letter of December 9, 1988.[1]

"Beaufort Shelf--At the summary given of this area at the assessment review in Anchorage, I was a bit bothered by two aspects of the presentation. I did not have the feeling that the reviewer had a good feel for the stratigraphy of the North Slope, and I felt that insufficient consideration was given to the source rock potential of the Cretaceous rocks. Without seeing the input parameters, however, I have no way of knowing how these factors may have influenced the overall appraisal. Nevertheless, I have no big problem with the 5% fractile figure of 1.74 billion barrels of economically recoverable oil for this province.

Chukchi Sea--The presentation given for this province at the Anchorage review was excellent. This is not to suggest that some of the other reviews were not also well done, but this one presented information that was new to me, concerning an area of considerable potential, even though the technological challenges in developing hydrocarbon resources are formidable. Without detailed study on my part, and without knowing what the input parameters were, I am unable to make any specific comments on the geologic evaluation and appraisal of the various parts of this area. However, given what is known of the geology and the technological obstacles, the range of figures given is probably not unrealistic."

Mr. Garnett Pessel of the same agency commented in a letter of November 17, 1988 as follows:[1]

'Geology for the offshore area, as presented by the Minerals Management Service, was mostly good, and in many cases, excellent. The presentation on the Chukchi Sea was particularly noteworthy. My major criticism concerned the geology of the Beaufort Shelf, which seemed very superficial, and possibly flawed. In particular, the Tertiary and Upper Cretaceous sediments were not broken down into coherent units, or, more accurately, depositional sequences. Industry, the Canadian Geological Survey, and the Alaska Division of Oil and Gas are all working at breaking these sediments into seismic sequences, which were deposited in a complex of partially overlapping basins, particularly in the eastern part of the Alaskan Beaufort Shelf. Correlation of the sediments across the Beaufort Shelf from Alaska to Canada is dependent on understanding these sequences. Also, the appraisal predicated the possibility of Baird Group equivalent rocks (limestones and clastic sediments) in the Barrow area, a supposition that is unlikely to be true. Because the Baird Group rocks exposed in the Brooks Range are allocthanous, their presence in the Barrow area autocthon would seem to be highly speculative. However, it is questionable whether a better geologic framework would affect the appraisal numbers to any significant extent."

Reference - Appendix D

1. C. G. Groat, Robert Jordan, and Perry Wigley, "Review of Geological Information Utilized by U. S. Geological Survey and Mineral Management Service in Their Assessment of U. S. Undiscovered, Conventionally Recoverable Oil and Gas Resources," Oil and Gas Assessment Review Committee, American Association of State Geologists, December 1988.

3. DEVELOPMENT AND PRODUCTION: PRESENT AND FUTURE

3.1 Introduction

In this section, producing fields, known nonproducing fields, and undiscovered resources are analyzed to determine remaining recoverable oil, economically recoverable reserves, and minimum economic field sizes (MEFS) for the undiscovered resources. Development costs, operating costs, transportation costs, state and federal taxes, and royalties are analyzed for producing fields and determined for known undeveloped fields and undiscovered resources. The economics model used to perform the analyses is described. The model was used to determine the minimum economic field sizes (MEFS) for the Arctic National Wildlife Refuge (ANWR) area, the Chukchi Sea area, the Beaufort Sea area, and the National Petroleum Reserve - Alaska (NPRA) area.

3.1.1 North Slope Development Summary

The exploration history and current status of known reserves and resources on the North Slope of Alaska has been discussed in **Section 2.1** and **Section 2.2** of this study. **Figures 2-7** and **2-9** in **Section 2.2** are maps showing the location of the known fields and areas of exploration.

As discussed in **Section 2**, the developed fields include the Prudhoe Bay field which includes the Lisburne Participating Area, the Kuparuk River field, the Endicott field, and the Milne Point field. The Niakuk and Point McIntyre reservoirs are sufficiently advanced in delineation and development planning that they are included in the Most Likely Case of this study. There are permitting (See **Sections 3.2.1 and 5.5**) and facilities sharing problems to be resolved but it is anticipated that these problems will be resolved in time for these fields to be developed and put on production in the next 3 to 4 years. Existing petroleum development on the North Slope is supported by approximately 1123 miles of pipelines to connect the producing facilities in these fields to Pump Station No. 1 of the Trans Alaska Pipeline System (TAPS), and about 346 miles of roads. About 7035 acres of land have been covered by gravel for facilities, drill sites, roads, and camps. Ten river crossings and three airfields are used for petroleum-related activities. A 370 mile gravel haul road, the Dalton Highway, connects Deadhorse and Fairbanks, and the 798 mile TAPS pipeline connects Prudhoe Bay to Valdez.[1] The March 1990 total North Slope production rate was about 1.8 MMBPD.

The Prudhoe Bay/Deadhorse industrial complex serves as the major support base for North Slope and Beaufort Sea exploration and development. This complex has living quarters, warehouse facilities, and a state operated airport.

The Prudhoe Bay field, discovered in 1967, was unitized and put on production in June 1977. BP Exploration (Alaska) Inc. (BP) operates the western half of the field and ARCO Alaska operate the eastern half of field. The production rate in March 1990 was about 1.4 MMBPD. More than 6.6 BBO had been produced from the field and shipped through TAPS by 1/1/90. The developed area of the Prudhoe Bay Unit includes about 200 square miles of the 400 square mile field. Unit facilities include six oil/gas separation plants (gathering centers or flow stations), 38 drill pads with a total of about 887 active wells, a central gas facility, a central compression plant, a central power plant, a field fuel gas unit, a crude oil topping plant to refine crude oil for North Slope use, a waterflood seawater treatment facility, a gravel airstrip, 200 miles of roads, permanent living quarters, a dock, two construction camps, offices, and two water injection plants.

The Kuparuk River field, located 40 miles west of Prudhoe Bay, was discovered in 1969 by ARCO Alaska, Inc. (ARCO) and British Petroleum. ARCO is the field operator. Original oil-in-place (OOIP) was about 5.3 BBO and the remaining recoverable reserves are estimated to be about 1.5 BBO based on a 40% recovery rate. This makes it the second largest oil field in the United States. Production began in December 1981 and the March 1990 production rate was about 306 MBPO. Facilities currently include three central production facilities, 329 producing wells and 256 injection wells (800 total wells are planned), the Kuparuk Operations Center (offices and housing for 384 people), the Kuparuk Industrial Center, a central gas plant, and a seawater plant. Oil is delivered to TAPS at Pump Station No. 1 through a 26 mile, 24-inch crude oil line, built in 1984. A 26 mile, 16-inch oil line which was used for transporting gas off the unit is currently idle. Additional facilities include 94 miles of roads and a 300 foot bridge across the Kuparuk River, a topping plant, two construction camps (one accommodates 650 people and the other 360), and one gravel airstrip.

The Lisburne reservoir, located directly below the Prudhoe Bay Sadlerochit formation and operated by ARCO as the Lisburne Participating Area of the Prudhoe Bay Unit, had original oil-in-place of about 3.0 BBO. The remaining reserves are about 157 MMBO. Development began in 1984 and initial production began in December 1986. March 1990 production was about 39 MBPD from 64 producing wells. Lisburne facilities include one central production facility, five onshore gravel pads, 50 miles of pipeline and four water disposal wells. A pilot waterflood project was shut down in early 1990 after disappointing results.

The Endicott reservoir of the Duck Island Unit is located 30 miles east of Prudhoe Bay. It is the first oil and gas field to be developed in the Alaskan Beaufort Sea. BP is the operator. Estimated remaining reserves are 311 MMBO.[2] Production began in October 1987. The March 1990 production was 100.4 MBPD and is expected to average 100 MBPD BPD through 1991 before starting to decline. The field is developed from two gravel islands, which are located 2.5 miles offshore. There are about 55 active wells of which 38 are producers. The two islands are connected with each other and shore by a five-mile-long gravel causeway. There is a 700 foot breach in the causeway to shore. There is also a 1.5 mile causeway through the Sagavanirktok (Sag) River delta that connects the offshore causeway to an onshore gravel road. A gravel road, 8.7 miles long, connects the causeways with the existing Prudhoe Bay road system at Drill Site 9. An elevated oil pipeline connects the field to TAPS at Pump Station No. 1. Other facilities include an onshore disposal pit for drilling effluents, an onshore gravel pit, a base camp with living quarters for 600 people, a warehouse, offices, fuel tanks, base operations camp, seawater intake facilities for the waterflood, and a dock.

The Milne Point field, located northeast of the Kuparuk field, was discovered in 1969 and unitized in 1979. Conoco, Inc. operates the field which covers 21,000 acres and has about 53 MMBO of remaining reserves. Production was initiated in November 1985 at a rate of 10 MBPD from 24 wells on two pads. Production was suspended in January 1987 and restarted in April 1989. The March 1990 production was about 19.5 MBPD from 26 producers. Facilities include a permanent camp for 50 people and a construction camp for 300 people. The Milne Point field is connected to the Kuparuk spine road by about 19 miles of gravel road, and a 15 mile pipeline carries the oil from the field to the Kuparuk Pipeline. Waterflood facilities include a 45 MBPD capacity water injection system serving 17 injection wells.

The Point McIntyre field discovered in 1988 is located two miles north of the Prudhoe Bay producing area. It has estimated reserves of 300 MMBO.[3] Production from the reservoir is expected to peak at 60 MBPD about 2 years after operations are initiated. Four delineation wells have been drilled.[4] Development of the field could occur in the mid-1990's. For this study a start-up date of 1993 is used. Still to be determined are the full size of the field, provisions for facilities sharing and related agreements, and resolution of tax treatment if facilities are shared. Also, the type of unitization and selection of a unit operator are yet to be completed.[3]

The Niakuk field was discovered in March 1985 by BP.[1] The reservoir is located about 1 mile offshore in the Beaufort Sea just North of Prudhoe Bay. Reserves are estimated to be about 57 MMBO. Production is expected to peak at about 20 MBPD within 2 years of start-up and stay at the peak rate for about 3 years before declining. The permitting process was begun in 1988, with the filing of an Environmental Assessment and Project Description.[5,6] Included in the development plan is construction of a 1-1/4 mile gravel-fill causeway, containing a 350-ft breach, connecting the field to shore. Recent decisions by the Army Corps of Engineers (COE) indicate that an alternative to gravel-fill causeways may be required to complete this development. Although the operator has announced plans to indefinitely defer development of this field, a start-up date of 1993 is used in this study.[7]

Other discovered resource accumulations are listed in **Table 2-5**.

3.2 Currently Producing Fields

Reserves and economic projections for seven North Slope fields are covered in this section. Fields that are producing are the Prudhoe Bay Unit, Permo-Triassic Participating Area (hereafter called Prudhoe Bay Unit), Lisburne Participating Area (hereafter called Lisburne), Kuparuk River Unit, Milne Point Unit, and Duck Island Unit (also called Endicott). The other two fields covered are the Point McIntyre and Niakuk. These were included because planning is sufficiently advanced to allow development within the next 3 to 4 years.

3.2.1 Production Forecasts

Future rate forecasts were developed for three production scenarios. A reference case scenario included only the five fields currently on production, whereas, the most likely and high reserve case also include Point McIntyre and Niakuk. The reference case included only in-place projects whereas, the most likely and high cases included planned and potential projects.

3.2.1.1 Reference Case Forecasts. Forecasts of future production rates published by the Alaska Department of Natural Resources (ADNR), Division of Oil & Gas[8] for the Prudhoe Bay Unit, Lisburne, Kuparuk River Unit, Milne Point Unit, and Endicott were reviewed. Discussion with ADNR representatives revealed the forecasts were derived from published data on project plans and a blend of the available production forecasts. Model studies were not used in making the forecasts. The individual field forecasts made by the ADNR are realistic estimates for in-place programs in each of the currently producing fields. These forecasts may include oil volumes that can not be economically recovered. Determination of the reduction in oil recovery due to economic limits is covered in **Section 3.2.7**. They do not include potential increases from expansions of recovery programs without performance history, approved new recovery programs not yet installed, or from future programs in the long range plans of the operators. The combined forecast make up the total North Slope production forecast under the scenario of no new investments and is adopted as the low recovery case for this study. The projected recoverable oil[a] for this case totals about 6.3 BBO, and is listed by field in **Table 3-1.**

Table 3-1. Reference Case Producing Fields - Projected Recoverable Oil at 1-1-90 (MMBO)

Field	Formation	Recoverable
Prudhoe Bay	Permo-Triassic	4902
Kuparuk River	Kuparuk	935
Duck Island	Endicott	283
Prudhoe Bay	Lisburne	156
Milne Point	Kuparuk	55
	TOTAL	6331

3.2.1.2 **Most Likely Case Forecasts.** The increase in projected recovery which can reasonably be expected as a result of future investments and project expansions were determined for each of the fields to form a most likely scenario. Of the discovered but undeveloped accumulations, only the Point McIntyre and Niakuk fields are considered sufficiently advanced in planning to be included in the Most Likely Case. A listing of the productive and known but undeveloped North Slope oil and gas accumulations are shown in **Tables 2-1** and **2-2** in **Section 2.1.2.** A general idea of the future development plan for each of the fields was obtained from testimony presented at hearings before the Alaska Oil and Gas Conservation Commission (AOGCC), plans of development and reports filed with the AOGCC, Financial Analyst Meeting Reports, published articles, letters, internal Company reference material, and meetings with individual field owners.

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a. Recoverable oil is the volume of oil that can be recovered if productions operations are continued without consideration of an economic limit. Reserves for this study are the economically recoverable oil volumes.

3.2.1.2.1 **Prudhoe Bay Unit**--Future projects that should improve the producing rate and/or increase ultimate oil recovery are:

1. Drilling of wells on reduced spacing and the completion of development drilling in the peripheral areas of the field and the West End[9]
2. Complete installation of the first expansion of the Gas Handling Facility (GHX-1)10[10]
3. Development of the Hurl State area[11,12]
4. Install and place in service the second expansion of the Gas Handling Facility (GHX-2)[10]
5. Expand the waterflood to new areas, and expand the area where miscible gas enhanced oil recovery process is being applied[9]
6. Continue the well-workover programs.

If successful, these programs will increase ultimate recovery from the Permo-Triassic formation in the Prudhoe Bay Unit by about 1.4 BBO above those in the Reference Case (Tables 3-1 and 3-2).[10,12]

3.2.1.2.2 **Kuparuk River Unit**--Only about 85% of the original oil-in-place volume was developed by January 1, 1990.[13] Much of the increased projected recovery for this field will result from completion of field development. In addition to development drilling, future programs which should improve the producing rate or ultimate oil recovery or both are:[14]

1. Expansion of the area where miscible gas enhanced oil recovery process is being applied
2. Continuation of infill drilling on 160 acre spacing with further reduction to 80 acre spacing in some areas
3. Continuation of well stimulations by fracture treatments.

If successful, these programs will increase recovery from the Kuparuk River Unit by about 580 MBO over those in the Reference Case (Tables 3-1 and 3-2).[10]

3.2.1.2.3 Lisburne--After disappointing results, the initial stage of waterflood development was shut down. The only project in the future plans of the owners is the drilling of infill wells.[15] The drilling of these additional wells will increase recovery by about 3 MMBO above those in the Reference Case (Table 3-1 and 3-2). The drilling of these wells is necessary to achieve the predicted ultimate recovery.

3.2.1.2.4 Milne Point Unit--Prediction of future recovery is more difficult due to the interruption of production and water injection during the field shut-down from January 1987 through March 1989.[16,17] During shutdown, equipment modifications were made to increase injection rate and three wells were drilled. Since restarting production and water injection operations, unit production had reached 19.5 MBPD in March 1990 as compared to the 1986 average of 12.9 MBPD. There have been no apparent adverse affects from the shut-down.[18] Future development plans for the Kuparuk Formation within the Milne Point Unit, call for drilling wells to complete development of the productive area.[17] This is necessary to reach the projected recovery. Improved recovery performance, or the implementation of an Enhanced Oil Recovery (EOR) method would be required to increase the recovery over that in the Reference Case (Tables 3-1 and 3-2).

3.2.1.2.5 Duck Island Unit/(Endicott)--The original recovery estimates for the Endicott Formation of the Duck Island Unit, were based on reservoir model studies performed by the owners.[19] As a result of improved reservoir performance, the owners' estimate of ultimate recovery has been increased from 350 to about 393 MMBO.[2] The improved performance has resulted in reducing the number of wells to be drilled from 100 wells to about 80 wells. Additional recovery could result from EOR methods under consideration.[19] Improved performance has increased predicted recovery by about 28 MMBO over those in the Reference Case (Tables 3-1 and 3-2).

3.2.1.2.6 Niakuk Field--Development of this field, located about 1-1/4 miles offshore on the East side of the Prudhoe Bay Field, was first proposed in May 1988, but has been delayed by the permitting process.[4] Although the operator has announced plans to indefinitely defer development, for this study it is assumed that approvals will be obtained so that development can be initiated in time for first production to occur in late 1993. Production rates and recovery estimates contained in the Environmental Assessment and Project Description appear reasonable and are adopted for the Most Likely Case.[6] Predicted ultimate recovery for this field is about 58 MMBO.

3.2.1.2.7 Point McIntyre Field--This oil accumulation, located about two miles North of the Prudhoe Bay Unit production area, is slated for development by 1993, pending resolution of tax and permitting issues.[4] Based on the discovery well and four delineation wells, reserves are estimated at about 300 MMBO.[20] Production could be initiated at an early date if the owners' plans are approved to utilize existing production facilities at the nearby Lisburne Field.[4,10] The owners' ultimate recovery estimate of 300 MMBO is used as the most likely recovery.

Projected ultimate recoverable oil for these seven fields is about 8.7 BBO and is listed by field in **Table 3-2.**

Table 3-2. Most Likely Case Fields - Projected Recoverable Oil at 1-1-90 (MMBO)

Field	Formation	Recoverable
Prudhoe Bay	Permo-Triassic	6307
Kuparuk River	Kuparuk	1514
Duck Island	Endicott	311
Pt. McIntyre[a]	Kuparuk	300
Prudhoe Bay	Lisburne	159
Niakuk[a]	Kuparuk	58
Milne Point	Kuparuk	55
	TOTAL:	8704

a. Production estimated to start in 1993.

3.2.1.3 **High Case Forecasts (Advanced Oil Recovery Techniques).** Currently one or more secondary recovery techniques are being applied at all of the active fields on the North Slope. Surplus gas is being injected into the gas caps in the Prudhoe Bay, Lisburne, and Endicott. Gas is injected into wells drilled as injectors or converted producers in the Kuparuk River and Milne Point Units. All fields except Lisburne have at least partial-field water injection projects. Prudhoe Bay and Kuparuk River Units have miscible recovery project areas where water and enriched gas are alternately injected (WAG Process). There is no indication that other EOR processes are being actively considered for any of the producing North Slope Fields. Expansion of the current processes to new field areas has already been considered in the Most Likely Case.

Further enhancement of recovery might come through the application of other processes such as:[21]

1. Miscible CO_2 flooding
2. Non-miscible CO_2 flooding
3. Foam to improve WAG processes
4. Surfactant flooding
5. Polymer flooding
6. Alkaline flooding
7. Steam injection
8. Hot water injection
9. Hot-gas cycling
10. In situ combustion.

Economical application of any of these EOR processes after the completion of waterflooding is unlikely because of the large volumes of water which would have to be produced before any increased oil recovery could be achieved. Upside recovery, if any, to be recovered from North Slope fields would come from the early application of an EOR process or improved effectiveness of some process already being employed. As a maximum upside case, it was assumed that, except for Prudhoe Bay Unit, ultimate recovery would be increased by about 10% in each field included in the Most Likely

Case. Because the Prudhoe Bay Unit is partially developed for enriched miscible gas recovery the potential increased recovery was assumed to be 5%.

For these assumed higher recoveries to become reality, significant improvements in existing EOR technology would be required or new EOR technology would have to be developed. No additional investments for facilities or wells were assumed, however, operating costs were increased. The increased recovery used for this High Case are listed by fields in Table 3-3.

Table 3-3 High Case Fields - Projected Recoverable Oil at 1-1-90 (MMBO)

Field	Formation	Recoverable
Prudhoe Bay	Permo-Triassic	6984
Kuparuk River	Kuparuk	1666
Duck Island	Endicott	342
Pt. McIntyre[a]	Kuparuk	330
Prudhoe Bay	Lisburne	191
Niakuk[a]	Kuparuk	63
Milne Point	Kuparuk	60
	TOTAL	9636

a. Production estimated to start in 1993.

3.2.2 Development Costs By Field

When the Prudhoe Bay Field was developed in the mid-1970's, the design and quality control requirements were more restrictive than ever imposed on an onshore oil field.[21] Equipment was massive and extensive redundancy was built into the equipment and controls.[22] Since the development of Prudhoe Bay, significant advances in technology and practices have been made.[21] Design and construction of small sized facility modules are reducing both cost and gravel pad sizes.[21,23,24] The joint use of Prudhoe Bay and Lisburne facilities, is being considered in the development plans for the Niakuk[6] and Point McIntyre Fields.[4,10] New designed drilling rigs and more accurate drilling practices have reduced the well spacing on drilling pads from 130 feet in Prudhoe Bay initially to 10 feet in the Duck Island Unit.[25] Earlier studies on development in the Arctic were performed before much of todays' information was available.[22,26,27] Although no single source of information was complete for overall project capital investments, sufficient information was available to make reliable estimates of capital investments over the project life for each of the producing fields.[4,20,23,24,28,29,30,31,32,33,34,35] Reliable information was also available for the Point McIntyre and Niakuk fields.[4,6,20,31]

3.2.2.1 Future Investments. Total investment expenditures before January 1, 1990, were estimated from published information. Estimated costs to drill and complete wells were broken out of the prior years total investments to obtain the estimate of installed facilities costs. The total facilities costs for each field were allocated to an expenditure year. The costs were then inflation adjusted to 1990 dollars based on the estimated year of expenditure. An estimate of each fields' future facilities cost, in 1990 dollars was developed from published information. The future costs were allocated over the time frame indicated for each field. A relationship of facilities costs, in 1990 dollars, as a function of peak oil production rate was determined for each producing field and Niakuk and Point McIntyre fields. The results are shown in Figure 3-1. This figure shows that technology improvements, joint use of facilities, and design modifications have resulted in reducing facilities costs, as discussed previously. A further cost-saving for fields developed after the Prudhoe Bay Unit, was the existence of an in-place infrastructure of support facilities including roads, airport and dock. Any new development area, remote from the Prudhoe Bay/Kuparuk River Field area, will have to pay for the establishment of its support infrastructure.

The experience gained in the Prudhoe Bay area can be applied to potential new development areas on the North Slope. The facilities cost factors for the Kuparuk River Unit, Milne Point Unit, Endicott and Lisburne Participating area were averaged to obtain a forecasting parameter of $14,200

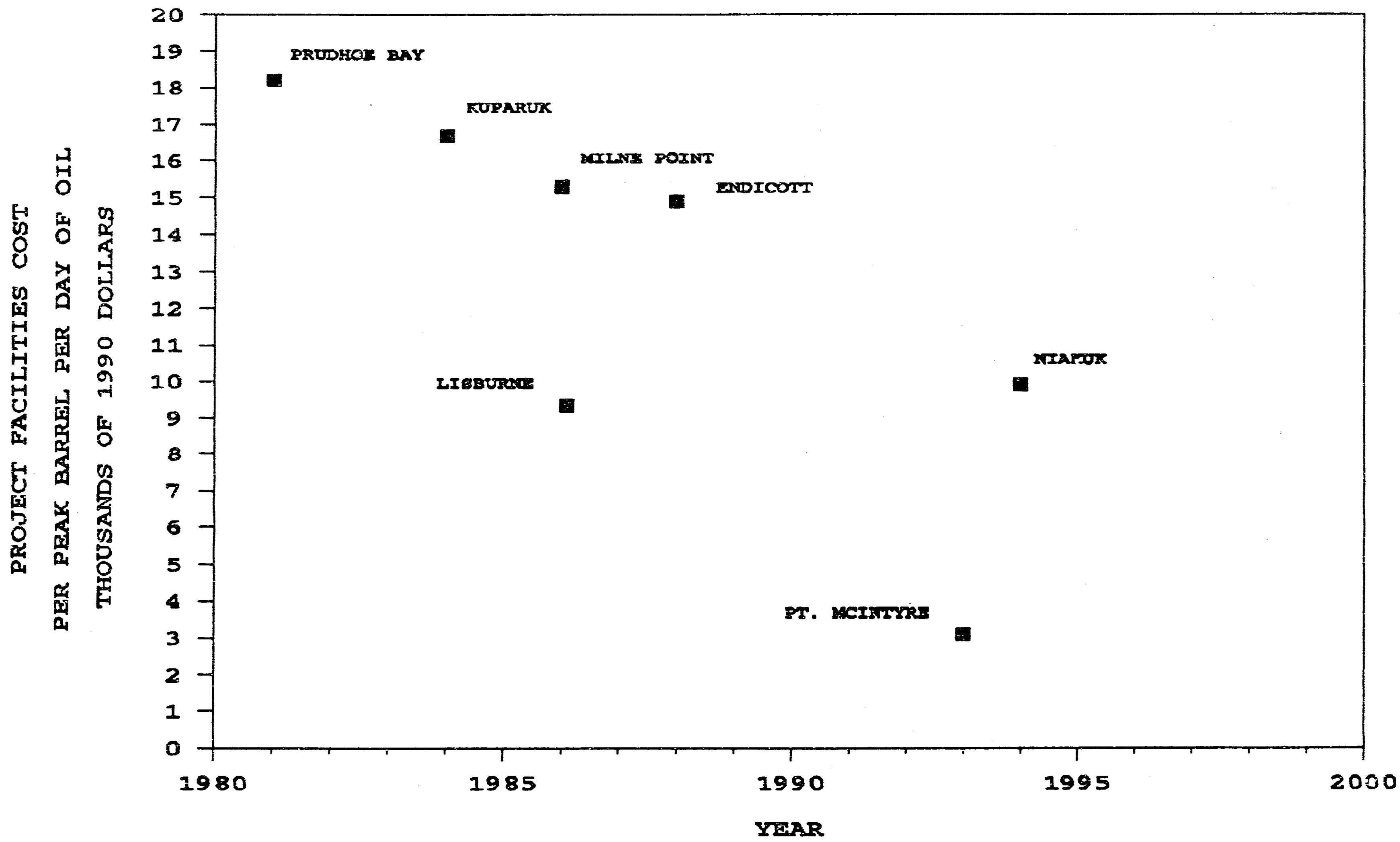

Figure 3-1. North Slope Alaska Project Facilities Cost Versus Project Installation Date.

per daily peak oil rate in January 1, 1990 dollars. This average facilities cost factor was used in economic calculations for known undeveloped fields in **Section 3.3** and for the ANWR and NPRA undiscovered resources in **Section 3.5.**

3.2.2.2 Drilling Costs. The time required to drill and complete wells in Prudhoe Bay has been reduced by about 50% since 1977. The learning curve on drill-and-complete days shows a reduction from 35 days in 1977 to about 17 days in 1987.[6] The cost to drill and complete the average well in the Prudhoe Bay Field has been reduced from about $2.5 MM in 1985,[35] to $2.2 MM in 1988,[6] and to $2 MM in 1989.[36] The Lisburne Field also experienced a reduction in drilling and completion costs from about $5 MM in 1985 to less than $3 MM in 1987.[35] The cost of drilling development wells in Endicott has been reduced by 40% of the original projected cost, without reductions in rig costs.[21] The cost to drill and complete a Kuparuk River Field well during 1987 was about $2 MM.[13] This shows that although several years and many wells are required, drilling costs can be reduced with experience and improvements in drilling technology. The delay in obtaining permits for the Niakuk Field is reported to have increased per well drilling and completion costs from about $2.8 to $3.2 MM.[37] Insufficient information was available to determine drilling and completion costs for the Milne Point Unit, Endicott, and Point McIntyre Field. The drilling and completion costs for the Milne Point Unit were assumed to be about the same as those in the Kuparuk River Unit. Drilling and completion costs for the Point McIntyre Field and the Duck Island Unit were estimated from Lisburne well cost versus departure (distance of horizontal deviation of the bottom hole location from a vertical well) distance data.[6] An average departure of 5000 feet was assumed to give a cost of about $2.8 million. Drilling costs for the fields included in the Most Likely Case are summarized in **Table 3-4**. These drilling costs depend on the field location (offshore/onshore), depth of the formation, and the experience gained in drilling a large number of wells in a field.

3.2.2.3 Benefits of Facilities Sharing. Facilities sharing can consist of joint use of such things as roads, pipeline supports, equipment storage areas, waste disposal facilities, and camps. An even higher degree of facilities sharing consists of joint use of pipeline systems, fluid processing

Table 3-4. Drilling and Completion Costs (1990 Dollars)

Project	MM $
Prudhoe Bay Unit	2.04
Kuparuk River Unit	2.04
Milne Point Unit	2.04
Endicott	2.85
Point McIntyre Field	2.85
Lisburne	3.05
Niakuk Field	3.25

equipment, gas treating and compression equipment, and water injection equipment in addition to those listed above. Such utilization of facilities is beneficial to both fields since the use of surplus capacity in one field reduces the investments required at the other. Of equal importance is the reduced requirements for gravel pads which reduces the environmental impact of developments. A potential savings of $150 MM has been reported for the Point McIntyre Field if facilities sharing agreements can be reached with Lisburne owners.[10] The Niakuk owners are reportedly planning on a facilities sharing agreement with either the Prudhoe Bay Unit or Lisburne.[6] Although no cost savings have been published for Niakuk, a savings of about $85 MM was estimated to be possible. Such facilities-sharing arrangements have undoubtedly been instrumental in the owners plans to develop smaller projects.

3.2.3 Operating Costs by Field

Published data on current operating costs are limited. Although limited, sufficient data were available to forecast operating costs for all scenarios in this study. Operating costs include the following;

- Labor supervision, overhead, and administrative costs
- Communications, safety, catering
- Supplies and consumables
- Routine process and structural maintenance

- Well service and workover
- Insurance on facilities
- Transportation of personnel and supplies.

As discussed in **Section 3.4**, sensitivities were run on operating costs.

3.2.3.1 Data Sources and Methodology. Current operating cost information was available for the Prudhoe Bay Unit,[38] the Milne Point Unit,[18,39] and the Niakuk Field.[6] Additional operating cost data were taken from the Deaken,[27] Young and Hauser[26] and National Petroleum Council (NPC) studies.[22] Operating costs for 1990 were estimated for Prudhoe Bay Unit, Milne Point Unit and Niakuk. These estimates were then expressed as cost per barrel of total fluid produced using the current oil and water production statistics reported to the AOGCC.[40] The operating costs for Lisburne and Endicott were based on an extrapolation of the NPC low operating cost curve. The costs determined by this method were also expressed as cost per barrel of total fluid produced. Operating costs determined by this methodology are listed in **Table 3-5.**

Table 3-5. Operating Costs (1990 Dollars)

Field	Operating Cost $/Barrel of Fluid
Prudhoe Bay Unit	1.00
Kuparuk River Unit	1.19
Niakuk Field	1.19
Milne Point Unit	1.49
Lisburne	1.40
Endicott	1.40

To determine future operating costs, the cost per barrel of total fluid produced was applied to estimated future volumes of total fluid produced for each year of production. To accomplish this, each field history of oil and water production was combined with cumulative recovery to develop a produced water percent (water cut) versus percent cumulative recovery relationship. Because of the high operating costs for North Slope fields it was assumed that the percent water produced at depletion of economic reserves would be 80%. The data points were plotted using semi-log coordinates in order to construct a curve. The shape of the curve between the known points and the end point of 80% water and 100% recovery was patterned after the waterflood performance predictions published for Milne Point[41] and Endicott.[19] The curve constructed for the Prudhoe Bay Unit is shown in **Figure 3-2**.

To use this forecast method in later work, a typical North Slope water cut versus percent cumulative recovery was developed using all data excluding Prudhoe Bay Unit data. Since Prudhoe Bay development occurred over a long time period, those data were excluded as not being representative of the range of field sizes to be evaluated. The typical water cut curve developed for use in forecasting is shown in **Figure 3-3**.

3.2.3.2 Royalty Oil Processing Fee. The State of Alaska pays a portion of the operating costs directly chargeable to the processing of its royalty share of produced oil to meet pipeline specifications. The processing fees, per barrel of royalty oil, currently agreed to are:[42]

- Prudhoe Bay Unit - $0.73
- Kuparuk River Unit - $0.395
- Lisburne - $0.73
- Endicott - $0.47
- Milne Point Unit $None

Due to the uncertainty concerning possible future agreements between the State and operators in other potential producing areas, a royalty oil processing fee was not utilized in those evaluations.

3.2.4 Oil Price Forecasts

The Energy Information Administration (EIA) has prepared basic input data for the National Energy Strategy (NES) Study.[43] Three oil price

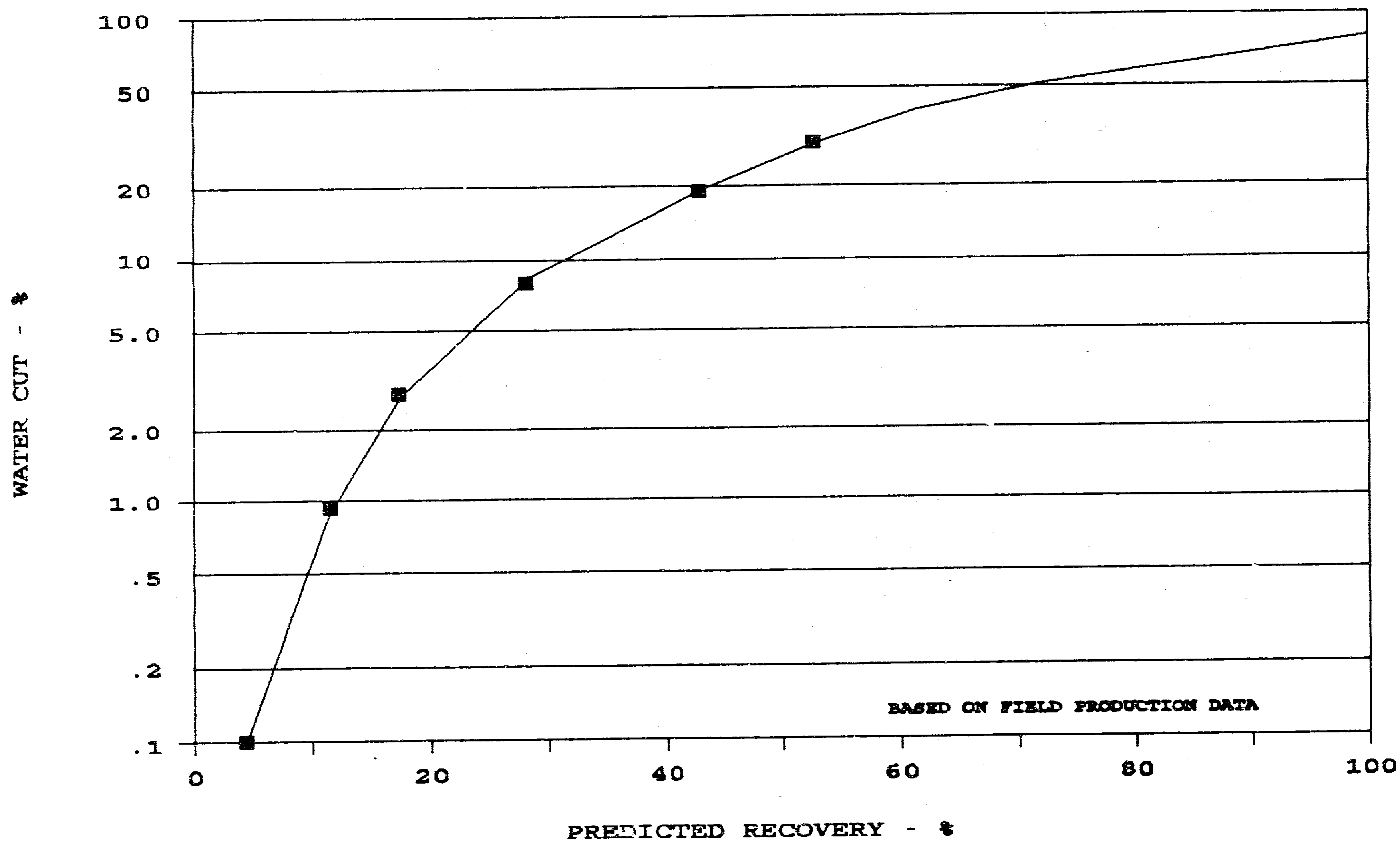

Figure 3-2. Prudhoe Bay Unit Permo-Triassic Water Cut Curve, Percent Water Cut Versus Percent Ultimate Recovery.

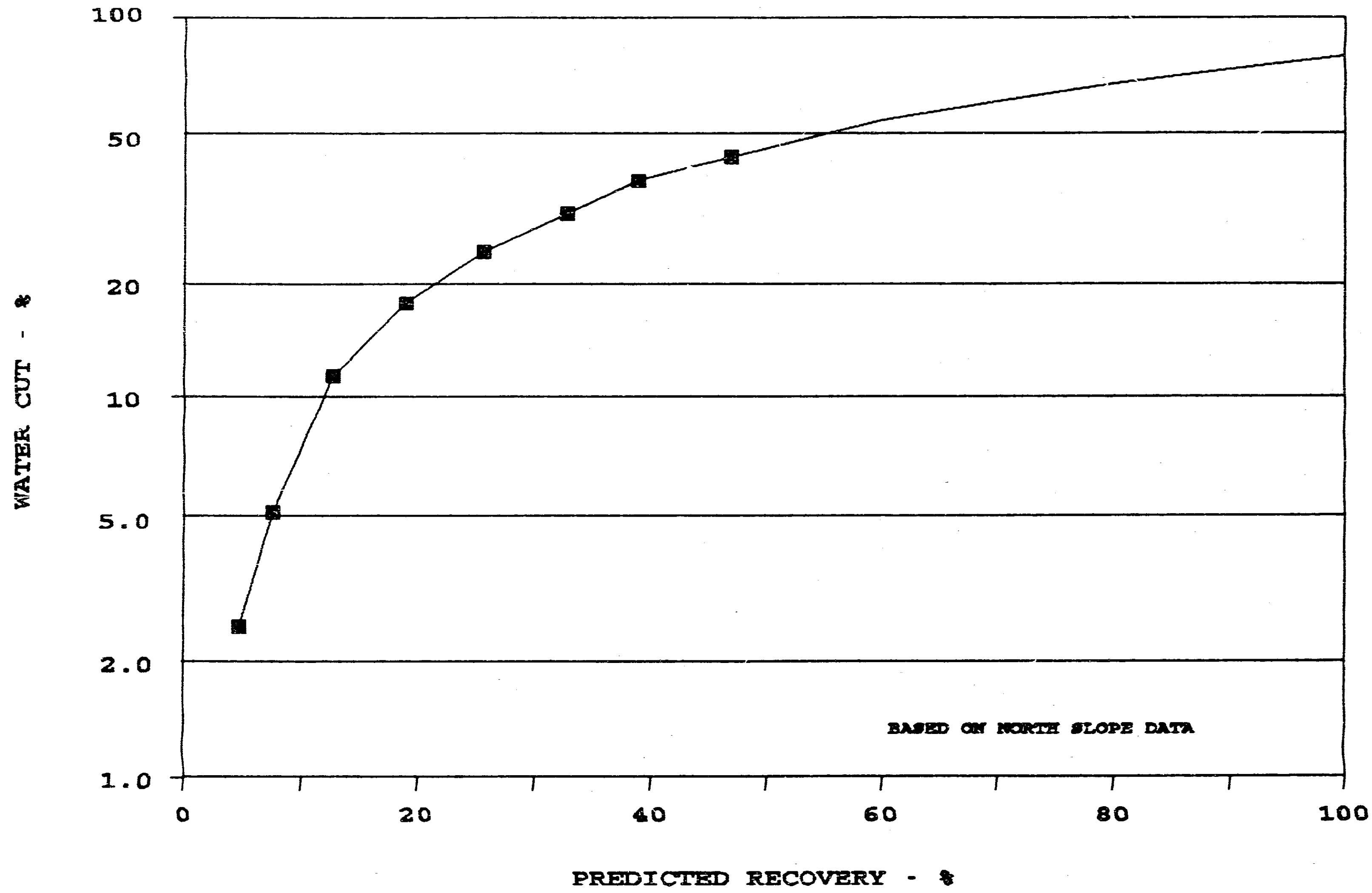

Figure 3-3. Typical Water Cut Curve, Percent Water Cut Versus Percent Predicted Recovery.

forecasts, developed by the EIA for the NES study, were adopted for this study. These price forecasts are dated June 18, 1990. The three forecasts are the Revised NES Reference, the High World Oil Price and the Low World Oil Price Cases. These prices are the average U. S. refiner acquisition costs of imported oil.

