Undiscovered Oil and Gas Resources, Alaska Federal Offshore

OCS Monograph
MMS 98-0054

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Summary, 1995 Assessment of Undiscovered Oil and Gas Resources Alaska Federal Offshore

Province	Conventionally Recoverable*		Economically Recoverable**	
	Oil, bbo	Gas, tcfg	Oil, bbo	Gas, tcfg
AA, Aleutian Arc	negligible	negligible	negligible	negligible
ATNPAP, Aleutian Trench and North Pacific Abyssal Plain	negligible	negligible	negligible	negligible
BS, Beaufort Shelf	8.84	43.50	2.27	not available
BSDWB, Bering Sea Deep Water Basins	negligible	negligible	negligible	negligible
BSMB, Bering Shelf-Margin Basins	negligible	negligible	negligible	negligible
CB, Chukchi Borderland	negligible	negligible	negligible	negligible
CBBS, Canada Basin-Beaufort Slope	negligible	negligible	negligible	negligible
CI, Cook Inlet	0.74	0.89	0.27	not available
CS, Chukchi Shelf	13.02	51.84	1.14	not available
GOAS, Gulf of Alaska Shelf	0.63	4.18	0.05	negligible
HB, Hope Basin	0.11	4.06	negligible	0.12
NAB, North Aleutian Basin	0.23	6.79	0.02	0.88
NOB, Norton Basin	0.05 (ngl)	2.71	negligible	0.02
NVB, Navarin Basin	0.50	6.15	negligible	0.04
SGB, St. George Basin	0.13	3.00	negligible	0.05
SKS, Shumagin-Kodiak Shelf	0.07 (ngl)	2.65	negligible	negligible
SMHB, St. Matthew-Hall Basin	<0.01 (ngl)	0.16	not evaluated	not evaluated
TOTAL FOR ALASKA FEDERAL OFFSHORE	24.31	125.93	3.75	1.11

* *risked, mean, undiscovered, conventionally recoverable oil and gas*
** *risked, mean, undiscovered, economically recoverable oil and gas*
bbo, billions of barrels of oil; tcfg, trillions of cubic feet of gas; ngl, natural gas liquids that are recovered with gas; mean values for provinces may not sum to offshore total because of rounding

Copies of this report (OCS Monograph MMS 98-0054) may be obtained upon request by contacting:

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SUMMARY OF ASSESSMENT RESULTS
1995 National Resource Assessment
Alaska Federal Offshore
U.S. Minerals Management Service

by

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1. SUMMARY OF RESULTS FOR ALASKA FEDERAL OFFSHORE

This report summarizes the Minerals Management Service (MMS) 1995 assessment[1] of the quantities of undiscovered oil and gas that lie beneath 1.8 million square miles of submerged Federal lands offshore of Alaska. Estimates include both undiscovered ***conventionally recoverable***[2] resources, unconstrained by economics, and undiscovered ***economically recoverable***[3] resources.

The Alaska offshore is estimated to offer a mean potential for undiscovered, ***conventionally recoverable oil and natural gas liquids*** of 24 billion barrels, with a 5-percent chance of oil potential exceeding 34 billion barrels. Undiscovered gas potential (mean value) is estimated at 126 trillion cubic feet, with a 5-percent chance of gas resources exceeding 230 trillion cubic feet. Approximately 90 percent of the undiscovered conventionally recoverable oil in offshore Alaska occurs within the Chukchi shelf (13 billion barrels) and Beaufort shelf (9 billion barrels) provinces, part of the greater Arctic Alaska oil and gas province. The Arctic Alaska province has a discovered oil endowment of 70 billion barrels (commercial reserves, 16.4 billion barrels) and presently produces about 1.5 million barrels per day through the Trans-Alaska Pipeline System (TAPS).

Most of the undiscovered oil and gas in the Alaska offshore occurs in accumulations too small to warrant commercial exploitation at this time. Only about 15 percent of the undiscovered oil offshore Alaska could be profitably recovered at prices approaching those that exist today. Most of the ***economically recoverable oil resources*** occur beneath the Beaufort shelf (2.27 billion barrels of oil) and Chukchi shelf (1.14 billion barrels of oil). Elsewhere in the Alaska offshore, only Cook Inlet offers any economically recoverable oil, here estimated at 0.27 billion barrels.

Most of the ***conventionally recoverable gas resources*** occur beneath the Beaufort and Chukchi shelves, but gas in these provinces is considered uneconomic because no infrastructure exists for transporting gas to markets outside of Alaska.

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[1] *based on data available as of January 1995*

[2] *oil, natural gas, and natural gas liquids recoverable from a discrete subsurface pool into a well by natural flow or pumping, or addition of pressure, using modern extraction technologies. Resources not assessed include gas in geopressured brines, tar deposits, oil shales, coal gas, or gases in clathrates (gas hydrates).*

[3] *the undiscovered resource volume in each province which, if discovered, could be produced profitably given realistic estimates for costs of exploration, development, production, and transportation*

This report summarizes the results of a 4-year study involving a large MMS staff of geoscientists, with technical input from industry, academia, and other government agencies. This assessment of the Alaska Federal offshore was conducted as part of a national appraisal of all Federal offshore lands in the United States performed by the MMS concurrently with a U.S. Geological Survey (USGS) assessment of all onshore lands and submerged lands in State waters (USGS, 1995). The MMS assessments are conducted periodically (Cooke, 1985, 1991; Cooke and Dellagiarino, 1989), and the results are used to guide management of leasing and exploration policies and programs in the Federal offshore.

In Alaska, Federal waters generally extend seaward of 3 miles from shore. For the purposes of this assessment, the Alaska offshore was divided into 17 provinces, located in figure 1.1 and plate 1.1. Eleven of these provinces, all on the continental shelves, offer potential for conventional supplies of oil and gas. Within these 11 assessment provinces, oil and gas endowments were calculated for 74 exploration plays.

The quantities of oil and gas were calculated using two computer models (***GRASP*** and ***PRESTO***) that statistically analyze input data provided as ranges of values reflecting different probabilities for occurrence. These data are drawn from a vast offshore database of geophysically mapped prospects, data from offshore wells, and development cost data gathered over years of offshore work in Alaska.