3.2.4.1 Discussion. The NES study oil prices are not given for each year as shown in **Table 3-6**. Oil prices for the years not reported were obtained by straight line interpolation. The results are shown in **Figure 3-4**. The data, as interpolated, were used as the average delivered price of North Slope crude oil in the Lower 48 States. The indicated lower 48 Alaska North Slope crude quality differential is small,[6] and was not used as a deduction in calculating the sales price at Pump Station No. 1 (inlet to TAPS). Its exclusion would be more than offset by variations in the mix of crude oil sold on the West Coast and Gulf Coast. As discussed in **Section** 3.2.5.3, the initially assumed West Coast sales totaled 70% of the crude oil delivered to the TAPS terminal at Valdez.

Table 3-6. National Energy Strategy Study Oil Prices[43]
(1989 Dollars Per Barrel)

Year	Low World Oil Price Case	Revised NES Reference Case	High World Oil Price Case
1990	16.80	16.80	16.80
1995	14.40	20.40	25.89
2000	19.82	27.80	33.91
2005	23.91	32.85	41.90
2010	25.91	36.82	47.41
2015	27.10	39.82	49.99
2020	28.50	42.04	52.70
2025	30.20	44.19	54.51
2030	31.08	45.55	55.50

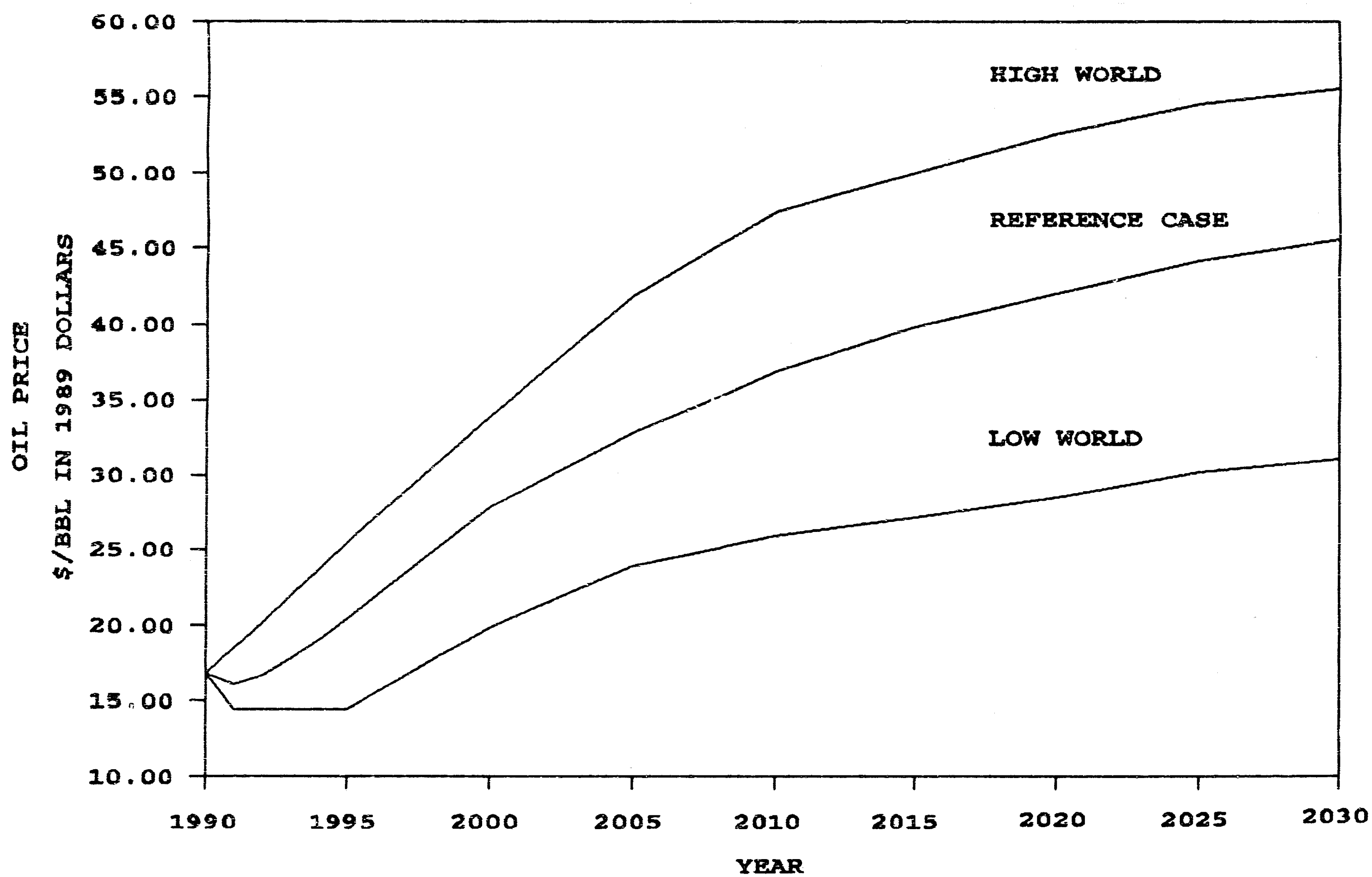

Figure 3-4. Trends of the Average U. S. Refiner Acquisition Costs Of Imported Oil. $/BBL in 1989 Dollars Versus Years From 1990 Through 2030.

3.2.5 Alaska North Slope Oil Delivery System (ANSODS) Tariffs

Operating cost components of ANSODS include pipeline tariffs for TAPS and the field pipelines that deliver crude oil to Pump Station No 1. Actual tariffs were used where available. Future TAPS tariffs were estimated using available methology and data, and tariffs for all other field developments were calculated using a simple estimating formula.

3.2.5.1 TAPS Tariffs. TAPS was activated in 1977 as a common carrier. The owners file separately for annual tariff rates. The investment costs, operating expenses, dismantling costs, taxes and return on investment are currently being amortized on the reserves volumes and reserves lives of the five producing North Slope Fields.[32] For several years a controversy existed between the State of Alaska (and others) and TAPS owners with respect to determination of tariff charges. The tariff disputes were settled by agreement dated June 28, 1985.[44] The agreement specified methodology for determining future maximum tariff charges and set the maximum allowed for years 1982 through 1985. Through 1989 the owners were allowed a fixed after tax return. Beginning in 1990, the profit allowed is tied to volumes transported.[32] The method used to calculate the maximum tariff allowed is set out in the Settlement Agreement.

The term is through the year 2011, with provision to renegotiate after the year 2006. Because production forecasts from several fields and potential fields in this study extend beyond the year 2011, the current settlement terms were assumed to extend throughout the life of any field.

For estimation of future tariffs, certain simplifying assumptions were made in the TAPS tariff settlement methodology to calculate the tariffs used in this study. These assumptions were:

- Single ownership of the pipeline
- Total throughput goes to the Valdez Terminal
- No new investments after 1990

- Operating expenses increased to $530 MM in 1990 and held constant (1990 Dollars) for facility life to provide for heightened oil spill response capability along TAPS and in Prince William Sound,[10,45] and continued corrosion abatement
- Addition of a total of $700 MM for corrosion abatement over the period 1989 through 1996
- State and federal income taxes to remain unchanged
- Simplified depreciation
- Net carry-overs are zero.

Using these simplifying assumptions, a schedule of estimated annual total revenue requirement[a] covering the life of all projects in this study was determined. TAPS tariff schedules were then calculated for each different scenario examined. The TAPS Tariff Schedules for the Reference, Most Likely and High Recovery Cases are contained in **Table 3-7**. The tariffs were escalated in the economic evaluations.

3.2.5.2 Field Pipeline Tariffs. TAPS Pump Station No. 1 is located in the approximate center of the Prudhoe Bay Unit area. The field owners deliver crude oil to Pump Station No. 1 for transport to Valdez. Only the Prudhoe Bay Unit and Lisburne deliver their crude oil, condensate and natural gas liquids directly to Pump Station No. 1. A number of smaller pipelines deliver crude from the other fields. The Kuparuk River Unit and Endicott are served by separate pipelines about 26 miles in length. The Milne Point pipeline is about 12 miles long and ties into the Kuparuk River pipeline at the east edge of the Kuparuk River Unit area. The field or unit owners pay a field tariff for the transportation of their oil to Pump Station No. 1. The tariffs for these three fields are:[7]

- Kuparuk River Unit - $0.61/BBL
- Endicott - $0.71/BBL
- Milne Point Unit - $2.02/BBL.

a. Annual total revenue requirement is the total annual income to TAPS owners necessary for the owners to receive the allowed return on their investment.

Table 3-7. Estimated Taps Tariff Schedules
(1990 Dollars/Barrel)

Year	Low Recovery	Most Likely	High Recovery
1990	3.82	3.64	3.43
1991	3.62	3.40	3.20
1992	3.55	3.30	3.00
1993	3.44	3.02	2.77
1994	3.27	2.79	2.58
1995	3.25	2.53	2.38
1996	3.14	2.40	2.18
1997	3.07	2.29	1.99
1998	3.16	2.37	2.01
1999	3.39	2.53	2.16
2000	3.71	2.77	2.33
2001	4.01	2.93	2.46
2002	4.53	3.26	2.74
2003	5.11	3.60	3.02
2004	5.71	4.00	3.35
2005	5.82	4.65	3.87
2006	7.41	5.11	4.27
2007	8.51	5.83	4.74
2008	9.78	7.05	5.29
2009	11.22	7.73	6.00
2010	13.06	8.43	7.02
2011	15.62	9.25	7.64
2012	18.72	10.04	8.35
2013	23.87	11.10	9.09
2014	28.02	12.07	9.92
2015	33.00	13.27	11.37
2016	46.00	14.45	12.40
2017	86.53	15.84	13.53
2018	-	18.77	14.75
2019	-	20.56	16.12
2020	-	22.17	17.63
2021	-	24.64	19.26
2022	-	26.99	21.05
2023	-	28.79	23.00
2024	-	31.92	25.14
2025	-	40.82	27.48
2026	-	59.02	30.05
2027	-	118.90	53.97

A field pipeline tariff is required for each of the non-producing fields, both known and potential, examined in this study. The pipeline construction costs presented by Young and Hauser[26] and the National Petroleum Council[22] were referenced for evaluating development of potential fields. Rather than perform pipeline tariff calculations for each field pipeline situation, a simple estimating formula was used.[46] On comparison, the formula gave acceptable estimates for North Slope pipelines.

$$\text{TARIFF} = \frac{\text{Cost to Construct Pipeline, Haul Road, and Pump Stations (\$)}}{\text{Total Oil Volume to be Transported (BBL)}} \times 3.35 = \text{\$/barrel.}$$

3.2.5.3 Market Value. Adjustments in crude prices are made for differences in quality of North Slope crude oils delivered to TAPS. This quality difference is based on measured API gravity. A penalty is assessed for any crude oil below the weighted average with API gravity TAPS crude quality. A premium is paid for any crude of with API gravity above the TAPS crude quality. The differential is 1.8 cents for each 0.1° API variation, above or below the current weighted average TAPS crude quality of 27.4° API. There is a similar quality adjustment applicable to crude oil delivered to the Kuparuk River Pipeline. Currently the quality differential is 1.6 cents per 0.1° API variation above or below a crude quality of 23° API.[7]

3.2.6 Marine Transportation.

The crude oil, condensate, and natural gas liquids mixture is shipped by tanker to West Coast and Gulf Coast delivery points. Currently about 70% is delivered to the West Coast. Over the past 4 years the percent of North Slope crude delivered to the West Coast has increased from 53% to the current level.[47] The percentage of deliveries to the West Coast may vary as the supply of North Slope crude declines. However, for the purposes of this study, it was assumed that the percentage split of delivery of North Slope crude between the West and Gulf Coasts will remain at the current level.

Costs for shipping Alaska North Slope crude by tanker to the Gulf Coast has declined by about 57% over the past 5 years.[47] No further decline in shipping rates is expected with worldwide non-communist demand for crude oil increasing, the worldwide tanker surplus declining to low levels, and no prediction of surplus capacity from new construction.[48] Because the uncertainty of the outcome of Congressional consideration of tanker safety,[49] no adjustment, other than general inflation, was made to the average marine transportation cost of $1.45 per barrel (January 1990 Dollars) determined for this study. As noted, this is a composite West Coast/Gulf Coast delivery price.

3.2.7 Taxes and Royalties

3.2.7.1 State of Alaska. The royalty rates applicable to leases in the five producing fields were based on state of Alaska information.[8] These rates are listed in **Table 3-8.**

Table 3-8. State Leases - Royalty Rates

FIELD	ROYALTY - %
Prudhoe Bay Unit	12.5
Lisburne	12.5
Kuparuk River Unit	12.5
Endicott	14.0[a]
Milne Point Unit	18.0[a]

a. Weighted average of all leases.

The average field wide royalty rates that would apply to undeveloped fields, both known and potential, are unknown. They will depend on which type royalty applies; fixed royalty, sliding scale royalty, or net profit sharing. For ease of calculation, a fixed 12.5% royalty rate was assumed for all State leases, in all economic evaluations.

State taxes included in the evaluations are severance, property, conservation, conservation surtax, and state income tax. It was assumed that no changes would occur in these taxes throughout the life of any field in the study. The economic model is described and methods of calculating these taxes are discussed in **Section 3.7**.

3.2.7.2 Federal. Federal leases are issued with various royalty types, similar to those listed for the State. Again, for simplification of economic calculations, a fixed royalty rate of 16.67% was assumed for all federal leases included in any field evaluation.

The federal income tax rate of 34% was assumed to remain constant for the duration of the life of the fields in this study. **Section 3.7** contains a description of the application of federal income taxes.

3.2.8 Results of Economic Evaluations

Assumptions used in the economic evaluations for the Reference, Most Likely, and High Cases are contained in **Tables 3-9** and **3-10**. **Table 3-11** shows the economically recoverable reserves for each case, under the assumption that there will be no sales or transport restrictions during the projected life of the fields.

Projected production rates versus time for the Most Likely Case are shown on **Figure 3-5**. These forecasts illustrate the dominant role of Prudhoe Bay in North Slope oil production. Yearly average production rates by field for the Most Likely Case used in **Figure 3-5** are in **Appendix A, Table A-1**. The projected production rates were composited for fields included in the Reference, Most Likely, and High Cases and are shown on **Figure 3-6**. Yearly average production rates for these cases are in **Appendix A, Table A-2**. Only those reserves which can be economically recovered by each field under unrestricted sales conditions are included.

Table 3-9. Assumptions For Economic Evaluations - Reference Case

---

1. Operating costs as discussed in **Section 3.2.3.**

2. Future facilities cost estimates.

Field	MM$
Prudhoe Bay Unit	1067
Kuparuk River Unit	237
Endicott	247
Lisburne	0
Milne Point	42

3. Future development wells.

Field	Number of Wells
Prudhoe Bay Unit	183
Kuparuk River Unit	230
Endicott	36
Lisburne	52
Milne Point	0

4. Future active producing wells.

The projected decline of future active producing wells was determined by one of the following sets of equations. These equations represent curves developed from industry experience and engineering judgement.

Curve A - For the production period between 80 and 98% of ultimate recovery the current number of active producers is:

Producers = [181.1011 - 1.0112 (% of ultimate recovery)] x Maximum Active Producers ÷ 100.

- For the production period between 98 and 100% of ultimate recovery, the current number of active producers is:

Producers = [1845.3988 - 17.9939 (% of ultimate recovery)] x Maximum Active Producers ÷ 100.

Table 3-9. (Continued)

Curve B - For the production period between 60.4 and 95% of ultimate recovery, the current number of active producers is:

Producers = [124.5528 - 0.4065 (% ultimate recovery)] x Maximum Active Producers ÷ 100.

- For the production period between 95 and 100% of ultimate recovery, the current number of active producers is:

Producers = [458.3330 - 4.3330 (% of ultimate recovery)] x Maximum Active Producers ÷ 100.

The curve used for each of the fields in the Reference Case were:

Field	Curve
Prudhoe Bay Unit	A
Kuparuk River Unit	B
Endicott	B
Lisburne	B
Milne Point	B

5. Oil price schedule as discussed in **Section 3.2.4.**
6. Recoverable oil volumes as shown in **Table 3-1.**
7. Recovery forecasts from the Alaska Division of Natural Resources.[8]
8. Taxes as discussed in **Section 3.2.7.**
9. Royalties as discussed in **Section 3.2.7.**
10. Transportation costs as discussed in **Sections 3.2.5** and **3.2.6.**
11. TAPS tariff schedule as shown in **Table 3-7.**
12. A constant 3.5% inflation factor was used throughout the life of the developments.
13. Cash flow discounted at 10% (nominal).

Table 3-10. Assumptions For Economic Evaluations - Most Likely and High Cases

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1. Operating costs as discussed in **Section 3.2.3.**

2. Future facilities cost estimates.

Field	MM$
Prudhoe Bay Unit	4307
Kuparuk River Unit	2021
Endicott	247
Lisburne	0
Milne Point	42
Point McIntyre	188
Niakuk	188

3. Future development wells.

Field	Number of Wells
Prudhoe Bay Unit	400
Kuparuk River Unit	432
Endicott	36
Lisburne	52
Milne Point	0
Point McIntyre	86
Niakuk	14

4. Future active producing wells.

   The projected decline of future active producing wells was determined by one of the sets of equations discussed in Item 4 of **Table 3-9.**

   The curve used for each of the fields in these two cases were:

Field	Curve
Prudhoe Bay Unit	A
Kuparuk River Unit	B
Endicott	B
Lisburne	B
Milne Point	B

Table 3-10. (Continued)

---

5. Oil price schedule as discussed in **Section 3.2.4.**
6. Recoverable oil volumes as shown in **Table 3-2.**
7. Recovery forecasts as shown on **Figure 3-5.**
8. Taxes as discussed in **Section 3.2.7.**
9. Royalties as discussed in **Section 3.2.7.**
10. Transportation costs as discussed in **Sections 3.2.5** and **3.2.6.**
11. TAPS tariff schedule as shown on **Table 3-7.**
12. A Constant 3.5% inflation factor was used throughout the life of the developments.
13. Cash flow discounted at 10% (nominal).

Table 3-11. Projected Future Recoverable Oil and Economically Recoverable Reserves at 1/1/90 (MMBO)

Low Recovery Case Producing Fields

Field	Formation	Recoverable	Economically Recoverable
Prudhoe Bay	Permo-Triassic	4902	4859
Kuparuk River	Kuparuk	935	935
Duck Island	Endicott	283	279
Prudhoe Bay	Lisburne	156	154
Milne Point	Kuparuk	55	53
	TOTAL	6331	6280

Most Likely Case Fields

Field	Formation	Recoverable	Economically Recoverable
Prudhoe Bay	Permo-Triassic	6307	6266
Kuparuk River	Kuparuk	1514	1514
Duck Island	Endicott	311	311
Pt. McIntyre[a]	Kuparuk	300	298
Prudhoe Bay	Lisburne	159	157
Niakuk[a]	Kuparuk	58	57
Milne Point	Kuparuk	55	53
	TOTAL	8704	8656

High Reserves Case Fields

Field	Formation	Recoverable	Economically Recoverable
Prudhoe Bay	Permo-Triassic	6984	6862
Kuparuk River	Kuparuk	1666	1666
Duck Island	Endicott	342	342
Pt. McIntyre[a]	Kuparuk	330	327
Prudhoe Bay	Lisburne	191	191
Niakuk[a]	Kuparuk	63	63
Milne Point	Kuparuk	60	57
	TOTAL	9636	9508

a. Production estimated to start in 1993.

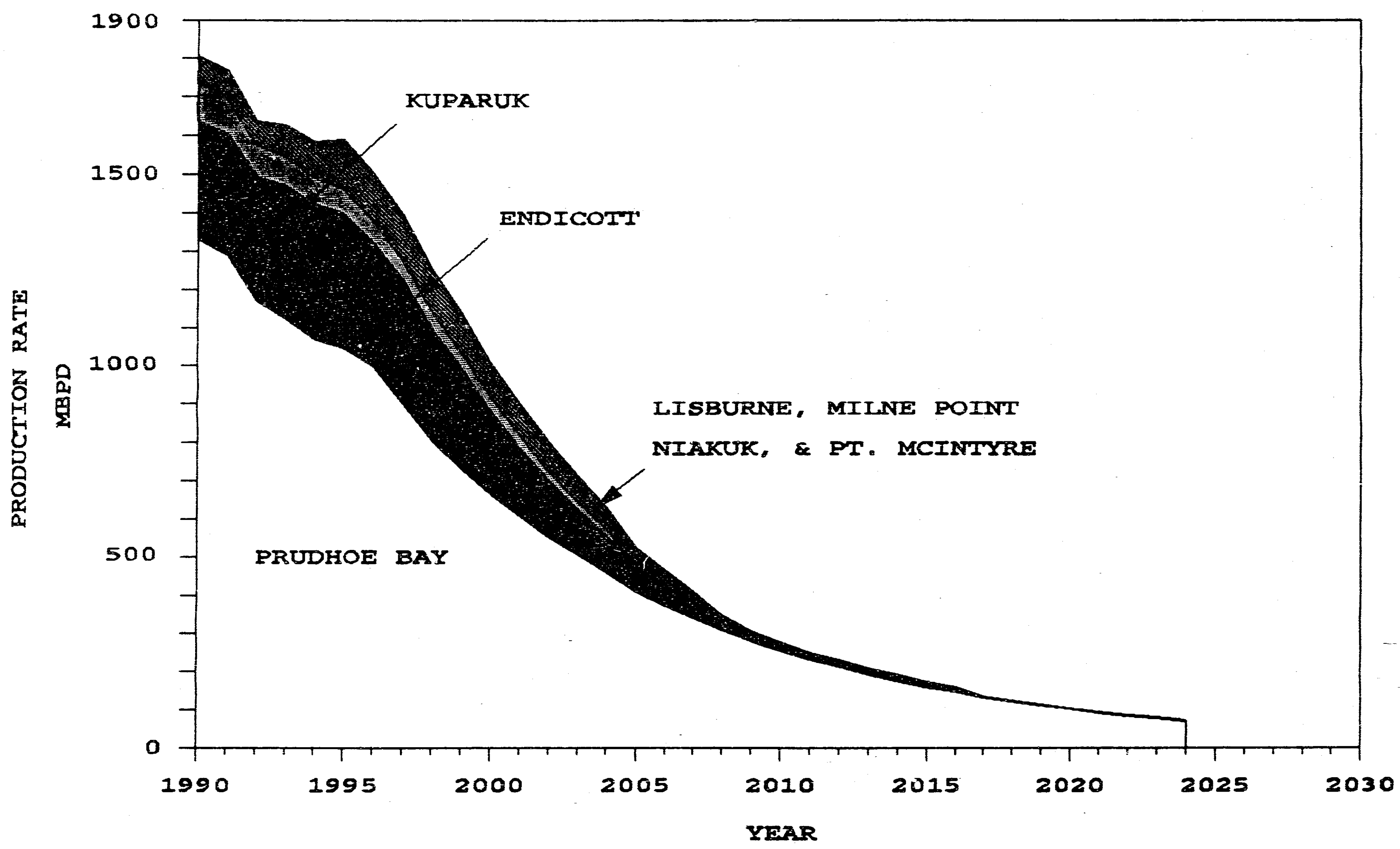

Figure 3-5. North Slope Fields - Projected Production Rates Versus Time for the Most Likely Case.

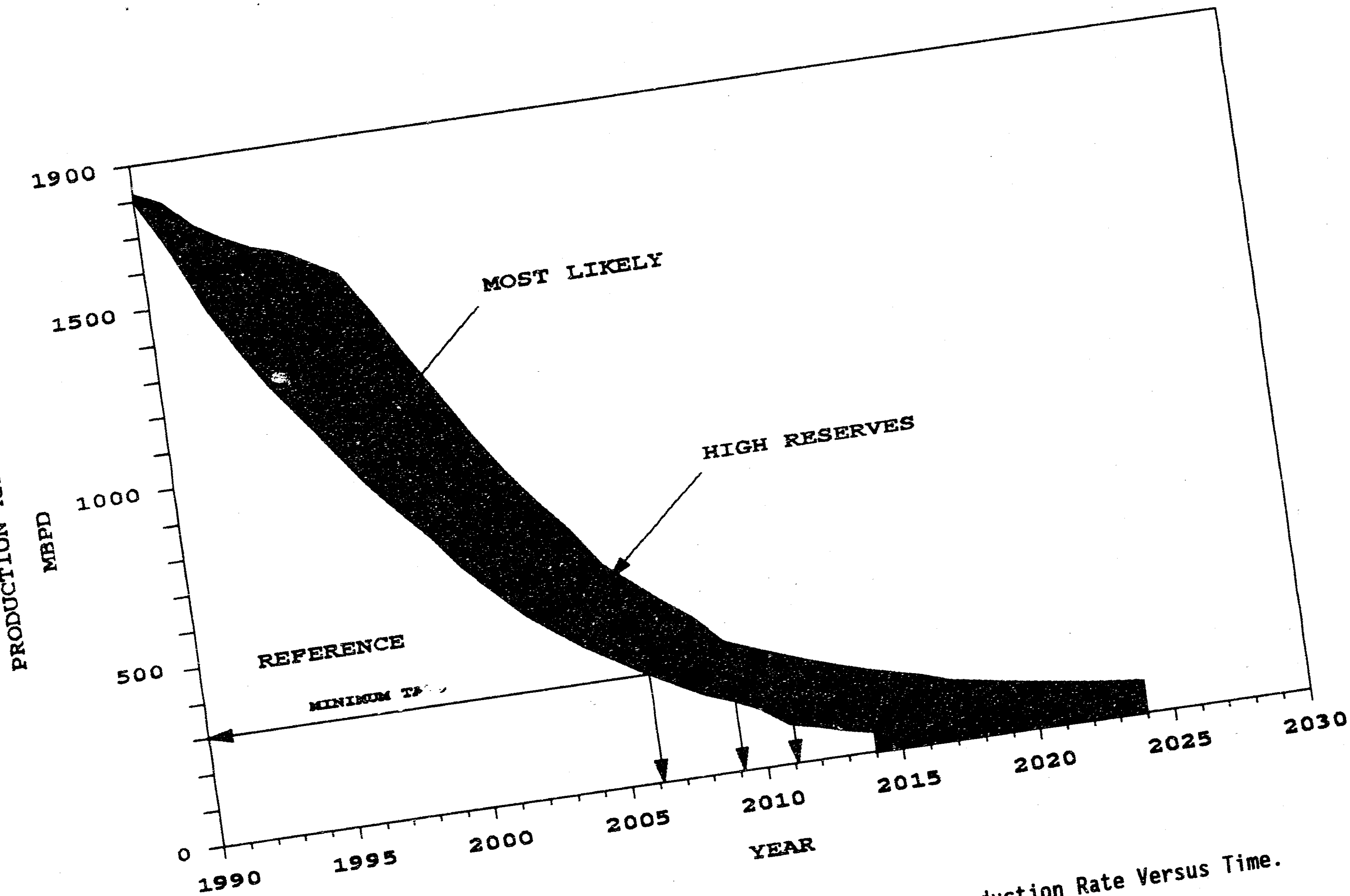

Figure 3-6. North Slope Alaska - Composite Production Forecast, Production Rate Versus Time.

3.2.9 Trans Alaska Pipeline System (TAPS) Minimum Throughput

At start-up of TAPS in 1977, the pipeline capacity was 300 MBPD. Since 1977, the design capacity has been raised to 1.42 MMBPD by the addition of planned pump stations and modifications to existing pump stations (see Section 4.1.3). With existing equipment, the minimum capacity is 600 MBPD. To operate below the 600 MBPD throughput rate, mechanical revisions would be required that would essentially be the reverse of installations made to increase throughput from start-up rates to the current design capacity of 1.42 MMBPD. Rates significantly below 300 MBPD would require additional mechanical modifications and would result in a greater decrease in the oil temperature in route to Valdez, which would cause an increase in the oil viscosity and more wax problems. The increased formation of wax is the more critical and costly of these factors.[45]

Operating at low throughput volumes would not result in significant savings in operating costs. The infrastructure requirements for spill response and maintenance result in fixed costs which are independent of throughput. Costs for corrosion control and increased personnel requirements at Valdez following the recent oil spill in Prince William Sound, have increased annual expense budget for TAPS from about $250 MM up to $530 MM. All of these costs will be factors in the minimum throughput rate of the pipeline and in the tariffs at lower throughput rates. Intermittent operation of the pipeline is also not considered to be a viable option for accommodating low throughput rates due to the fixed expense costs.[45]

For the purpose of this study, a minimum throughput rate of 300 MBPD was assumed. If further study reveals that viable economic options exist to continue operations at lower throughput rates, determination of the reduced effect on reserves in each of the scenarios considered in this study is straightforward.

3.2.10 Composite Reserves Curves With TAPS Limitations

The projected remaining economically recoverable reserves versus time for each of the three study cases are shown in **Figure 3-7**. Using a minimum TAPS throughput of 300 MBPD and **Figure 3-6**, pipeline shutdown will occur in about year-end 2006 for the Reference Case, year-end 2009 for the Most Likely Case, and 2010 for the High Case. From **Figure 3-7**, it is seen that reductions in recoverable reserves of about 640 MMBO would occur for the Reference case and about 1.0 BBO in the Most Likely and High Cases. These "lost" reserves result in significant reduced income to the state of Alaska, the federal government, and the field owners. These losses are shown in **Table 3-12**.

Table 3-12. Lost Income Due to TAPS Minimum Limit of 300 MBPD ($ Billion)[a]

	Reference Case	Most Likely Case	High Case
State of Alaska			
• Taxes	2.4	6.1	6.1
• Royalty	2.4	5.7	6.1
Federal government	3.6	8.7	9.2
Field owners	7.0	15.8	17.9
TOTAL	15.4	36.3	39.3

a. Sum of dollars in year of occurrence

Loss by State and Federal Governments and Field Owners - % of Total

	Reference Case	Most Likely Case	High Case
State of Alaska	31.4	32.5	31.1
Federal government	23.3	23.9	23.4
Field owners	45.3	43.6	45.5
TOTAL	100.0	100.0	100.0

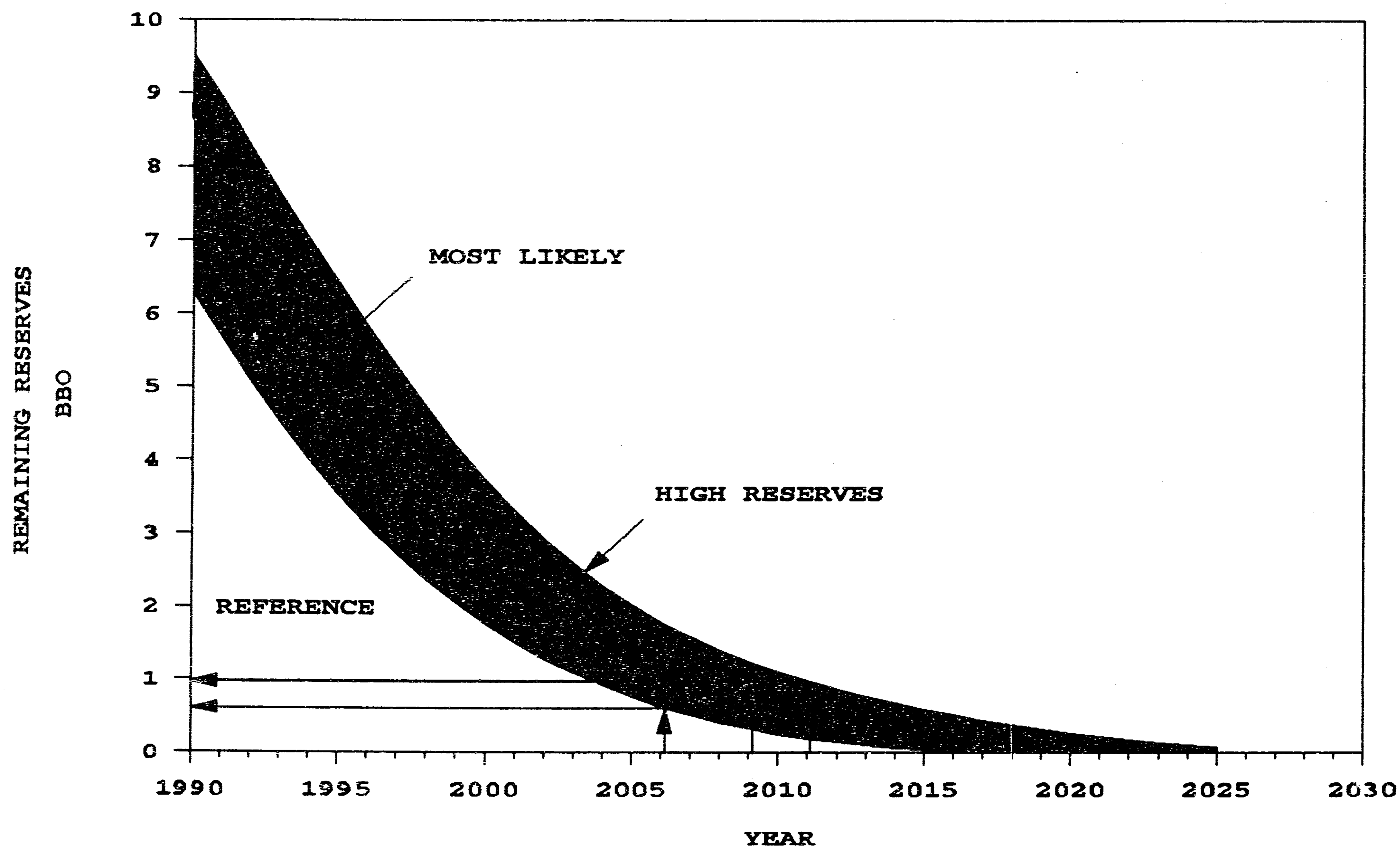

Figure 3-7. North Slope Alaska - Composite Reserves Forecast, Remaining Reserves Versus Time.

3.3 Known Undeveloped Fields

The known undeveloped fields on the North Slope are listed in **Table 2-5**. Based on the available data many are either too small to be developed economically, are gas or gas condensate fields, or there is insufficient data to make an estimate of recoverable reserves with any degree of accuracy. The heavy oil/tar resource contained in the Ugnu sands is not producible with current technology and is not included in this analysis since its development is not expected to occur in the next 30 years.

Point Thomson is a 300 million barrel gas condensate field located about 60 miles from Pump Station No. 1. The earliest possible date for development is concluded to be after a gas sales line has been constructed. A problem will still exist in marketing the condensate. Neither TAPS nor the Valdez terminal are designed for light hydrocarbon shipments. A large volume of crude oil similar to that from the Prudhoe Bay area would have to be available for blending with Point Thomson condensate. The degree of uncertainty associated with timing and with production and marketing schemes is too high for Point Thomson to be included as a potential field development in the foreseeable future.

The only resource accumulations listed in **Table 2-5** that are believed to contain sufficient reserves potential to be considered for development are West Sak, Seal Island, Sandpiper, and Gwydyr Bay.

3.3.1 Reserve Estimates.

Potentially recoverable reserves for the four field areas listed above were taken from published data, or in the case of West Sak, were calculated using assumed reservoir parameters.

3.3.1.1 West Sak. West Sak, discovered in 1969, is a shallow, low temperature, heavy oil reservoir, much of which is contained within the boundary of the Kuparuk River Unit area. Estimates of the resource-in-place range up to a maximum of 20 BBO. Delineation drilling of the reservoir began in 1971 and continued through 1982. Since then, the operators efforts have concentrated on reservoir data collection and pilot testing of recovery methods.[50] Research and engineering studies are continuing into 1990 but at a reduced scale until all issues relating to the use of Kuparuk River Facilities are resolved.[8] Although the production volumes from the pilot tests are not yet public information,[51] the operator reports the tests are successful and that (hot) waterflooding is a viable recovery mechanism.[50] Potential recoverable oil was estimated at 423 MMBO. The formula and factors used for this calculation are shown in **Table 3-13**. To recover this oil volume, the recovery processes applied must be effective over the entire project area or improved recovery processes must be developed.[52]

3.3.1.2 Seal Island/North Star. The Seal Island/North Star accumulation was discovered in 1984. The area, in 39 feet of water, is six miles offshore and about 12 miles northwest of Prudhoe Bay. A unit area designation has been filed to cover an area in state and disputed federal/state waters. A total of five wells have been drilled within the proposed unit area and have led to recoverable estimates of between 150 and 300 MMBO.[10,21,53] Because the reservoir data on this field are not available for review, the lower published reserve estimate was chosen for evaluation. It is possible that the data obtained by the delineation drilling could confirm the higher number.

3.3.1.3 Sandpiper. The Sandpiper Island accumulation was discovered in 1986 on federal offshore leases. The discovery well was drilled from the man made Sandpiper Island in 49 feet of water[21] about 10 miles west of Seal Island/North Star. Very little information has been published on this accumulation (see **Table 2-5**). Sandpiper appears to be similar to the Seal Island/North Star areas that have both been indicated to have a Sadlerochit pay zone. As a test of the field size required for near shore development, Sandpiper was assumed to contain 150 million barrels of recoverable oil.

Table 3-13. West Sak Field - Potential Recoverable Oil Determination

Table 3-13. West Sak Field - Potential Recoverable Oil Determination

$$\text{BSTOIP} = \frac{7758 \times \text{area} \times \phi \times (1-S_w) \times h \times \text{N/G Ratio}}{\text{FVF}}$$

Potential Recoverable Oil = STO(BBL) X R_f

Assumed Reservoir Parameters:	Area	50,000 acres
	Porosity - ϕ	25%
	Water saturation	20%
	Gross pay	160 feet
	Net-to-gross ratio	0.75
	FVF	1.10
	Recovery factor	5%

$$\text{BSTOIP} = \frac{7758 \times 50{,}000 \times .25 \times (1-0.20) \times 160 \times 0.75}{1.1}$$

BSTOIP = 8,463,272,727 BBLS

Potential recoverable oil = 8,463 MMBO x 0.05

Potential recoverable oil = 423 MMBO

where,

BSTOIP - barrels of stock tank oil originally in the reservoir

7758 - converts volume from cubic feet per acre-foot to barrels per acre-foot

area - surface acres underlain by productive reservoir rock

ϕ - porosity or the percent of void space in the bulk rock volume

S_w - pore volume that is occupied by water (%)

h - gross thickness of formation, in feet containing hydrocarbons

N/G ratio - percentage of gross thickness that contains recoverable hydrocarbons

R_f - recovery factor is the percent of the BSTOIP which can economically be recovered.