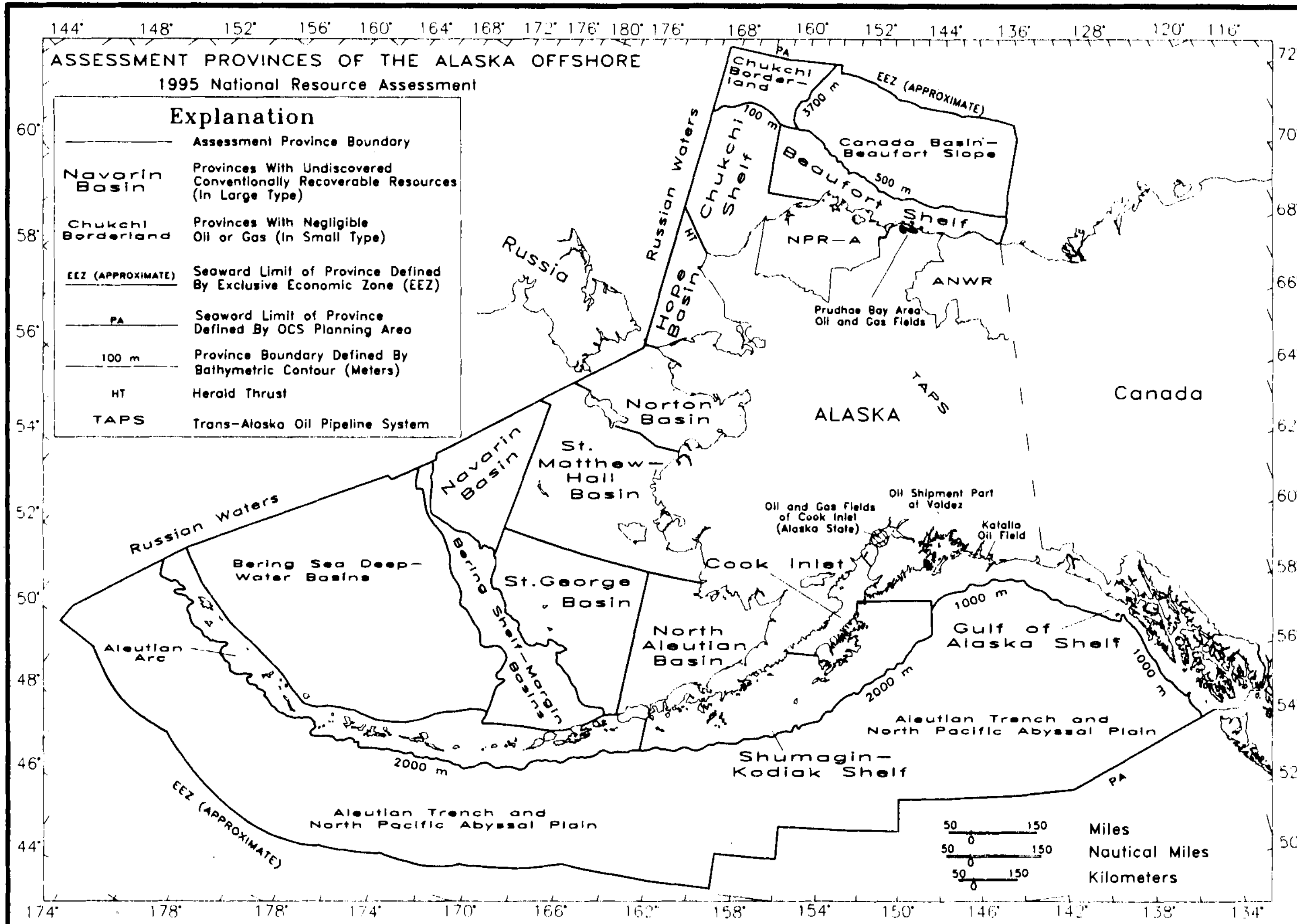


Figure 1.1: Alaska offshore assessment provinces, 1995 National Resource Assessment.

2. CONVENTIONALLY RECOVERABLE OIL AND GAS

Federal submerged lands offshore Alaska offer a high potential for undiscovered, conventionally recoverable oil and gas resources, ranging up to 33.57 billions of barrels of oil (BBO) and 229.53 trillions of cubic feet of gas (TCFG) (5-percent probability). Most of these undiscovered resources occur in the Beaufort shelf and Chukchi shelf assessment provinces. Mean (or average) estimates for the undiscovered potential of the Alaska offshore are 24.31 BBO and 125.93 TCFG. Assessment results for subregions and assessment provinces are summarized in table 2.1. Cumulative probability distributions for undiscovered oil, gas, and total hydrocarbon energy in barrels of oil-equivalent (BOE) for the Alaska Federal offshore are shown in figure 2.1.

The Beaufort shelf and Chukchi shelf assessment provinces contain 90 percent of the undiscovered oil resources and 79 percent of the undiscovered gas resources (compared at mean values) of the entire Alaska offshore. The high proportion of offshore oil and gas resources estimated to be present in the Arctic offshore provinces is consistent with the fact that 92 percent of Alaska's onshore commercial oil reserves occur in northern Alaska[1]. The dominance of the Arctic in the distributions of both offshore undiscovered resources and proven onshore reserves simply reflects the rich endowment of Arctic Alaska and adjoining continental shelves with the key ingredients for oil and gas accumulations—prolific source rocks, excellent reservoir rocks, and numerous potential traps of large areal dimensions.

Among the provinces of the Arctic subregion, the sparsely explored Chukchi shelf offers the highest potential for undiscovered resources, with a 5-percent chance for recoverable oil resources as high as 21.94 BBO (table 2.1). Navarin basin, owing to its large size and an abundance of large potential traps, offers the greatest potential of the gas-prone provinces of the Bering shelf subregion. Among provinces of the Pacific margin subregion, Cook Inlet offers the greatest potential for remaining undiscovered oil reserves in Federal waters.

Very small quantities of liquid hydrocarbons are reported in the assessments of Norton basin, St. Matthew-Hall basin, and Shumagin-Kodiak shelf provinces. These three provinces were modeled as offering potential for gas only. The volumes reported as oil are therefore actually natural-gas liquids or condensate derived as a by-product of gas production.

[1]*No gas reserves in Arctic Alaska are presently commercial because there is no transportation infrastructure. However, the untapped reserves in the Prudhoe Bay area amount to about 28.2 TCFG (AKDO&G, 1995), or about three times the commercial gas reserves in all of the Bering shelf or the Pacific margin (essentially Cook Inlet).*

TABLE 2.1
RISKED, UNDISCOVERED, CONVENTIONALLY RECOVERABLE OIL AND GAS

AREA	OIL AND NGL (BBO)			GAS (TCFG)			BOE (BBO)			MPhc
	F95	MEAN	F05	F95	MEAN	F05	F95	MEAN	F05	
ALASKA OFFSHORE	16.85	24.31	33.57	58.01	125.93	229.53	28.68	46.72	70.61	1.00
ARCTIC SUBREGION	14.68	21.96	31.18	38.02	99.41	201.13	22.52	39.65	63.25	1.00
BERING SHELF SUBREGION	0.36	0.91	1.81	6.98	18.80	38.64	1.65	4.26	8.57	1.00
PACIFIC MARGIN SUBREGION	0.72	1.44	2.49	2.12	7.72	18.34	1.15	2.81	5.50	1.00
ARCTIC SUBREGION										
CHUKCHI SHELF	6.80	13.02	21.94	9.81	51.84	141.75	8.59	22.24	44.75	1.00
BEAUFORT SHELF	6.28	8.84	11.96	20.10	43.50	79.15	10.29	16.58	24.84	1.00
HOPE BASIN	0.00	0.11	0.34	0.00	4.06	12.67	0.00	0.83	2.59	0.61
BERING SHELF SUBREGION										
NAVARIN BASIN	0.00	0.50	1.21	0.00	6.15	18.18	0.00	1.59	4.41	0.88
N. ALEUTIAN BASIN	0.00	0.23	0.57	0.00	6.79	17.33	0.00	1.44	3.62	0.72
ST. GEORGE BASIN	0.00	0.13	0.41	0.00	3.00	9.72	0.00	0.67	2.14	0.94
NORTON BASIN	0.00	0.05 (NGL)	0.15	0.00	2.71	8.74	0.00	0.53	1.70	0.72
ST. MATTHEW-HALL	0.00	<0.01 (NGL)	<0.01	0.00	0.16	0.69	0.00	0.03	0.13	0.44
PACIFIC MARGIN SUBREGION										
COOK INLET	0.32	0.74	1.39	0.40	0.89	1.65	0.39	0.90	1.68	1.00
GULF OF ALASKA	0.18	0.63	1.43	0.94	4.18	10.59	0.36	1.37	3.27	0.99
SHUMAGIN-KODIAK	0.00	0.07 (NGL)	0.29	0.00	2.65	11.35	0.00	0.54	2.30	0.40

__BBO__, billions of barrels of oil and natural gas liquids; __TCFG__, trillions of cubic feet; __BOE__, total oil and gas in billions of energy-equivalent barrels (5,620 cubic feet of gas=1 energy-equivalent barrel of oil); reported __MEAN__, resource quantities at the mean in cumulative probability distributions; __F95__, the resource quantity having a 95-percent probability of being met or exceeded; __F05__, the resource quantity having a 5-percent probability of being met or exceeded; __MPhc__, marginal probability for hydrocarbons for basin, i.e., chance for the existence of at least one pool of undiscovered, conventionally recoverable hydrocarbons somewhere in the basin. Resource quantities shown are risked, that is, they are the product of multiplication of conditional resources and Mphc. Mean values for provinces may not sum to values shown for subregions or region because of rounding. All liquid resources in Norton basin, St. Matthew-Hall basin, and Shumagin-Kodiak shelf are natural gas liquids that would only be recovered by natural gas production.