3.3.1.4 Gwydyr Bay Unit. The Gwydyr Bay Unit area lies along the north central Prudhoe Bay Unit boundary. Discovery was made in 1969 in the Sadlerochit formation. The ADNR has estimated recoverable reserves of about 10 MMBO. Other sources (**Table 2-5**) indicate recoverable reserves are between 30 and 60 MMBO. For this study the upper estimate of 60 MMBO was used to determine the level of profitability of a small field in close proximity to Pump Station No. 1. The assumed reservoir parameters used to calculate potential reserves of 60 MMBO are shown in **Table 3-14**.

Table 3-14. Gwydyr Bay Unit - Potential Reserves Calculation

Assumed Reservoir Parameters	
Area (acres)	2880
Porosity (%)	22
Water saturation (%)	30
Thickness (feet)	80
Formation volume factor	1.45
Recovery factor (%)	32

Using the formula in **Table 3-12**, the reserves estimate is 60.7 MMBO. A reserves volume of 60 MMBO was used.

3.3.2 Individual Field Forecasts.

The method used to develop an annual forecast of production rates for the Gwydyr Bay, Seal Island/North Star, and Sandpiper fields is similar to the ones used by Young and Hauser[26] and the National Petroleum Council.[22] After the total recoverable reserve volume was determined or assumed, the annual peak rate was set at a specific percentage of the ultimate recovery. The rates for the early years were increased until the peak rate was achieved. The peak rate was held constant for a specified number of years after which peak production was declined at either 12 or 15% per year. The decline rate was chosen to give a 15 year or greater project life. The factors used to prepare the production forecasts used are listed in **Table 3-15**.

Field Size(MMBO)	Peak % of Ultimate Recovery	Yearly % of Ultimate Recovery 1	2	3	4	Years at Peak Rate	Decline Percent
50 to 300	10	3	7			3	12
300[a]	7	3	5			4	15
300 to 725	10	3	7			4	15
725 to 1350	10	3	5	7		4	15
1350 to 3000	7	3	4	5		7	12
3000 to 7250	6	1	3	4	5	8	12

a. Limestone Reservoir similar to Lisburne of Prudhoe Bay Unit.

An 8 year rate forecast for an average West Sak well was developed as follows:

- Year 1 - 10 BBLS/day
- Year 2 - 35 BBLS/day
- Year 3 - 250 BBLS/day
- Year 4-8 - 22% decline.

This gives a total per well recovery of about 339 MBO. For the total West Sak field, the peak rate reached was about 70 MBPD. The assumed project had a staged development over 17 years with 150 wells being drilled each year, except the final year when 100 were drilled. This resulted in the peak rate being maintained for 8 years.

3.3.3 Development Costs

Facilities costs for these four fields are based on Prudhoe Bay area historical data. The average facilities cost factor discussed in Section 3.2.2.1 was used in determining the total facilities investment required for each field development over its project life. Modifications were made for the two offshore Beaufort Sea fields to provide for their higher anticipated costs. Costs were estimated for a central processing and production island and three satellite producing islands.[6] These costs were then added to each fields' facilities costs determined by the average then added to each fields' facilities costs determined by the average facilities cost factor, and the peak production rate for each field. The facilities costs for the West Sak development were reduced by 40% overall as an estimated result of shared facilities.[50] This totals about $450 MM over the life of the project as outlined in this study.

The cost to drill and complete producing wells in the Gwydyr Bay Unit, and the Seal Island/North Star, and Sandpiper fields were based on the cost to drill similar wells in the Prudhoe Bay area. For offshore wells, the Endicott and Point McIntyre well cost of $2.85 MM was used. For the Gwydyr Bay Unit, the Lisburne well depth is most comparable. However, because the Lisburne wells encounter hydrogen sulfide, additional costs are incurred.[35] The amount of these added costs is unknown. The drilling and completion cost of a Gwydyr Bay Unit well was set at $2.85 MM for the economic evaluations.

The total cost to drill, complete and test 21 West Sak Delineation wells was $49.665 MM (1990 dollars).[50] The average cost ($2.365 MM) of these delineation wells is believed to be greater than the cost of a development well. The report on the use of carbon dioxide for improving the recovery of West Sak oil, indicates the cost to drill and complete a producer is about $1.5 MM (1990 dollars).[52] This was used in the field economics.

3.3.4 Operating Costs

A curve of annual operating costs versus daily fluid production rate was prepared using the project operating cost data developed in **Section 3.2.3** on the five producing fields and the Niakuk Field. The curve is shown in **Figure 3-8**. The operating cost data taken from this curve compares favorably to inflation adjusted costs from Young and Hauser[26] and the NPC.[22]

The cost curve was used to determine the annual operating costs for each year of production up to and including the first year of peak oil production rate. The annual operating cost for the peak rate was converted to a cost per barrel of total fluid produced during that year. The total produced fluid

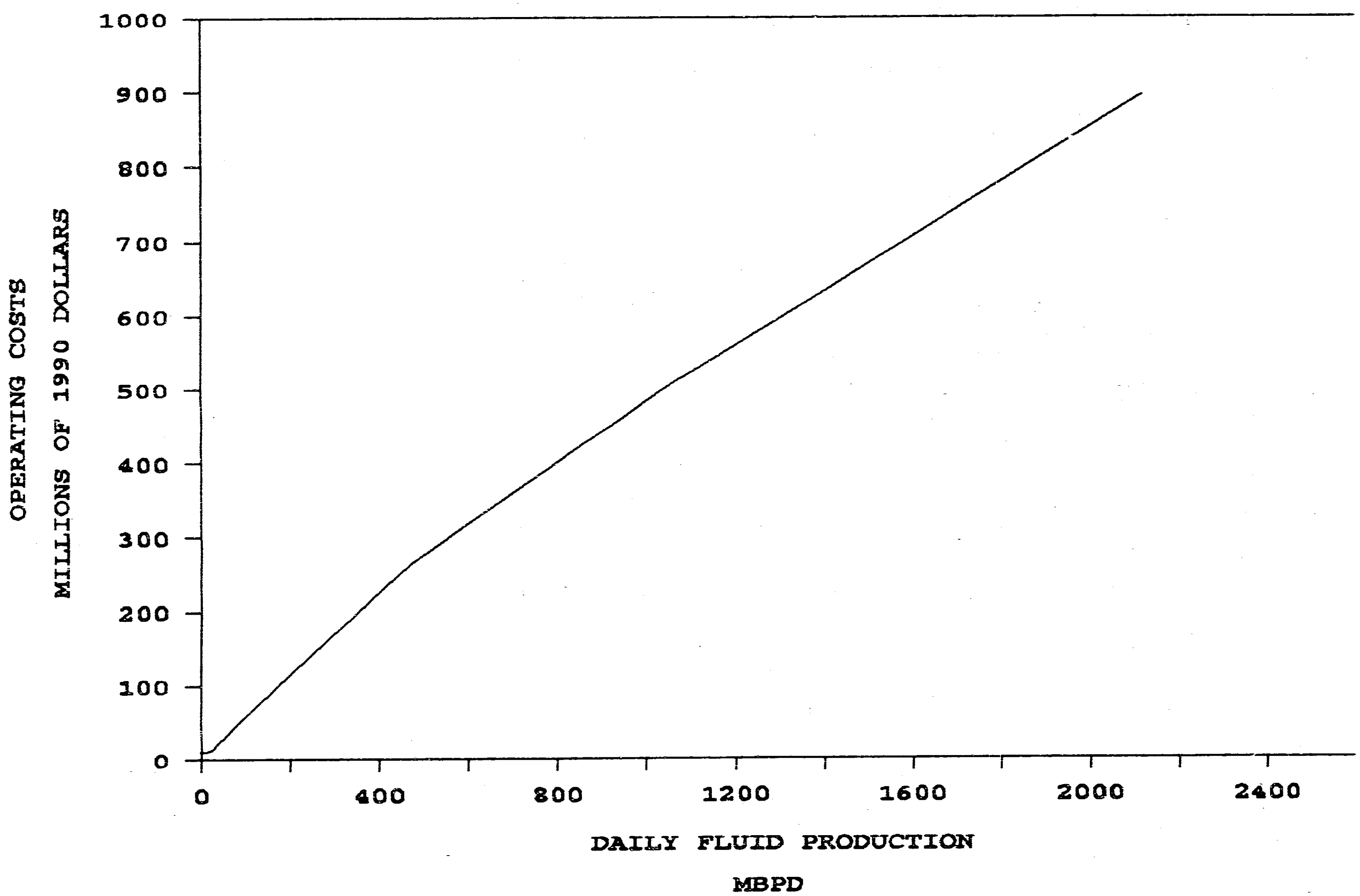

Figure 3-8. Annual Operating Costs ($MM) Versus Daily Fluid Production Rate.

volume was obtained from the water cut versus percent cumulative recovery curve in **Figure 3-3**. The operating cost for each succeeding year was determined using the water cut curve, the production forecast and the per barrel operating cost.

This method was used to determine the future operating costs for the Gwydyr Bay Unit. This method was also used for determining the future operating costs for the Seal Island/North Star and Sandpiper fields except the operating costs were increased 20% to account for the expected higher operating cost of an offshore field.

Review of the available information on the West Sak field leads to the conclusion that operating costs will be higher than any of the fields currently producing on the North Slope.[50] Operating cost assumptions in the University of Alaska study were considered.[52] The following operating cost segments were used for West Sak economics:

- Fixed Costs - $50MM/year,
- Well Workovers - $3.00/bbl Oil/year
- Facilities Sharing - $1.34/bbl Total Fluid.

3.3.5 Pipeline Tariffs by Field

The development scenario for the Sandpiper and Seal Island/North Star fields and the Gwydyr Bay Unit included the joint use of a field pipeline to deliver oil to Pump Station No. 1. The 18 mile, 24 inch offshore pipeline cost was based on the NPC Study Table E-20, (Cost and Timing Estimates, Marine Pipelines).[22] The 14 mile, 20 inch onshore pipeline cost was based on Young and Hauser's, estimated total costs for pipeline construction (Figure 7).[26] After inflation to January 1, 1990 dollars, those costs, and the recoverable reserves for the three fields were used with the pipeline tariff estimating formula (see Section 3.2.5.2) to determine the field tariff for each project. The indicated tariffs for these three fields are;

- Gwydyr Bay Unit - $0.93/bbl

- Seal Island/North Star Field - $1.94/bbl
- Sandpiper Field - $3.95/bbl.

The West Sak development scenario assumed a participating development area within the Kuparuk River Unit. It was assumed that West Sak would be charged the same field pipeline tariff as the Kuparuk River participating area (see **Section 3.2.5.2**). The tariff is $0.61/bbl.

3.3.6 Taxes and Royalties

3.3.6.1 State of Alaska. As stated in **Section 3.2.7**, a royalty rate of 12.5% was assumed applicable to all undeveloped state leases onshore and offshore in this study.

The state taxes applicable to onshore and offshore state leases and to onshore federal leases are also listed in **Section 3.2.7**.

No state taxes or royalties apply to leases offshore federal leases.

3.3.6.2 Federal. As noted in **Section 3.2.7** federal royalties were assumed to be a uniform 16.67% for simplification of economic calculations. The federal income tax rate of 34% is assumed to remain constant throughout the life of the fields in this study.

3.3.6.3 Disputed Acreage Leases. Most of the leases included in the proposed North Star Unit (Seal Island/North Star) were issued as a result of the 1979 Joint State/Federal Beaufort Sea Lease Sale. For the purpose of this report, and ease of evaluation, all of the leases in the field area were treated as state leases for royalty and state tax calculations.

3.3.7 Economic Limit Analysis

Using the program described in **Section 3-7**, economic analyses were run on each of the Known Undeveloped Fields to determine if they individually met a 15% nominal rate of return on investments. It was assumed that 15% would meet the minimum requirement for new development projects. West Sak, with a calculated 11% nominal rate of return, was the only project which did not meet that economic hurdle. West Sak resources were included as reserves even though the economics were below the 15% hurdle used for other fields because of its location within the Kuparuk River Unit and the opportunity to utilize Kuparuk River Unit facilities. Development within an established area such as Kuparuk River Unit is less risky than in remote areas such as NPRA, ANWR or offshore. The economic parameters discussed in **Section 3.3** and the additional assumptions set out in **Table 3-16** were used in the evaluations.

Table 3-16. Assumptions for Economic Evaluations - Known Undeveloped Fields

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1. Recoverable oil volumes and forecast rates as discussed in **Sections 3.3.1** and **3.3.2.**

2. Operating costs as discussed in **Section 3.3.4.**

3. Future facilities cost as discussed in **Section 3.3.3**, with these modifications;

    a. Sandpiper - added cost to install a platform

    b. Seal Island/North Star - added cost to install a platform

    c. West Sak - Reduced facilities investment by estimated savings resulting from facilities sharing with Kuparuk River Unit.

4. Future development wells requirement as discussed in **Section 3.7.2.1.**

5. Productive area for both Seal Island/North Star and Sandpiper prospects was assumed as 7040 acres.

6. A producing well/injection well ratio of six producers for each four injectors was used.

7. Future active producing wells were determined by using the Curve B formulas presented in **Table 3-9**, Item 4.

8. Oil price schedule as discussed in **Section 3.2.4.**

9. Taxes and royalties as discussed in **Section 3.2.7.**

10. Transportation costs as discussed in **Sections 3.2.5, 3.2.6,** and **3.3.5.**

11. TAPS tariff schedule as shown in **Table 3-7.**

Table 3-16. (Continued)

12. All surplus gas was assumed to be reinjected and/or used in an EOR process.

13. A constant 3.5% inflation factor was used in the evaluations.

14. Cash flow discounted at 15%. (nominal)

15. Except for West Sak, a recovery factor of 32% was assumed. This is approximately the average of after waterflood projections for North Slope fields (excluding PBU).

Under these prescribed conditions, the economically recoverable reserves for each of these fields are listed in **Table 3-17**.

Table 3-17. Projected Recoverable Oil and Economically Recoverable Reserves for Known Undeveloped Fields at 1-1-90 (MMBO)

Field	Recoverable	Economically Recoverable
Gwydyr Bay Unit	60	58
Seal Island/North Star	150	145
Sandpiper	150	147
West Sak	423	385
TOTAL	783	735

3.3.8 Composite Alaska North Scope Forecast

The projected production rates were composited for the Known Undeveloped Fields. These composited rates are superimposed on the projected production rate of the Most Likely Case, and are shown in **Figure 3-9** (see **Appendix A, Table A-3** for composite rates). Only those reserves which can be economically recovered by each field under unrestricted sales conditions are included.

3.3.8.1 TAPS Minimum Flow Rate Impact. The projected remaining economically recoverable reserves versus time for the Known Undeveloped Fields are superimposed on the remaining economically recoverable reserves versus time for the Most Likely Case In Figure 3-10. Using a minimum TAPS throughput of 300 MBPD and Figure 3-9, TAPS will shut down in about 2014 for this scenario. From Figure 3-10, reductions in recoverable reserves of about 600 MMBO and about 160 MMBO would occur respectively, for the Most Likely Case and the Known Undeveloped Fields. The most significant conclusion from Figure 3-9 and Figure 3-10 is that Known Undeveloped Fields near Pump Station No. 1 extend the life of producing fields and TAPS by only 5 years.

3.4 Sensitivity Cases

Under any conditions, forecasting variables into the future is difficult. Projections can be affected by unforseen events and changes in timing. Although the variables determined in this study appear reasonable, the sensitivity of increasing or decreasing seven variables were tested to determine the magnitude of change over the ranges evaluated. It is concluded that the interpretation of data and the assumptions made, led to evaluations and results which fall within reasonable limits.

3.4.1. Variables Tested.

Sensitivity cases were run using variations of operating cost development cost, transportation costs, severance taxes, oil price, federal taxes, inflation rates and nominal discount rate. The variables tested and their sensitivity ranges are listed in Table 3-18.

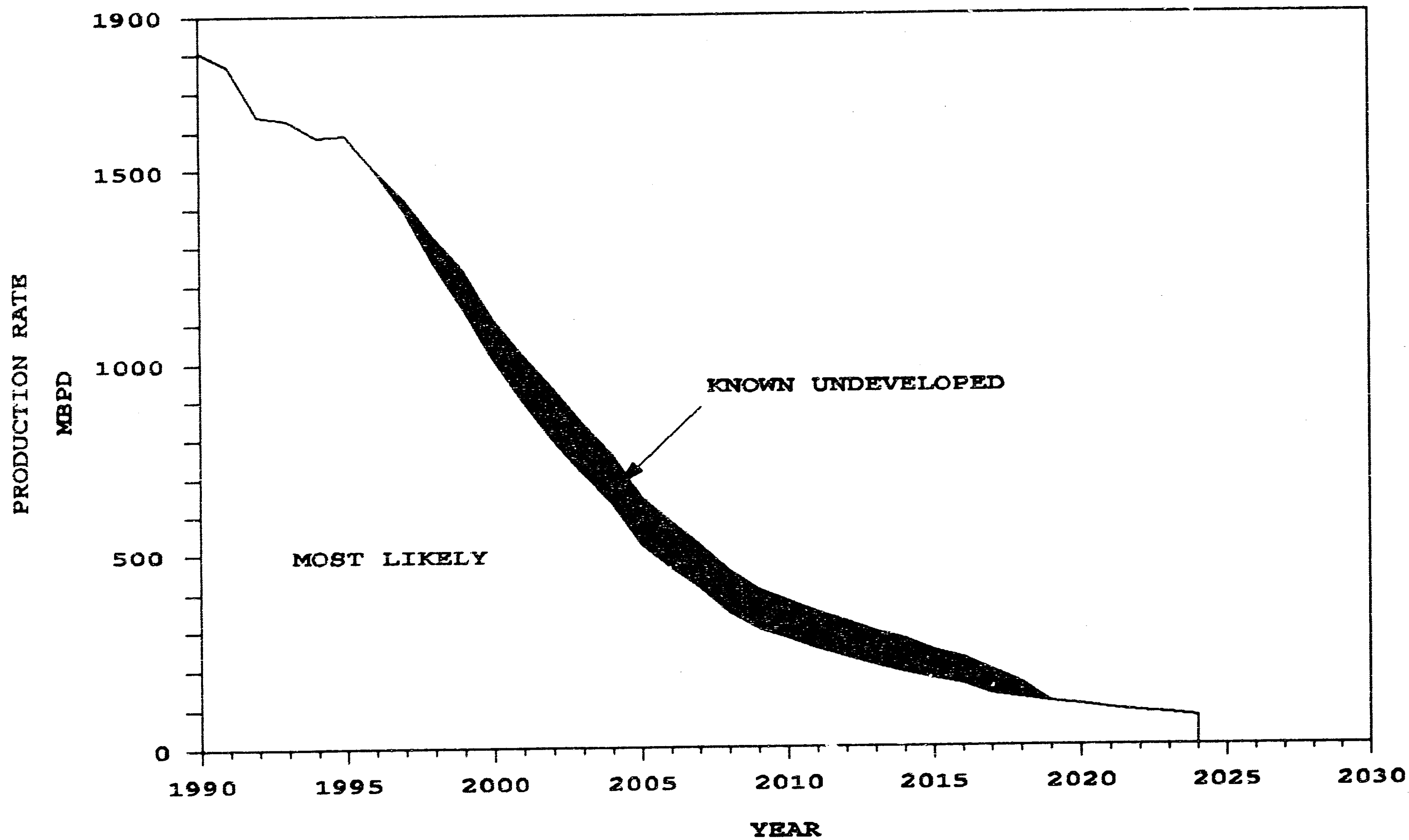

Figure 3-9. Composited North Slope Forecast - Most Likely Case plus Known Undeveloped Fields, Production Rate versus Time.

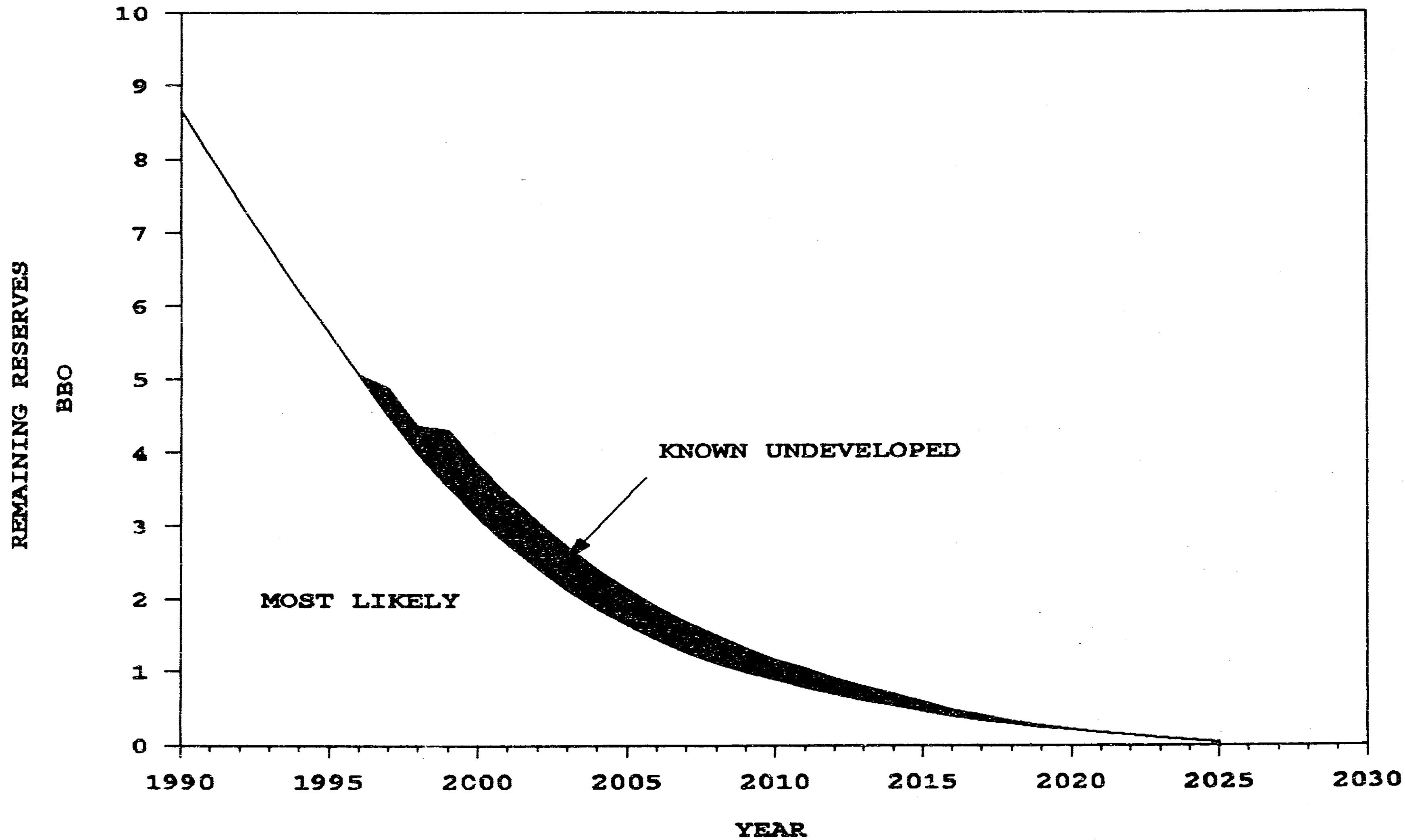

Figure 3-10. North Slope Alaska - Most Likely Case plus Known Undeveloped Fields, Composited Remaining Reserves versus Time.

Table 3-18. Sensitivities Tested-Range of Variables

Variable	Low Test	High Test
Operating cost	0.70	1.30
Development costs	0.70	1.30
Transportation costs	0.70	1.30
Inflation rates	0.70	1.30
Severance taxes	0.70	1.30
Federal income taxes	0.70	1.30
Nominal discount rate	0.70	1.30
Oil price[43]	Low World Oil Price[a]	High World Oil Price[a]

a. See Table 3-2.

3.4.2 Results of Sensitivity Studies

The changes in cumulative discounted cash flow (DCF) generated by a project was used as a basis for determining the relative effect of decreasing or increasing a variable. The largest increase or decrease in cumulative DCF occurred when using low world and high world oil prices. The most sensitive of the other variables tested was nominal discount rate. Investments and severance taxes were the least sensitive of the variables tested. The magnitude of changes in cumulative DCF for the variables tested for Prudhoe Bay Unit, Endicott, and Point McIntyre are shown in Figures 3-11 through 3-13.

It can be seen from these figures that a ± 30% variation in the variables results in some large increases or decreases in cumulative DCF. For example, a ± 30% variation in transportation costs for the Prudhoe Bay Unit would change cumulative DCF by about ± \$3 billion. In the much smaller Point McIntyre, the same variation in transportation costs would increase or decrease cumulative DCF by about \$180 million. Variation of the future investment costs would result in changes in cumulative DCF of ± \$1 billion and ± \$50 million for Prudhoe Bay and Point McIntyre respectively.

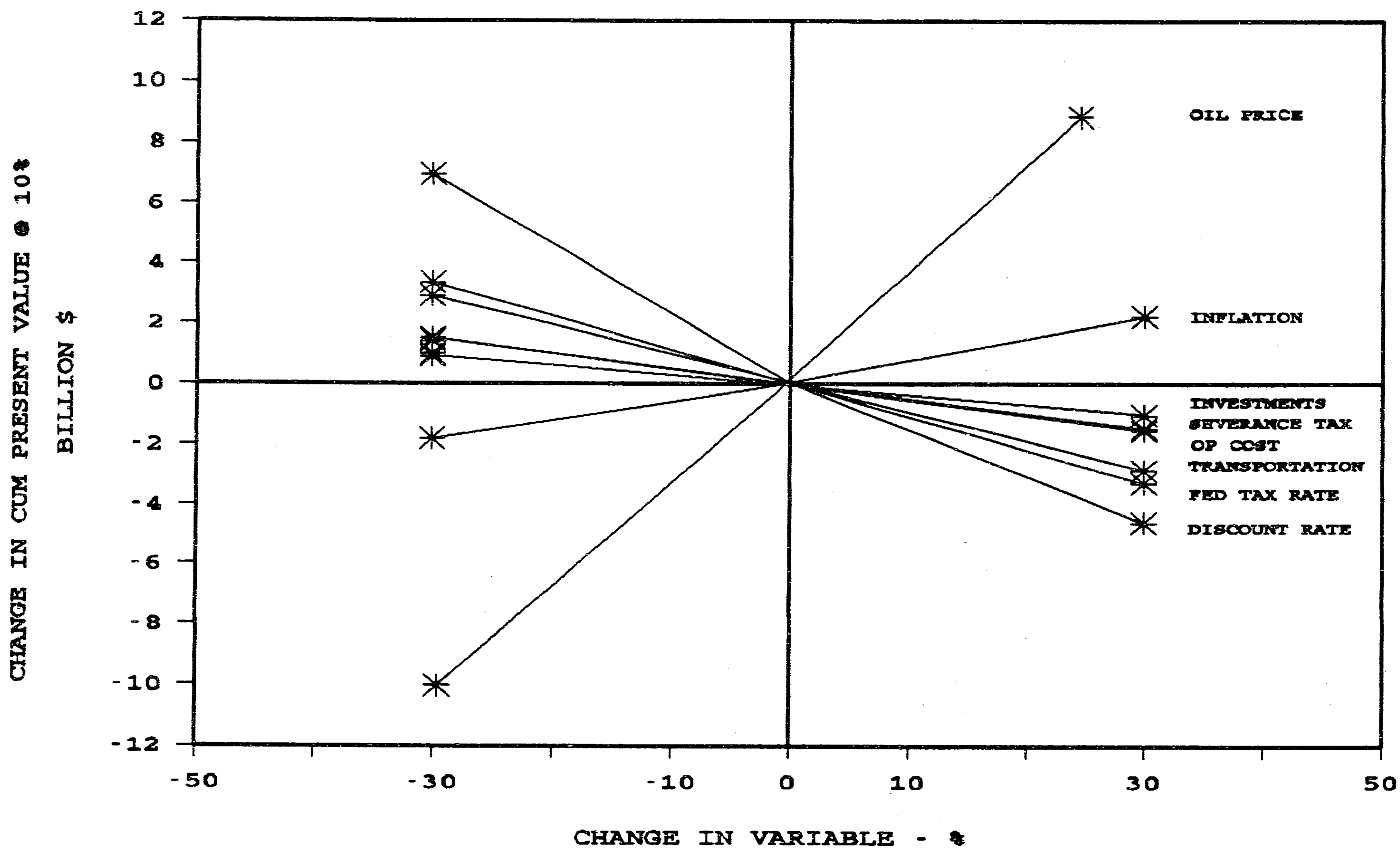

Figure 3-11. Prudhoe Bay Economic Sensivities - Change in Cum Present Value (10%) vs Change in Variable.

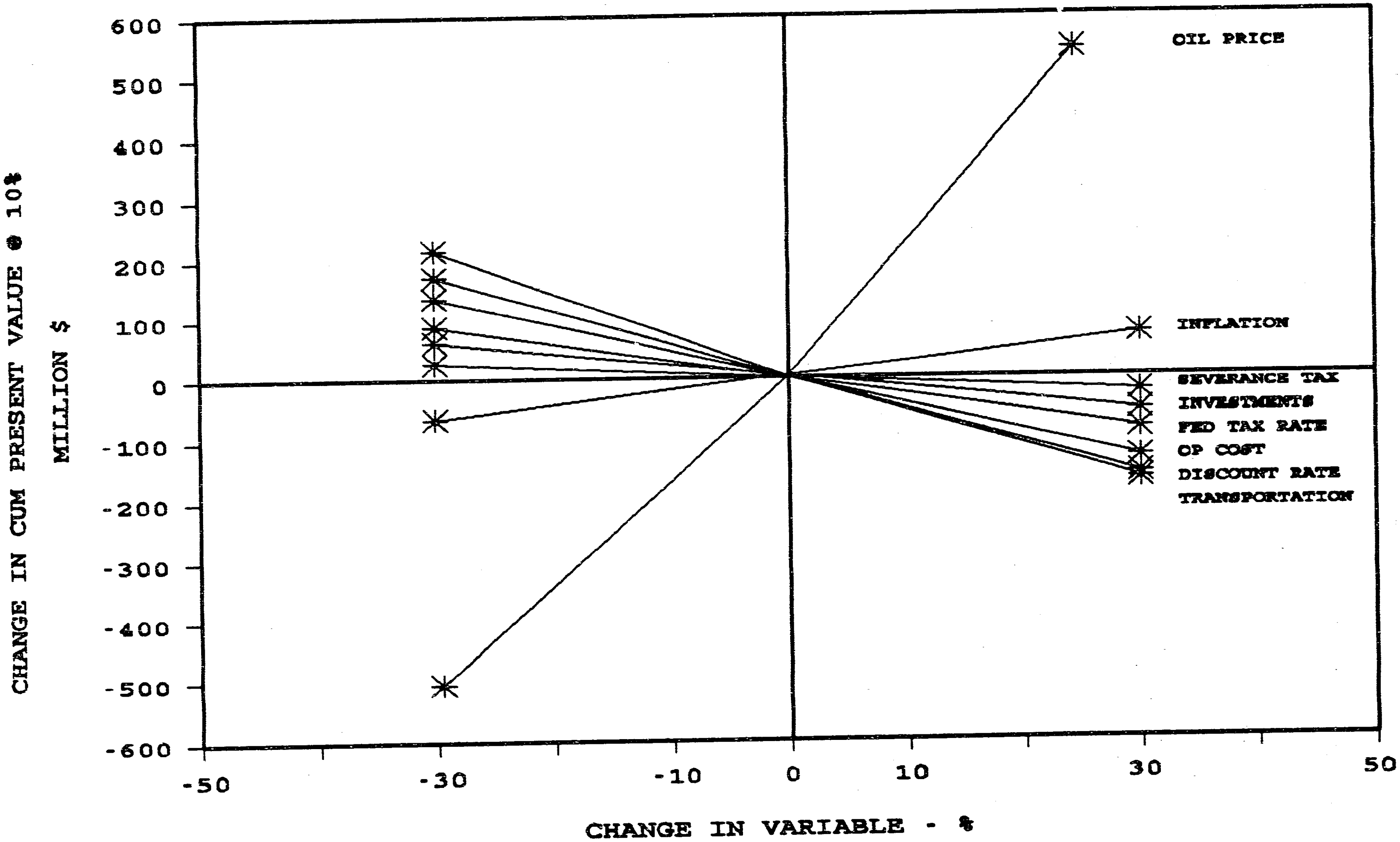

Figure 3-12. Endicott Economic Sensivities - Change in Cum Present Value (10%) vs Change in Variable.

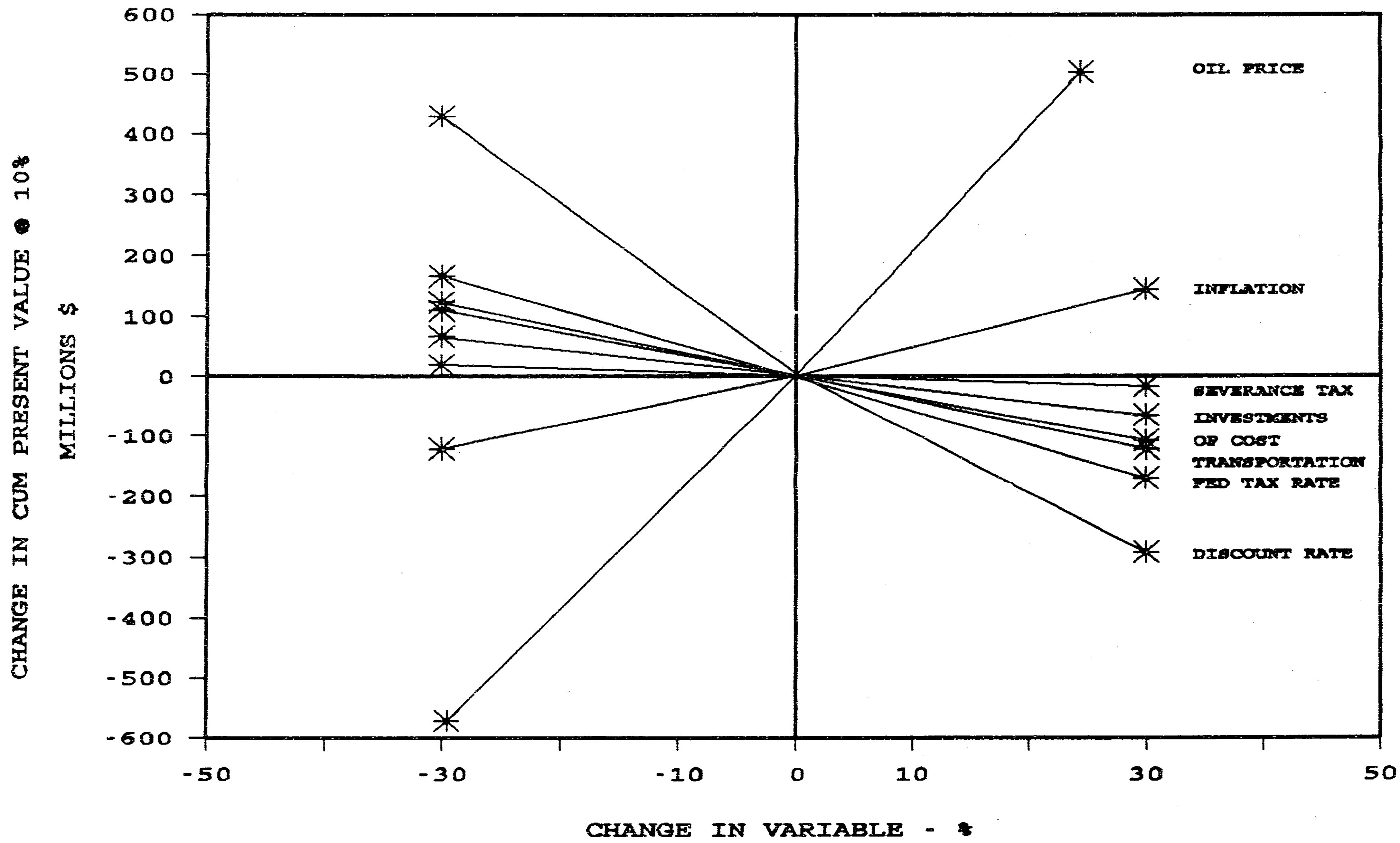

Figure 3-13. Point McIntyre Economic Sensivities - Change in Cum Present Value (10%) vs Change in Variable.

Using Low World Oil Prices resulted in negative cash flow for Milne Point Unit, West Sak, and Niakuk. Such oil prices would most likely result in active projects being shut-in and new potential projects not being developed.

3.4.3 Environmental Cost

The newer North Slope fields have been developed while using improvements in facilities and operating practices to lessen the environmental impacts of their development. Fields such as Kuparuk River Unit and Endicott have reduced requirements for gravel and surface usage, employed improved oil field services, and improved methods of waste disposal. These and other environmental issues are covered in **Section 5**. The cost of compliance with environmental regulations or the mitigation of environmental impact actions can be categorized as; Exploration and Development Delays, Increased Development and Operating Costs, and Mitigation and Litigation Costs.

One of the best known examples of the cost of compliance, and one which encompasses the three categories above, is the TAPS pipeline. After about a year of studies and planning, several suits to halt pipeline construction were filed. Following legal and legislative proceedings, pipeline construction was commenced 3-1/2 years later, after pipeline legislation received Presidential approval.[54] By the time initial pipeline construction was completed in 1977, the cost of the entire system was approximately $8 billion dollars as a result of the delays and required mechanical changes.[55]

3.4.3.1 Exploration and Development Delays. Costs involved in delaying a project are normally increases in facilities and operating costs. If the delay on the North Slope is between 5 to 10 years, the risk of being unable to sell the produced oil becomes greater. With no new discoveries, TAPS will most likely be shut down by 2014. Unless a project is able to deliver sufficient volumes to keep TAPS operating, a premature shutdown could occur, resulting in "lost" reserves. The risk of this occurring could prevent development of new discoveries. Because of the seasonal nature of various activities, (e.g. winter exploration and summer sealift deliveries) a full year of activity could be lost for delays up to 6 months.

Delayed development would also result in:

- Reduced present value of project to owners
- Reduced or delayed taxes and royalties to state and federal government.