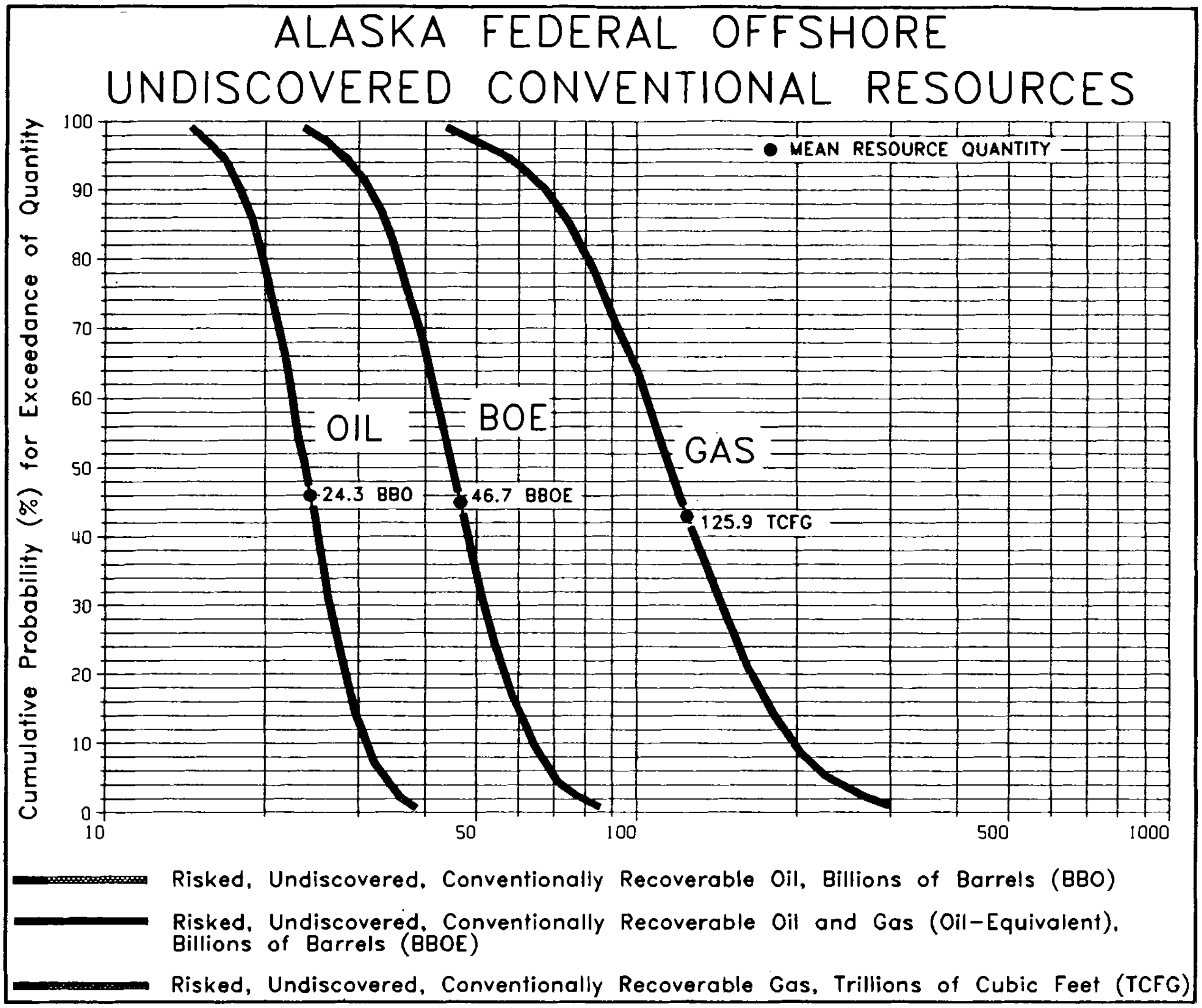


Figure 2.1: Cumulative probability distributions for risked, undiscovered, conventionally recoverable oil, gas, and total hydrocarbon energy in BOE (barrels of oil-equivalent, 1 barrel of oil=5,620 cubic feet of gas) for Alaska Federal offshore.

3. ECONOMICALLY RECOVERABLE OIL AND GAS

The economic phase of the 1995 assessment estimates the undiscovered resource volume in each province which, if discovered, could be produced profitably given realistic estimates for costs of exploration, development, production, and transportation. The quantities of economically recoverable resources are generally a minority fraction of the much larger estimates for conventionally recoverable resources. Only 8.5 percent of the conventionally recoverable resources on a barrels-of-oil-equivalent (BOE) basis are estimated to be economically recoverable at current oil prices.

The resources that are economically recoverable from the Alaska Federal offshore are shown in table 3.1. Economic volumes of oil and gas for provinces are reported at commodity prices of $18 per barrel (oil) and $2.11 per thousand cubic feet (gas), or approximately current market prices.

Ninety-one percent of the economic oil[1] of the Alaska offshore occurs in the Beaufort and Chukchi shelf assessment provinces. The other nine provinces account for the remaining 9 percent.

Most of the undiscovered conventionally recoverable offshore gas also occurs in the Arctic (tbl. 2.1), but none of this gas is considered economic at this time. No gas transportation system exists to carry gas from Arctic Alaska to a southern market, and several gas fields (about 28 trillion cubic feet of gas reserves) near the head of the existing oil pipeline transportation corridor already await development. These huge onshore gas fields will surely fill any newly constructed gas line for some years to decades following construction. Therefore, it is very unlikely that development of new Arctic offshore gas fields will occur in the foreseeable future. For these reasons, we conclude that the Beaufort and Chukchi shelf assessment provinces offer no economic gas resources at the present time.

Other than the Beaufort and Chukchi shelf provinces, only the Cook Inlet province is likely to contain economically viable oil resources at current prices. Although the geologic resources are modest compared to the Arctic, the proximity to existing infrastructure and potential markets contributes to reduced development costs in the Cook Inlet province. As in the Beaufort and Chukchi provinces, the economic assessment for the Cook Inlet considered only oil production, largely because all of the undiscovered accumulations were modeled as oil pools overlain by gas caps. To optimize oil recovery, produced gas would be reinjected for reservoir pressure maintenance and no gas would be extracted for sale from the gas cap. Only decades later, after exhaustion of the oil reserves, would offshore oil-production platforms be converted to allow recovery of the gas reserves.

The remainder of the Alaska offshore provinces are generally gas-prone and lack production and transportation infrastructure. The small volumes of oil listed for most of the gas-prone provinces are largely natural gas liquids that would only be recovered as a by-product of gas production. Because potential markets are in the western Pacific Rim, produced gas must be shipped to market as liquefied natural gas (LNG). The substantial costs of constructing an LNG infrastructure typically cannot be supported by the relatively small gas fields in these remote, high-cost locations. Of the gas-prone assessment provinces in the Bering shelf subregion, the North Aleutian basin is estimated to contain the majority—79 percent—of the economically

[1] *risked, mean, undiscovered, economically recoverable oil at a delivered price of $18 per barrel*

recoverable gas of the entire Alaska offshore.

The relative chances for economic success among the Alaska offshore provinces are indicated by the ratio of economically recoverable BOE (barrels-of-oil equivalent, oil and gas combined) resources to conventionally recoverable BOE resources, shown as the E/C values in table 3.1. The BOE E/C values range from 0.30 in Cook Inlet to negligible (less than 0.01) in Navarin basin. This suggests that many undiscovered pools in Cook Inlet are large enough to support relatively low-cost development, whereas the undiscovered hydrocarbon pools in Navarin basin, though perhaps large, are typically too small to support the relatively high costs of development in that remote area. Navarin basin offers essentially no economic potential despite the fact that it offers the highest total geologic endowment outside the Arctic (1.59 BBOE, tbl. 2.1). The BOE E/C ratios (tbl. 3.1) identify the Cook Inlet, Beaufort shelf, and North Aleutian basin assessment provinces as those offering the highest reward/risk opportunities.

All provinces were assessed on a stand-alone basis, with no sharing of development infrastructure between adjacent provinces. For some provinces (Beaufort, Chukchi, and Cook Inlet) at least some existing infrastructure was utilized for the simulated development of undiscovered fields. Otherwise, new infrastructure was designed and entirely supported by production from each province in the economic models. Sensitivity tests, where several provinces shared infrastructure costs (for example, LNG facilities), generally resulted in improved economic viability. Despite shared infrastructure strategies, most of the gas-prone provinces nevertheless remain subeconomic at mean resource volumes and current commodity prices. However, it must be emphasized that in any of these subeconomic provinces, economic resources could be recovered from unusually large pools (less likely to exist than mean sizes) or at commodity prices above current levels.

Economic results are summarized in price-supply graphs produced by the ***PRESTO-5*** computer program. These graphs illustrate the volumes of resources that could be profitably recovered, if discovered, across a range of commodity prices. Price-supply graphs for those three provinces that offer economic oil at current ($18) oil prices are given in figures 3.1, 3.2, and 3.3, for the Beaufort shelf, Chukchi shelf, and Cook Inlet assessment provinces, respectively. Price- supply graphs for 10 Alaska offshore provinces are provided in separate chapters later in this report.

The three curves shown on each price-supply graph illustrate the range of risked economic potential, with exceedance probabilities ranging from 95 percent (low-side potential) to 5 percent (high-side potential). These estimates are risked; they include both the geologic risk that resources are actually present and recoverable as well as the economic risk that the simulated development leads to profitable production at the prices shown.

The Beaufort shelf results for the low case (F95, or 19 in 20 chance of occurrence) predict that at least 0.72 billion barrels of oil (BBO) are economically recoverable at an oil price of $18 per barrel (fig. 3.1c). The high case (F05, or 1 in 20 chance) predicts an undiscovered economic potential (at $18) of at least 4.44 BBO, or 6 times larger than the low case. The mean case has an average or expected economic potential of 2.27 BBO at $18. The ratio of economic to conventionally recoverable oil in Beaufort shelf province is 0.26, second only to Cook Inlet oil at 0.36. Beaufort shelf assessment province clearly offers good opportunity for future commercial developments at reasonable levels of risk.

The Chukchi shelf price-supply curves (fig. 3.2c) support the widely held perception that higher prices will be required to overcome higher development costs in that remote corner of the Arctic offshore. For example, in the low case, any commercial development in Chukchi shelf will require oil prices above $27 per barrel (in constant 1995 dollars). A broad envelope surrounds the mean case, with a high case (4.48 BBO) nearly 4 times larger than the mean

TABLE 3.1
RISKED, UNDISCOVERED, ECONOMICALLY RECOVERABLE OIL AND GAS

AREA	OIL (BBO)			GAS (TCFG)			BOE (BBO)			E/C
	F95	MEAN	F05	F95	MEAN	F05	F95	MEAN	F05	
ALASKA OFFSHORE	1.41	3.75	7.65	0.02	1.11	4.33	1.43	3.95	8.20	0.08
ARCTIC SUBREGION	1.15	3.41	7.25	0.00	0.12	0.00	1.15	3.44	7.31	0.09
BERING SHELF SUBREGION	0.00	0.02	0.22	0.00	0.99	10.82	0.00	0.19	2.11	0.04
PACIFIC MARGIN SUBREGION	0.00	0.32	0.79	0.00	negl	0.01	0.00	0.32	0.80	0.11
ARCTIC SUBREGION										
CHUKCHI SHELF	0.00	1.14	4.48	N/A	N/A	N/A	0.00	1.14	4.48	0.05
BEAUFORT SHELF	0.72	2.27	4.44	N/A	N/A	N/A	0.00	2.27	4.44	0.14
HOPE BASIN	0.00	negl	0.00	0.00	0.12	0.00	0.00	0.03	0.00	0.04
BERING SHELF SUBREGION										
NAVARIN BASIN	0.00	negl	0.00	0.00	0.04	0.00	0.00	negl	0.00	negl
N. ALEUTIAN BASIN	0.00	0.02	0.20	0.00	0.88	7.71	0.00	0.18	1.77	0.13
ST. GEORGE BASIN	0.00	negl	0.00	0.00	0.05	0.00	0.00	0.01	0.00	0.02
NORTON BASIN	0.00	negl	0.00	0.00	0.02	0.00	0.00	negl	0.00	negl
ST. MATTHEW-HALL	N/E	N/E	N/E	N/E	N/E	N/E	N/E	N/E	N/E	N/E
PACIFIC MARGIN SUBREGION										
COOK INLET	0.00	0.27	0.71	N/A	N/A	N/A	0.00	0.27	0.71	0.30
GULF OF ALASKA	0.00	0.05	0.30	0.00	negl	negl	0.00	0.05	0.30	0.04
SHUMAGIN-KODIAK	0.00	negl	0.00	0.00	negl	0.00	0.00	negl	0.00	negl

ECONOMIC ASSUMPTIONS: 1995 base year, $18 per barrel oil price, $2.11 per thousand cubic feet (MCF) gas price, 0.66 gas value discount, flat real prices and costs, 3% inflation, 12% discount rate, 35% Federal tax rate; units of BBO, billions of barrels; TCFG, trillions of cubic feet; BOE, total oil and gas in billions of energy-equivalent barrels (5,620 cubic feet of gas=1 energy-equivalent barrel of oil). Oil resources include crude oil and natural gas liquids (NGL). Gas resources include nonassociated dry gas and associated solution gas. All provinces analyzed on a stand-alone basis. N/A refers to Not Available (lacking transportation infrastructure and/or market). N/E refers to Not Evaluated because of very low resource potential. Negl refers to negligible (less than significant figures listed). E/C is ratio of risked, mean economically recoverable BOE to risked, mean conventionally recoverable BOE (from table 2.1). Mean values for provinces may not sum to values shown for subregions and region because of rounding.