3.4.3.2 Increased Development and Operating Costs. The 2 year delay in obtaining permits has increased the estimated development cost of the Niakuk Field by $74 MM. The estimate of operating costs has also been raised during the past 2 years. If the Army Corps of Engineers decision on gravel causeways is upheld, then estimates of facilities costs are increased between $54 and $106 MM to provide for a continuous bridge to the drilling island. Operating costs are also estimated to increase for bridge maintenance.[6]

If the operator is denied the permit to construct a causeway and an artificial drilling and production island, the only alternative would be to develop by directional drilling. Investment costs are estimated to increase by $15 MM and operating costs would increase between $5 and $26 MM over the project life. More importantly, the onshore wells could not reach the entire reservoir and an estimated 20 MMBO would be lost. The project would not be economical under these condition.[6]

3.4.3.3 Mitigation and Litigation Costs. There was no information on the costs to litigate environmental disputes. The duration can be months to years as occurred with TAPS for example. Thus, the cost can be very high.

There are several examples of the costs to mitigate environmental impacts. At Endicott, the operator is spending about $8 MM per year to continue gathering data concerning possible adverse effects the causeway may have on sealife.[56] That concern has caused the COE to consider rescinding Endicotts permit and requiring that an additional breach be installed. The retrofitting of the causeway is estimated to cost about $40 MM.[57]

In the discussions on opening up the ANWR 1002 area for exploration, some consideration has been given to "winter-only" drilling. Some of the prospects, because of their depth could require more time than the drilling season would allow. This would require temporary abandonment of the well, with the exploratory effort being completed the following year. It has been estimated the cost of such a well would be increased from $20 to $50 MM over an exploration well that was granted a continuous drilling permit.[56]

There are conflicting viewpoints on the impact that North Slope development has had on the wildlife and other environmental values. One issue is whether artificial gravel pads should be removed or restored and revegetated.[21] There is some thought that removal could be more damaging than restoration and would be more costly regardless of the outcome.[58] The temporary drilling pad used to drill Chevrons' KIC well is currently being rehabilitated. The success of this effort will help clarify the arguments on long term effects from such operations.[21]

3.5 Undiscovered Resources

The Alaska North Slope is divided into five geologic provinces or exploration areas. These areas and their potential for containing recoverable oil and gas are discussed in **Section 2.3**. For this section, the areas are designated as ANWR, Chukchi Sea, NPRA, Northern Foothills, and an area consisting of the TAPS Pipeline Corridor and Beaufort Sea. This study contains results of field evaluations in each of the five areas. The TAPS pipeline corridor and Beaufort Sea were combined under **Section 3.3** with the previously discussed evaluation of the development of the Gwydyr Bay Unit (onshore) and the Seal Island/North Star and Sandpiper areas (offshore). These were stand-alone projects except for the joint use of the field pipeline to TAPS. The Gwydyr Bay Unit represented a small field within a few miles of TAPS. The Seal Island/North Star and Sandpiper areas were near shore Beaufort Sea developments in up to 49 feet of water. Evaluation of potential fields in ANWR, Chukchi Sea, and NPRA (and Northern Foothills) is covered in this section. Stand-alone field sites are determined for an East ANWR, West ANWR, and for a Chukchi Sea field about 125 miles offshore from Icy Cape. The simultaneous development of several small fields was also analyzed to determine if the construction of a pipeline from ANWR to TAPS could be justified on this basis. The development of potential NPRA fields was examined assuming that a pipeline to transport crude oil from a Chukchi Sea discovery to TAPS had already been constructed.

The TAPS pipeline corridor (Arctic Coastal Plain), the Beaufort Shelf, and Chukchi Sea are areas with current or planned exploration drilling activity. Lease sales in ANWR and NPRA must be held before either of these areas can be explored by the oil industry. The probabilities for discoveries in these areas is discussed in **Section 2.4.1**. ANWR and the Chukchi Sea are the only two areas where sizeable reserves discoveries are believed possible.

In both areas, the time from lease sale to date of first production is estimated at greater than 10 years. The Office of Technology Assessment estimated in 1988 that about 12 years would be required after a lease sale until a discovery could be brought on production.[21] This assumed that a discovery would be made 3 years after a lease sale. The NPC projected a period of 9 years after lease sale to date of first production in ANWR and 14 years before production could commence on a discovery in the Chukchi Sea.[22] Based on current conditions, the time required after lease sale, to initiate production was 12 years for ANWR and 14 years for the Chukchi Sea. As exploration is already in progress in the Chukchi Sea, it was assumed the 14 year period would end in 2004 for Chukchi Sea evaluation purposes.

3.5.1 Reserves and Production Forecasts

Reserves volumes were calculated for the ANWR prospects using the 1987 USGS reservoir volume parameters[59] and the reserves formula in **Section 3.3.1 (Table 3-13)**. Such estimated reservoir data are not available for the Chukchi Sea and NPRA areas. A recovery factor of 32% of OOIP was used. The recoverable reserves volumes determined for ANWR range from 75 MM to 2.9 BBO depending on the prospect size being considered. Two recoverable reserves sizes were used in the Chukchi Sea evaluation. These were 2.6 BBO and 7.25 BBO. In the NPRA area, one prospect containing 75 MMBO was assumed for the Northern Foothills, and one prospect containing 300 MMBO in the Meade Arch. These reserves are consistant with the discussions in **Section 2.3**. Production was forcasted using factors listed in **Table 3-15**.

3.5.2 Development and Operating Costs

The facilities investments over the project life, including waterflooding facilities, was determined using the peak oil rate (see **Section 3.3.2.2**) with the development cost factor discussed in **Section 3.2.2.1**. The development cost factor was determined by using data from fields benefitting from an in-place service infrastructure. To provide for the cost of an infrastructure, the facilities costs for all new areas of development were increased by a factor of 1.15. This increase was applied in all evaluations in this study.

Cost to drill and complete exploration and development wells in the onshore prospects was taken from Young and Hauser's work[26] and inflated to 1990 dollars. Comparison shows these costs are higher than for comparable wells in the NPC study.[22] Young and Hauser development well costs are also higher than comparable wells in the Prudhoe Bay area. Application of a project learning curve is justified in prospects with large numbers of wells. The learning curve chosen equates to a 50% reduction in real dollars for drilling and completion costs over a 10 year period. The cost to drill exploration wells and to drill and complete development wells as a function of depth is shown in **Figure 3-14**.

3.5.3 Transportation Scenarios By Area

The use of TAPS to transport newly discovered reserves from the North Slope is the most economical method. TAPS is no longer operating at maximum throughput capacity. A maximum rate of about 2.1 MMBPD was achieved with the use of drag reducing agents (DRA). All prospect development scenarios in ANWR, Chukchi Sea and NPRA transported oil through field pipelines connecting to TAPS at Pump Station No. 2.

3.5.3.1 ANWR (Area 1002). Various development scenarios were considered for ANWR, each of which required a different field pipeline configuration and tariff calculation and a different TAPS tariff. Costs of field pipelines were determined from the data of Young and Hauser.[26] The field pipeline tariff was

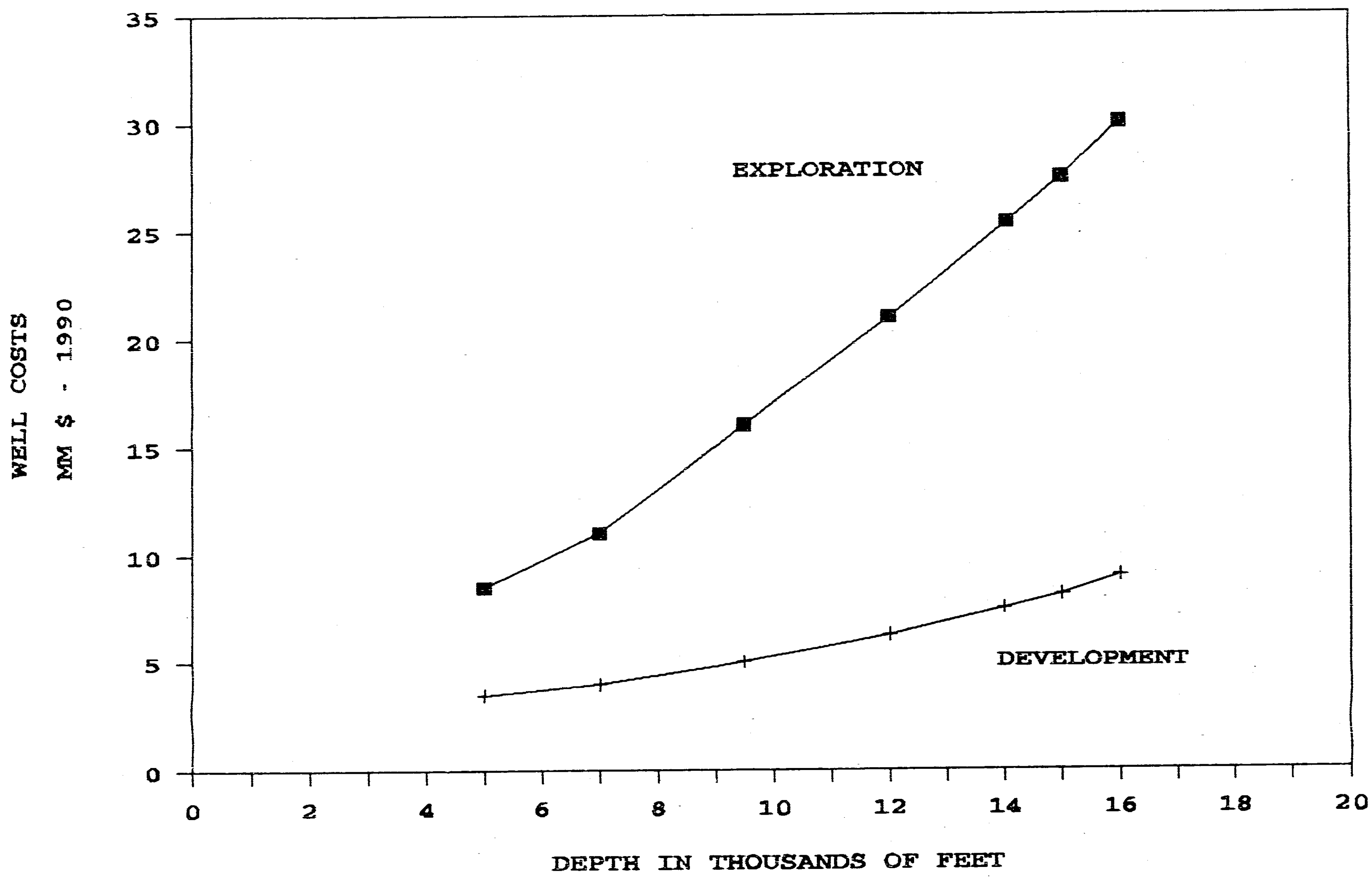

Figure 3-14. Cost to Drill and Complete North Slope Alaska Wells Versus Depth.

then calculated using the pipeline tariff estimating formula in **Section 3.2.5.2**, using the reserves for each particular development scenario. For each of these scenarios a new TAPS tariff was estimated as discussed in **Section 3.2.5.1**. In the instances where a field pipeline served more than one field, a separate tariff was determined for each field based on its position along the pipeline route. Each new development scenario required the calculation of a new TAPS pipeline tariff based on the revised throughput volumes.

3.5.3.2 Chukchi Sea. Three development scenarios were considered for the Chukchi Sea. Each scenario required the calculation of a field pipeline tariff. The cost of the offshore portion of these lines were determined using the data on Tables E-11 and E-20 of the NPC study.[22] The cost of the onshore portion of these lines were determined using data on Tables E-6 and E-15 of the NPC study and from Young and Hauser.[26] The first two scenarios covered a single Chukchi Sea field development. The third scenario included the development of two fields in NPRA. The field pipeline tariffs were calculated using the method described in **Section 3.2.5.2**. In the one instance where three fields were served by the onshore line, a separate main line tariff was calculated for each field based on the location of the field along the pipeline route. Each new development scenario required the calculation of a new TAPS pipeline tariff based on the revised throughput volumes.

3.5.3.3 NPRA. A single development scenario was considered for NPRA. The scenario included one field in the Meade Arch and a second field in the Foothills. Each field required a feeder pipeline to transport oil to the main Chukchi Sea pipeline. The formula in **Section 3.2.5.2** was used to calculate the field pipeline tariff for each feeder line. Each fields' respective tariff on the segment of the Chukchi Sea pipeline used to transport its oil to TAPS Pump Station No. 2 was also determined.

3.5.4 Economic Evaluations.

Economic analyses using the program described in **Section 3-7**, were run on five development scenarios for ANWR, three scenarios for Chukchi Sea, and one for NPRA. Assumptions used in these analyses are listed in **Table 3-19.**

Table 3-19. Assumptions for Economic Evaluations - Undiscovered Resources

1. Recoverable oil volumes as discussed in **Section 3.5.1.** Rate forecasts were determined according to **Table 3-15.** A 32% recovery factor was used.

2. Development and operating costs were determined according to **Section 3.5.2.**

3. Future development well requirement as discussed in **Section 3.7.2.1.**

4. Prospect productive area assumed:

Prospect	Area (acres) for Section 3.5	Area (acres) for Section 3.6
ANWR West - Stand Alone #5	16,900	16,900
ANWR East - Stand Alone #19	25,920	51,840
ANWR Prospect No. 1	19,520	--
ANWR Prospect No. 20	--	32,000
ANWR Prospect No. 21	13,120	26,240
ANWR Prospect No. 24	6,080	--
Chukchi Sea	64,000	64,000
NPRA - Meade Arch	29,600	--
NPRA - Foothills	5,760	--

5. A producing well/injection well ratio of six to four was used.

6. Future active producing wells were determined by using the formulas in **Table 3-9**, item 4 as follows:

   - For recoverable oil less than 2500 MMBO - Curve B
   - For recoverable oil greater than 2500 MMBO - Curve A.

7. Oil price and TAPS tariff schedule as discussed in **Sections 3.2.4** and 3.2.5.

8. Taxes and royalties as discussed in **Section 3.2.7.**

9. Transportation costs as discussed in **Section 3.2.6** and **3.5.3.**

10. A nominal rate of return of 15% was used.

11. For the Chukchi Sea potential development project, individual platform costs were taken from NPC Table E-2.[22]

12. Based on the bottom hole locations of wells in the Prudhoe Bay Unit it was assumed each Chukchi Sea platform could develop four sections.

Table 3-19 (Continued)

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13. All surplus gas was assumed to be used as fuel, injected into the reservoir, or used in an EOR process.

14. A constant 3.5% inflation factor was used in the evaluations.

3.5.5 Minimum Economic Field Size.

Economic evaluations were made to determine the MEFS for developments in the NPRA, ANWR, and Chukchi Sea areas. MEFS is defined as a field (or group of fields) having a recoverable reserve volume that will give a 15% nominal rate of return after paying all costs of development on a stand alone basis. This includes the cost of a crude sales line to Pump Station No. 2 by payment of a pipeline tariff calculated by the formula in **Section 3.2.5.2.**

3.5.5.1. ANWR. Minimum field size economics were run for three field developments scenarios. These were a West ANWR stand-alone (Prospect No. 1), an East ANWR stand-alone (Prospect No. 19), and an ANWR multiple small fields case (Prospects Nos. 1, 21, and 24). The locations of these prospects are shown on **Figure 3-15**. MEFS for each of these prospects, determined using the Low World Oil, the Revised NES Reference, and the High World Oil Price Cases in **Table 3-6** are listed below:

	MMBO at Low World Oil Price	MMBO at Revised NES Reference Oil Price	MMBO at High World Oil Price
West Stand-alone	545	400	250
East Stand-alone	1045	600	400
Cluster Fields	950	700	440
• No. 1	300	215	135
• No. 21	450	340	215
• No. 24	200	145	90

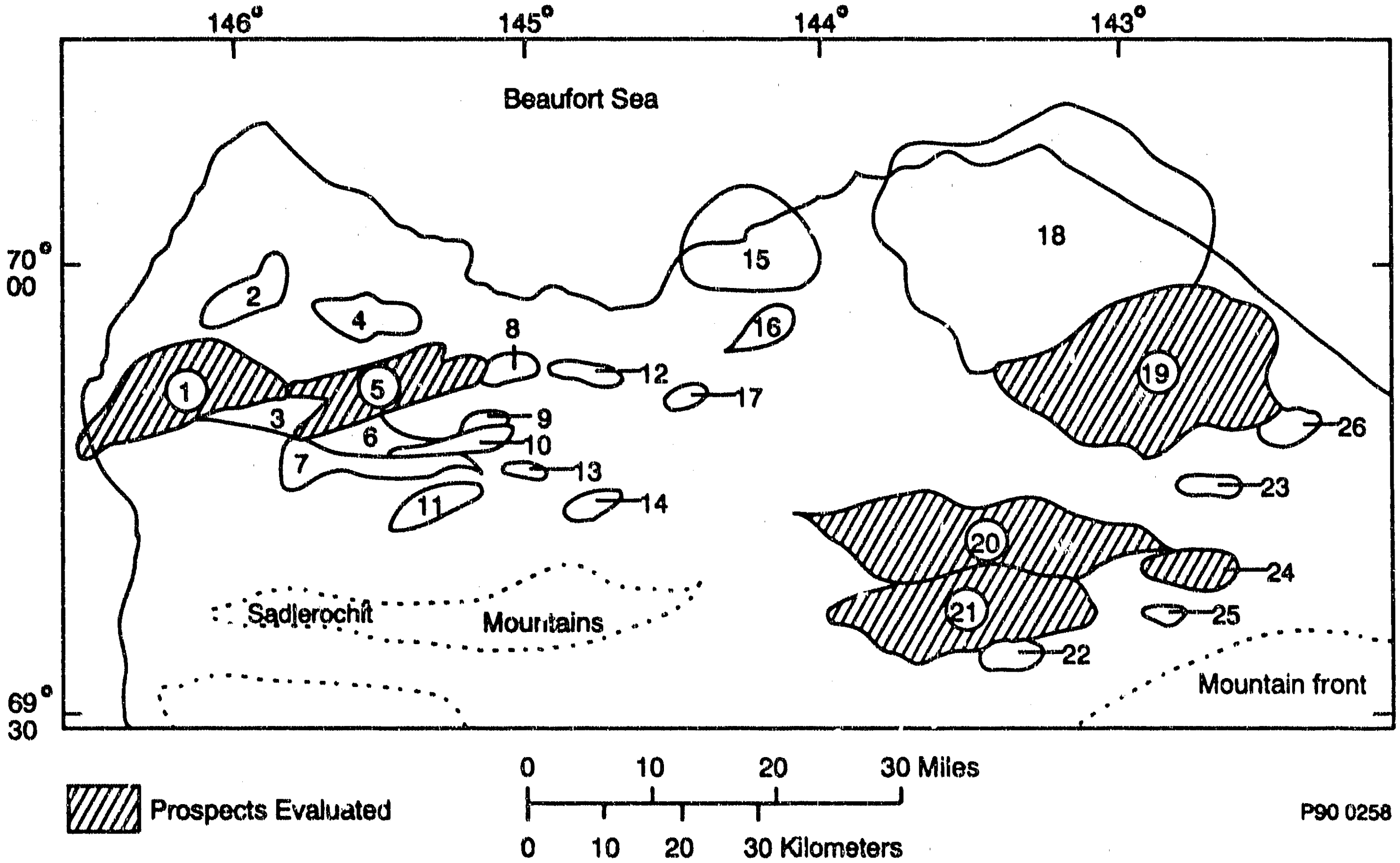

Figure 3-15. Arctic National Wildlife Refuge Area 1002, Prospect locations.

3.5.5.2 Chukchi Sea. Minimum field size economics were run for a single prospect development about 125 miles northwest of Icy Cape. The location of this potential prospect is shown in **Figure 3-16**. The minimum field sizes were determined using the three oil price forecasts in **Table 3-6**. These field sizes are:

MMBO at Low World Oil Price	MMBO at Revised NES Reference Oil Price	MMBO at High World Oil Price
4350	2600	1800

3.5.5.3 NPRA. Two potential prospect areas were chosen to test the MEFS in NPRA with the condition that a pipeline was in place for transporting Chukchi Sea oil to TAPS Pump Station No. 2. One prospect is in the Meade Arch area located in central NPRA, about 60 miles north of the NPC pipeline corridor.[22] The second prospect is in the foothills in South-Central NPRA about 15 miles south of the pipeline corridor. Locations of these two potential prospects are shown on **Figure 3-16**. MEFS determined using the price forecasts in **Table 3-6**, are:

	MMBO at Low World Oil Price	MMBO at Revised NES Reference Oil Price	MMBO at High World Oil Price
Meade Arch	400	300	190
Foothills	100	75	50

3.5.6. Significance of Potential Developments.

Although the stand-alone fields (MEFS) discussed in **Section 3.5.5**, are individually large enough to justify construction of a field pipeline, their effect on ANSODS is minimal.

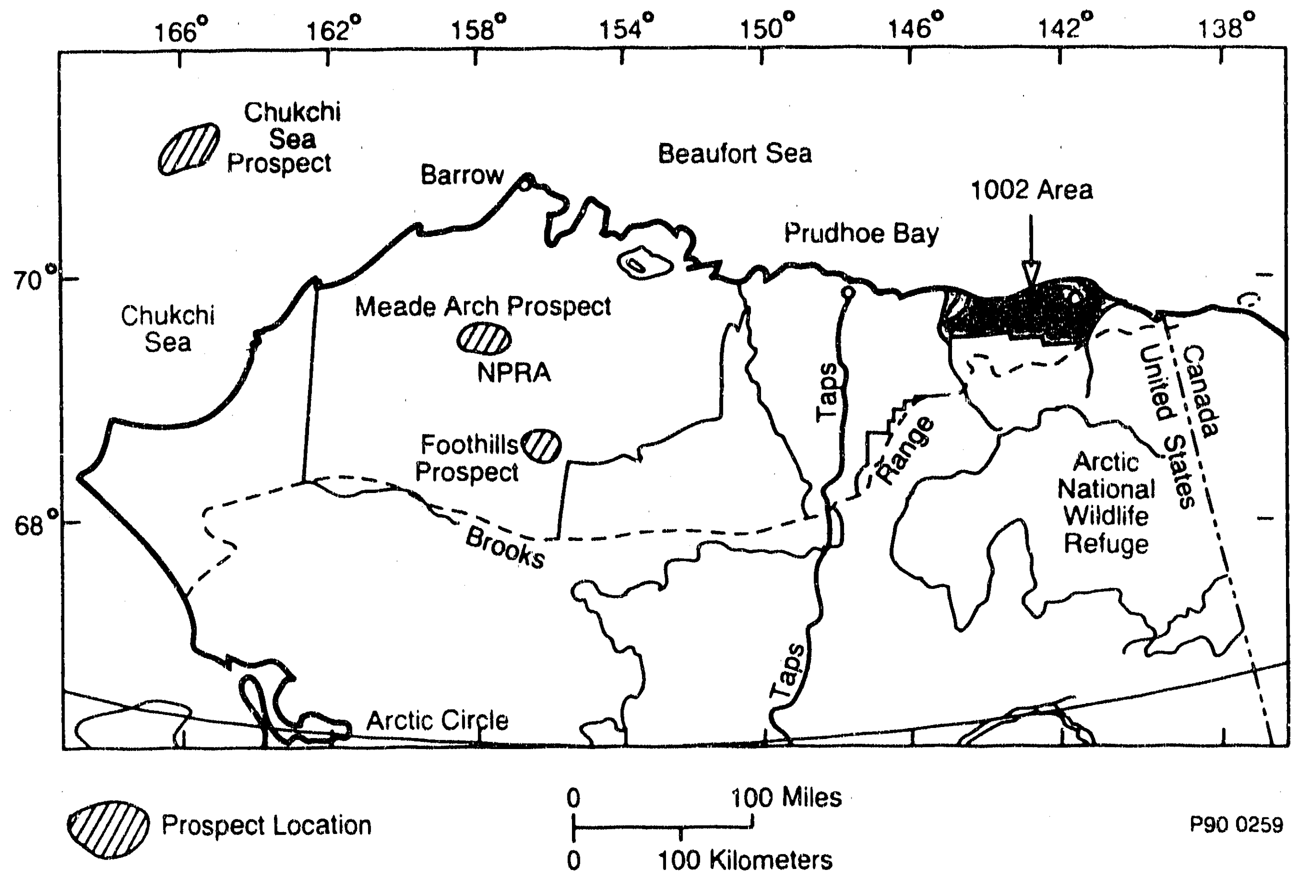

Figure 3-16. Chukchi Sea and NPRA - Assumed Prospect Locations.

3.5.6.1 ANWR. The ANWR stand-alone fields and the multiple small fields, would extend the life of TAPS by 2 to 3 years and increase reserves for the Most Likely Case and Known Undeveloped Fields by a maximum of 370 MMBO. The ANWR multiple small fields rate and remaining reserves effects are shown in **Figure 3-17** and **3-18**, respectively. The composite production rates for this case are in **Appendix A, Table A-4**.

3.5.6.2 Chukchi Sea and NPRA. The stand-alone prospect for the Chukchi Sea has about four times the recoverable reserves as the ANWR multiple small fields. More significant than the ANWR scenario, the Chukchi Sea prospect plus the two NPRA prospects with their greater reserves, higher producing rates, and longer life, extend the TAPS operating life by 11 years and increase reserves for the Most Likely Case and Known Undeveloped Fields by about 600 MMBO. The production rate effect for the Chukchi Sea and NPRA is shown on **Figure 3-19**. The remaining reserves for these prospects are shown on **Figure 3-20**. The composite production rates for this case are in **Appendix A, Table A-5**.

3.6 Discussion of Potential High Recovery Developments

Both ANWR and Chukchi Sea exploration provinces are believed to have potential for accumulations of much greaer size than those resulting from the MEFS evaluations described in **Section 3.5.5**. (see **Section 2.4.1**)

3.6.1 ANWR.

Four prospects in ANWR were selected to illustrate a high recovery case. These prospects are indicated to have sufficient areal extent, closure, and reservoir quality rock to contain larger volumes then originally calculated.[59] These prospects, which can be located in **Figure 3-15** are No's. 5, 19, 20, and 21. The recoverable oil volumes determined for these prospects are:

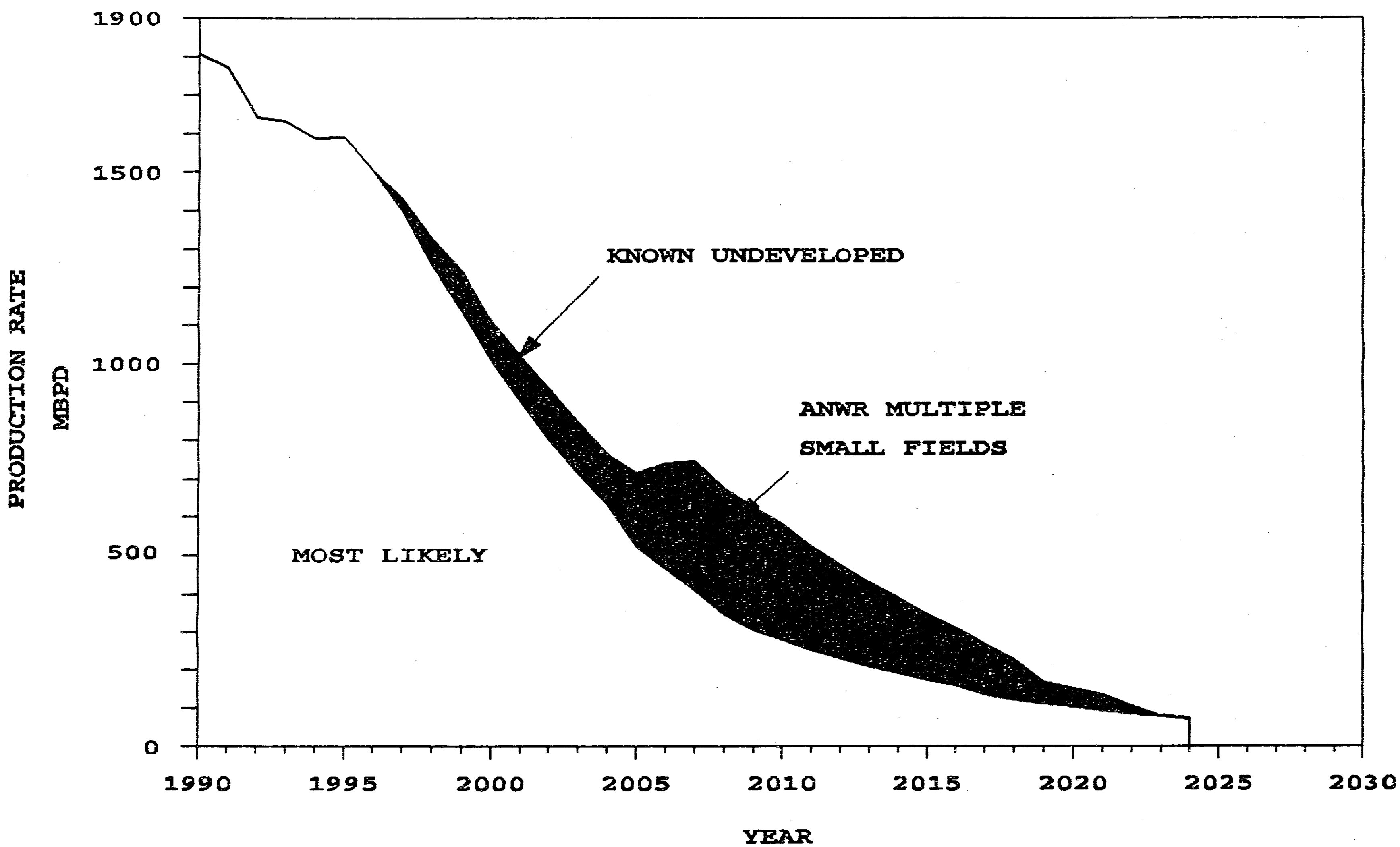

Figure 3-17. Composite North Slope Plus Multiple Small Fields in ANWR - Production Rate Versus Time.

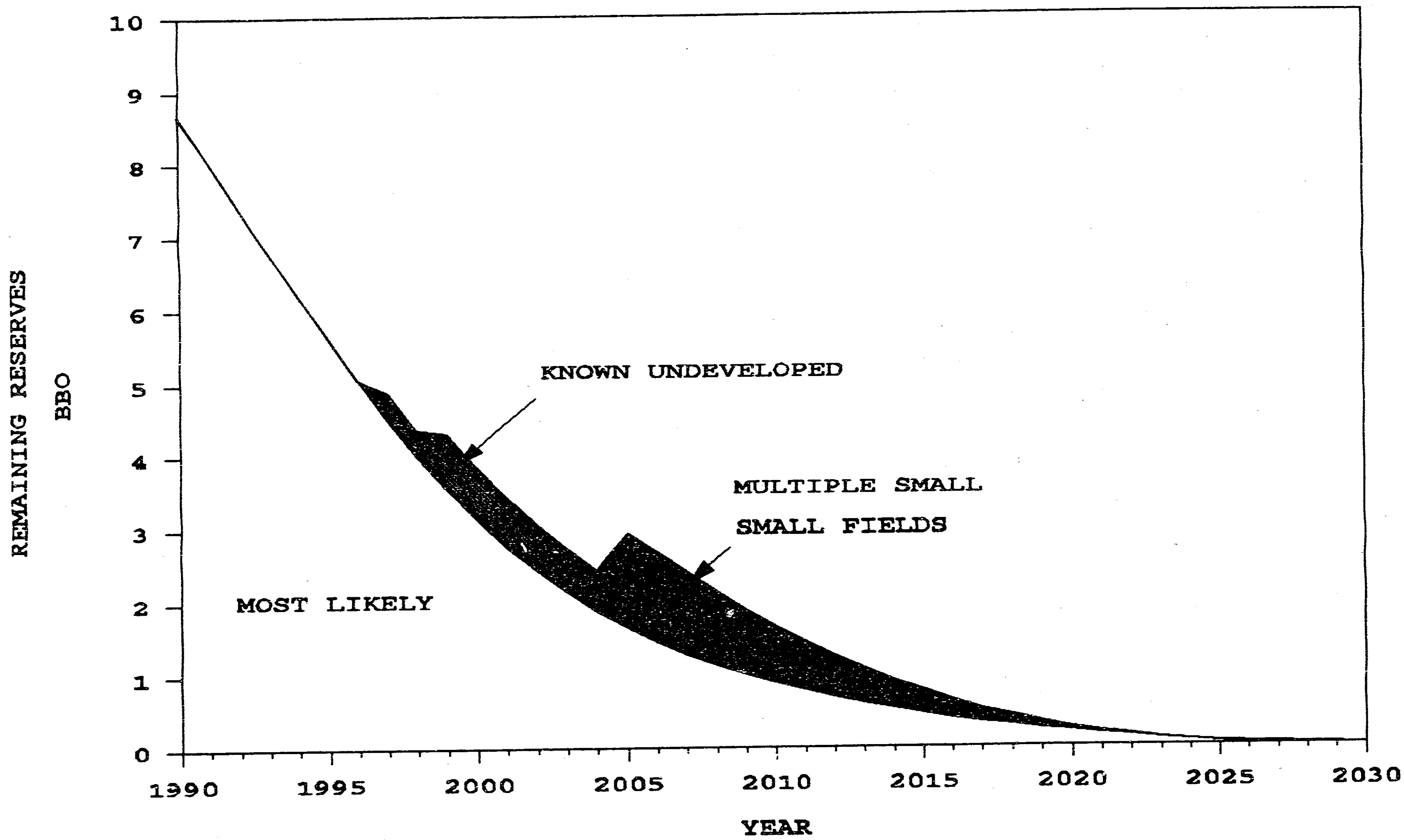

Figure 3-18. Composite North Slope Plus Multiple Small Fields in ANWR - Remaining Reserves Versus Time.

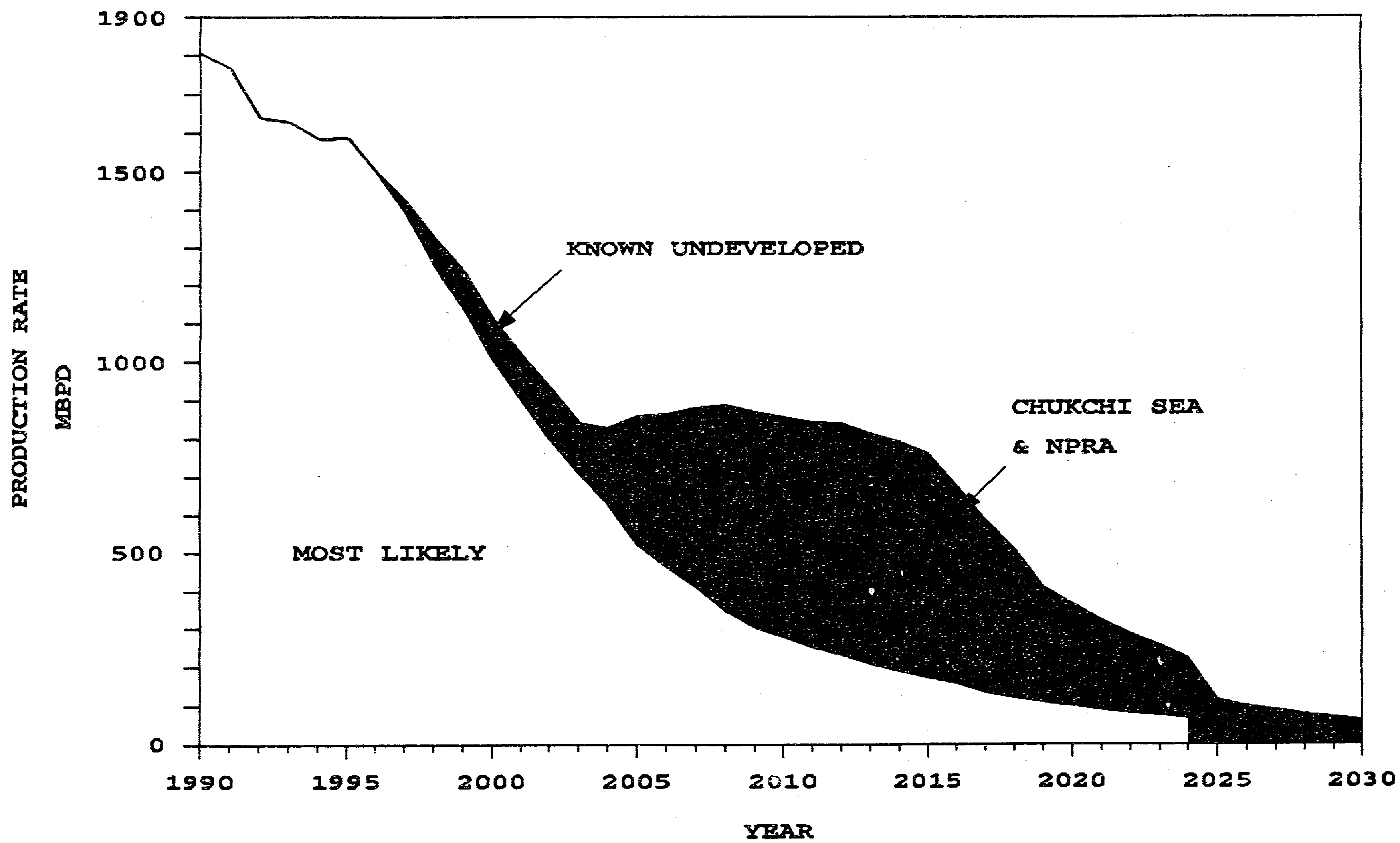

Figure 3-19. Composite North Slope Plus Chukchi Sea Stand-Alone and NPRA - Production Rate Versus Time.

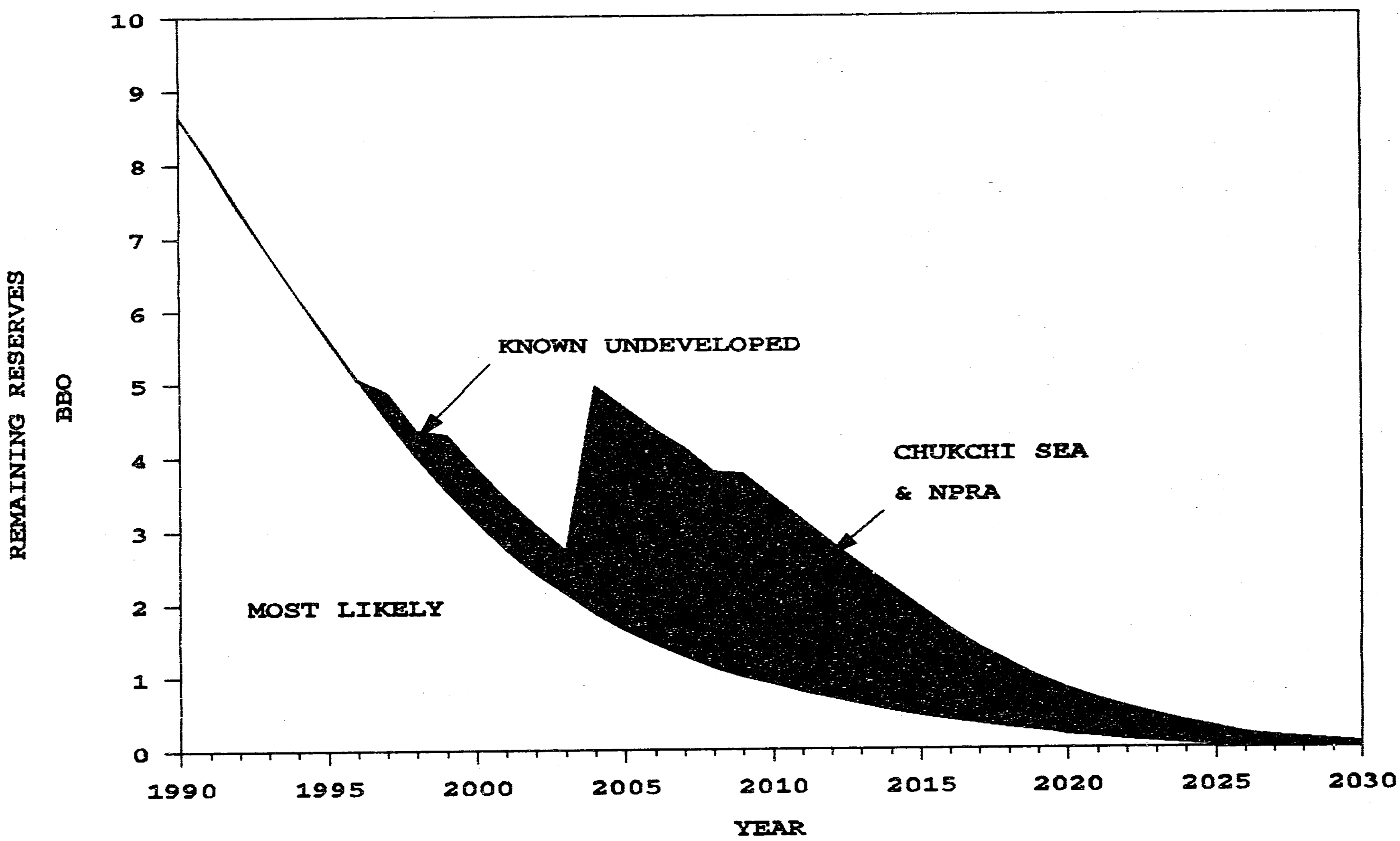

Figure 3-20. Composite North Slope Plus Stand-Alone Chukchi Sea and NPRA - Remaining Reserves Versus Time.

Prospect		BBO
5		0.95
19		2.90
20		1.35
21		1.15
	TOTAL	6.35

Using the economic analysis parameters in **Table 3-19**, the economically recoverable reserves that were determined are:

Prospect		BBO
5		0.94
19		2.85
20		1.33
21		1.13
	TOTAL	6.25

Figure 3-21 shows the production rate effect for this high recovery case. The remaining reserves for these fields are shown in **Figure 3-22.** This ANWR multiple high recovery scenario would extend the operating life of TAPS by about 10 years and increase reserves for the Most Likely Case and Known Undeveloped fields by about 575 MMBO. The composite production rates for the case are in **Appendix A, Table A-6.**

3.6.2 Chukchi Sea.

With the possibility of future giant or super giant discoveries being made in this geologic province, an accumulation containing 7.25 BBO of recoverable oil was shosen for evaluation. This case shows the effect of a near-Prudhoe Bay size field on operations of then-producing fields and TAPS. Using the economic analysis parameters in **Table 3-19**, the economically recoverable reserves are 6.93 BBO.

A Chukchi Sea field of this size would extend the operating life of TAPS by about 13 years and increase reserves for the Most Likely Case and Known

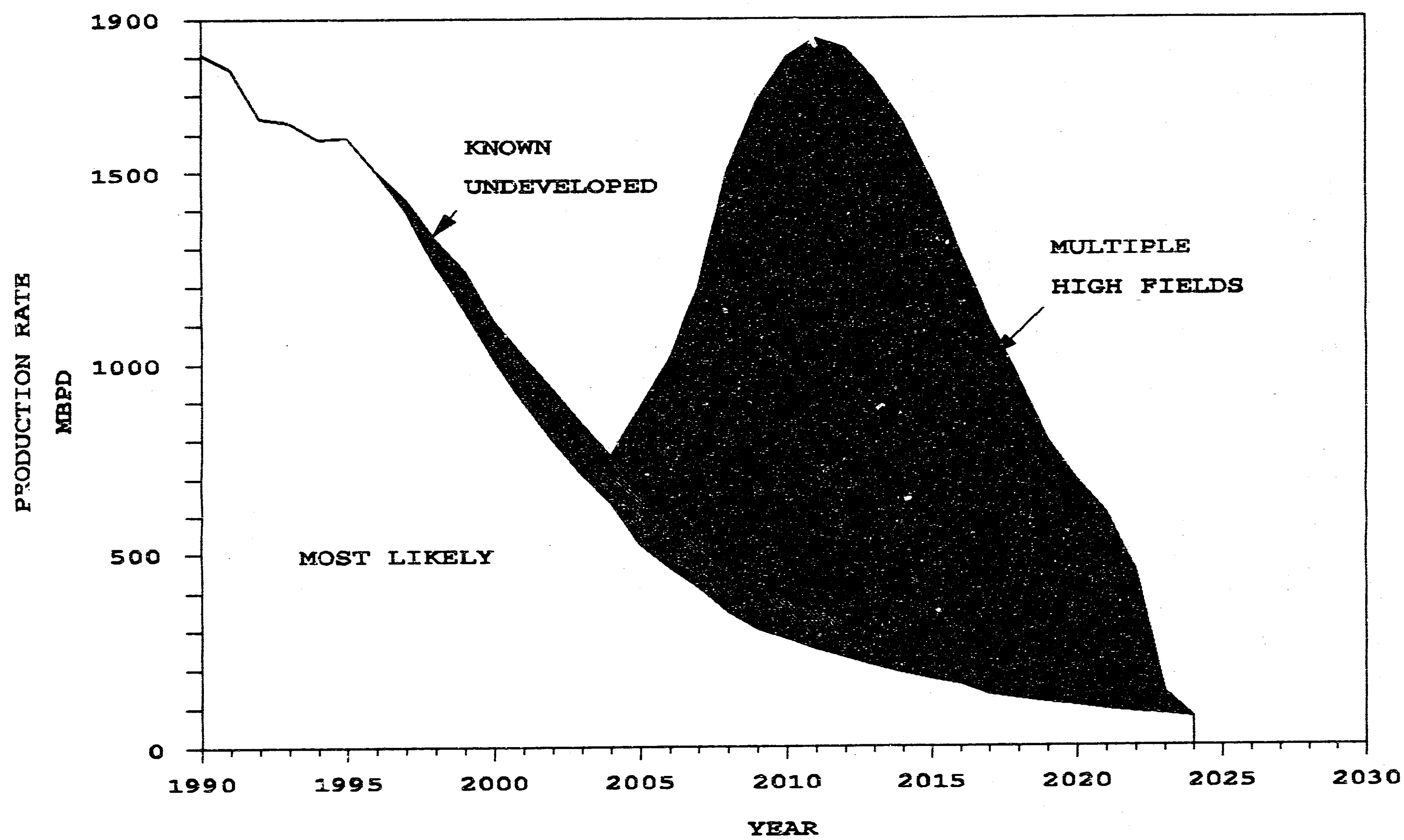

Figure 3-21. Composite North Slope Plus ANWR Multiple Field High - Production Rate Versus Time.

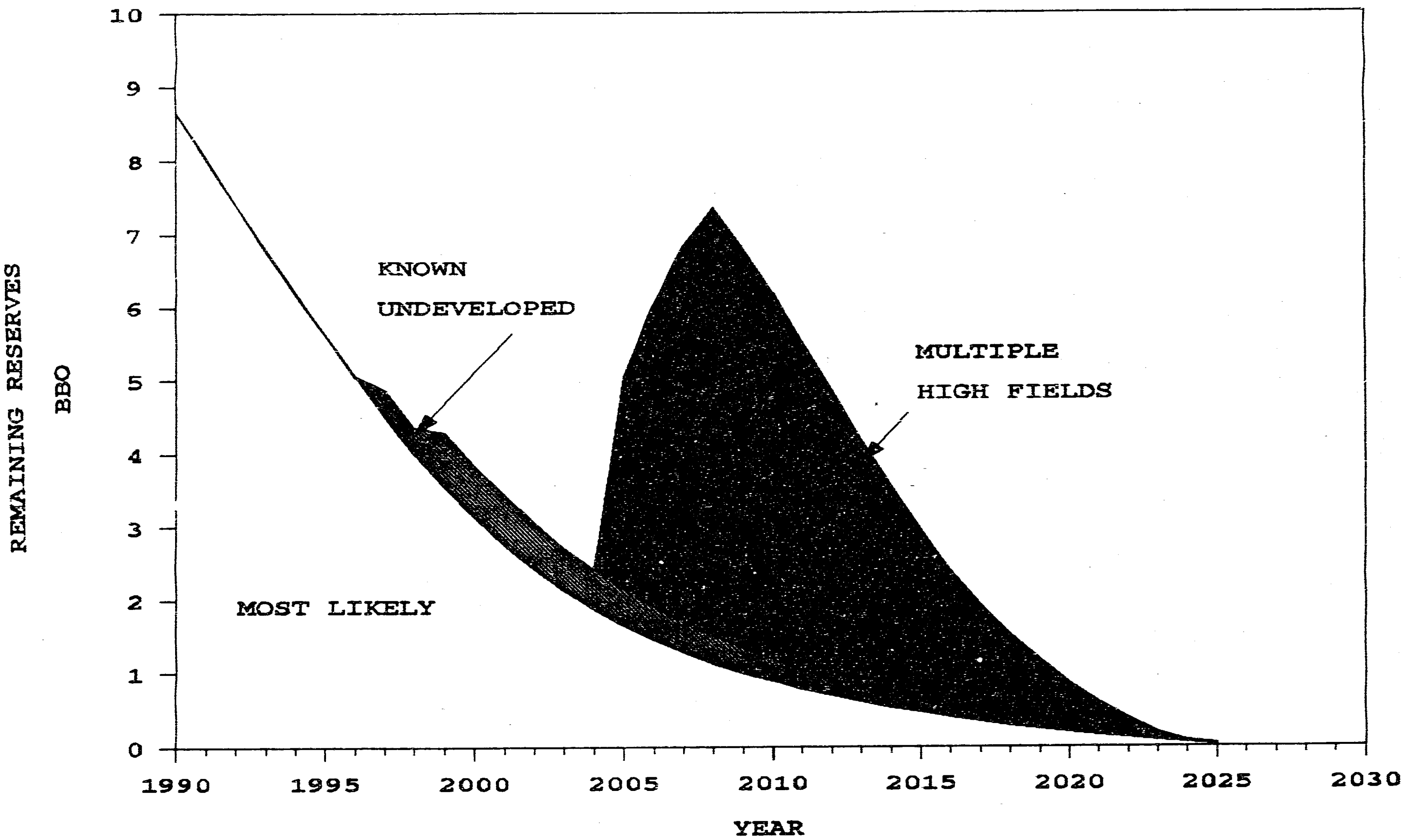

Figure 3-22. Composite North Slope Plus ANWR Multiple High - Remaining Reserves Versus Time.

Undeveloped fields about 700 MMBO. **Figure 3-23** shows the effect of the production from such a prospect. The remaining reserves for such a prospect are shown in **Figure 3-24.** The composite production rates for this case are in **Appendix A, Table A-7.**

3.6.3 Timing and Effect of Future Discoveries.

North Slope production is declining and the evidence is overwhelming that future plans of the field owners will only be successful in slowing the decline rates for short periods, even with the development of known nonproducing fields. At present, TAPS has excess capacity (assuming utilization of DRA) of about 300 MBPD. Under the producing rate projections in the Most Likely Case, the excess capacity will increase to about 1.3 MMBPD by the year 2000. **Figure 3-25** shows the growth of excess TAPS capacity under the Most Likely Case scenario. For a minimum TAPS operating rate of 300 MBPD, pipeline shutdown will occur in 2009 for this case.

Also shown in **Figure 3-25** is the indicated maximum TAPS throughput volume of 2.5 MMBPD if required mechanical modifications are made and the use of DRA is continued.

3.6.4 Conclusions.

Review of **Figures 3-17** through **3-25** shows:

- The development of small known fields or discovery of additional small fields whether onshore or offshore will not have a significant impact on productive life of the North Slope fields unless the total number of fields is quite large - on the order of 15 to 20.

- Only the discovery of several large fields in ANWR or in the Chukchi Sea will significantly extend the life of TAPS, the Prudhoe Bay area, and any new fields developed on or after the year 2000.

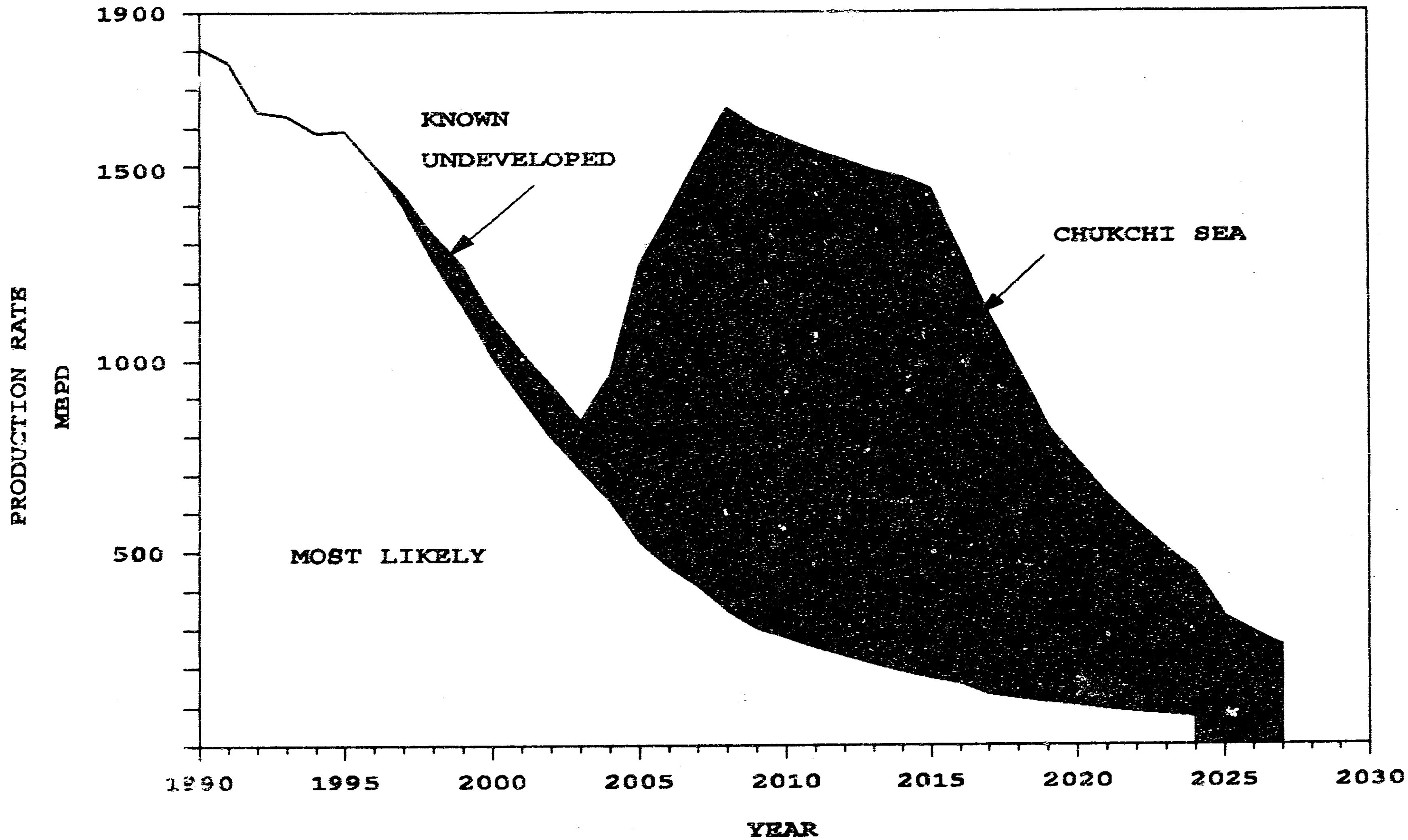

Figure 3-23. Composite North Slope Plus Chukchi Sea Super Giant - Production Rate Versus Time.

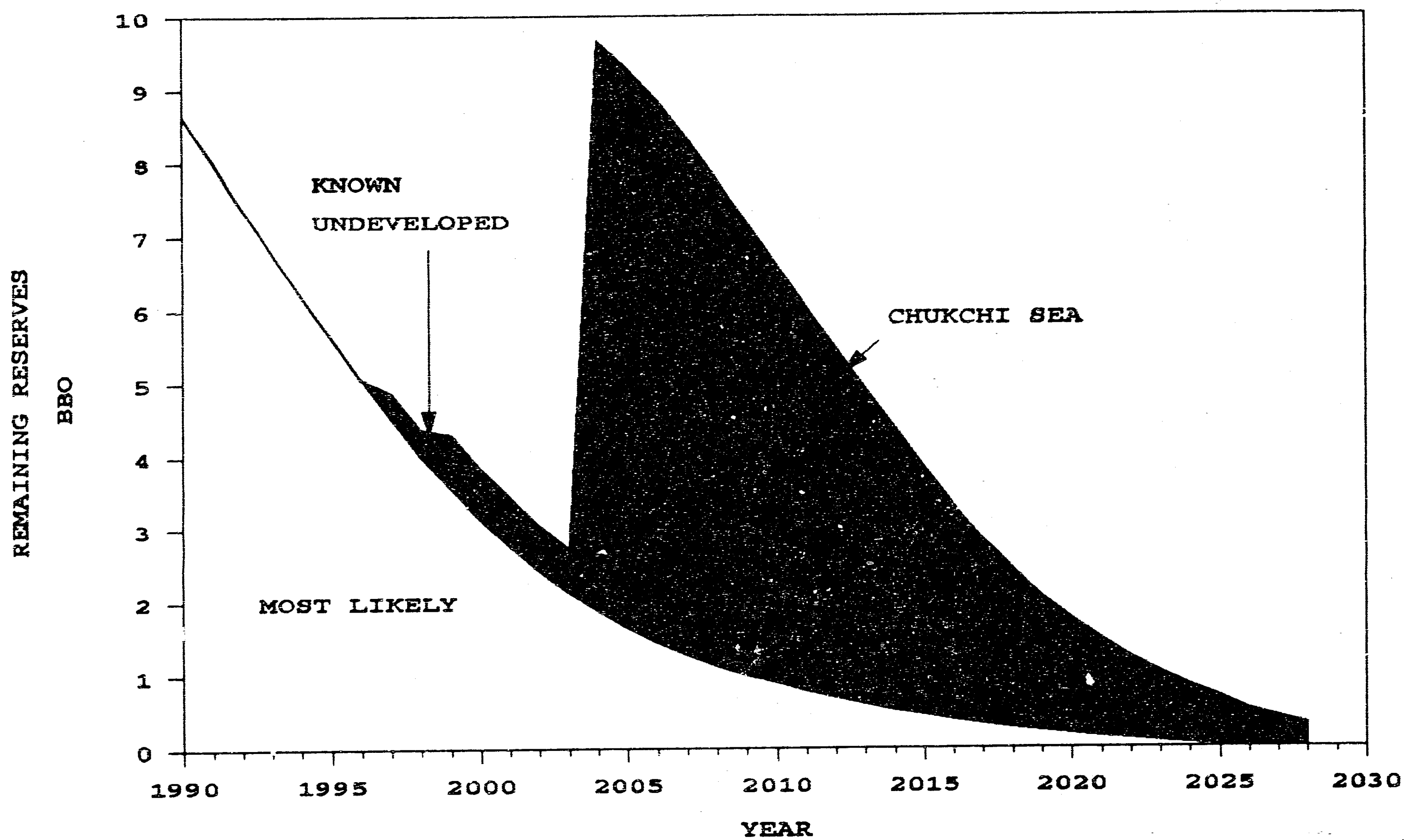

Figure 3-24. Composite North Slope Plus Chukchi Sea Super Giant - Remaining Reserves Versus Time.

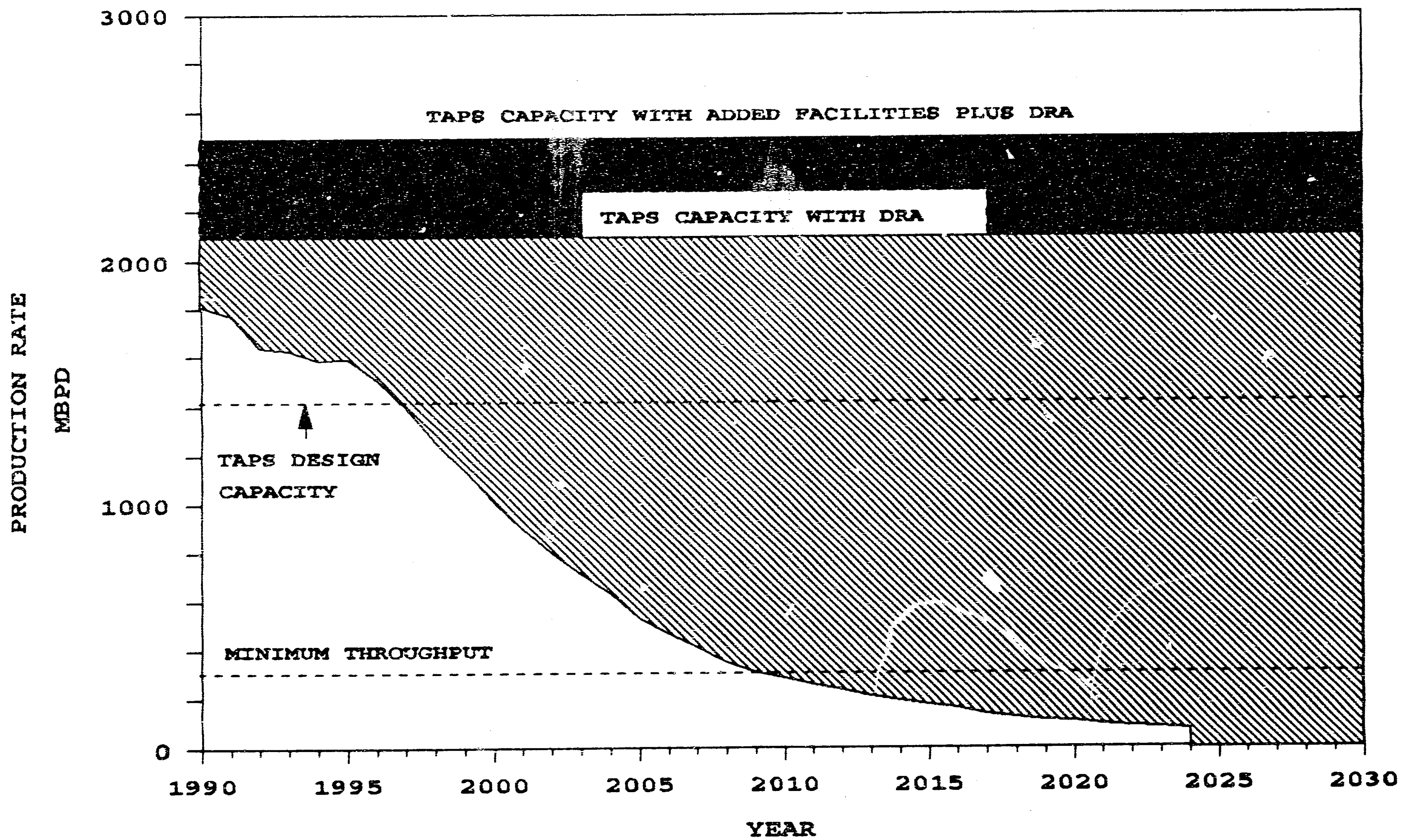

Figure 3-25. Trans Alaska Pipeline System Capacity With Most Likely Case Production.

- Delays in exploring for and developing new discoveries can result in large volumes of unrecovered economically producible reserves due to a shutdown of TAPS. TAPS minimum throughput of 300 MBPD equates to over 100 MMBO/year.

3.7 Economic Model

A commercially available financial software package[a] was used to develop the Alaska economic study model. This software allows the easy creation of a financial model and has extensive features for querying the model, construction of "what if" scenarios, goal seeking features, and flexible reporting and graphics ability.

3.7.1 Model Description

A discounted cash flow model was used to evaluate the historical and projected economics of the arctic Alaska oil resource. The model was constructed so that the appropriate level of detail for the various producing, known undeveloped, and undiscovered resource scenarios could be used depending on the available information. Of primary interest in this study was the determination of the economic limit for each case considered. The economic limit is defined as the point in time after payback when the operating cash flow goes negative. This is in contrast to operating a field until all the recoverable oil is produced. Producing fields and known undeveloped fields use historical and projected production and investment schedules reflecting the information known about these fields. Undiscovered resource economics used a series of relationships between the original oil-in-place, production schedules, investments, investment timing, and operating costs similar to the Young and Hauser study.[26]

The geologic, geophysical, and lease acquisition costs are assumed to be sunk costs, and are excluded from economic calculations. All operating losses

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a. Interactive Financial Planning System (IFPS), EXECUCOM. *The use of a commercial product neither implies endorsement or recommendation.*

are assumed to be used to offset the operator's taxable income in other operations, and no depletion allowance is used. Inflation and discounting is calculated at the mid-year. All capital was assumed to be 100% equity with no debt financing or leverage.

3.7.2 Resource Parameters.

The OOIP and ultimate recovery factors are primary inputs. Oil production from this resource base is accomplished in several ways:

- Historical and projected production schedules can be directly entered into the model
- Undiscovered resource production schedules were extrapolated from a peak production rate followed by an exponential decline as discussed in Section 3.3.2
- The build-up to peak production rate and the length of time of peak production are variables in the model.

A percent water cut versus percent predicted ultimate recovery relationship was used to calculate water production. The water and oil production were summed to give total fluid production. This feature is used to calculate operating costs on a per barrel fluid lifted basis.

The productive area and base well spacing (160 acres) are entered to calculate the total number of development wells to be drilled. Producing wells as a percentage of total wells was entered. As a field nears depletion, the number of active producers is reduced as a function of recovery. This procedure closely mirrors the late life operations of a producing field. The average well rate was calculated by the total field production rate divided by the number of active producers. Oil production terminates when the specified reserves are depleted.

3.7.3 Capital Investments.

Project investments include exploration, delineation, and development well costs; production facilities; and offshore production platforms where applicable. All investment costs are input as 1990 dollars and inflated to then current dollars using the applicable inflation category:

- Historical and projected well costs, counts, and timing are directly entered for the producing and known undeveloped fields.
- Well costs for undiscovered resources are related to a series of cost versus depth curves for the exploration and development wells. Delineation wells are assumed to cost the same as development wells. Development well costs are reduced with time to approximate the gaining of experience and optimization of drilling practice during field development.
- Historical and projected facilities costs are directly entered.
- Undiscovered resource facilities are determined on a cost per peak barrel of oil production. Onshore facilities cost was determined in **Section 3.2.2.2** to cost $14,200 per peak barrel of oil production, on January 1, 1990.
- Offshore production platforms are directly entered for all cases.

3.7.3.1 Costs. Tangible costs are assumed to be 100% of production facilities and platform investments, 30% of development well costs, and 10% of exploration and delineation well costs.

3.7.3.2. Timing. Undiscovered resource investment timing was related to the assumed first year of production with exploration, delineation, and development drilling occurring a specified number of years prior to the first production. The actual scheduling of the exploration, delineation, and development drilling programs is determined by institutional, regulatory, and environmental constraints and can be varied in the economic model.

3.7.4 Operating Costs.

The total field operating costs are calculated on a cost per barrel of fluid lifted basis. As discussed in **Section 3.2.3**, the historical total operating cost for the different fields was expressed as a function of total fluid production. The historical and known undeveloped operating cost per total fluid lifted was directly entered and inflated at general inflation. The undiscovered resource cases use the relationship derived above to estimate yearly operating cost as a function of total daily fluid lifted.

A percent water cut versus percent of ultimate predicted recovery relationship was used to estimate water production (**Section 3.2.3.1**). Historical reservoir water cut performance was extrapolated for the projected cases using the actual reported production history, while the undiscovered cases used an analogous water cut curve based on the estimated size of the resource and type of expected producing formation. The oil production rate and recovery at any point in time is used to calculate the water production. The oil production rate and water production rate are summed for total fluid production rate. This approach differs from previous studies, but is considered an improvement as it incorporates historical and expected reservoir performance in the determination of operating cost.

3.7.5 Oil Price.

The base oil prices used were the National Energy Strategy Reference Case, expressed in 1989 dollars.[43] The base oil price was inflated at the general inflation rate to calculate the then current year base oil price. Additional adjustments are made for marine tanker transportation charges, TAPS tariff, field tariff, and API gravity price adjustments. The net result was a wellhead price per barrel in then current year dollars. The initial marine tanker transportation cost and field tariff are entered in 1990 dollars and adjusted by transportation inflation. The TAPS tariff schedule was calculated independent of the economic model to reflect the projected TAPS throughput rate for the various scenarios studied, entered on a yearly basis in 1990 dollars, and adjusted by transportation inflation.

3.7.6 Inflation Adjustment.

All costs are inflated to then current dollars from a 1990 base using a mid-year inflation. Four types of inflation can be used:

- General inflation, that was assumed to be related to the Gross National Product implicit price deflator
- A transportation inflation factor
- A drilling inflation factor
- An oil inflation factor which consisted of general inflation plus real oil price growth.

A future inflation rate of 3.5% for general, transportation, and drilling inflation factors, and zero for real oil price inflation were assumed. The historical annual percent change in the GNP price deflator is presented in **Figure 3-26**. The average for the years 1983 to 1989 is 3.36%. The projected rate is slightly greater than this value. Sensitivity runs to the inflation rate were made.

3.7.7 Royalty.

Royalty was calculated by multiplying the royalty rate for a specific field by the gross wellhead revenue. The royalty rate ranges from 12.5 to 18.0%, depending on the field. Royalty oil processing fees are paid by the state to the Unit Owners for treating the state's royalty oil to meet pipeline specifications. The processing fee is deducted from the royalty.

3.7.8 Tax Calculations

The determination of the undepreciated state and federal balances and property tax base was required to estimate future income for the currently producing fields. A historical case was run for Prudhoe Bay, Kuparuk River, Lisburne, Endicott, and Milne Point using the best available information for historical and announced investment schedules, amounts and categories. The historical runs were made to the year 1993 to provide an overlap for the forecast models. Year-end 1989 federal undepreciated balances as calculated in the historical runs were added to the depreciation for new investments starting in 1990. The year-end 1989 undepreciated balance was depreciated for

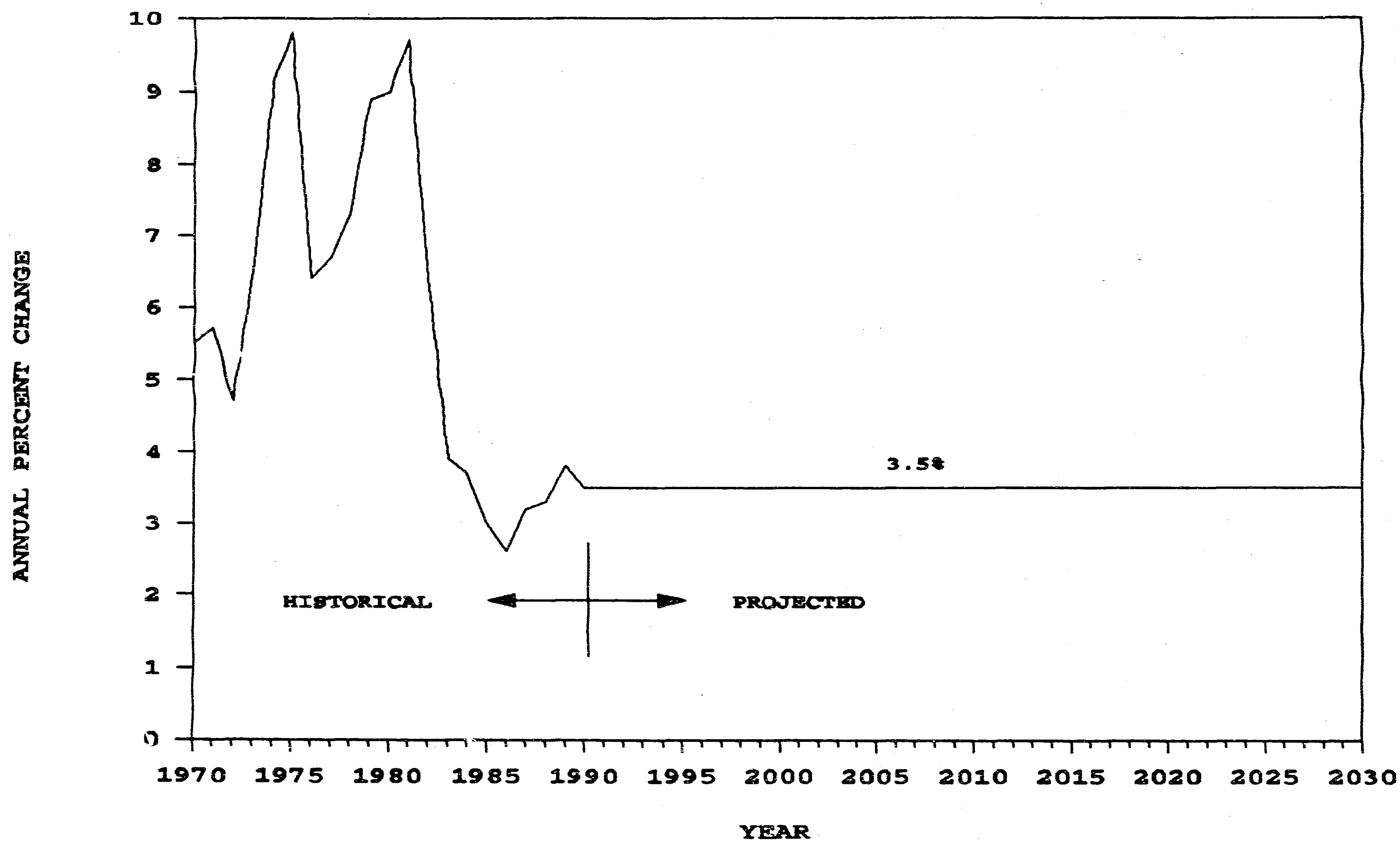

Figure 3-26 Historical Annual Percent Change in the Gross National Product Price Deflator.

various time lengths to provide the best match of the 1990 to 1993 historical overlap time periods. While not exactly matching the historical depreciation schedule, the total values were in very good agreement. There is a minor affect for the first 3 to 4 years of the forecast economic runs. Unamortized intangible drilling cost (IDC) balances were treated in a similar fashion.

3.7.8.1 State of Alaska Taxes. A major improvement in this model relative to previous studies is the incorporation of Alaska tax law for the treatment of state depreciation, property tax, severance tax with an economic limit factor (ELF), conservation tax and surtax, royalty processing fees, and state income tax. State taxes are calculated before federal income tax and are a deduction in determining federal taxable income.

3.7.8.1.1 Depreciation--The State of Alaska calculates depreciation on a units of production basis, on the total investment, (tangible and intangible), and only after the asset has been placed in service. A units of production depreciation factor was calculated using the yearly production divided by the current year's remaining reserves. The depreciable basis is the cumulative total investment less cumulative depreciation. The state depreciation is the product of the state depreciation factor and the depreciation basis. This amount is deducted as a non-cash expense.

3.7.8.1.2 Property Tax--The state property tax base is calculated using the inflation adjusted cumulative tangible investment, less the previous year's property tax base divided by the remaining project life. This value is adjusted by the general inflation rate, plus any additional tangible investment. The property tax (or ad valorum) is 2% of the current year property tax base.

3.7.8.1.3 Severance Tax--The state severance tax is calculated at 12.25% of the net wellhead value for the first 5 years of production and 15% thereafter multiplied by the economic limit factor (ELF) with a minimum tax of $0.80 (unescalated) per net barrel of production. Net production is defined as oil production less royalty. The ELF calculation used is the post-1989 formula, which is:

$$ELF = [1 - 300/\text{Daily Average Well Rate}]^x$$

where

$$x = [150{,}000/\text{Average Daily Field Rate}]^{1.5333}.$$

3.7.8.1.4 Conservation Tax--The conservation tax rate is $0.004 per barrel of net production and the conservation surtax, enacted after the <u>EXXON Valdez</u>, is $.05 per barrel of net production.

3.7.8.1.5 Income Tax Calculation--The state income tax rate is calculated as follows:

$$9.4\% * 1/3 * \left[\frac{\text{Alaska Sales}}{\text{Worldwide Sales}} + \frac{\text{Alaska Production}}{\text{Worldwide Production}} + \frac{\text{Alaska Assets}}{\text{Worldwide Assets}}\right]$$

Because it is difficult to independently determine any company's worldwide sales, production, and assets, a nominal effective state tax rate of 3% was used. This value compares favorably with the implicit effective rate from Deakin.[27] An effective rate of 1.5 to 3% is used by the Department of Revenue for revenue forecasting.[46]

The state income tax is calculated as follows:

- <u>Net Revenue</u> = Gross Revenue - (Royalty - Processing Fee)
- <u>Net Before State Income Tax</u> = Net Revenue - Total Operating Cost - Severance Tax - Conservation Tax - Conservation Surtax - State Property Tax - State Depreciation
- <u>Net After State Income Tax</u> = Net Before State Income Tax - State Income Tax + State Depreciation.

The state depreciation is added back for the calculation of federal taxes.

3.7.8.2 Federal Taxes. Federal income taxes are calculated after the state of Alaska tax calculations, with state taxes treated as a deduction from federal income. The federal income calculations involve the treatment of intangible drilling costs, depreciation, and federal income tax.

3.7.8.2.1 Federal Amortization of Intangible Drilling Costs· Federal tax law allows expensing and amortization of intangible drilling costs (IDC) and permits a more favorable treatment of depreciation. Current tax law permits 70% of the intangible drilling costs to be expensed in the year incurred and the balance amortized over 60 months. The model assumes that intangible drilling costs are 90% of exploration and delineation well costs and 70% of development well costs.

3.7.8.2.2 Federal Depreciation--Federal depreciation was calculated using a 7 year, 150% declining balance of the tangible investment with no switchover. This method is consistent with the approach used by the State of Alaska Department of Revenue. The tangible assets are assumed to have no salvage value at the end of the project. Federal law allows the choice of depreciation methods such as Accelerated Cost Recovery System (ACRS), straight line, declining balance, units of production, and sum-of-the-years digits with a switchover before the end of the depreciation life. No depletion allowance was used for the recovery of exploration and lease acquisition costs.

3.7.8.2.3 Federal Income Tax Calculation--The federal income tax rate is 34% of the federal taxable income. The non-cash deductions are added back to net income for the determination of cash flow.

The federal income tax, net income, and cash flow are calculated as follows:

- Net Income Before Federal Income Tax = Net After State Income Tax - Expensed IDC - Amortized IDC - Federal Depreciation
- Net Income = Net Income Before Federal Income Tax - Federal Income Tax
- Cash Flow = Net Income + Federal Depreciation + Amortized IDC - Tangible Investment.

3.7.9 Economic Determination

The yearly cash flow, as determined in Section 3.7.8.8.3, was discounted to determine the present value of the future cash flow. The economic limit is defined as the year cash flow is negative (after payout of the project). The most likely cases used a 10% nominal discount rate, while the known undeveloped and undiscovered resource cases used a 15% nominal discount rate to reflect the greater risk of these projects. The real discount rate is related to the nominal discount rate by the following equation from Stermole.[60]

$$[1/(1+i_n)]^n = [1/(1+f)]^n \times [1/(1+i_r)]^n$$

where

n = time periods
i_n = nominal discount rate
f = inflation rate
i_r = real discount rate.