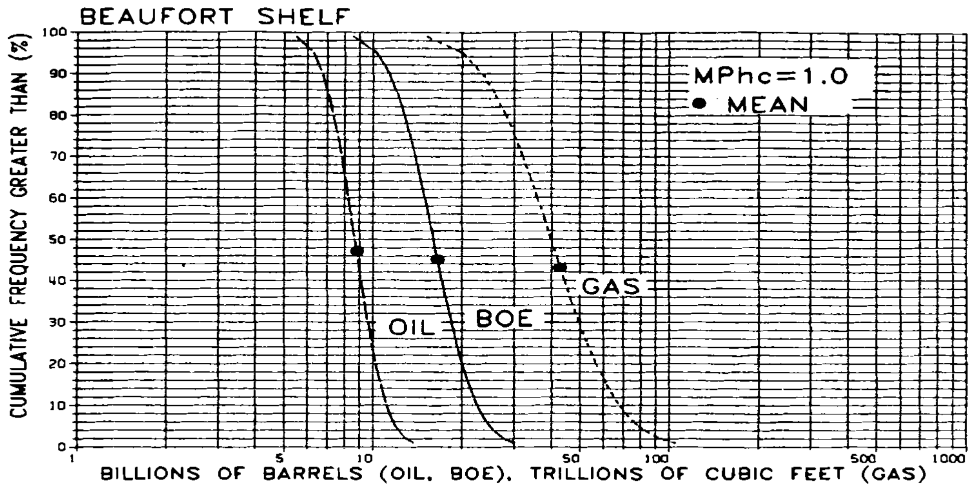
case (1.14 BBO) at $18 per barrel. The high-case oil potential of Chukchi shelf (4.48 BBO) is nearly the same as the high-case potential for Beaufort shelf (4.44 BBO). However, the fraction of economic to conventionally recoverable oil for the Chukchi shelf is 0.09, only about a third of that for Beaufort shelf (0.26), suggesting that commercial discoveries at $18 per barrel are much less likely in Chukchi shelf. Despite the large potential rewards, the comparatively low chance for economic success on Chukchi shelf, mostly owing to greater costs, is likely to dampen exploration interest.

The mean case for the price-supply analysis for Cook Inlet (fig. 3.3c) indicates 0.27 BBO of economic oil potential, much more modest than either the Beaufort (2.27 BBO) or Chukchi (1.14 BBO) shelf assessment provinces. The high-case potential for Cook Inlet exceeds 1.0 BBO at theoretical prices approaching $50 per barrel. The ratio of economic to conventionally recoverable oil is 0.36 (fig. 3.3b), suggesting that a significant fraction of the Cook Inlet oil resources occur in commercial-sized fields.

These estimates for undiscovered economic resources in all provinces assume extensive exploration drilling programs and discovery of ***all*** commercial deposits. This is very unlikely for a number of reasons. Given the low chance of commercial success coupled with the high cost of exploration, most of these provinces are not likely to be thoroughly tested in the foreseeable future. The few exploration wells that may be drilled in these immense geographic areas could easily fail to discover the rare commercial-sized pools. Economically recoverable resource estimates should be viewed as future commercial opportunities, rather than as discovered oil and gas reserves awaiting only a sufficient rise in oil prices to spark development.

This summary of the economic assessment for the Alaska offshore has focused on provinces likely to have recoverable oil at current commodity prices. However, many Alaska Federal offshore provinces contain no economically recoverable resources for the average (mean) case at current oil and gas prices. Future leasing and exploration activities in these presently subeconomic provinces will surely be driven by expectations of high-side potential, which assumes greater reward potential at higher risk, significantly higher prices, and perhaps innovative technology to reduce development costs.

A.



B.

BEAUFORT SHELF PROVINCE		
RESOURCE TYPE	MEAN OIL (BBO)	MEAN GAS (TCFG)
CONVENTIONALLY RECOVERABLE	8.84	43.50
ECONOMICALLY RECOVERABLE ($18)	2.27	N/A
RATIO ECONOMIC/CONVENTIONAL	0.26	N/A

C.

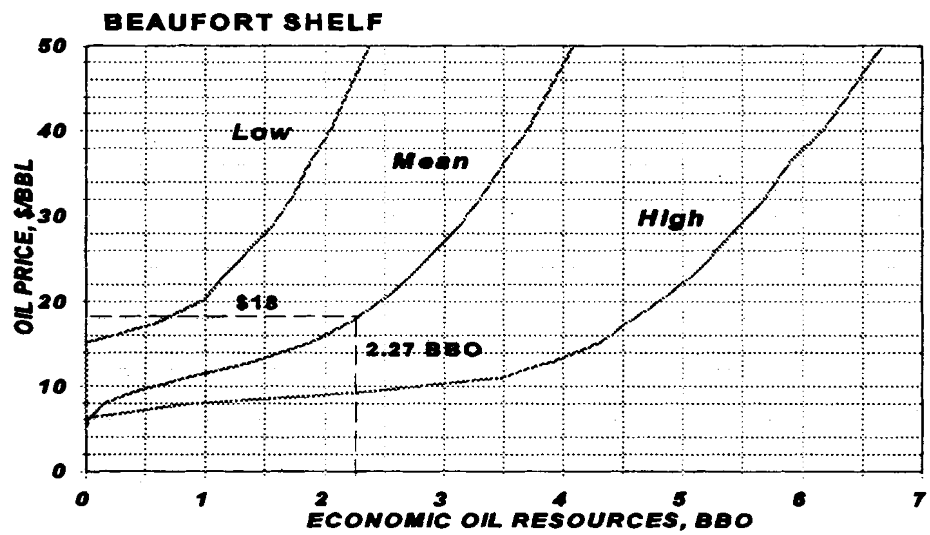
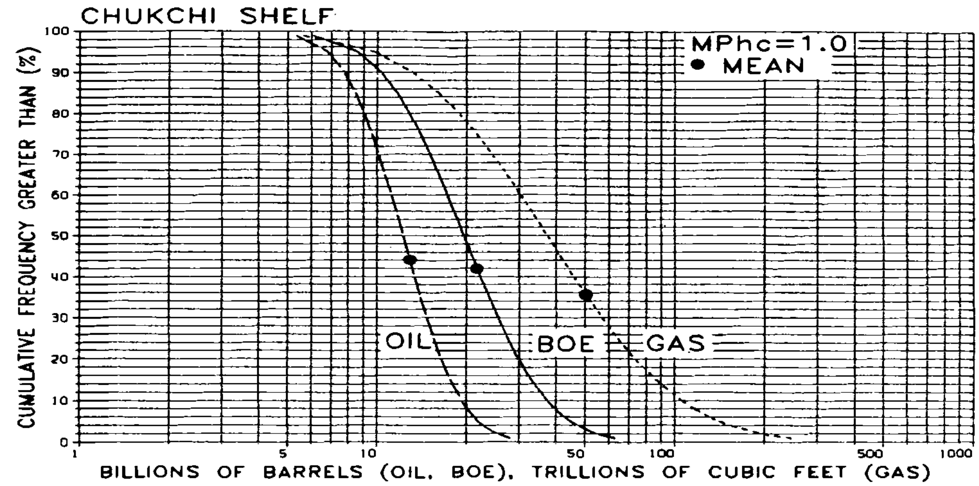


Figure 3.1: Economic Results for Beaufort shelf assessment province. (A) Cumulative frequency distributions for **risked, undiscovered conventionally recoverable resources**; (B) Table comparing results for conventionally and economically recoverable oil and gas; (C) Price-supply curves for **risked, economic oil** at low (F95), mean, and high (F05) resource cases.

BOE, total oil and gas in energy-equivalent barrels; MPhc, marginal probability for occurrence of pooled hydrocarbons in basin; BBO, billions of barrels; TCFG, trillions of cubic feet.

A.



B.

CHUKCHI SHELF PROVINCE		
RESOURCE TYPE	MEAN OIL (BBO)	MEAN GAS (TCFG)
CONVENTIONALLY RECOVERABLE	13.02	51.84
ECONOMICALLY RECOVERABLE ($18)	1.14	N/A
RATIO ECONOMIC/CONVENTIONAL	0.09	N/A

C.