With an inflation rate of 3.5% and a 30 year time period, the real discount rate for a nominal discount rate of 10 and 15% is 6.28 and 11.1%, respectively. The actual real discount rate for any specific project depends on the project life.

The yearly present values are summed to determine the cumulative net present value of each case considered. The model does not directly calculate the internal rate of return (IRR), but the IRR can be determined by solving for the discount rate that results in a cumulative net present value of zero at the end of the project.

Various sensitivity runs were made with the forecast model to determine the impact on the discounted cash flow and the economic limit. The results were plotted on a spider-plot to illustrate graphically the sensitivity of the various sensitivity variables. The results show the greatest sensitivity is to oil price.

3.7.10 Model Validation

The economic model was compared and validated with the Young and Hauser[26] and the Deakin[27] studies. While it was not intended to incorporate past tax law in the model, certain features were modified and included for comparison only. The Windfall Profits Tax was not made a part of the model. For validation, the following variables were included;

- Then current state and federal income tax rates
- Federal depreciation using ACRS
- More favorable tax treatment of IDC allowing 85% expensed and the balance amortized over 36 months
- A more favorable state ELF formula
- Actual GNP price deflators.

3.7.10.1 Young and Hauser Study[26]

The Young and Hauser study was evaluated by using the same inputs in the model, except that Young and Hauser did not separately calculate Alaska state income tax. The state tax rate was merged with the federal rate for an effective composite income tax rate. The transportation costs calculated in the Young and Hauser study were directly entered for the validation case. The results of the validation were within 5% of the Young and Hauser study. The differences are in reading values from graphs, interpolation errors, and in methods of calculating future operating expenses. The validation demonstrated the economic model was working satisfactorily and gave increased confidence in the results.

3.7.10.2 Deakin Study.[27] The Deakin study reviewed the oil industry profitability in Alaska from the years 1969 through 1987. The profit estimates were developed from publicly available information and a picture of Alaskan oil industry operations was presented. Results for the later years are more consistent than the earlier years. This is possibly a reflection of separate reporting of Alaskan production operations in annual reports in the later years.

As noted in **Section 3.7.10**, the calculation of Windfall Profits Tax was not included in this model, so comparison with Deakin for years prior to 1986 was not meaningful. A Prudhoe Bay model run compared favorably with Deakin's 1987 results for most of the income statement categories. A comparison of the calculated data is presented in **Table 3-20.**

Table 3-20. 1987 Prudhoe Bay Unit Data Comparison ($MM)

Deakin		This study	
Production Revenue	6573	Gross Revenue	6363
Depreciation	1074	Federal Depreciation	939
Operating Expenses	740	Total Operating Costs	737
Overhead	109	State Depreciation	107
Interest	146	Conservation Taxes	2
Royalty	787	Royalty	795
Severance Taxes	787	Severance Taxes	690
Property Taxes	150	Property Taxes	334
State Income Taxes	83	State Income Taxes	82
Federal Income Taxes	917	Federal Income Taxes	919
Profit	1780	Net Income	1783

The largest difference in the two statements is in property tax paid. This would result from smaller investment costs used in Deakin's study. All other directly comparable items are in good agreement.

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Appendix A

The following tables give the production rate schedules for the fields and cases analyzed in **Section 3**.

Table A-1. Yearly Average Field Production Rates for Most Likely Case (Values in parentheses are beyond the economic limit)

YR	PRUDHOE BAY UNIT PRODUCTION RATE (MBPD)	KUPARUK PRODUCTION RATE (MBPD)	ENDICOTT PRODUCTION RATE (MBPD)	LISBURNE PRODUCTION RATE (MBPD)	MILNE PT PRODUCTION RATE (MBPD)	NIAKUK PRODUCTION RATE (MBPD)	PT MCINTYRE PRODUCTION RATE (MBPD)
1990	1331.5	304.5	100.00	40.0	30	0	0
1991	1290.4	314.7	100.00	40.0	25	0	0
1992	1169.9	324.8	85.00	40.0	20	0	0
1993	1120.5	351.9	75.00	40.0	16	5	20
1994	1071.2	351.9	70.00	40.0	13	19	60
1995	1046.6	351.9	65.00	37.0	10	19	60
1996	997.3	324.8	60.00	34.0	8	19	60
1997	901.4	324.8	55.00	31.0	7	18	59
1998	802.7	294.4	50.00	28.0	6	15	58
1999	731.5	263.9	45.00	25.0	5	12	56
2000	665.8	216.4	40.00	20.9	(5)	10	53
2001	608.2	177.5	34.00	18.0	(5)	9	49
2002	553.4	145.5	29.00	15.2	0	7	44
2003	506.8	119.3	24.00	12.3		6	40
2004	460.3	97.8	20.25	9.5		5	36
2005	407.5	76.7	0	(5.2)		5	33
2006	372.9	54.8		0		4	29
2007	340.9	38.1				4	26
2008	309.0	14.5				(1)	23
2009	282.3	0				0	21
2010	258.4	0					19
2011	234.4	0					17
2012	215.7						15
2013	194.4						14
2014	178.5						12
2015	162.4						11
2016	149.1						(7)
2017	135.8						0
2018	122.5						
2019	111.9						
2020	103.8						
2021	93.2						
2022	85.3						
2023	79.9						
2024	72.0						
2025	(55)						
2026	(38)						
2027	(19)						

Table A-2. Composite Production Rates for Reference, Most Likely, and High Cases
(Values in parentheses are beyond the economic limit)

YR	REFERENCE CASE PRODUCTION RATE (MBPD)	MOST LIKELY CASE PRODUCTION RATE (MBPD)	HIGH RESERVES CASE PRODUCTION RATE (MBPD)
1989	--	--	--
1990	1801	1806.0	1823.5
1991	1661	1770.1	1787.0
1992	1487	1639.7	1714.6
1993	1360	1628.4	1666.8
1994	1240	1585.1	1630.3
1995	1139	1589.5	1608.8
1996	1036	1503.1	1566.1
1997	939	1397.2	1525.1
1998	852	1255.1	1409.1
1999	769	1140.4	1278.6
2000	669	1009.1	1158.5
2001	591	899.7	1033.0
2002	517	799.1	920.4
2003	457	712.4	819.7
2004	403	632.8	732.0
2005	356	525.2	621.2
2006	309	464.7	559.1
2007	267	412.0	497.2
2008	230	349.5	443.0
2009	197	305.3	364.3
2010	163	279.4	333.3
2011	110	253.4	304.7
2012	93	232.7	278.4
2013	71	209.4	254.1
2014	55	192.5	232.8
2015	(38)	174.4	212.1
2016	(19)	160.1	194.1
2017	0	135.8	166.5
2018		122.5	152.4
2019		111.9	139.4
2020		103.8	127.5
2021		93.2	116.7
2022		85.3	106.8
2023		79.9	97.7
2024		72.0	89.4
2025		(55.0)	(81.8)
2026		(38.0)	(74.8)
2027		(19.0)	(41.7)

Table A-3. Composite North Slope Production Rates (Most likely Case plus Known Undeveloped Case)
(Values in parentheses are beyond the economic limit)

YR	KNOWN UNDEVELOPED PRODUCTION RATE (MBPD)
1989	0
1990	0
1991	0
1992	0
1993	0
1994	0
1995	0
1996	0
1997	29.67
1998	69.21
1999	99.63
2000	102.26
2001	121.01
2002	133.66
2003	130.95
2004	127.84
2005	124.54
2006	121.27
2007	113.77
2008	107.37
2009	101.90
2110	97.23
2011	93.23
2012	89.81
2013	86.91
2014	84.40
2015	74.11
2016	67.94
2017	59.94
2018	42.56
2019	(29.01)
2020	(18.44)
2021	(10.16)
2022	(3.68)
2023	0

Table A-4. Composite North Slope Production Rates ANWR Multiple Small Fields

ANWR MULTIPLE SMALL FIELDS

YR	PRODUCION RATE (MBPD)
1989	0
1990	0
1991	0
1992	0
1993	0
1994	0
1995	0
1996	0
1997	0
1998	0
1999	0
2000	0
2001	0
2002	0
2003	0
2004	0
2005	65.75
2006	153.42
2007	219.17
2008	219.17
2009	219.17
2010	205.53
2011	177.71
2012	153.69
2013	132.97
2014	115.07
2015	99.60
2016	86.24
2017	74.70
2018	64.73
2019	56.10
2020	48.64
2021	42.17
2022	21.58
2023	0
2024	0
2025	0
2026	0
2027	0
2028	0
2029	0
2030	0

Table A-5. Composite North Slope Production Rates plus Chukchi Sea and NPRA

	CHUKCHI SEA W\NPRA
YR	PRODUCTION RATE (MBPD)
1989	0
1990	0
1991	0
1992	0
1993	0
1994	0
1995	0
1996	0
1997	0
1998	0
1999	0
2000	0
2001	0
2002	0
2003	0
2004	69.92
2005	209.72
2006	279.64
2007	349.51
2008	419.43
2009	419.43
2010	419.43
2011	419.43
2012	419.43
2013	419.43
2014	419.43
2015	419.43
2016	369.10
2017	324.81
2018	285.83
2019	251.53
2020	221.35
2021	194.79
2022	171.41
2023	150.84
2024	132.74
2025	116.81
2026	102.80
2027	90.46
2028	79.60
2029	70.05
2030	61.65

Table A-6. Composite North Slope Production Rates plus ANWR Multiple High Case

ANWR MULTIPLE HIGH CASE

YR	PRODUCTION RATE (MBPD)
1989	0
1990	0
1991	0
1992	0
1993	0
1994	0
1995	0
1996	0
1997	0
1998	0
1999	0
2000	0
2001	0
2002	0
2003	0
2004	0
2005	239.15
2006	427.97
2007	674.33
2008	1050.67
2009	1276.71
2010	1423.28
2011	1501.36
2012	1501.36
2013	1445.88
2014	1351.47
2015	1232.17
2016	1064.03
2017	919.11
2018	794.16
2019	686.41
2020	593.45
2021	513.25
2022	371.19
2023	60.28
2024	0
2025	0
2026	0
2027	0
2028	0
2029	0
2030	0

Table A-7. Composite North Slope Production Rates plus Chukchi Sea Super Giant Case

CHUKCHI SEA SUPER GIANT

YR	PRODUCTION RATE (MBPD)
1989	0
1990	0
1991	0
1992	0
1993	0
1994	0
1995	0
1996	0
1997	0
1998	0
1999	0
2000	0
2001	0
2002	0
2003	0
2004	198.67
2005	595.89
2006	794.56
2007	993.11
2008	1191.78
2009	1191.78
2010	1191.78
2011	1191.78
2012	1191.78
2013	1191.78
2014	1191.78
2015	1191.78
2016	1048.77
2017	922.92
2018	812.17
2019	714.71
2020	628.94
2021	553.47
2022	487.05
2023	428.61
2024	377.17
2025	331.91
2026	292.08
2027	257.03
2028	(266.19)
2029	(199.04)
2030	(175.16)

4. IMPACT OF A SHUTDOWN OF THE ARCTIC NORTH SLOPE OIL DELIVERY SYSTEM (ANSODS)

4.1 TAPS Operations and Limitations

The current and short term scenario on the North Slope is dominated by the Prudhoe Bay Field and continued operation of TAPS, as the analysis in Section 3 has shown. Limitations discussed in this section concerning increased throughput of condensate and NGL, transport and blending of very heavy crude oils with condensate, and maximum and minimum throughput capacity are all options that will need continuing review as economic conditions change. In most of these cases, alternatives exist that are technically possible if the economic conditions are favorable.

Problems experienced with shutting down and restarting TAPS, would be expected to be similar for connecting pipelines and field gathering systems and are not discussed in this report.

4.1.1 Mechanical Effects of Shutdowns

The mechanical effects of shutting down and restarting TAPS are important to consider because it may be necessary, as it has been in the past, to shut down the line for a few days to a few weeks for repairs and for longer periods of time should the production rate fall below the minimum operating rate for the pipeline or shipping from Valdez be shut down for environmental or other reasons.

4.1.1.1 Planned Shutdowns. Short term shutdowns of TAPS from a few days to a week or two do not require any significant preparations even in winter. The preparations required consist of protecting small lines in the pump station control rooms and circulation systems from freezing. Small amounts of water entrained in the oil can collect in the small lines and freeze unless they are flushed and freeze protected.[1] (Information contained in Section 4.1 was obtained from Reference 1 unless other references are given.)

The main 48 inch line can be shutdown for several weeks without encountering any unusual start-up problems. Freeze protection of the 48 inch line is not necessary.

Longer term shutdowns of several months would require essentially the same preparation as shorter shutdowns, i.e. freeze protection of the smaller lines. No unusual mechanical or start-up problems are anticipated. However, a significant number of people must be kept on duty for spill response and maintenance. During the warm shutdown of the Milne Point Unit from January 1987 to April 1989, about 20% of the normal operating staff remained on site.[2] A similar percentage of the personnel would likely be required for TAPS. Thus, a significant portion of the operating costs are fixed costs which would continue during a shutdown. Should an extended shutdown of many months or years occur, the economics of leaving the line full of hydrocarbons versus taking necessary steps to move them to Valdez for shipment to market would have to be determined by Alyeska.

4.1.1.2 Rapid Shutdowns. During the 13 years of operation of TAPS, there have been four shutdown periods of from 53 to 110 hours. Most recently, in January 1985, experience with a 66 hour rapid shut down proved that flow can be restarted with minimal problems for shutdowns of these durations. Flow restarts at a slow rate until the pipeline warms up. The problems encountered were with re-establishing flow control of the overall pipeline system. If an extended shutdown period were to result from a crash-down, the preparation steps used in a planned shutdown could still be performed without problems.

Crude oil solidification is not anticipated in the main 48 inch line. Effects caused by increased viscosity of the oil as it cools are slowly reversed as the pipeline warms up. Although none have been experienced to date, some problems could possibly occur in colder weather in the pump station control and fluid transfer systems. It is believed that all such problems can be corrected and managed.

4.1.1.3 Vaporization of Light Hydrocarbons. The pipeline system was designed as an atmospheric system. Thus, the volume of light hydrocarbons that can be blended with produced North Slope crude oils is limited. Some vaporization of light hydrocarbons could occur with pressure release, but this has not caused problems in any of the shutdowns that have occurred. The system has design features to prevent or correct vaporization. South of the Brooks Range a series of automated valves have been installed to prevent free flow of oil/NGL mixtures. In the event a problem arises with the valve installations, the entire line from Atigun Pass south to Pump Station No. 5 site can be relieved to tanks at that site. In addition, pipeline bleed-off valves are installed at critical points to permit bleed-off of vapor.[3]

4.1.2 Limitations on Throughput of Condensate and Natural Gas Liquids

The known quantities of gas and condensate on the North Slope are given in **Tables 2-1** and **2-5** of **Section 2**. The gas resources, discussed in **Section 2.2.4**, amount to 37 TCF. The Point Thomson field, a 300 MMB gas condensate field, was discussed in **Section 3.3.1**. These large quantities of gas and associated natural gas liquids (NGL), gas condensate, and the fact that TAPS excess capacity will increase as the production rate of the North Slope fields decline (**Section 3.6.4, Figure 3-25**) makes it desirable to determine the feasibility of blending greater quantities of lighter hydrocarbons with the crude oil stream.

4.1.2.1 Pipeline Design Limitations. The pipeline system is designed to transport hydrocarbons that are stable at atmospheric pressure (14.65 psi). The main limitations to increasing the amount of lighter hydrocarbons are the vapor emission limits at Valdez associated with loading of tankers, and unloading of the tankers at Lower 48 ports, where the vapor pressure allowance is more restrictive than the pipeline design.

All of the tankers used to ship crude from Valdez to delivery points in the Lower 48 states are Class B Tankers, which are designed to handle crude oil with a maximum of 11 psi Reid Vapor Pressure. The crude is stabilized at 7.5 psi Reid Vapor Pressure to meet restrictions at West Coast receiving points.

4.1.2.2 Requirements for Transporting a Greater Concentration of Condensate and NGL in TAPS. Because the existing pipeline system is designed to operate with liquids that are stable at atmospheric pressure, a redesign of the entire system could be required to raise the vapor pressure rating to the 200 to 300 psi range. This could conceivably cost in excess of $1 billion and take 2 to 3 years to design and install. Equally significant would be the cost for design and construction of a separation plant to split the products at Valdez and stabilize the crude. At present this is not considered a likely scenario.

An estimate of the amount of condensate and NGL that could potentially be carried if such facilities and modifications were installed is not possible until a design study has been made. It would depend on factors such as the composition of the hydrocarbon streams, the operating temperature of the pipeline system, and environmental issues.

4.1.3 Capacity of TAPS

Both the maximum and minimum throughput capacity of TAPS could come into play in the future depending on whether the decline of North Slope production continues or major discoveries are made on the North Slope.

4.1.3.1 Maximum Throughput Capacity. The current design capacity of TAPS is 1.42 MMBPD without the use of drag-reducing agents (DRA). The line has operated at rates as high as 2.1 MMBPD with the use of DRA. Theoretically, it can be operated at rates greater than 2.1 MMBPD with additional DRA. However, the cost of DRA for each additional barrel of capacity accelerates between throughput rates of 1.9 and 2.1 MMBPD. Because of this increasing cost of DRA, the maximum economical operating rate (at current design capacity) is probably 2.1 MMBPD.

Additional pumps at the 10 operating pump stations and the total equipping of two pump station sites that have never been operational would be required to raise the current design capacity to the original design maximum of 2.0 MMBPD without the use of DRA. The use of DRA could increase capacity to about 2.4 to 2.5 MMBPD.

4.1.3.2 Minimum Throughput Capacity. The pipeline capacity at start-up was 300 MBPD. With existing equipment, the minimum capacity is 600 MBPD. To go below that rate, mechanical revisions would be required that would essentially be the reverse of installations made to increase throughput from the start-up rate to the current design capacity of 1.42 MMBPD. Rates somewhat lower than 300 MBPD could possibly be maintained without mechanical problems. (As discussed in **Section 3.2.8**, a lower limit of 300 MBPD was chosen for this study rather than assume an unproven lower value.) Low rates would result in temperature problems such as viscosity increase and wax deposits. Increased formation of wax deposits is more critical than the increase in viscosity. These effects could be controlled but would be costly.

Operating at low throughput volumes would not result in significant savings in operating costs. The infrastructure requirements for spill response and maintenance result in fixed costs which are independent of rate. Costs for corrosion control and increased personnel requirements along the pipeline and at Valdez (150 people added) following the oil spill, have increased Alyeska's annual expense budget from $250 MM up to $500 MM. Another factor which would reduce the net wellhead crude oil sales price would be increased transportation costs if dual-hull tankers are required to transport Alaskan North Slope crude at some future date. All of these factors will be involved in the determination of the economic life of TAPS.

Intermittent operation of the pipeline to continue operations below the continuous operational minimum is not considered an option at the present time because of the economics of line operation described above, i.e. fixed expense costs would continue.

4.1.4 Transport of Heavy Crude Oils and Blending of Heavy Crude and Condensate

The existence of heavy crude oil deposits such as West Sak and Ugnu raise questions concerning the transport of much heavier crude oil than currently produced from North Slope fields and the possibility of blending these heavier crude oils with lighter crude oil, condensate, and NGL.

Many possibilities are mechanically possible if they can be shown to be economically feasible. Limitations are imposed by the vapor pressure restrictions and other restrictions such as corrosion control and wax deposition. Corrosion gets worse for temperatures above 120°F, and wax deposition gets worse as temperatures fall below 120°F. The oil temperature is a maximum of 145°F at Pump Station No. 1. At Pump Station No. 6 the temperature has decreased to approximately 120°F and at the terminal at Valdez it is approximately 115°F. The temperature of Kuparuk oil at the wellhead is an average of 90°F. West Sak oil has an even lower wellhead temperatures. Throughput of large volumes of this crude would result in increased wax problems.

4.2 Impact on Other Arctic Facilities and Producing Fields

A detailed analysis of the problems and costs associated with temporary shutdowns of North Slope field gathering systems and producing fields was beyond the scope and time limitations of the present study. Also, information that exists in the literature and the experience of the industry on the effects of discontinuing operations on fields is limited. Thus, the information available has been summarized in this section.

4.2.1 Facilities

The requirements for flushing and freeze protecting flowlines and maintenance of control systems and equipment would be similar to TAPS. During the warm shutdown of the Milne Point Unit from January 1987 to April 1989, about 20% of the normal operating staff remained on site.[2] A similar percentage of the normal staff would have to be kept on site at other fields to maintain the equipment and provide for safety and environmental concerns. Thus, a significant portion of the normal operating costs would continue during any temporary shutdown.

4.2.2 Producing Fields

As noted in **Section 3.2.1**, Milne Point Unit production was 19.5 MBPD in March 1990 as compared to the 1986 average of 12.9 MBPD and there have been no adverse effects from the shutdown.[3] As noted above, the shutdown of Milne Point lasted over 2 years but in a field that had only been in operation for slightly over 1 year. A shutdown occurred in the Trading Bay Unit, McArthur River Field for portions of 2 months in 1976 as a result of a platform fire. The Hemlock Formation had been under waterflood since 1969 and this event occurred very near the point at which the field went on decline.[4] The unit owners were unable to determine definitively that any loss in ultimate recovery occurred as a result of this shutdown.[5] Thus, the evidence for the effects of shutdown of large fields with mature secondary and EOR projects such as Prudhoe Bay do not exist to the knowledge of the authors.

In response to a request from the Department of Energy in May 1989 concerning the possible impacts associated with a long term field-wide shut-in of the Prudhoe Bay Field, BP Exploration (Alaska) Inc. provided the following conclusions:[6]

> "<u>Impacts of Prolonged Shutdown</u>
>
> Prior to any production, the field was in 'equilibrium' (no fluids were moving). Once production commences, primarily oil and gas are removed from the reservoir, a substantial portion of the gas re-injected in the gas region, and the aquifer encroaches towards the oil in response to the voidage (pressure decline). During this time, the reservoir system is in a state of non-equilibrium. In the event of a prolonged shut-down of the field, the system would begin to equilibrate. The potential negative impacts of equilibration are as follows:
>
> 1) Oil would be pushed into previously gas swept regions in EWE[a] and the main field causing at a minimum delayed/deferred recovery of reserves and potential loss of reserves due to field life considerations. In the main field area there is also the possibility of water moving into previously gas swept regions

---

a. EWE (Eileen West End) - The western part of the Prudhoe Bay Unit. The EWE and the main area have separate gas caps underlain by oil columns.

(along with oil) which could result in some oil being trapped.

2) Aquifer influx could drive oil into original gas cap regions in the EWE area which would likely result in lost reserves from creating a residual or trapped saturation.

3) A potential loss of ultimate recovery in the EOR areas due to aquifer encroachment resulting in waterblocking. There is also the potential for the miscible injectant to gravity segregate which would reduce the efficiency of the EOR process."

and,

> "Simulation models used to study development options and reservoir management strategy are inherently large due to the vast size of the field and thus are unable to fully capture the entire slate of impacts associated with a prolonged shutdown. Quantifying the exact volume of oil potentially lost is difficult and largely dependent on the duration of any such event. Impacts would be closely linked with the final equilibration pressure which is primarily a function of the size and characteristics of the aquifer. The aquifer here is only grossly understood and there are still many uncertainties associated with long term performance."

Based on the data available, it is not possible to reach definitive conclusions concerning the impact on North Slope fields of a shutdown. Due to the lack of historical evidence upon which to base an estimate of the impact, any conclusions would have to be based on reservoir simulations. Therefore, any such conclusions would basically be theoretical. As noted by BP, the size of the Prudhoe Bay field and the recovery mechanisms in operation in various parts of the field make it unlikely that the effect can be quantified. It is clear that such an event would be costly due to the continuation of operating and maintenance costs in addition to the lost revenue to industry and government.

4.3 Impact on National Energy Supply and Revenue

4.3.1 Introduction

The Energy Information Administration (EIA) states that domestic oil output was 7.7 MMBPD in 1989 and that the decline rate is about 6%/year.[7,8] The EIA projections indicate that Alaskan production, which accounted for about 25% of the Nation's oil production in 1989 will decrease more rapidly than other domestic production. This is a result of the Prudhoe Bay field entering its decline phase in 1989 and the dominance of Prudhoe Bay on Alaskan production. The EIA projections show a national production rate of between 4.1 and 5.6 MMBPD in 2010 with the Alaskan portion amounting to about 10%. Import dependence is projected by the EIA to increase from 42% in 1989 to 54 to 67% in 2010.

4.3.2 Impact of ANSODS Shutdown

The impact of a shutdown of ANSODS on the nations' oil supply can be estimated from the analysis presented in **Section 3**. From **Figures 3-5** and **3-6**, the effects of a shutdown of ANSODS at selected years have been determined based on the Most Likely Case production forecast from **Table 3-6**, the Revised Reference NES Case oil prices in 1989 dollars per barrel, and for an escalation of the NES prices by 3.5%/year. The increase in cost of imports is given as the cost on a yearly basis. These effects are presented in **Table 4-1**.

Table 4-1. Effects of ANSODS Shutdown on U.S. Domestic Oil Production and Increased Cost for Imports
(MMBPD and $ Billions/year)

Year	Total U. S. Production Rate	North Slope Production Rate	% of Total U.S.	Increased Cost of Imports	
				$-1989	$-Escalated
1990	7.4	1.8	25	11	11
1995	6.4	1.6	22	12	14
2000	5.8	1.0	17	10	15
2005	5.4	0.5	10	6	10
2010	5.0	0.3	6	4	8

The impact on State of Alaska taxes and royalty, federal taxes, and industry profit of a shutdown of ANSODS is shown on **Figure 4-1** for the Most Likely Case of **Section 3**. The effects are shown in terms of total remaining revenue to the State and Federal governments and net profit to industry in billions of dollars. For example, a total shutdown in 1995 would result in a loss to all parties of $161 billion over the potential life of the projects. The breakdown of the loss in revenue and profit is as follows:

		$ Billion[a]
Federal government	-	37
State of Alaska		
Taxes	-	30
Royalty	-	24
Industry	-	70
TOTAL	=	161

---

a. Sum of dollars in year of occurrence.

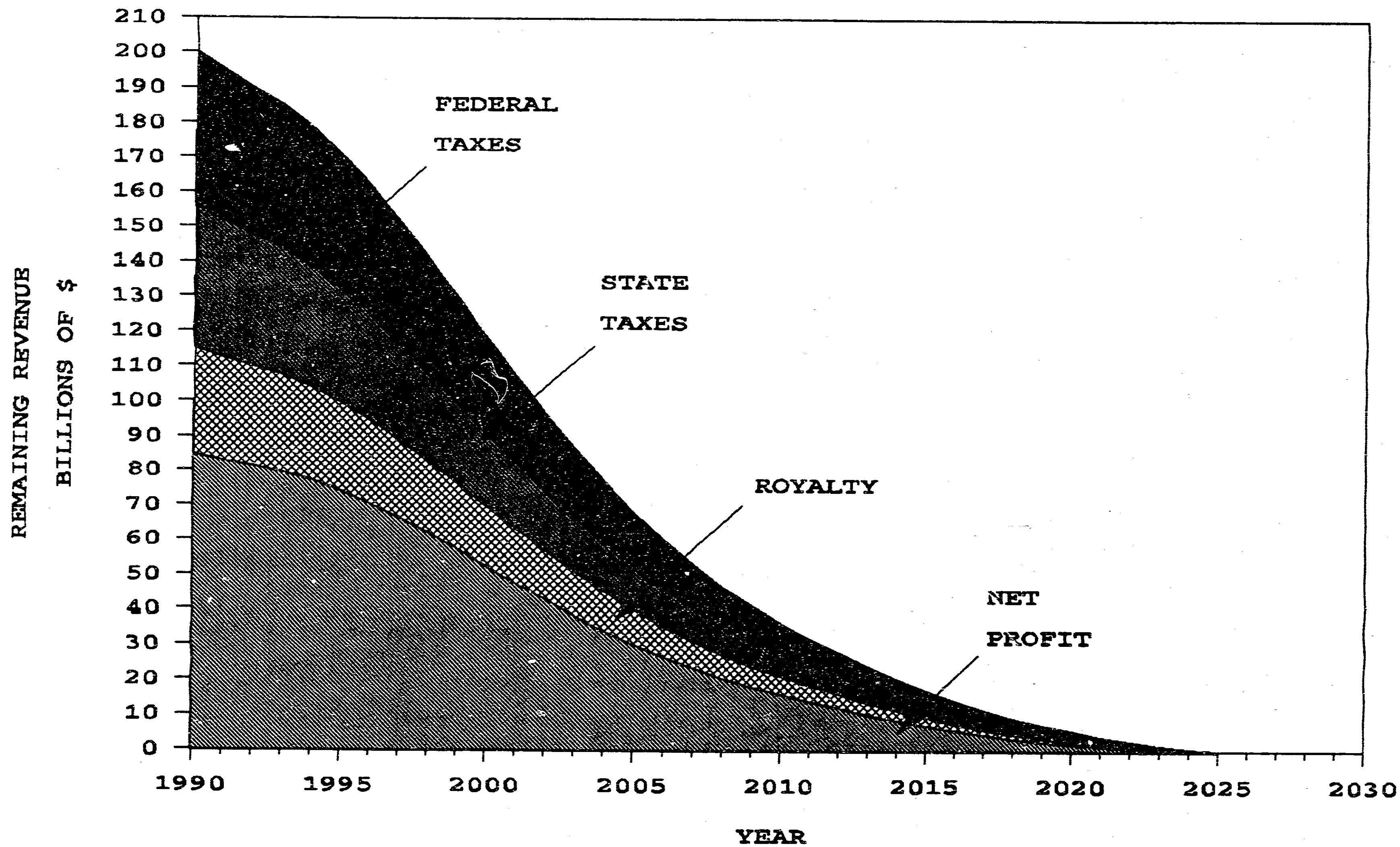

Figure 4-1. Impact of a Shutdown of ANSODS on Revenue to the State of Alaska and the Federal Government and on Net Profit to the Industry From 1990 Through 2025.

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5. ENVIRONMENTAL ISSUES

5.1 Background

The purpose of this section is to summarize the environmental issues relating to development of oil and gas rescurces on the North Slope of Alaska, and to evaluate and discuss the potential impact these issues could have on future development of oil and gas resources. The ultimate impact on oilfield development that can *potentially* be associated with these issues ranges from relatively small increases in production costs to the prevention of development.

A brief summary of the environmental characteristics of the North Slope is provided, followed by a discussion of the permitting processes associated with exploration and development. Given the wide range of credible scenarios, the future costs associated with compliance with changing environmental regulations and policies are very difficult to assess. Where possible, the relative importance of each issue is provided, from an economic standpoint. Where the positions taken by industry and environmental groups are in opposition to one another, we have attempted to provide an objective viewpoint. In no case do we attempt to mediate between opposing factions, nor do we attempt to suggest the direction that resolution to any particular issue should take. When describing how a particular issue could impact subsequent development of North Slope reserves, we are necessarily assuming the "worst case" scenario form the point of view of the oil companies. This is inevitable, but should not be misinterpreted as promoting the point of view of the environmental groups. Furthermore, in some cases, issues are sufficiently complex to allow several divergent viewpoints.

Oil development on the North Slope is currently restricted to an area of approximately 400 square miles. All the producing North Slope fields feed into the Trans-Alaska Pipeline System (TAPS), which delivers oil through an elevated pipeline along an 800-mile route from Prudhoe Bay to Valdez, an ice-free port in southern Alaska. Because the TAPS has been in operation for several years, and future development of North Slope oil reserves would merely alter the *source* and the overall *characteristics* of the oil rather than the operation of the pipeline, environmental concerns associated with the TAPS and with subsequent transportation of the oil from the port of Valdez are not addressed in this report.

Similarly, accidents involving oil spills during transport of the oil after leaving the North Slope are beyond the scope of this report. The March, 1989 accident involving the supertanker Exxon Valdez that was responsible for the spill of an estimated 10.9 million gallons of oil into the Prince William Sound is therefore not considered within the scope of this report. Although such accidents are not specifically addressed in this report, such accidents may have significant impacts on development through changes in public attitudes or legislative actions or both.

5.1.1 Site Characterization

Brief, generic descriptions of the North Slope environs are provided for both onshore and offshore areas.

5.1.1.1 Description of Onshore Areas. The North Slope of Alaska consists of a coastal plain that extends from the Arctic Ocean on the north to the foothills of the Brooks Range to the south, and from the Canadian Border on the east to the Chukchi Sea to the west. The coastal plain of the North Slope covers an area of approximately 69,000 square miles. The area can be classified as a desert by virtue of the low precipitation totals typical of the region. Approximately 18 cm (7 in.) of precipitation falls annually on the North Slope. Although little precipitation actually falls, snow can fall at any time of the year. The ground surface of the North Slope is covered with ice and snow over much of the year. Winter temperatures can typically drop to between -55 and -60°F, and can produce associated wind chills of -115°F. Summertime temperatures can reach 70°F or higher. Winds are typically moderate to strong, and blow predominately from off-shore.

The terrain of the North Slope exhibits very little relief, with local drainage patterns creating elevation changes on the order of seven to 49 ft. An important feature of the area is the permafrost, which underlies all land surfaces on the North Slope, typically extending to depths in excess of several hundred feet below the surface. During the long summer days, the permafrost thaws to depths of one to two ft. The area then becomes, in effect, a wetland, covered by ponds, marshes, and low vegetation which provide habitat for abundant wildlife resources. The characterization of the coastal plain as wetlands has important implications in terms of development of oil or other industries in the area, as is discussed in Section 5.3.1.

5.1.1.2 Description of Offshore Areas. The continental shelf within the Chukchi and Beaufort Seas is broad and relatively flat. Maximum depths within the lease areas are around 80 m (260 ft.). Subsea permafrost, a relic feature that is formed during periods of major glaciation when sea level was lowered exposing large portions of the continental shelf to subfreezing temperatures, is found in some areas, but its extent and distribution is unknown. The general climatic conditions along Arctic Coast of Alaska are characterized by relatively strong winds, cold temperatures during the summer and winter, and low annual precipitation. Tides are small in the Chukchi and Beaufort Seas, generally not exceeding 0.3 m (1 ft.). Sea ice typically begins to form in the Chukchi in late September or early October, and all of the area is covered usually by the beginning of December. Freeze times in the Beaufort Sea are somewhat earlier. Nearshore ice begins to melt by mid-May, and pack ice begins to retreat northward by July. In March or April, the landfast ice zone may extend to depths of up to 30 m (100 ft). The ice-free period around Barrow typically involves a window of only 5 or 6 weeks, which greatly limits the feasibility of shipping of materials to the oil fields by sea. Ice gouging, an important consideration in pipeline location, may occur in water up to 43 m (140 ft.) deep, and may extend up to 65 km (40 mi) offshore.

5.1.2 Locations and Expected Production Volumes of Known Fields

The locations of the North Slope oil and gas fields are shown on Figures 2-7 and 2-9 of Section 2.2.1. Table 5-1 is a summary of the currently producing North Slope oil fields which provides a listing of the support facilities constructed for each field. Additional data describing known North Slope oil and gas fields are presented in Tables 2-1 and 2-5 of Section 2.

Table 5-1. North Slope Petroleum Development Summary[a] (as of January 1990)

	PRUDHOE BAY	LISBURNE	KUPARUK	MILNE POINT	ENDICOTT
Discovery date	12/67	12/67	4/69	10/69	3/78
Size of oil pool (square miles)	400	125	400	45	40
Production start-up date	6/77	12/86	12/81	11/85	10/87
Production to date (MMBO)	6606	52	615	7[b]	82
January 1990 average production rate (MBPD)	1380	36	297	20	103
Remaining reserves (MBO)	6266	157	1514	53	311
Total existing wells	936	75	595	41	58[c]
Drill sites/pads	38	5	34	4	2
Production centers	6	1	3	1	0
Base camps	2	1	0	0	0
Construction camps	2	0	2	0	0
Power plants	1	0	1	1	1
Topping plants	1	0	1	0	0
Gas compression plants	1	1	1	1	1
Sea water treatment plants	1	0	1	0	1
Docks	1	0	1	0	1
Causeways	1	0	0	0	1
Water injection centers	2	d	d	d	d
Associated support and industrial sites	1	0	1	0	0
Airports and company-operated airstrips	2	0	1	0	0
Pipelines (miles)	63[e]	e	418	15	28
Roads(miles)	200[e]	18	94	19	15
Acreage covered (acres)	5374[e]	e	1409	54	198
River crossings	3[e]	e	5	1	1

a. After Reference 1 and Sections 2 and 3 of this report.
b. Field shut down in January 1987. Restarted in April 1989.
c. 80 wells planned.
d. Water injection system included in production centers. Lisburne shut down.
e. Lisburne numbers included in Prudhoe Bay.

5.1.3 Land Ownership

The majority of the known petroleum reserves are located on state-owned lands, including Prudhoe Bay and Kuparuk. The exceptions are on lands administered by various federal agencies within the Department of Interior (DOI), and include the Arctic National Wildlife Refuge (ANWR) (U.S. Fish and Wildlife Service), the National Petroleum Reserve - Alaska (NPRA) (Bureau of Land Management), and the various offshore areas beyond the three-mile limit (Minerals Management Service).

5.2 Environmental Permitting Process

5.2.1 Who Regulates What?

One of the problems associated with evaluating the environmental implications of oil development on the North Slope is the complexity of the regulatory framework involved with oilfield leasing and operations. Several agencies within the federal and state governments are to varying degrees involved with the permitting process on the North Slope. Local government is also involved, although to a lesser extent. The net result is that the permitting process is complex, and the acquisition of the required permits for exploration and development can require a number of years.

5.2.1.1 Federal Government. Federal agencies involved in the permitting process on the North Slope include the Department of Interior (Bureau of Land Management, Minerals Management Service, and Fish and Wildlife Service), the Department of Defense (Army Corps of Engineers), the Department of Commerce (National Marine Fisheries Service), the Department of Transportation (Offshore Oil Pollution Compensation Fund), the Department of Agriculture, and the Environmental Protection Agency. The primary legislative actions concerning the development of the North Slope oil reserves are described below.

5.2.1.1.1 Alaska National Interest Lands Conservation Act (ANILCA)--Authorized in 1980, ANILCA is administered by the U.S. Departments of the Interior and Agriculture. This Act designated major conservation units for federally owned lands in Alaska, significantly expanding the lands administered by the National Park Service and the Fish and Wildlife Service. Section 1003 of ANILCA prohibits oil and gas leasing and other development leading to production unless authorized by an Act of Congress.

The potential ramifications associated with ANILCA are critical to the ultimate disposition of petroleum reserves within the ANWR. Passage of the ANILCA in 1980 doubled the size of the ANWR to 19 million acres while closing it to all petroleum exploration. Recognizing the oil and gas potential of the ANWR, however, Section 1002(b) of ANILCA set aside the 1.5 million acres within the northern most part of the coastal plain of the refuge for further study. The Act mandated a comprehensive inventory and assessment of the biological resources of the ANWR coastal plain and potential impacts of oil and gas exploration, development and production. Known as the "1002 Area," a reference to Section 1002(b) of ANILCA, the DOI conducted a five year resource evaluation of the oil potential and environmental consequences of 1002 area. As land manager of the ANWR, FWS was given the task of preparing the resource assessment, which was published as a Final Environmental Impact Statement (EIS) in April 1987. The EIS recommended that all the 1002 area be opened to oil and gas leasing, concluding that "the Coastal Plain is the nation's best single opportunity to increase significantly domestic oil production over the next 40 years."[2] DOI estimates for the resource potential of the 1002 area are discussed in **Section 2.4**. Should leasing ultimately be permitted, activities will be conducted under authorizations issued by the FWS as land manager, as well as by other agencies. Leasing and other activities leading to oil and gas production within the ANWR must first be authorized by Congress.

5.2.1.1.2 Clean Air Act (CAA)--Authorized in 1970 and reauthorized in 1977, the CAA is administered by the EPA and the State of Alaska. The CAA established National Ambient Air Quality Standards for six priority pollutants: SO_2, NO_x, particulates, Pb, CO, and O_3. The CAA also requires pollutant source controls to comply with the "best available control technology" for existing sources, and "new source performance standards" for major new sources or major source modifications. The primary standards are designed "to protect human health with an adequate margin of safety", while the secondary standards represent the levels "necessary to protect the public welfare from adverse effects". The CAA also established national emission standards for hazardous air pollutants (NESHAPS), and "prevention of significant deterioration" increments for SO_2, NO_x, and particulates.

5.2.1.1.3 Clean Water Act (CWA)--The CWA was first authorized in 1948, and was reauthorized in 1972 with the passage of the Federal Water Pollution Control Act (FWPCA). The CWA is administered by the EPA and the Army Corps of Engineers (COE). Three major programs within the CWA impact oil and gas operations:

- **National Pollutant Discharge Elimination System (NPDES).** Regulates discharges into U.S. waters from point sources (Section 402). Effluent limitations are imposed, which restrict the quantities, rates, and concentrations of pollutants, and dictate relevant compliance schedules.

- **Control and prevention of spills of oil and hazardous materials.** Administers (a) spill prevention, (b) spill reporting, (c) spill clean-up, and (d) liability for the cost of clean-up.

- **Discharges of dredge and fill materials into U.S. wetlands (Section 404).** Governs the placement of fill in "navigable waters", which includes "wetlands."

5.2.1.1.4 Coastal Zone Management Act (CZMA)--Authorized in 1972, the CZMA is administered by the U.S. Department of Commerce. The CZMA provides a cooperative federal/state mechanism to protect the coastal zone and resolve conflicts among competing uses. The Act provides standards and funding for coastal states to prepare coastal management programs. Section 307 of the CZMA, the Federal Consistency Provision, requires federal activities affecting the coastal zone to be conducted to the maximum extent practicable consistent with approved State programs, and requires that applicants for federal licenses and permits affecting the coastal zone certify that their activities, including those on the outer continental shelf, are consistent with state programs coastal zone management programs. CZMA regulations have special provisions relating to energy production, including the requirement that the exploration and production activities on the outer continental shelf (OCS) be consistent with the state coastal zone management program. State programs must also provide adequate consideration of the national interest in the planning and siting of energy facilities.

5.2.1.1.5 Comprehensive Environmental Response, Compensation, and Liability Act (CERCLA, or "Superfund")--Authorized in 1980 and reauthorized in 1986 as the Superfund Amendments and Reauthorization Act (SARA), CERCLA is administered by the EPA. CERCLA requires that certain releases ("Reportable Quantities") of hazardous substances from a facility or vessel be reported to the National Response Center. CERCLA authorizes federal response to a release or a "substantial threat" of a release into the environment of a hazardous substance or a pollutant or contaminant if it poses an "imminent and substantial danger to the public health or welfare."

5.2.1.1.6 Emergency Planning and Community Right-to-Know Act--This act was authorized in 1986 and is administered by the EPA and the State of Alaska. Key features include emergency planning and notification requirements and reporting requirements in the event of a release of hazardous materials.

5.2.1.1.7 Endangered Species Act (ESA)--Authorized in 1973, the ESA is administered by the FWS and the NMFS. The Act states that no federal agency may take any action (e.g. issue a permit) that might "jeopardize the continued existence of an endangered species", as determined by the FWS or the NMFS. Under the ESA, endangered species cannot be "harassed, hunted, captured, or killed". Offshore drilling has been determined to "harass" bowhead and gray whales, resulting in the need for an "incidental take permit". Since 1979, a seasonal drilling restriction has prohibited, or more recently restricted the types of activities that can be conducted while bowhead whales are present. Operations conducted in areas occupied by other endangered species (e.g. the peregrine falcon) may also be restricted so as not to jeopardize their existence.

5.2.1.1.8 Fish and Wildlife Coordination Act (FWCA)--Authorized in 1934, the FWCA is administered by the FWS, the NMFS, and the EPA. The Act requires other federal agencies to consult with these agencies when any stream or other water body is to be modified. Commenting agencies are then to recommend means of preventing loss of fish and wildlife and of environmental improvement. This act provides the opportunity for resource agencies to comment on permit applications, often resulting in permit stipulations.

5.2.1.1.9 Marine Mammal Protection Act (MMPA)--The MMPA was authorized in 1972, and is administered by the FWS and the NMFS. With certain exceptions, the "taking" (defined as "the harassing, hunting, capturing, or killing") of sea mammals is prohibited. The FWS is responsible for sea otters, walrus, and polar bears, while the NMFS is responsible for seals, sea lions, whales and porpoises. When operations occur that may result in the harassment of marine mammals, an "Incidental Take" permit is required. Conducting research on marine mammals requires a scientific research permit. Oil industry operations must also be designed to "minimize interference with native hunting of these animals."

5.2.1.1.10 National Environmental Policy Act (NEPA)--NEPA was authorized in 1969, and is administered by the EPA. The Act established long-term national policy with the goal of promoting "conditions under which man and nature can exist in productive harmony, and fulfill the social, economic, and other requirements of present and future generations." Every federal agency must consider the environmental impacts of "proposals for legislation or other federal actions significantly affecting the quality of the human environment". The results of an agency's evaluation are to be contained in a detailed Environmental Impact Statement (EIS), unless a "Finding of No Significant Impact" (FONSI) indicates that an EIS is not required. An EIS is subject to the review of other federal, state, and local agencies, as well as the general public.

5.2.1.1.11 Outer Continental Shelf Lands Act (OCSLA)--This Act is administered by the DOI, and was originally authorized in 1953. The OCSLA was amended in 1975 and 1978, and established federal jurisdiction over submerged lands on the outer continental shelf (OCS). Guidelines are provided by the Act for implementing an OCS minerals development program including oil and gas and provides a program to expedite exploration and development of the OCS. The OCSLA requires that leasing be tempered to ensure protection of the human, marine, and coastal environments. The 1978 amendments to the Act established the Offshore Oil Pollution Compensation Fund administered by the Secretary of Transportation to provide compensation for oil spill cleanup costs and damages. Major regulatory provisions relating to the conduct of OCS oil and gas operations were revised in 1988 (30 CFR 250) and include exploration and development and production plans, pollution prevention and control, drilling operations, well completion and workovers, platforms and structures, pipelines, and production. Other provisions call for environmental studies of lease sale areas and establishment of an OCS Advisory Board to provide a forum for input from coastal states.

5.2.1.1.12 Resource Conservation and Recovery Act (RCRA)--Initially authorized in 1976, RCRA has been amended in 1980 and 1984. The Act is administered by the EPA and the State of Alaska, and provides "cradle to grave" management of hazardous wastes. Wastes uniquely associated with oil and gas exploration and production operations are exempt from regulation under RCRA, and the EPA recommended to Congress in 1988 that this exemption be retained. Congress is expected to re-examine the oil and gas exemption under waste minimization legislation or the reauthorization of RCRA.

5.2.1.1.13 Safe Drinking Water Act (SDWA)--Originally authorized in 1974, the SDWA was reauthorized in 1986. The Act is administered nationally by the EPA, and is administered in Alaska by the Alaska Oil and Gas Conservation Commission and the Alaska Department of Environmental Conservation (ADEC). The SDWA established major programs in the regulation of public drinking water systems, and the protection of underground sources of drinking water. A list of contaminants has been established with enforceable drinking water limits. The Underground Injection Control (UIC) Program prohibits the subsurface emplacement of fluids that may result in the contamination of a potential source of drinking water.

5.2.1.1.14 Toxic Substances Control Act (TSCA)--The TSCA is administered by the EPA, and was authorized in 1976. The purpose of TSCA is to impose regulatory control over all chemicals produced or used in the United States. Controls include testing, recordkeeping, reporting, and notice requirements. Management regulations to control the handling and disposal requirements were established under TSCA for some chemical substances and mixtures, including polychlorinated biphenyls (PCBs) and asbestos.

5.2.1.2 State Government. Several agencies of the State of Alaska are also involved in the permitting process. These agencies and their principal concerns are described below.

5.2.1.2.1 Alaska Department of Environmental Conservation (ADEC)-The ADEC is responsible for air quality control, new source performance testing, black smoke reporting, ambient air monitoring, and PSD permitting within the State of Alaska. Responsibilities also include implementation of the solid waste management program, regulation of the disposal of oily waste, drill muds and cuttings, and other non-hazardous oilfield wastes, maintenance of water quality standards, including drinking water monitoring. It manages wastewater disposal regulations covering all discharges to state lands and waters not already covered by federal NPDES permit. It also reviews NPDES permit applications for water and waste water certification; investigates and cleans up sites contaminated by oil or hazardous substances; and requires contingency plans for many types of facilities. ADEC administers drinking water program for protection of community water systems under the SDWA and is also responsible for pesticide control.

5.2.1.2.2 Alaska Department of Fish and Game (ADF&G)--ADF&G is responsible for the management of fish and game resources in the state. Regulatory responsibilities include management of commercial fisheries, hunting and habitat protection. ADF&G issues permits for activities including construction and use of equipment in anadromous fish streams. It also reviews and comments on permit applications to other state agencies.

5.2.1.2.3 Alaska Department of Natural Resources (ADNR)--ADNR has broad responsibilities to manage the state's natural resources on state lands, including oil and gas, minerals, forests, water, and agriculture.

- **Division of Oil and Gas.** Responsible for the management and regulation of the state's oil and gas resources, including the development and implementation of a five-year lease sale program that is updated annually, and approval of plans for exploration and development for all activities on state oil and gas leases.

- **Division of Land and Water Management.** Regulates miscellaneous land use activities on state lands, including land-use permits (e.g. tundra travel, ice roads), temporary water use permits and water rights permits, pipeline right-of-way leases, and oil and gas activities not under oil and gas lease. It also reviews and comments on other state permit applications with respect to land and water use considerations.

5.2.1.2.4 Alaska Oil and Gas Conservation Commission (AOGCC)--The AOGCC manages the issuance of drilling permits and the Underground Injection Control (UIC) program used to regulate all Class 2 injection used both for enhanced oil recovery and disposal of industrial wastes which are exempt from RCRA.

5.2.1.2.5 Division of Governmental Coordination (DGC)--The DGC implements the Alaska Coastal Management Program (ACMP), including responding to federal consistency certifications required by Section 307 of the CZMA, and rendering conclusive consistent determinations for projects requiring two or more state agency or federal permits. The Alaska Coastal Management Act was passed in 1977 (AS 46.40).

5.2.3.2.6 Department of Public Safety (DPS)--The DPS is responsible for review of fire codes plans.

5.2.1.3 Local Government. The North Slope Borough (NSB) is also involved in the regulatory framework supporting oil exploration and development activities on the North Slope. Local involvement includes:

5.2.1.3.1 Oil/Whalers Cooperative Agreement--It promotes communication between Eskimo whalers and the oil activities in order to avoid interference with the subsistence hunting of whales by the Alaskan Eskimos.

5.2.1.3.2 North Slope Borough Coastal Management Program--It approves, and makes recommendations to the DGC on the "consistency" of permit applications with its program.

A summary of the typical time requirements for acquiring the necessary permits for exploration and development of oil reserves on the North Slope is provided in Table 5-2. The excessive length of time required for obtaining the permits necessary to operate on the North Slope is of importance for two reasons:

1. If several years are required to obtain drilling permits, operation of the TAPS could become uneconomic *before* oil can be produced from new fields. This could conceivably result in the premature shutdown of the TAPS, and prevent oil produced in new areas from reaching the market;

2. Long delays due to permitting times result in increases in the cost of oil production. Additional costs associated with the permitting process may cause marginally-economic fields to become uneconomic.

Table 5-2. Summary of Typical Permits Required for North Slope Oil Development[3]

PERMIT	AGENCY	PROCESSING TIME (DAYS)	
		RANGE	AVERAGE
Lease Operations Permit	ADNR	120-180	141
Miscellaneous Land Use Permit	ADNR	120-180	
Tide Lands Lease	ADNR	120-180	
Material Sales (Gravel)	ADNR	120-180	
Water Appropriations Permit	ADNR	30-60	46
Water Well Authorization	ADNR	45-60	
Right-of-Way Permit (Pipelines)	ADNR	180-270	
Archaeological Clearance	ADNR	90-180	170
Permits to Drill/Sundry Approval	AOGCC	7-14	
UIC - Class II Wells	AOGCC	7-14	
Coastal Zone Management	DGC	30-120	
Fire Code Plan Review	DPS	60-180	60
Permit of Flare	ADEC	30-60	30
Open Burn Permit	ADEC	30-60	30
Air Quality Permit to Operate	ADEC	30-90	30
PSD Air Permit	ADEC	180-360	
Solid Waste Disposal Permit	ADEC	120-180	160
Hazardous Waste Siting	ADEC	?	445
401 Water Quality Certification	ADEC	120-180	
Waste Water Disposal Permit	ADEC	60-90	90
Waste Water/Sewage Permit	ADEC	90-120	
Drinking Water System Approval	ADEC		90
Annular "Pumping" Permit	ADEC	60-120	90
Oil Spill Contingency Plan	ADEC	90-180	120
Surface Oiling Permit	ADEC	30-60	30
Food Service Permit	ADEC		60
Title 16 Permit (Fish Streams)	ADF&G	120-180	45
State Refuge Use Permit	ADF&G		30
Critical Habitat Areas Permit	ADF&G	60-90	
Alteration of Water Course (Dam)	ADF&G	90-120	
NPDES Waste Water Discharge Permit	EPA	180-360	180
Class I UIC Non-Hazardous Permit	EPA	360-1550	1000
RCRA Hazardous Waste TS&D	EPA	360-1550	1460
TSCA PCB Permit	EPA	180-720	360
SPCC Plan	EPA	60-90	
Section 404 Permit	COE	60-180	170
404 Permit Review	EPA/FWS	60-180	170
Section 10	COE	60-180	170
Bridge over Navigable Waters	COE	90-120	
Permit to Drill/Sundry Approval	BLM	15-30	20
Special Use Permit-Wildlife Refuges	FWS	90-120	
Land Use/Development Permit	NSB	30-120	45

5.3 Environmental Issues and Impacts on Arctic Alaska Development

The continued development of the North Slope of Alaska and adjacent offshore areas for oil production requires the consideration of numerous environmental issues (e.g., impacts to wetlands, air quality, and fish and wildlife). Many of the environmental impacts associated with these issues can be ameliorated through the application of mitigative measures, the types and extent of which are determined by the state and federal permitting process summarized above. A few environmental issues, however, may be controversial enough to delay further development substantially, or to even prevent development of a particular field. Specifically, three of the eight issues discussed below could *conceivably* prevent development from occurring in certain areas:

1. "no net loss" of wetlands
2. construction of solid-fill causeways
3. construction of pipelines connecting new fields to the TAPS.

Other issues, although probably not capable of preventing development independently, could increase the costs of exploration and production. Various combinations of restraints associated with these more "minor"issues could collectively preclude development in certain areas, however.

Concerns regarding the impact of exploration and development on the environment are centered on four principal activities:

1. Transportation of materials and equipment
2. Construction of pads, foundations, and pits
3. Disposal of wastes generated
4. Removal of equipment and materials after completion of the drilling.

The primary differences between the exploration and development of oil reserves on the North Slope and other areas of the U.S. involve the extreme environmental conditions found in the Arctic which impact the choice and use of oilfield technologies, the remoteness of the area, and the presence of of oilfield technologies, the remoteness of the area, and the presence of permafrost. Designs for technologies for operating at sub-zero temperatures draw heavily on advanced concepts in technologies such as metallurgy, elastomers, lubricants, and fuels. All drilling rigs and production facilities where people work must be enclosed and heated. Exterior steel structures must be built from special arctic-grade steel to prevent brittleness associated with very low temperatures. Most pipelines and flowlines are insulated either to prevent water from freezing, to avoid increased viscosity of the crude oil, or to avoid permafrost melting. Because of the harshness of the climate and the remoteness of the North Slope, typical on-site construction methods are difficult and expensive. Major North Slope facilities are therefore built in huge modules in the lower 48 states, barged to the slope, and installed on prepared foundations.

It is not the intent of this section to provide a comprehensive review of the issues facing development of the North Slope. This section contains (a) a general description of the impacts associated with each issue, (b) the jurisdiction (or permit process) of the state and federal agencies, (c) potential mitigative measures for impacts associated with each issue, and (d) the *potential* implications for future development. As stated in the introduction to this section, we have taken an objective approach to summarizing the environmental issues described below. Where two diametrically opposed viewpoints are offered by industry and the environmental groups, we have attempted to describe the differences between the opinions. In cases where many divergent opinions exist, however, only "representative" viewpoints are described. Also, since the purpose of this section is to describe how various environmental issues *could conceivably* impact development of North Slope oil resources, the impacts described necessarily represent a "worst case" scenario according to the viewpoint of the petroleum industry. This should not be misinterpreted as an endorsement of the "environmentalist" viewpoint.

5.3.1 Wetlands

The loss of wetland habitat is currently an important environmental issue related to North Slope oil development.

5.3.1.1 Impacts. Most wetlands losses on the North Slope of Alaska occur from the placement of gravel for roads and for the construction of drill pads, living areas, and pump stations.[4] This type of infrastructure is required for oilfield development and production. The gravel base for roads, etc., which is between 3.0 to 4.6 m (10 to 15 ft) thick, protect the fragile permafrost from melting. While this gravel base protects the permafrost, it also removes and alters wetlands habitat. In addition, several ancillary impacts occur as a result of this gravel base (e.g., fugitive dust, wildlife disturbance [noise], blockage of wildlife migrations, and long-term changes in drainage patterns). Oil development has directly affected about 30,000 acres of wetlands habitat in Alaska, about two one-hundredths of one percent (0.02%) of the historic level of 170 million acres.[4]

Wetlands are defined by the CWA as "*those areas that are inundated or saturated by surface or ground water at a frequency and duration sufficient to support, and that under normal circumstances do support, a prevalence of vegetation typically adapted for life in saturated soil condition. Wetlands generally include swamps, marshes, bogs, and similar areas.*" While little precipitation falls on the North Slope of Alaska, most is classified as wetlands habitat. Much of the year the North Slope is frozen and snow covered with permafrost present just below the surface year round. However, as spring and summer approach, permafrost and topography combine to create wetlands habitat. Most of Alaska's wetlands habitat occur on top of permafrost conditions.

Currently, much debate is being centered on the management, restoration, and preservation of wetlands in the United States. A major issue is the "No Net Loss" policy being considered by the U.S. Congress. Wetlands on the North Slope of Alaska are a key issue in the debate. The petroleum industry believes that inclusion of Alaskan wetlands in the "No Net Loss" policy would be inappropriate for two reasons:

- Inclusion of Alaskan wetlands in a "no net loss" policy would not offset net wetland reduction across the Nation. The loss of wetland habitat in the contiguous U.S. far exceeds that lost in Alaska. Approximately 116 million acres of wetlands in the contiguous United States have been lost. This amounts to about one-half (54%) of the originally estimated (215 million) acres. Only 99 million acres remain in the contiguous U.S. In Alaska, about 80,000,[a] acres of wetlands have been lost to all developments. This amounts to less than five one-hundredths of one percent (.05%) of the originally estimated (170 million) acres present at the time of territorial accession in 1867.[4]

  The petroleum industry contends that even with complete restoration of affected wetlands in Alaska, the overall net loss of wetland acreage in the contiguous U.S. would be offset by only seven one-hundredths of one percent (0.07%).[4]

  Post, ADFG, in his review of the Alaskan Wetland Issue, states that the loss of any wetland habitat in Alaska cannot be ignored.[5] Post contends that,[5]

  > "... *resource managers should place greater emphasis on evaluating habitat impacts ... and on implementing mitigation requirements that offset losses of wetlands in Alaska, since such losses diminish fish and wildlife populations.*"

- Wetlands in Alaska are functionally different than those in the lower 48 states.[4] Thus, they believe that wetlands on the North Slope <u>should not</u>

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a. Petroleum industry is responsible for just under 30,000 acres; 20,000 acres on the North Slope and 10,000 in the rest of the state.

be governed by the "No Net Loss" policy. The petroleum industry recommends that Arctic tundra should be exempt from any "no net loss" policy, particularly mitigation requirements for off-site compensation.

Resource agencies, however, argue that wetlands in the Arctic regions share many of the attributes of temperate wetlands, and should be included in the "No Net Loss" policy. Post, based on the majority of the literature that he examined, concludes that arctic wetlands as a whole perform the same wetland functions as temperate wetlands.[5]

Thus, research and debate continues on the function of wetlands and the importance of wetland loss in Alaska. The decision about whether to include Alaska wetlands in a "no net loss" policy will be decided in the U.S. Congress. The potential impact on oil and gas development on the North Slope of Alaska is discussed below in **Section 5.3.1.4**.

5.3.1.2 Jurisdiction/Permitting. The protection of wetlands comes under the jurisdiction of both federal and state resource agencies. The federal government protects wetlands through Section 404 of the CWA, which requires a permit to allow any filling (e.g., placement of gravel) of wetlands habitat. The permit program is administered by the COE, which is required by the Fish and Wildlife Coordination Act to consult with appropriate federal and state resource agencies prior to granting each permit. The CWA specifies that EPA shall promulgate guidelines for the COE's use in evaluating permit applications. In Alaska, the several state and federal agencies participate in the review of a Section 404 permit application, including FWS, EPA, NMFS, ADFG, ADNR, and ADEC. EPA maintains the authority to veto a project approved by the COE when the agency feels the dictates of the CWA have not been followed, or that the project would result in "unacceptable" adverse impacts (e.g., on fishery, wildlife).

In addition, the North Slope Borough's (NSB) Coastal Management Program oversees development projects on the North Slope. Proposed projects must meet the permitting requirements of the NSB and be consistent with the State of Alaska Coastal Management Program (ACMP).

5.3.1.3 Mitigative Measures. Avoidance and minimization are two strategies used by the petroleum industry to mitigate North Slope wetlands habitat reduction.[4] The most effective type of strategy involves the early planning and interaction between design engineers and environmental specialists. Facility consolidation, winter construction, and rehabilitation research are used to help reduce the impact of development.

The petroleum industry believes that the present permitting system and mitigative efforts are sufficient to protect Alaska wetlands habitat. Several Acts and permit systems are designed to protect wetlands habitat. Through the permit process, impacts and mitigative measures are evaluated to ensure that the least possible harm is done to wetlands habitat.

Several comprehensive wetlands habitat bills have recently been introduced in Congress. These include: The Wetlands No Net Loss Act of 1989 (H.R. 1746), North American Wetlands Conservation Act (S. 804), and North American Wetlands Conservation Act (H.R. 2587).

These nationwide policies are being considered to achieve *no overall net loss* of the Nations's wetlands habitat. This policy would require the replacement or restoration of wetlands habitat adversely affected by development. While these policies are not yet in effect, the FWS is using a <u>working definition</u> of the "No Net Loss" policy: *wetlands gains must offset losses both in function and acreage.*

EPA and the COE signed a memorandum of agreement Feb. 7, 1990, that clarified the environmental criteria to be used in evaluating compliance with the Section 404(b) guidelines. EPA and the COE point out that the memorandum is only a "guidance" document to be used by field offices to evaluate mitigation proposals in permit applications. The guidelines provide for avoidance, minimization, and compensatory mitigation for wetlands conversion. The guidelines also allow for a wetlands "bank". The President's Domestic Policy Council is currently working to develop specific guidelines for the establishment of a wetlands bank and for use of it as compensatory mitigation for projects that destroy or damage wetlands.

5.3.1.4 Implication for Future Development. National policies (e.g., U.S. Congressional decision on the "No Net Loss" issue) and permits (e.g., Section 404 of the CWA) regulating wetlands habitat will have a significant affect on future development and production of oil reserves on the North Slope of Alaska. Since most of a North Slope is considered wetlands habitat, a strict enforcement of the "No Net Loss" policy would effectively prevent further development and production of oil on the North Slope. On Alaska's North Slope, mitigation or compensation of wetland habitat losses would not be possible under a strict interpretation of the "No Net Loss" policy. It would be nearly impossible to avoid loss of wetlands habitat on the North Slope. Avoidance would be the only mitigative strategy in the presence of a National "No Net Loss" policy. Using the FWS's current *working* definition of "no net loss", replacement of affected wetlands habitat would not be a viable alternative on the North Slope.

However, in previous development projects, the FWS suggests that wetlands habitat in areas of known oil reserves be protected from future development as replacement for wetlands habitat lost elsewhere.

If the "No Net Loss" policy is not adopted or is adopted excluding Alaska, the permit system presently in place will regulate wetland habitats. The present permit system will likely continue to allow development of wetland habitats. The petroleum industry believes that the present system of permits adequately protects wetland habitats on the North Slope of Alaska.[4]

5.3.2 Causeways

Issues related to the construction and use of solid-fill causeways are currently being debated between industry, environmental groups, and various state and federal agencies. The future of development of several known and suspected reservoirs may ultimately be dependant on the outcome of these debates.

5.3.2.1 Impact. Future offshore oil and gas development in the Arctic will likely involve the transportation of offshore-produced fluids onshore, as well as the transport of equipment onshore. One of the proposed methods for transversing the nearshore areas is through pipelines supported by solid-fill gravel causeways.[6] Causeways simply provide an elevated surface consisting of gravel that extends for some distance offshore.

Two types of solid-fill gravel causeways can be defined, unbreached and breached.[7] Unbreached causeways provide a continuous road-pipeline corridor made of gravel extending offshore to a pump station. A breached causeway has one or more areas spanned by bridges. These breaches or open areas allow water and fish movement through the causeway.

On the North Slope of Alaska, solid-fill causeways are used to:

- access deeper water for enhanced oil recovery
- dock barges carrying large modules and other equipment
- access nearshore production facilities and to support pipelines for transportation of produced fluids through nearshore areas.

To-date, breached causeways have been constructed for oil and gas production (Endicott) and to provide for waterflooding and docking (West Dock).

Several hypotheses exist regarding the potential impact of solid-fill causeways on the environment. The general focus centers on changes to temperature and salinity distribution patterns in nearshore areas.[8] The EPA has identified several major concerns relating to the effects of solid-fill gravel causeways on nearshore oceanographic processes in the central Alaskan Beaufort Sea.[9] These impacts proposed by EPA include:

- alteration of natural flow patterns along the coast by deflecting relatively warm brackish water offshore

- modification of regional upwelling processes, allowing cold marine water to enter shallow nearshore areas

- offshore deflection of the coastal plume and enhanced upwelling resulting in discontinuities in the once continuous coastal band of relatively warm brackish water.

In addition, alterations to the physical processes and the temperature and salinity distribution patterns may impact anadromous fish and their habitat.[9]

BP Exploration states that many of the impacts attributed to causeways, are *natural processes* occurring on a regional scale and are therefore independent of solid-fill gravel causeways.[10] Conversely, EPA has concluded that causeways are responsible for significant adverse changes to nearshore circulation patterns, and that these changes degrade habitat for anadromous fish.[9]

In response to EPA's position, BP Exploration claims that EPA's conclusions were not consistent with the data collected since 1981 at part of the Endicott and West Dock monitoring programs.[10] It is the industry's contention that:

1. Only localized and transitory changes to water temperature and salinity have been identified.

2. Regional scale processes are not affected by causeways and shallow nearshore areas are not now more saline or colder than they were prior to causeway construction.

3. There is no evidence, either historic or recent, to suggest that the nearshore area was ever a continuous band of relatively warm brackish water.

In a review of causeway reports, the COE Waterways Experiment Station has noted that the important linkage between changes to fish habitat and changes or harm to fish populations has not been established.

The petroleum industry is continuing to fund monitoring studies required by regulatory and resource agencies on the effects of causeways to fish and to their habitats in the nearshore areas.

5.3.2.2 Jurisdiction/Permitting. The protection of nearshore and open water areas comes under the jurisdiction of both federal and state resource agencies. The federal government protects these nearshore and open water areas through several Acts including Section 404 of the Clean Water Act, which governs placement of fill in "navigable waters" (see **Section 5.3.1.2**).

The Alaska District Office of the COE has issued an "advanced" Public Notice providing guidance to the oil and gas industry on the construction of gravel-fill causeways (breached and unbreached) compared to other alternatives. In this guidance document, the COE has designated the following access methods to be less environmentally damaging alternatives:

- Directional Drilling
- Subsea pipelines
- Elevated pipelines
- Elevated causeways.

The advanced Public Notice states that "The *practicability* of each of the above [alternatives] must be refuted by the applicant on a case by case basis... ." Other uses of causeways for transportation and docking facilities and their need for access to deeper waters are specifically excluded from application of this guidance.

The petroleum industry believes the proposed policy is incompatible with the existing legal framework for promulgation of policy. Industry believes that the COE's action constitutes an attempt to exercise power granted under Section 404(c) to EPA. The industry views the causeway policy as a general denial for a specific type of project (gravel causeways for oil and gas development); an action that is not allowed by COE regulations. Further, the proposed "policy statement" would be an unauthorized intrusion into the rights of the states to manage and develop lands and leases under their jurisdiction. Finally, the petroleum industry believes that the COE, in drafting this policy, has ignored the results of over ten years of studies conducted on existing causeways.

The CZMA provides a cooperative federal-state mechanism to protect the coastal zone and resolve conflicts among competing uses. Section 307, the Federal Consistency Provision, requires that applicants for federal licenses and permits affecting the coastal zone certify that their activities, including those on the outer continental shelf, are consistent with approved state programs. The CZMA is administered by the U.S. Department of Commerce (see **Section 5.2.1.1.4**, *Coastal Zone Management Act*). The State of Alaska and the North Slope Borough have approved Coastal Management Programs.

The Endangered Species Act, 1973, requires federal agencies not to take any action (e.g., issue permits) that might "jeopardize the continued existence of an endangered species." Section 7 of the Act requires consultation with the FWS or NMFS, if an endangered species is involved (see **Section 5.2.1.1.7**, *Endangered Species Act*).

The Marine Mammal Protection Act (MMPA), 1972, with certain exceptions, prohibits the "taking" (e.g., harass, hunt, capture, or kill) of marine mammals. The FWS is responsible for sea otters, walrus, and polar bears; the NMFS is responsible for seals, sea lions, whales, and porpoises (see **Section 5.2.1.1.9**, *Marine Mammal Protection Act*).

The Outer Continental Shelf Lands Act, 1953 provides the federal government with jurisdiction over submerged lands seaward of state boundaries. The Act requires that the leasing program be tempered to ensure fair market value, and protection of the human, marine and coastal environments (see **Section 5.2.1.1.11**, *Outer Continental Shelf Lands Act*).

The North Slope Borough's Coastal Management Program oversees development projects on the North Slope. Proposed projects must also meet the permitting requirements of the NSB Land Management Regulations.

5.3.2.3 Mitigative Measures. Breaching (creating a bridged gap in the causeway) is the primary means of mitigating impacts to fish migration. Several alternatives exist to a breached, solid-fill gravel causeways, each with their own set of environmental impact (see **Section 5.3.2.2**).[7] The petroleum industry, resource agencies, environmental consultants, and regulatory agencies disagree over the environmental impacts of the different methods for accessing nearshore oil and gas reserves. While all of the above alternatives are technically feasible, some will require more technical development and environmental analysis than others. Thus, the reliability of estimates of construction cost, schedule, and environmental impacts varies considerably among the alternatives.

5.3.2.4 Implication for Future Development. Because of the Alaska District COE guidance relating to the construction and use of gravel causeways for petroleum development, permits for solid-fill causeways will be difficult to obtain in the future. Recently, the Atlantic Richfield Company of Alaska (ARCO) elected to drill from shore, using directional drilling technology, instead of building the proposed Lisburne Causeway. ARCO felt that directional drilling, in this case, was an economically viable alternative to causeway construction.[11] It is likely that the COE will recommend alternatives to solid-fill gravel causeways in future nearshore oil exploration and development.

The recently proposed "policy statement" by the COE would force the petroleum industry to demonstrate that all alternatives to the solid-fill gravel causeway are not feasible (as described in **Section 5.3.2.3**). The petroleum industry contends that all of the alternatives are likely to result in additional capital or operation and maintenance costs, which could potentially make otherwise economic fields uneconomical. Also, some of these alternatives, especially those involving the use of buried pipelines, may cause more environmental damage (e.g., due to oil spills) than would solid-fill causeways.

5.3.3 Pipeline Issues

A third important issue to the development of oil resources in the future involves the construction of additional pipelines in the Alaskan Arctic. Future onshore and offshore oil and gas development in the Arctic would likely involve the construction of pipelines to connect newly-developed fields to the existing TAPS pipeline.

5.3.3.1 Impacts. Most credible scenarios for future development of North Slope petroleum resources call for the construction of two major pipeline systems; one to the east and one to the west of the TAPS pipeline. The first will connect the 1002 area of ANWR to the TAPS, while the other will connect the Chukchi Sea development area with the TAPS. These two systems are described below:

- **ANWR:** Administered by the DOI-FWS, as part of the National Wildlife Refuge system, ANWR is located along the Canadian border in the extreme northeast corner of Alaska, with its western boundary some 60 miles to the east of Prudhoe Bay. The expected method for transporting crude oil to market from the ANWR 1002 area involves the construction of an east-west pipeline connecting the 1002 area oil fields with TAPS. This route roughly bisects the 1002 area before crossing state lands and meeting TAPS at Pump Station No. 1 or Pump Station No. 2 using an elevated pipeline. The exact location of the pipeline would be determined by the locations of oil discoveries, both within the 1002 area and on State Lands west of ANWR. It is expected that the route would be adjusted so as to minimize the impact to surface resources and to meet engineering requirements.

- **Chukchi Sea:** The Chukchi Sea lease area is located off the northwest shore of Alaska. One of the primary concerns regarding development of oil resources in the Chukchi Sea (as well as the Beaufort Sea) involves the construction and use of pipelines to transport the oil to shore and subsequently on to market. Subsea pipelines are expected to carry the oil produced in the Chukchi Sea to an onshore pipeline that will connect with TAPS at Pump Station No. 2. Pipeline landfall would be expected to occur at or near Point Belcher, in part due to its proximity to the western extent of the Beaufort Sea Sale 97 area, which that could theoretically share facilities and pipelines.

The preferred alternative for transporting oil from the Chukchi Sea to TAPS is through a pipeline extending about 650 mi, approximately following the 700 ft contour, crossing the Colville River near Umiat, and connecting to TAPS at Pump Station No. 2. Such a pipeline would cross approximately 10 rivers and large tributaries. The exact route of the pipeline would vary if production within the NPRA or the Beaufort Sea could be served by such a pipeline, or depending on where gravel sources are more accessible. A service road would be constructed paralleling the pipeline, to be maintained as a private road. The off-shore pipeline would be laid in a trench to ensure that it is not damaged by drifting ice masses. Pipeline placement below the level of ice-gouging would be required in the area where ice gouging could occur.

Impacts associated with the construction and maintenance of such pipelines include disturbance of caribou, Arctic peregrine falcon, reduction of habitat (e.g., fish habitat at stream crossings and wetlands habitat), water quality, and potential increases in hunting pressure. Pipeline spills resulting from corrosion of the pipelines or other factors are also potentially of concern.

A site-specific assessment of pipeline construction from landfall areas to TAPS is discussed in the *Beaufort Sea Planning Area Oil and Gas Lease Sale 124* Draft EIS[12] and the *Chukchi Sea Oil & Gas Lease Sale 109* Final EIS.[13] These EIS's identify several concerns on caribou and other wildlife resources from pipeline construction. These include: (1) disturbance and displacement of caribou and other wildlife within a few miles of the corridor, (2) local reductions in habitat use by some caribou (particularly cows and calves) and other wildlife within about 1 mi (1.6 km) of the corridor, (3) increases in hunting pressure, (4) contamination of rivers due to oil spills, and (5) reductions in water quality and fish habitat due to increases in erosion.

The petroleum industry believes much of the current information on the impacts of oil exploration and development related to caribou has been misinterpreted by the fish and wildlife resource agencies. They cite current population numbers as evidence that any effects generated by oilfield operations have been small.

5.3.3.2 Jurisdiction/Permitting. The construction of pipelines and associated developments (e.g., roads along corridor) are governed by federal and state regulations. The Clean Water Act, Endangered Species Act, and Fish and Wildlife Coordination Act require certain permitting processes to be followed. A Legislative Environmental Impact Statement prepared by the DOI recommends that the Congress of the United States ... "*enact legislation directing the Secretary [of Interior] to conduct an orderly oil and gas leasing program for the 1002 area at such pace and in such circumstances as he determines will avoid unnecessary adverse effect on the environment.*"[2] There as been much opposition to the leasing of land in ANWR for oil and gas exploration and development. Currently, the U.S. Congress is considering a recommendation to allow exploratory drilling in ANWR.

The COE and EPA are considering methods to facilitate the processing of Section 404 permits (Clean Water Act). The COE announced, on April 19, 1989, that the EPA proposes to take action in accordance with Subpart I of the Section 404(b)(1) guidelines, *Planning to Shorten Processing Time*, specifically 40 C.F.R. Section 230.80. This has resulted in an "advanced identification process." The purpose of the Advanced Identification Process (ADID) is to provide information to shorten individual or general permit application and processing.

The petroleum industry believes that the ADID would not facilitate the permit process. Also, they believe the scientific basis for the process is unsound. In addition the ADID does not take into account (1) that Congress has provided for development of state owned land, (2) the rights in property of leaseholders, (3) alternatives to the process, and (4) the adequacy of existing regulatory programs.

5.3.3.3 Mitigative Measures. Several strategies have been used to mitigate the potential impacts of pipelines on wildlife populations. These include: (a) adjusting pipeline height, (b) separating the pipeline from a busy road, (c) providing ramps for caribou to cross, (d) routing roads to avoid major migration routes, and (e) construction during the winter. Robertson and Curatolo found that the best mitigative technique includes elevating the pipeline 5 ft. (1.5 m) above the tundra and separating the pipeline at least 400 ft (122 m) from roads with traffic.[14]

Pipeline spills can be largely avoided through routine maintenance and repair activities and other preventative actions. Spill response activities can help to minimize the impacts associated with pipeline spills.

5.3.3.4 Implication for Future Development. The Legislative EIS and subsequent decision by Congress and the ADID could significantly affect future pipeline construction on the North Slope. A decision by Congress not to allow oil and gas exploration and development in the ANWR would preclude the need for pipelines east of the Canning River Delta. This would effectively shutdown further development of oil reserves on the North Slope east of the Canning River Delta.