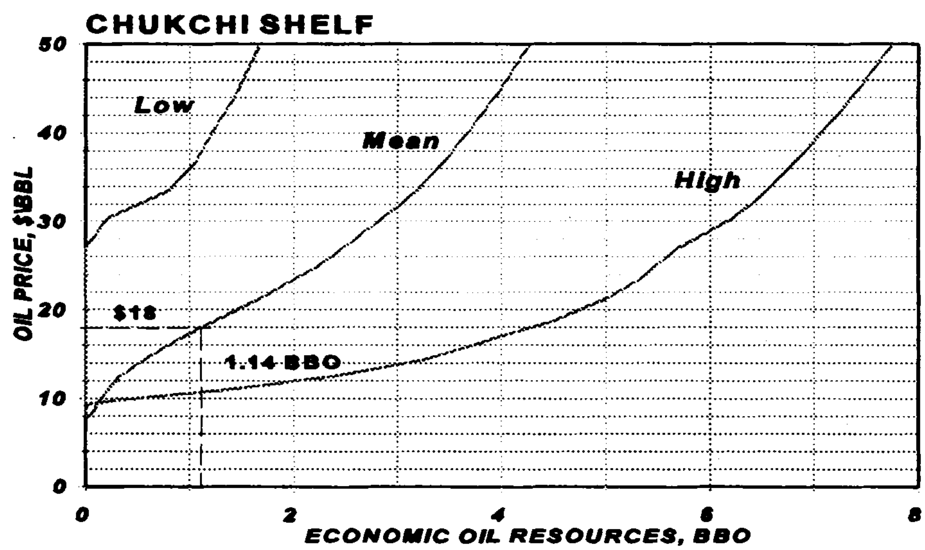
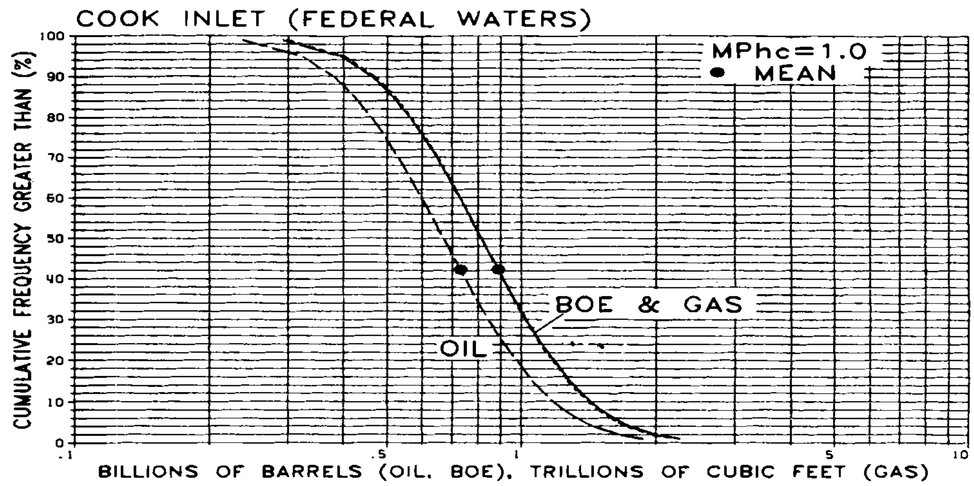


Figure 3.2: Economic Results for Chukchi shelf assessment province. (A) Cumulative frequency distributions for **risked, undiscovered conventionally recoverable resources**; (B) Table comparing results for conventionally and economically recoverable oil and gas; (C) Price-supply curves for **risked, economic oil** at low (F95), mean, and high (F05) resource cases.

BOE, total oil and gas in energy-equivalent barrels; MPhc, marginal probability for occurrence of pooled hydrocarbons in basin; BBO, billions of barrels; TCFG, trillions of cubic feet.

A.



B.

COOK INLET PROVINCE		
RESOURCE TYPE	MEAN OIL (BBO)	MEAN GAS (TCFG)
CONVENTIONALLY RECOVERABLE	0.74	0.89
ECONOMICALLY RECOVERABLE ($18)	0.27	N/A
RATIO ECONOMIC/CONVENTIONAL	0.36	N/A

C.

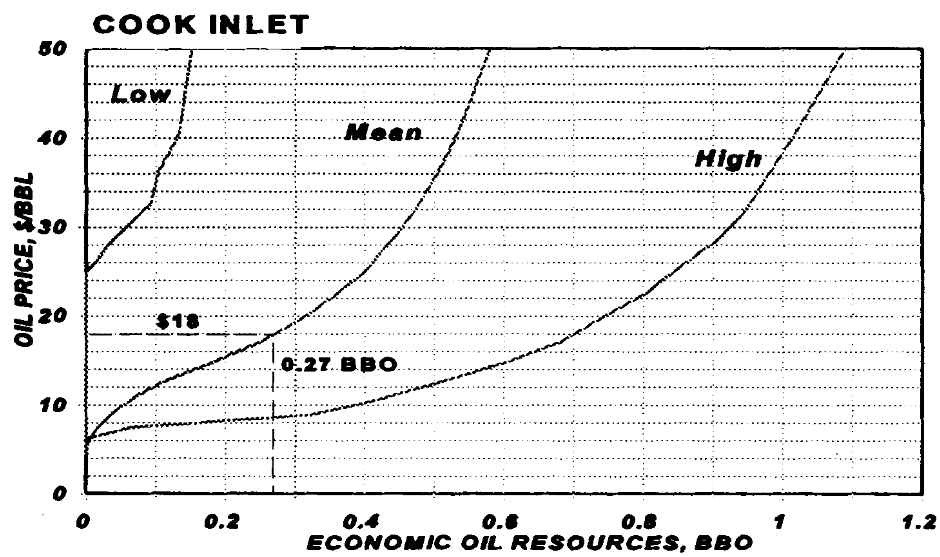


Figure 3.3: Economic Results for Cook Inlet assessment province. (A) Cumulative frequency distributions for **risked, undiscovered conventionally recoverable resources**; (B) Table comparing results for conventionally and economically recoverable oil and gas; (C) Price-supply curves for **risked, economic oil** at low (F95), mean, and high (F05) resource cases.

BOE, total oil and gas in energy-equivalent barrels; MPhc, marginal probability for occurrence of pooled hydrocarbons in basin; BBO, billions of barrels; TCFG, trillions of cubic feet.

The 1995 Minerals Management Service (MMS) assessment of the Alaska offshore produced significantly different results from assessments completed in 1984 (Cooke, 1985), 1987 (Cooke and Dellagiarino, 1989), and 1990 (Cooke, 1991). The difference in results when compared with these three previous assessments cannot be traced to a single, simple cause. The latest assessment incorporates major changes to the basic database, as well as numerous changes in methodology, definitions, and quantitative economic assumptions. Although the net effect of these changes varied for each assessment province, the current assessment can be characterized as broader in scope and more optimistic than previous MMS assessments.

Even though previous assessments were conducted very differently, comparisons with the 1995 assessment are inevitable and can be a natural first step to determine the magnitude of change and identify possible causes. As an introduction to topics covered in this chapter, table 4.1 summarizes several key differences among MMS assessments. The most comparable elements of the 1984, 1987, 1990, and 1995 assessments are compiled in tables 4.2 (oil) and 4.3 (natural gas).

1984 ASSESSMENT

A review of the evolutionary path of MMS resource assessment methodology places the current assessment in context and suggests reasons for the changes observed over time. When the Secretary of the Interior originally established the MMS in 1982, the new bureau's Resource Evaluation Office was created in large part from the U.S. Geological Survey (USGS) Conservation Division, which had been responsible for oil and gas leasing in the Federal Outer Continental Shelf (OCS) and for estimating the oil and gas potential of specific tracts. Areawide or province[1] estimates of oil and gas potential had been the purview of the USGS Geologic Division. With the creation of a bureau focused on OCS oil and gas leasing and development in an environmentally safe manner, all resource assessment and evaluation activities in support of the OCS program, including areawide resource estimates, were transferred to MMS.

The first systematic assessment of all offshore areas published by MMS in 1984 (Cooke, 1985) produced estimates of undiscovered, economically recoverable oil and gas resources

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[1]*__Prospects__ are the smallest geologic feature assessed. A __tract__ is an element of a man-made grid, used to identify areas for leasing. Often in Alaska, prospects are large enough to extend into several tracts. A geologic __play__ contains geologically related prospects, having a similar hydrocarbon source, reservoir, and trapping mechanism. A __basin__ is a large downwarped region serving as a center of sediment deposition. It can contain numerous plays. A geologic __province__ is a large area or region unified geologically by means of a single dominant structural element or a number of contiguous elements. A province could be defined to contain a single basin or may contain several related or similar basins. __Area__ is the most all-encompassing term and can be used to describe an administrative unit, such as the Beaufort Sea Planning Area. Offshore areas offered for lease are organized by administrative planning areas. When speaking in general terms, "areawide," "basinwide," and "province" estimates are sometimes used interchangeably even though they have distinct meanings. Certain "areas" contain a "province" with one "basin." The point in this general text is to distinguish large scale (area/province/basin) estimates from the very specific, small scale (prospect) estimates. Play estimates represent an intermediate level between the two extremes.*

TABLE 4.1
KEY DIFFERENCES: MMS ASSESSMENTS

ASSESSMENT	1984	1987/1990	1995
Models Used	**PRESTO 1**	**PRESTO 3**	**GRASP / PRESTO 5**
Economics-Free Scenario?	**No**	**Yes**	**Yes**
Economically Recoverable Cases	**Base ($29/bbl; $4.56/Mcf)**	**Base ($18/bbl; $1.80/Mcf) High ($30/bbl; $3.00/Mcf)**	**Price-Supply Curves**
Level of Focus	**Prospect**	**Prospect (organized by plays)**	**Play Analysis (with prospects)**
Prices	**Ramped**	**Ramped**	**Flat**
Unidentified Prospects?	**No**	**Yes**	**Yes**
Assessment Areas	**Planning Areas**	**Geologic Provinces and Planning Areas**	**Redefined Geologic Provinces**
Defining Characteristics	**–First MMS systematic assessment –Focus on near-term potential**	**–3 economic assessments –Broader perspective**	**–More plays, prospects –Lower geologic risks –Models directly linked –P-S curves**

under a single set of economic assummptions representing the prevailing conditions. This initial focus by MMS on economic potential is not surprising, given a background heavily based on evaluation of economically viable projects proposed for leasing and development. This first MMS assessment met a near-term goal of identifying areas of high oil and gas resource potential to assist with developing the 1982 to 1987 5-year offshore oil and gas leasing program (MMS, 1982).

Areawide resource assessments (as opposed to prospect evaluations for specific lease sales) were a new function for MMS, so the National Research Council of the National Academy of Sciences was contracted to review the MMS 1984 resource assessment methodology. The National Academy of Sciences review was generally favorable and stated that the MMS method was "systematic, documentable, and theoretically sound" (National Research Council, 1986, p. 29). A number of specific, helpful suggestions for improvement were offered, including: (1) pursuing a grouped-prospect play assessment methodology compatible with existing models; (2) reporting the undiscovered resource base and the economically attainable potential; (3) developing a systematic process for including potential from postulated (unmapped or unidentified) prospects; and (4) explaining differences between current and previous assessments. Subsequently, MMS revised its assessment methodology, incorporating the suggestions from the National Academy of Sciences.

1987 ASSESSMENT

In 1986, concern over price volatility and its impact on developable resources was heightened after a dramatic decrease in oil prices. To quantify the effects of prices on undiscovered resource estimates, MMS broadened the 1987 resource assessment to include three categories of estimates: (1) the undiscovered resource base, which indicated the technically recoverable, geologic potential by removing economic constraints; (2) a primary economic case, based on prevailing economic conditions, and (3) an alternative economic case, based on a significantly higher, but still realistic, set of economic conditions. These three categories of estimates show a spectrum of possible results and allow estimation of results at other prices through interpolation. This was a true *National* Assessment, with the USGS assessing undiscovered resources onshore and in State waters and the MMS assessing the Federal offshore.

Following a period of intense leasing and exploration, Alaska exploration activity peaked in the mid-1980's, with several discoveries in the Beaufort Sea, none regarded as commercial at that time. A number of factors occurred that led to significant changes from the 1984 Alaska offshore assessment to the 1987 assessment:

- The ***Arctic offshore*** had been viewed as having high resource potential, but several oil discoveries resulting from the exploration effort, all confined to the Beaufort Sea, were subeconomic at the time. Finally, the petroleum industry explorers suffered a "significant emotional event" with the disappointing outcome of the Mukluk prospect exploratory well. Roughly $1.5 billion had been spent to acquire exploration leases on this large and attractive prospect. The prospect was condemned by a single $140 million exploration dry hole, plugged and abandoned in 1983. This event, followed by an oil price crash in 1986, had a crippling effect on oil industry attitudes towards Alaskan offshore exploration, at least in the short term. The exploration results at Mukluk and elsewhere in the Beaufort Sea impacted the 1987 assessment by increasing geologic risks. The collapse in oil prices increased economic risk. The decrease in gas prices condemned Alaskan gas prospects as uneconomic (at least under base case assumptions), further increasing overall economic risk for commercial development.
- The ***Bering Sea*** planning areas underwent their first extensive exploration cycle, with the largest and most promising prospects being drilled first, with fairly dismal results. Twenty-four exploratory wells were drilled in the Bering Sea during the interval between the 1984 and 1987 assessments. None were deemed capable of producing in paying quantities. Resource estimates for the Bering Sea provinces were drastically reduced because of information gained from exploration. The Bering Sea subregion was viewed as gas prone for the 1987 assessment, condemning the near term economic viability for the area, as reflected by a subsequent lack of industry interest in leasing or exploration.
- In the ***Pacific Margin*** subregion, exploration in the Federal portion of the Cook Inlet had disappointing results, and the drilling of large prospects in the Gulf of Alaska had failed to discover producible hydrocarbons. The major exploration effort in the Federal offshore had occurred prior to the 1984 assessment (22 wells in Cook Inlet and Gulf of Alaska; three more were drilled in Cook Inlet between the two assessments). Changes to the economic assumptions for the 1987 assessment had the most significant impact on the overall results for this subregion.

The combination of these factors reduced resource estimates for the Alaska offshore 1987 assessment as compared with the 1984 assessment. Despite negative drilling results and lower oil and gas prices, representatives of the natural gas industry questioned the lower gas resource estimates found in the 1987 assessment.

In response to gas industry concerns, the Secretary of the Interior asked the Association of American State Geologists to review the geologic information used in the assessment. After a series of regional workshops, the Association of American State Geologists submitted their findings, which included the following summary statement regarding the assessment of the Federal Offshore: "The assessment of undiscovered, conventionally recoverable oil and gas resources on the Outer Continental Shelf (OCS) is supported by an adequate data base, personnel with suitable expertise and training, and a disciplined, structured process that produces results that inspire confidence." (AASG, 1988, p. 2).