The ADID would identify areas sensitive to development (e.g., important wildlife habitat). Gravel removal and gravel placement for construction of pipeline-road corridors, drilling pads, etc. would not be permitted in sensitive areas. The ADID, if adopted in the Colville River Delta, would preclude from development large areas of the delta. Designation of the Colville River as "Special Habitat Area" by the U.S. Fish and Wildlife Service could prevent the construction of the pipeline and service road, or at the least result in the use of a significantly different, more costly route. If applied in the same manner elsewhere, such as the coastal plain of ANWR, those areas may also become inaccessible to oil exploration and development. In addition, development in large areas to the west of the Colville River may also be precluded. It would be difficult, for example, with large areas removed from development, to find pipeline-road corridors through the Colville River Delta to reach oil and gas resources in NPRA or the Chukchi Sea. Construction of corridors around the delta may be too costly.

5.3.4 Air Quality

Air quality is dependant on meteorology, geography, and the types of fuel and equipment used. Meteorological conditions that govern the transport of air pollutants generated on the North Slope differ from those found in the rest of the United States. Harsh climatic conditions found on the North Slope dictate that oil and gas processing equipment be designed in a modular arrangement. Exhaust stacks are usually kept short, due to the high winds typical of the North Slope. A small number of centralized facilities are used where gathering and production activities are concentrated.

5.3.4.1 Impacts. The primary sources of air emissions from current North Slope oil and gas production facilities are turbines and process or utility heaters fired by natural gas. This equipment is required to supply the power necessary to produce and transport crude oil and natural gas, to separate gas, oil, and water, and to reinject gas and water into the reservoir. Due to their size, number, and proximity to one another, these sources are considered to be the dominant contributors to North Slope emissions inventories. The Alaska Oil and Gas Association has recently proposed a study to determine the fate of flue gasses generated on the North Slope.

The principal emissions of concern from natural-gas fired turbines located on the North Slope are nitrogen oxides (NO_x), although varying quantities of particulate matter, sulphur dioxide (SO_2), carbon monoxide (CO), and hydrocarbons (HC) are also emitted. Emissions of the other CAA priority pollutants are minimal. Emissions of SO_2 are small because the H_2S content of North Slope natural gas is very low (10 to 15 ppm). The natural gas is free of lead, so lead emissions in the area are also negligible. Low concentrations of CO (10 ppm or less) can be attributed to the nearly complete oxidation of the carbon in the fuel. Hydrocarbon emissions, the precursors to O_3, are minimal. Natural gas and dry controls incorporated into the combustion chamber design result in the control of NO_x emissions from the gas turbines. Other priority pollutants are also limited by the fuel type used, which contains low concentrations of sulphur and ash.

The maximum annual concentrations of NO_2 from various North Slope oil and gas operations, as predicted by dispersion modeling, are summarized in **Table 5-3**. These model predictions have been shown to be conservative, as monitoring conducted since the modeling has shown that actual NO_2 concentrations are considerably lower that the predicted values from these models. Even the highest annual concentration immediately downwind of the facilities listed above are below the 100 $\mu g/m^3$ permitted values (see **Section 5.3.4.2.1**).

Table 5-3. Predicted Maximum Annual NO_2 Concentrations

	NO_2 Concentration ($\mu g/m^3$)
Prudhoe Bay Unit	62.6
Kuparuk Unit	48.4
Lisburne Development Unit	14.0
Endicott Development Unit	73.0
Milne Point Project	10.0

• **Flare System.** Part of the necessary safety system associated with oil processing facilities is a flare system to which, under normal conditions, excess gas is diverted and burned cleanly. Under occasional abnormal operating conditions when the exact mixture of gases and heat cannot be controlled (i.e. equipment failure), a build-up of excessive gas pressures may occur. For the purpose of safety, this build-up must be relieved immediately by diverting large volumes of gas to a secondary burning system. These occurrences, which are infrequent and short lived, generate a sooty "black smoke." Although combustion remains around 95% complete, the black smoke generated in this manner is visible, resulting in a brief degradation of visibility that can extend for over 100 miles, as well as contributing to the atmospheric concentrations of criteria pollutants. The principal components of the unburned fraction are CO, CH_4, and soot. Even an emission concentration of 0.5% soot results in a sooty appearance for the flame.

• **Arctic Haze.** Arctic haze was first described as early as 1956 - well before any oil development on the North Slope. Arctic haze is believed to result from the long-range transport of minute particulate and aerosol pollutants originating in the industrial areas of the middle latitudes of Eurasia. Concentrations of arctic haze are typically low at ground level, increase with elevation to a maximum concentration usually at an altitude of several thousand meters, before eventually decreasing. Arctic haze over the North Slope oil fields is found at altitudes ranging from several hundred to 6000 m. A stable arctic boundary layer tends to reduce mixing from aloft to the surface. Because the haze is present at high altitudes above the Prudhoe Bay oil fields, local emission sources are not believed to contributor.

A fingerprinting process has indicated that emissions typical of Europe and Asia match those found in the arctic haze.[15,16] The haze undergoes a pronounced seasonal variation characterized by a winter maximum and a summer minimum. This pattern can be correlated with the seasonal variation exhibited in atmospheric transport and removal mechanisms associated with pollutant transport from the middle latitudes of Eurasia. Data collected near the ground surface, which included emissions from the Prudhoe Bay facilities does not match the fingerprint of the high altitude arctic haze. Overflight data from NOAA has indicated that North Slope oil and gas production does not contribute to the arctic haze.

• **Local Visibility.** An additional problem related to North Slope oil production activities, as recognized by the ADEC, involves reductions in local visibility due to locally-generated air pollutants. These impacts may result from various pollutants generated by turbines and process or utility heaters fired by natural gas, or from fugitive dust generated by transportation, construction, and other physical activities. The flare system may also be involved with the generation of local visibility problems.

5.3.4.2 Jurisdiction/Permitting. The ADEC is responsible for air quality control, new source performance testing, black smoke reporting, ambient air monitoring, and PSD permitting. Both the EPA and the ADEC have established limits for atmospheric pollutants on the North Slope.

5.3.4.2.1 EPA Air Quality Standards. NAAQS requirements of the CAA established safe levels for ambient concentrations of six priority pollutants: CO, O_3, NO_2, SO_2, Pb, and total suspended particles. These levels represented the maximum concentrations of these pollutants allowable in the ambient air. Both primary and secondary standards have been issued for each criteria pollutant, based on various time frames for measurement of ambient airborne concentrations (e.g. 3 hours, 24 hours, one month, etc.). These standards are shown in **Table 5-4**.

Table 5-4. Federal and State of Alaska Air Quality Standards ($\mu g/m^3$)

Pollutant/Time Frame	NAAQS Primary	NAAQS Secondary	ADEC
NO_2 annual average	100	100	100
O_3 1-hour maximum	235	235	235
CO 1-hour maximum	40000	40000	40000
CO 8-hour maximum	10000	10000	10000
SO_2 3-hour maximum	---	1300	1300
SO_2 24-hour maximum	365	---	365
SO_2 annual average	80	---	80
TSP 24-hour maximum	260	150	150
TSP annual geometric mean	75	60	60
NMHC 6-9 a.m. maximum	160	160	160

The 1977 amendments to the CAA required that limits be established for allowable *increases* in ambient concentrations in those areas meeting the NAAQS values. This provision is referred to as the "Prevention of Significant Deterioration" (PSD). Incremental limits were then established to ensure that the air quality would not deteriorate in these so-called "attainment areas." In a relatively clean area such as the North Slope, therefore, these incremental limits would prevent pollutant concentrations from ever reaching the maxima established by the ambient standards.

The CAA also requires pollutant source controls to comply with the "best available control technology" (BACT) for existing sources, and "new source performance standards" for major new sources or major source modifications. The CAA established National Emission Standards for Hazardous Air Pollutants (NESHAPS), and "prevention of significant deterioration" (PSD) increments for SO_2, NO_x, and particulates in Class I and Class II areas.

5.3.4.2.2 **ADEC Permitted Levels.** ADEC permits obtained for North Slope operations currently require that any single gas-fired turbine emit less than 150 ppm NO_2. Predicted maximum annual NO_2 emissions are provided for the existing North Slope operations. Permits are for NO_2, so the listed NO_x values are conservative. ADEC permitted atmospheric pollutant levels are also shown in **Table 5-4**. Concentrations generally approach background levels within approximately 3 to 5 km downwind. ADEC permitted emission *volumes* are shown in **Table 5-5** for the current oil production activities on the North Slope.

Table 5-5. North Slope Permitted Atmospheric Emission Estimates (ton/y)

	NO_x	SO_2	CO	HC	PM
Prudhoe Bay Unit	52118	181	12276	3200	1802
Kuparuk Unit	12926	84	2564	47	340
Lisburne Development Unit	2203	257	624	15	88
Endicott Development Unit	6355	78	1200	726	120
Milne Point Project	766	18	139	165	16
TOTAL	74368	618	16803	4153	2366

5.3.4.2.3 **Determination of Compliance**-- Compliance with air quality regulations is determined through the institution of stack testing and air monitoring programs.

• **Stack Testing.** Routine for new equipment and must follow testing procedures mandated by EPA. Each type of turbine or heater is tested on the North Slope by an independent third-party contractor soon after the equipment is put into operation to verify that the emission limits for criteria pollutants of concern are met. A representative of the ADEC is typically present to monitor these tests. Procedures for carrying out these tests is in 40 CFR 60. To date, the North Slope equipment consistently meets NO_2 permit requirements, and generally produces emissions well below mandated limits.[17]

• **Air Monitoring.** An air monitoring program on the North Slope was conducted by the operators of the Prudhoe Bay oil fields from April 1979 through March 1980 to determine the ambient quality prior to the start of a major expansion program. This program was required by EPA prior to obtaining permits for the proposed facilities. Ambient levels of all air pollutants measured during this program were below the limits set by national standards, with the exception of a single instance when the primary standard for total suspended particulates was exceeded. This event was attributed to wind-blown dust rather than equipment emissions.

Baseline air quality levels were determined from this monitoring program, from which the incremental limits for SO_2 and particulates could be established. As the result of the facility expansions, another monitoring program was required following construction. A post-construction monitoring program was required to determine whether the only criteria pollutant (NO_2) was meeting the national standards, and whether the general air quality in the vicinity of Prudhoe Bay was sufficiently below the established standards so as to allow continued industrial expansion. Ambient air monitoring programs were initiated at Kuparuk and at Prudhoe Bay in 1986 to monitor the post-construction ambient air quality. These programs, which are being implemented by third party contractors, were developed in cooperation with EPA Region 10 and the ADEC, and remain in operation, and involve the use of "near-field" and "far-field" monitoring stations at both Kuparuk and Prudhoe Bay. The "near field" stations were established to assess the ambient air quality at the site of each unit, while the far-field stations assess background air quality levels several kilometers downwind of the production facilities. Air monitoring data collected from the programs must follow EPA guidelines for reporting, site surveillance and quality control.

All measurements taken to date indicate pollutant levels significantly below the most stringent standards, with the occasional exception of wind-borne particulates. These occasional particulate levels are high only during the brief summer. Data collected indicate that CO and O_3 levels are well below the levels set by the most stringent standards. Due to a lack of sources, lead is not being measured.

Table 5-6 contains a summary of air quality monitoring data collected at the Prudhoe Bay Unit during the 1989 calendar year. The ambient air quality data measured during this 12-month period were well below the Alaska and National ambient air quality standards established by either the ADEC or the EPA, which are also shown in **Table 5-5**. The data is collected at the Central Compressor Plant (CCP) and the Well Pad A (A PAD) monitoring stations.

5.3.4.3 Mitigative Measures. Mitigative measures with respect to air quality include the potential for retrofitting existing pollutant sources with additional pollution-control devices. These could be the result of the BACT provision of the CAA, or could be included as specific requirements of the individual permits. More stringent permitted emission levels could also result in the need for retrofitting.

Table 5-6. Actual measured concentrations of atmospheric pollutants, January - December, 1989.

POLLUTANT	MEASURED CONCENTRATION ($\mu g/m^3$) CPP	A PAD	EPA/ADEC STANDARDS
NO^2			
Annual Mean	13.2	9.4	100
O_3			
Maximum 1-hour	105.8	119.6	235
SO_2			
Maximum 3-hour	15.7	--	1300
Maximum 24-hour	13.1	--	365
Annual Mean	<7.9[a]	--	80
TSP			
Maximum 24-hour	54.0	--	150
Annual geometric mean	6.3	--	60
IP			
Maximum 24-hour	24.1	--	150
Annual Mean	5.7	--	50

a. At or below the minimum detection limit of 7.9 $\mu g/m^3$

5.3.4.4 Impact for Future Development. The costs associated with complying with air pollution standards are considered part of the normal operating costs for a given development project. While not insignificant, it is not expected that these costs would prevent the development of a particular oil field. Regardless, there are three factors related to air quality that deserve discussion regarding future North Slope oil development:

• **Incremental Limits**--The entire North Slope of Alaska is, for regulatory purposes, considered an "attainment area", and is therefore subject to the incremental limits established under the 1977 amendments to the CAA. These increments, which are based on baseline air quality levels, are added to the baseline conditions, establishing new standards that are more stringent than the NAAQS. For example, if the baseline level of particulates in an area is 11 ug/m^3, and the allowable incremental increase is 37, particulate concentrations from all sources, including new ones, cannot exceed 48 ug/m^3. This incremental limit is in effect the new standard for the area, and is much more stringent than the national standard of 260 ug/m^3 for particulates. Increments have been established for particulates and SO_2 and NO_x. The CAA also established three different regional classifications, each with its own allowable increment. The North Slope is designated a Class I, or pristine area, with minimal industrial growth, and therefore have the lowest allowable increments. Only minimal increases are allowed in concentrations of particulates and SO_2 compared to the baseline levels.

To meet with the more stringent requirements recommended by the ADEC, wet controls would be necessary.[18] The excessive cost associated with the acquisition and treatment of water for wet control and the problem of freezing water lines and excessive formation of ice fog contribute to the low feasibility of this control method.

Imposition of more stringent NO_2 source emissions requirements, such as proposed NO_x emission limits of 100-125 ppm,[18] may result in added costs.

• **Best Available Control Technology (BACT)/New Source Performance Standards**-- Since the PSD regulations went into effect, both existing and new emission sources in attainment areas are required to use the "BACT" to minimize their emissions. New sources of atmospheric pollutants must also meet the set of national emission limits referred to as "new source performance standards". These regulations establish limits on the emissions from new sources. A new emission source is therefore evaluated by the amount it will contribute to the levels of pollutants in the air within the locale of the source. Before an operating permit can be obtained for a source, analyses of the local air quality and the emission control technology that will be used must be performed. The air quality analysis usually consists of:

1. An examination of the pre-construction ambient air monitoring data to determine existing air quality

2. Dispersion modeling to predict impacts from the new facility.

This air quality analysis must show that continuous operation of proposed emission sources, in conjunction with the emissions from the new facilities, will not exceed the national standards. In addition, the allowable incremental limit for increases in ambient concentration of total suspended particulates and SO_2 must be met.

An analysis of the technology must also be completed to examine the methods used to control emissions from the proposed source. Regulations stipulate that facilities must use the best available technology, which environmental, energy, and economic impacts from proposed sources to consider, and sets the maximum permitted emissions from the exhaust of the equipment. These maximum permitted emissions must be at least as stringent as the new source performance standards. Following startup of a new facility, "stack tests" are performed to measure actual emissions from the source to determine compliance with the permit levels.

Control equipment proposed for new sources must represent the "best available control technology" (BACT). This is defined as the "emission limitation which represents the maximum reduction achievable for each regulated air pollutant, taking into account energy, environmental, and economic impacts and other costs; the resulting emissions must comply with applicable emission standards." The BACT emission limit must be at least as stringent as that established under Section 111 or 112 of the CAA (Standards of Performance for New Stationary Sources (NSPS) and the NESHAP. Interpretation of the "BACT" by the ADEC could result in permits being dependant on the implementation of new, more costly pollution control equipment.

• **Ban on Use of Halon Gases**-- Pursuant to the CAA and the Montreal Accord, the production and use of halon gases will be restricted by EPA beginning in 1992. The goal is a total phase out of the use of these materials by the year 2000. These gases are among the class of materials that has been implicated in the destruction of the stratospheric ozone layer, and their ban could have a significant impact on oil production on the North Slope. Specifically, Halon 1301 ($CBrF_3$) and 1211 (CF_2ClBr) are used in oil production activities as fire extinguishing agents and for the prevention of explosions. These materials are colorless, odorless gases that have low toxicity and are extremely effective as fire extinguishing agents. Because most North Slope equipment is physically enclosed within modules, fire suppression equipment must be non-hazardous to personnel and non-destructive to oil and gas processing equipment. These gases meet these criteria. Halon 1301 is the only gaseous extinguishing agent accepted for use in occupied areas by the National Fire Protection Association.

Several methods have been proposed by the United Nations Environmental Program for reducing halon use, and where possible these methods have been applied at existing North Slope facilities. It is doubtful that these alternatives could completely replace the use of halon gases while maintaining the level of safety and other advantages offered by their use.

5.3.5 Waste Disposal

5.3.5.1 Impacts. The impacts associated with waste management practices on the North Slope are dependant on the waste type, the volume of waste generated, and the treatment and/or disposal methods used. These variables are described below.

5.3.5.1.1 Wastes Generated--A number of different classifications of waste are generated on the North Slope. Some are directly related to oil production while others result from support activities. Most of the oilfield wastes generated on the North Slope are not hazardous, and of those that are, some are regulated under RCRA regulations whereas others are not.

5.3.5.1.1.1 RCRA Exempt Wastes--Wastes uniquely associated with oil and gas exploration and production operations are exempt from regulation under the RCRA hazardous waste regulations. These wastes include drilling muds, drill cuttings, produced water and associated wastes, and consist primarily of natural substances contaminated with very small concentrations of chemical additives.

• **Drilling Muds.** Fluids which are typically comprised of water-based mixtures of clays and weighting materials, to which small amounts of various materials have been added. Drilling muds serve to lubricate the drill bit and helping to control pressures in the underground formations. Drilling muds also help to prevent uncontrolled releases of oil or gas from the well. Muds are normally recycled several hundred times during a drilling operation. This recycling involves cleaning the circulating mud to prevent buildup of drill bit cuttings and other solids in the mud. Occasionally, an oil-based mud is used to drill a well. This mud is recycled as much as possible, and then injected for disposal. Drilling muds have a variety of brand names, but all consist of three basic components: a base liquid (typically fresh or salt water), a viscosifier (a clay and/or polymer), and a weighting material (commonly barite). A mix of special additives may also be used to enhance properties of the mud and meet the range of temperature, Ph, viscosity, deflocculant and corrosion needs.

• **Drill Cuttings.** Small fragments of rock and soil that are removed from the well bore by the drill bit. These materials are removed from the drilling muds when the muds are recycled.

• **Produced Water.** Groundwater that comes to the surface mixed with oil, and which must be separated from the oil before the oil can be sent to TAPS. This separation of water from crude oil occurs at the gathering centers and flow stations. The majority of the roughly 750 MBPD of produced water handled in the Prudhoe Bay field is reinjected into the oil reservoir as part of waterflood or enhanced oil recovery (EOR) projects. The remaining produced water, not suitable for use in EOR programs is injected in approved disposal wells with Class II injection permits.

• **Associated Wastes.** Include all other types of wastes generated by various processes associated with oil and gas production. Approximately 650,000 barrels of associated wastes are produced in the Prudhoe Bay oil field each year. Most of these wastes are water-based wastes containing suspended solids and oil. Some of the "associated wastes" are potentially hazardous due to their hydrocarbon content. These wastes are covered by the RCRA oil and gas exemption, and include the following;

- Tank bottom sludges
- Spill residues and contaminated soils
- Truck/tank/cellar wastewaters
- Dehydration unit wastes from the gathering centers
- Pipeline pigging wastes
- Wastes from well workovers
- Miscellaneous wastes.

5.3.5.1.1.2 RCRA Wastes--Wastes that are not intrinsically associated with the exploration and production of oil or gas resources are not exempt from the RCRA hazardous waste regulations. These include primarily those wastes generated by service contractors.

5.3.5.1.1.3 Solid Wastes-- At Prudhoe Bay, non-hazardous wastes are disposed of at a solid waste landfill located at Deadhorse that is administered by the North Slope Borough.

5.3.5.1.1.4 Radioactive Wastes-- Drilling operations could generate small quantities of radioactive wastes. These can be generated when drill pipes are cleaned to remove the scale that accumulates on the surfaces. Depending on the uranium and thorium content of the strata through which the core was drilled, the scale may contain small quantities of these materials and their radioactive daughter products (including radium and radon).

5.3.5.1.2 Disposal Methods-- Traditionally, drilling muds and cuttings have been disposed of in unlined reserve pits built as part of the gravel pads. Centralized reserve pits were used at each pad. Under current operating practices, only water-based drilling muds are placed in reserve pits. The petroleum industry has discontinued the practice of using reserve pits for the disposal of oily muds and cuttings and associated wastes on the

North Slope. Current management practices include the storage of solids in completely lined surface impoundments and injection of liquids in Class II disposal wells. In 1988, the Prudhoe Bay oil field produced approximately 560,000 bbl of muds and cuttings. About 62% of this waste was injected into the ground, while 32% was placed in reserve pits. As of 1989, there were over 250 reserve pits in existing developments on the North Slope, ranging in capacity from 4.5 to 13.5 million gal of used drilling mud, cuttings, and associated wastes. Liquid reserve pit wastes contain small amounts of metals (e.g. aluminum, arsenic, barium, cadmium, chromium,lead, mercury, silver, and zinc), along with aromatic hydrocarbons (derived from oil-bearing formation cuttings), other hydrocarbon components such as paraffins and olefins, and various chemical additives. Seepage has been known to occur in the past through the embankments of some of these unlined reserve pits. Release of materials from some of these unlined reserve pits has been implicated in the observed increases in the concentrations of salts and metals in adjacent waters. In sufficient quantities, and with sufficient exposure times, many of these components of liquid reserve pit wastes can be harmful to aquatic organisms and to waterfowl and other birds (i.e. bioaccumulation of heavy metals and/or other contaminants in water fowl and other local wildlife). A recent study has indicated that phytoplankton, zooplankton, and vascular plants on the North Slope were not significantly bioaccumulating metals from the reserve pit fluids. Bioaccumulation in the trophic levels beyond the primary producers remains uncertain, however.

Current compliance with ADEC waste management regulations involves the use of impermeable liners in the pit embankments, maintenance of the pits as fluid-free as possible, and the implementation of a comprehensive monitoring program to ensure that state standards are being met. The petroleum industry has therefore discontinued the practice of using reserve pits for the disposal of oily muds and cuttings and associated wastes on the North Slope. Current management practices include the storage of solids in completely lined surface impoundments and injection of liquids in Class II disposal wells.

Depending on the content of the reserve pit fluids, these materials were traditionally permitted by the ADEC to be discharged to the tundra or to the roads or gravel pads. Such discharges are no longer permitted (see **Section 5.3.8**).

The operators of the Prudhoe Bay field are in the process of designing a facility for the improved management of associated wastes, as well as for wastes generated by oilfield service contractors. This facility will be used to manage wastes through waste minimization and recycling. Wastewater will be treated and reused, and oil in the waste will be removed and added to the production oil. Solids will be removed and tested to ensure that they are innocuous, and can then be used for such purposes as road fill or for proper disposal in a landfill. These solids consist primarily of sand, gravel, and other earthen materials.

New technologies to deal with the disposal of drilling muds and cuttings are being explored. The first involves the use of excavation of the reserve pit into the tundra (rather than into the gravel pad). The waste can then be pumped into the permafrost where it is allowed to freeze, before covering the pit up and reestablishing vegetation. The waste effectively becomes part of the permafrost. A second method involves the drilling of a deep, large-diameter hole into which the waste is placed. This minimizes the area of the permafrost that is disturbed, while having the same basic result as the first technique. Finally, because cuttings from the upper levels of rock are similar to the gravel used for the pads, the cuttings are washed and made available for use on field roads. The remaining mud and water are suitable for disposal by deep injection. The new waste management facility under evaluation will provide recycling and disposal options for all service company wastes excluding sanitary waste and non-hazardous solid waste.

Hazardous wastes that are not exempt from the RCRA regulations are packaged, characterized, labeled, and manifested for shipment to permitted hazardous waste disposal/treatment facilities.

Solid waste is disposed of at a sanitary landfill operated at Deadhorse by the NSB. Because radioactive waste generation is a new issue, no standard method for disposal has been identified.

5.3.5.2 Jurisdiction/Permitting. Jurisdiction and permitting for waste disposal is a complex process involving agencies of the federal government (EPA, COE) and the State of Alaska (DEC). Congressional Acts involved include the CWA, RCRA, and CERCLA. Aspects of the CWA that pertain to oil industry waste disposal include the NPDES, which limits the quantities, rates, and concentrations of pollutants, and dictate relevant compliance schedules, the prevention, control, reporting, and cleanup of oil and hazardous materials spills, and the discharge of dredge and fill materials into wetlands.

RCRA and CERCLA are more specifically oriented toward waste disposal. Certain oil industry wastes that are "uniquely associated with oil and gas exploration and production operations" are specifically exempt from regulation under Subtitle C of the RCRA hazardous waste regulations. These include "drilling fluids, produced water, and other wastes associated with the exploration, development or production of crude oil or natural gas."

5.3.5.3 Mitigative Measures. Possible mitigative waste disposal measures involve treatment or removal of existing unlined reserve pits. This could result from a change in the permitting requirements by the ADEC, or a loss of the Congressional exemption from RCRA regulations. Depending on the number of these pits that would be affected, and the ultimate status of the waste contained in the pits, such action could be extremely costly.

5.3.5.4 Impact for Future Development. The potential impacts associated with waste disposal activities on the North Slope involve uncertainties associated with changes in waste disposal regulations. The phasing out of the use of reserve pits for disposal of drilling wastes could increase the cost of waste disposal significantly, depending on the alternative disposal methods available. Permits for future development may require that old, unlined reserve pits at existing facilities be treated or removed. The costs associated with such requirements could be significant.

If treatment requirements are imposed for drilling wastes, or if drilling wastes must be transported large distances for disposal, the added costs of compliance could be significant. Waste disposal options appear to be available, however, that would not result in the prevention of development due to costs. Resolution of the radioactive waste disposal issue is also uncertain at this time.

5.3.6 Offshore Drilling Restrictions

Permit restrictions may be placed on drilling that will preclude drilling operations during certain periods of the year in order to protect biological resources.

5.3.6.1 Impacts. If biological populations or habitats that require additional protection are identified within the lease area, the lessee may be required to conduct biological surveys to determine the extent and composition of such biological populations or habitats. Based on the results of these surveys, the lessee may be required to; (a) relocate the site of operations; (b) establish that the operation will have no significant adverse impact on the resource identified or that a special biological resource does not exist; (c) operate during those periods of time that do not adversely impact the biological resources; and/or (d) modify operations to ensure that significant biological populations or habitats deserving protection are not adversely affected.

Seasonal drilling restrictions are primarily tied to wildlife considerations, particularly in offshore areas with respect to whale migration. Specifically, seasonal drilling restrictions have been placed on operations in the Chukchi and the Beaufort Seas for the purpose of protecting bowhead whales primarily from the potential effects associated with oil spills. A second issue related to seasonal restrictions involves noise disturbance. Exploratory drilling, testing, and other downhole exploratory activities are prohibited in these areas during the spring (April/May) and fall (September/October) bowhead whale migration periods. The Industry Site-Specific Bowhead Whale Monitoring Program requires that lessees shall conduct a site-specific bowhead whale monitoring program during exploratory drilling activities to determine when bowhead whales are present in the vicinity of lease operations and the extent of behavioral effects due to these activities.

Offshore drilling has been determined to "harass" bowhead and gray whales, resulting in the requirement for an "incidental take permit" under the ESA. Since 1979, a seasonal drilling restriction has prohibited, or more recently restricted the types of activities that can be conducted while bowhead whales are present. Operations conducted in areas occupied by other endangered species (e.g. the peregrine falcon) may also be restricted so as not to jeopardize their existence.

5.3.6.2 Jurisdiction/Permitting. Regulatory authority of seasonal drilling restrictions involve numerous agencies of both the federal and state governments. For offshore activities, drilling restrictions may be related to the OCSLA, ESA, and MMPA. Such restrictions have been imposed on exploratory activities in the Beaufort and Chukchi Seas.

5.3.6.3 Mitigative Measures. As described above, seasonal restrictions on off-shore drilling or other operations could be imposed if the permitting agencies determine that wildlife could be impacted by the operation. Such restrictions would result in additional costs of operation. Significant additional costs would also be involved with the temporary shutdown of operation.

5.3.6.4 Impact for Future Development. Future development of offshore lease areas such as the Chukchi and the Beaufort Seas could be impacted significantly by the imposition of additional offshore drilling restrictions. The impact to development associated with offshore drilling restrictions in northern Alaska are compounded by the relatively short time periods that open water exists on the Beaufort an Chukchi Seas. The costs associated with such actions could be significant, and would be dependant primarily on the duration of the restriction period, as well as the volume of the field, and oil prices.

During the permitting process for the Endicott area, a near-shore field, the ADNR determined that seasonal drilling requirements would not be applied to Endicott. In offshore areas such as the Chukchi Sea and Beaufort Sea lease sale areas, however, exploratory drilling, testing, and other downhole exploratory activities have been prohibited during bowhead whale migration periods within known migration areas. Permittees here must conduct a site-specific bowhead whale monitoring program during exploratory drilling activities in order to determine when bowhead whales are present in the vicinity of lease operations and the extent of behavioral effects attributable to these activities. It is uncertain whether such restrictions will be applied to production activities.

5.3.7 Gravel Placement and Removal

5.3.7.1 Impacts. To prevent permafrost melting, roads (except ice roads), living quarters, and drilling pads must be built on gravel pads which insulate the underlying permafrost and provide a secure foundation.[19,20] Sources for this gravel include inactive stream beds, upland sites, river terraces, lagoons, etc. Resource agencies are concerned that the processes of *gravel mining* adversely affects water quality and fish habitat. The Petroleum Industry believes that these concerns are unfounded and maintain that gravel can be removed in accordance with agency guidelines.[19,20] The FWS maintains that the placement of gravel roads, living quarters, drilling pads, etc. cause; (a) changes in the behavioral reactions of individual animals, and (b) alters or reduces local habitat resulting in declines to wildlife populations, especially birds.[21] Brown states that while the construction of roads and drilling pads for oil development have altered some arctic wetlands, their wildlife functions have not been adversely impacted.[22]

5.3.7.2 Jurisdiction/Permitting. Federal, state, and local regulatory agencies review and approve any application for gravel removal. These permits typically include restrictions on removal techniques, periods of operation, and restoration. The proposed methods of gravel removal are reviewed by the ADFG and FWS on a case-by-case basis. See **Sections 5.3.1.2** and **5.3.2.2**, *Justification/Permitting* for *Wetlands Issues* and *Causeway Issues*.

5.3.7.3 Mitigative Measures. One of the key improvements in development technology has been the reduction in the land needed to support a drilling operation. The oil industry has been successful in avoiding high-value wetlands habitat and minimizing overall disturbance of wildlife and habitat.[22]

The petroleum industry uses a mitigative strategy of avoidance and minimization, combined with enhancement, to minimize the impact of gravel removal on the North Slope. Mitigative measures discussed in the ANWR EIS include not removing gravel from active stream channels of major fish bearing rivers or from barrier islands.[2] All gravel removal operations should follow prescribe guidelines (see **Section 5.3.7.1**). In addition, sites where large pits are created can be designed to provide fish and wildlife habitat after abandonment.[2] To reduce the impact on habitat, ice roads are used during the winter to move heavy equipment. During the summer, soft tire vehicles (rolligons) are used.

5.3.7.4 Implication for Future Development. The ability to use gravel as a base for protection of the permafrost is crucial to the continued development of the North Slope for oil and gas production. Pipelines built on top of these gravel bases provide the infrastructure to transport the oil and gas (e.g., through pipelines). Roads support the construction, operation, and maintenance of facilities.

Additional mitigative measures, such as rehabilitation (including the removal of the gravel base) at the end of the project life, may make development uneconomical. The impact of gravel removal on future exploration and development is dependant on several factors; (a) location and abundance of gravel source, (b) National Policy protecting wetlands (see **Section 5.3.1**), and (c) the new Advanced Identification Regulation to restrict fill material in sensitive areas (see **Section 5.3.2**).

The lack of adequate gravel supplies in the area would required transportation from greater distances or the mining of more sensitive areas. A National No-Let-Loss policy or the ADID may restrict areas available for gravel removal.

5.3.8 Water Quality and Use

5.3.8.1 Impacts. Drilling wastes have been traditionally disposed in reserve pits, of which there are approximately 450 on the North Slope. In North Slope permafrost areas, where evaporation rates are extremely low and snow drift fills in the reserve pits annually, these reserve pits are subject to breaching, overtopping, and seepage. Because discharges are necessary from the North Slope reserve pits, prior to the summer of 1987, the ADEC has permitted the discharge of reserve pit fluids to the tundra, or to roads and pads, depending on the contents of the reserve pit fluids. These permits established certain water quality standards that had to be met before such discharges were allowed. Since 1986, all such reserve pit fluids have been disposed of through approved injection wells on the North Slope. Tundra discharge is no longer used as a disposal method. Also prior to 1987, reserve pit fluids could by permit be used for road watering for the purpose of dust control. Again, the fluids had to meet water quality standards set forth in an ADEC permit. Road watering is still done for dust control on the North Slope, but fresh water sources are used. Reserve pit waters have not been used for road watering since 1986. These fluids may contain contaminants that could impact the food chain (especially the macroinvertebrate-bird chain).[23] Contaminants include heavy metals and hydrocarbons. Waste constituents include materials added to the drilling muds as weighting agents, viscosifiers, thinners, Ph and ion controls, dispersants, corrosion inhibitors, lubricants, emulsifiers, foamers, and flocculants.

The long-term impacts of leaching from reserve pits is not clear. U.S. Fish and Wildlife Service has found impacts on water quality in nearby ponds downstream from the reserve pits. Macroinvertebrate populations were decreased and were altered in composition. Turbidity, alkalinity, Ph, and conductivity tended to increase, and dissolved oxygen tended to decrease. There were increases in arsenic, barium, cadmium, chromium, and nickel.

Oil spills and spills of other hazardous substances occur in the operation of a large oil field. On the North Slope, 953 spills totalling 193,319 gallons were reported from 1985 to 1986. Of these, 66 spills exceeded

500 gal. Many of the smaller spills are contained on pads, whereas some reached the tundra.

Substantial amounts of freshwater are used in drilling and other oil production activities. Water supplies in the Arctic are not easily tapped year-round. Methods include trapping and melting snow, insulating small, non-fish-bearing lakes, flooding gravel pits, and desalinating seawater.

Climatic limitations on accessibility and availability of water are controlling factors in the water management process. The Alaskan arctic is an arid region, averaging 7 in./y with the majority of the precipitation in the form of snowfall. Spring "break-up" begins by late May or June and typically lasts three weeks. At this time, surface runoff quickly brings rivers to flood stage. Extended winter and the presence of permafrost at shallow depths causes minimal or non-existent groundwater movement. Nine months of the year, river and lakes are covered with ice. Reservoirs must be closely monitored to prevent dewatering.

5.3.8.2 Jurisdiction/Permitting. ADEC began regulating discharges in 1983, and granted a variance for disposal based on certain restrictions. Dewatering was prohibited if there was a visible oil sheen on the surface of the water in the pit, or "if toxic substances or salt concentrations exceed those expected to cause damage to vegetation, fish and wildlife, or could affect public health." Furthermore, stipulations were made that surface waters receiving these discharges could not violate the State Water Quality standards described in 18 ACC 70. Water quality variables measured include Ph, conductivity, dissolved oxygen, hardness, alkalinity, and turbidity.

In addition to ADNR's authority, the ADFG is responsible for review and approval of activities which effect fish populations. The Water Act only allowed ADFG to comment on water use permits and to recommend restrictions. However, after anadromous fish were found in the Sag River, Title 16 permits were developed to further regulate all anadromous fish streams and tributaries north of the Brooks Range.

5.3.8.3 Mitigative Measures. In-ground structures such as deepened lakes or reclamation of gravel mine sites are a cost effective way to provide a dependable winter water source. These reservoirs provide not only a water supply for domestic (including fire-fighting needs) and industrial needs, but also overwintering habitat for fish.

5.3.8.4 Implication for Future Development.

Water quality issues are not expected to add significant costs to the production of oil resources on the North Slope.

5.4 Compliance Costs

Definitive costs associated with compliance issues are not available at this time, but would involve increases in operating and legal expenses as well as delays in development. Various potential combinations of environmental restraints further complicate the prediction of impact to development. These costs would affect the economics of the fields, possibly making a marginal development uneconomic. The effect of costs and delays due to environmental and other constraints have been approximated by the economic sensitivity analysis presented in **Section 3.4**.

The time required to fully develop a new field on the North Slope can extend for periods in excess of a decade from discovery to the initiation of production. Further delays in development can add significantly to the costs associated with producing the oil. Historical timetables for development of some existing North Slope areas is provided in **Table 5-7**.

Regarding delays in production, two examples can be given to illustrate the time periods required to bring development areas on line. These two areas are the ANWR and the Chukchi Sea Development Area, and are described below:

Table 5-7. Actual Development Schedules, North Slope Fields

Development	Years from lease to discovery	Years from discovery to start-up	Total years lease to start
Prudhoe Bay	3	9	12
Lisburne	3	18	21
Kuparuk	4	12	16
Endicott	9	9	12
ANWR[a]	3	9	12
ANWR[b]	3	7	10

[a] ARCO Alaska, Inc., *Arctic National Wildlife Refuge Coastal Plain 1002 Area: Development Scenarios and Environmental Issues*, Attachment to written statement of Jim Weeks, Manager, Prudhoe Bay Field Operations, Before the U.S. House Subcommittee on Water and Power Resources, October 8, 1987

[b] Energy Information Administration, *Potential Oil Production From the Coastal Plain of the Arctic National Wildlife Refuge*, Revised Edition, SR/RNGD/87-01, October, 1987.

5.4.1 Arctic National Wildlife Refuge:

Projecting a development schedule for the ANWR or other North Slope areas is difficult, with much depending on the timing and sequence of events. The ANWR schedule is likely to be at least as long as 10 to 12 years, from lease sale to production start-up. A reasonable schedule, given that it will take several years to complete the lease sale, would be at least 15 years for the start of any substantial production. If a major field were discovered, production could be expected to span a period of at least 25 to 30 years from start-up. **If ANWR development follows common experience in other oil-producing regions, and if regulations, technology, and price-cost relationships allow, more exploration and discoveries will follow, spanning many years.** At Prudhoe, new fields are continuing to be brought into production some 20 years after the first strike.

Experience indicates that should ANWR exploration proceed and lead to discovery of a major oil field, commercial petroleum activities on the ANWR coastal plain are likely to continue into the middle of the 21st century. It is also likely that the development will use enhanced oil recovery techniques after production has started.

5.4.2 Chukchi Sea:

The estimated schedule for development of the Chukchi Sea lease area, as stated in the Environmental Impact Statement, is provided in **Table 5-8.** Once again, a period of at least 13 years is expected to lapse between lease and the outset of production.

Table 5-8. Chukchi Sea Sale 109 - Estimated Schedule of Exploration, Development, and Production[13]
(mean-case resource estimate)

ACTIVITY	SALE YEAR
Lease sale	0
Exploratory well drilling	3 to 8
Delineation well drilling	5 to 10
Initial production	13
Maximum production	12 to 19
Termination of production	31

5.5 References

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