In addition to the review of geologic information by the Association of American State Geologists, the Secretary also requested the National Research Council of the National Academy of Sciences to review the assumptions and procedures employed by both USGS and MMS in the assessment. In contrast to the conclusions reached by the State Geologists, the National Academy of Sciences committee stated after reviewing the assessment methodology "...that there may have been a systematic bias toward overly conservative estimates. Eliminating the probable sources of this bias will improve the accuracy and credibility of future assessments." (National Research Council, 1991, p. 4).

Key areas of concern identified by the National Academy of Sciences committee included (1) play definition, (2) conceptual plays, (3) dependencies among variables (particularly with respect to risking), and (4) unintended imposition of economic constraints on the technically recoverable resources.

1990 ASSESSMENT

In preparation for developing a new 5-year oil and gas OCS leasing program for 1992 to 1997, MMS reviewed the 1987 National Assessment in 1989 to determine whether estimates were still valid. In 1990, MMS updated the 1987 offshore assessment by changing resource estimates for five planning areas (out of 26), where significant new data had become available since 1987. Three of those areas were in Alaska: Beaufort Sea, Chukchi Sea, and Hope Basin. Additional seismic data had become available, and extensive mapping efforts associated with scheduled lease sales were largely completed. The wealth of newly mapped prospects in these areas warranted an assessment update. Other offshore areas did not have significant new data, and an update of oil and gas potential was not warranted.

1995 ASSESSMENT

The recommendations from the National Academy of Sciences, described above, were not released until after the 1990 assessment (National Research Council, 1991). The Academy recommendations were addressed by major modeling changes for the 1995 assessment, as described further in Chapters 9. This most recent assessment has evolved from the experiences gained from all previous MMS assessments.

The first concern mentioned in the National Academy of Sciences review was play definition. To improve play definitions, two previous National Academy of Sciences reviewers of the MMS assessment methodology, Dr. David A. White and Dr. Richard M. Proctor, were contracted to advise MMS for the 1995 assessment. The 1987 assessment recognized play groupings, but databases were constructed at the prospect level. Prospect results were aggregated into play endowments by the model. In the 1995 assessment, geologic plays were clearly defined as genetic groupings of prospects.

TABLE 4.2
OIL RESOURCES

**COMPARISON TO PREVIOUS MMS ASSESSMENTS,
TOTAL ALASKA FEDERAL OFFSHORE,
RISKED MEAN VOLUMES
(Billions of barrels)**

ASSESSMENT	1984	1987	1990	1995
CONVENTIONALLY RECOVERABLE	NA	3.84	NA	24.31
ECONOMICALLY RECOVERABLE (BASE CASE)	3.33	0.92	1.87	3.75
ECONOMICALLY RECOVERABLE (ALTERNATIVE HIGHER CASE)	NA	1.61	2.54	6.71

NA - Not Assessed

1984 data from Cooke, 1985, MMS 85-0012, p.17.
--Base case starting oil price $29/bbl
1987 data from Cooke and Dellagiarino, 1989, MMS 89-0090, p.43 (conv. rec.); p.34 (econ. base.); p.39 (econ. high).
--Base case starting oil price $18/bbl
--Higher case starting oil price $30/bbl
1990 data from Cooke, 1991, MMS 91-0051, p. 20 (econ. base.); p. 27 (econ. high).
--Starting oil prices unchanged from 1987 assessment.
1995 data - this publication
--Base case starting oil price $18/bbl
--Higher case starting oil price $30/bbl

Databases and model runs were constructed at the play level. Play definitions were reviewed and approved by the consultants, MMS Headquarters personnel, and all assessors, before any assessment work began. Initially, many more plays were defined than in previous assessments. As the assessment progressed and geologic model data were developed, some plays were merged, based on shared geologic characteristics. External feedback was obtained by presenting play definitions and summaries of geologic input distributions in a peer review meeting attended by industry and government representatives. MMS felt it was important to invite peer review of plays before running the computer programs, when the focus naturally shifts to the results.

The second concern raised by the National Academy of Sciences committee related to the inadequate representation of conceptual plays in the previous assessment. This concern was addressed in two ways. The first was by the inclusion of entirely speculative, untested plays with no seismically defined prospects (ignored in prior assessments). The second way was by estimating numbers of unmapped or conceptual prospects for all plays, even those with mapped prospects. In the latter case, the number of mapped prospects anchored the lower end value for the number of prospects probability distribution. Assessors then estimated a maximum conceivable number of prospects in the

TABLE 4.3
GAS RESOURCES

COMPARISON TO PREVIOUS MMS ASSESSMENTS, TOTAL ALASKA FEDERAL OFFSHORE, RISKED MEAN VOLUMES (Trillions of cubic feet)

ASSESSMENT	1984	1987	1990	1995
CONVENTIONALLY RECOVERABLE	NA	16.75	NA	125.93
ECONOMICALLY RECOVERABLE (BASE CASE)	13.85	0.00	0.00	1.11
ECONOMICALLY RECOVERABLE (ALTERNATIVE HIGHER CASE)	NA	5.91	7.82	2.22

NA - Not Assessed

1984 data from Cooke, 1985, MMS 85-0012, p.17.
--Base case starting gas price $4.56/Mcf
1987 data from Cooke and Dellagiarino, 1989, MMS 89-0090, p.43 (conv. rec.); p.34 (econ. base.); p.39 (econ. high).
--Base case starting gas price $1.80/Mcf
--Higher case starting gas price $3.00/Mcf
1990 data from Cooke, 1991, MMS 91-0051, p. 20 (econ. base.); p. 27 (econ. high).
--Starting gas prices unchanged from 1987 assessment.
1995 data - this publication
--Base case starting gas price $2.11/Mcf
--Higher case starting gas price $3.52/Mcf

play, which became the upper end value of the number of prospects distribution.

The third concern expressed by the National Academy of Sciences was their perception that probabilistic dependence was inadequately considered in the 1987 assessment. If two events are totally independent, the probability that both will occur is computed by multiplying the probabilities of each event occurring. If one event occurring increases (or decreases) the likelihood of another event occurring, then a positive (or negative) dependency exists. Properly computing combined probabilities between variable distributions having full or partial dependencies demands a more complex computer model.

The issue of dependency arises in three contexts:

1. ***Risking*** - The probabilistic models used in the assessment require estimates of the risks that individual pools are dry (contain no oil or gas resources), and the risk that the entire plays are dry (all potential prospects do not contain oil or gas pools because of the absence of one or more critical geologic factors). Probabilities are estimated for geologic factors that control the likelihood of an oil or gas accumulation, such as presence of source rocks, migration of hydrocarbons, timing, presence of an adequate reservoir, and preservation. The assumption of independence for these geologic events could overestimate the final estimate of risk, and result in lower resource estimates. This concern was addressed in the 1995 MMS

assessment by revising risking techniques to purposely avoid the possibility of treating dependent factors as independent. New risking sheets were adopted by MMS to provide a systematic framework to guide assessors through the risk estimation process. The risking methodology is fully described in Chapter 10.

2. ***Dependencies among variables used to compute resources*** - Dependencies do exist among variables used to compute oil and gas resources. For example, reservoir porosity and water saturation could have a strong inverse correlation, where high porosity values are associated with low values for water saturation. Older MMS models have allowed assessors to impose correlations on geologic variables. Assuming independence of the variables results in narrower distributions of resources. However, testing has shown that strong correlations are required to have any significance to final resource distributions. The geologic model used in the 1995 assessment allows assessors to inspect intermediate outputs to determine that ranges are not inappropriately constrained. If the variance is too narrow, then assessors have the option of modifying distribution statistics and rerunning the module until they are satisfied that the output range of values is sufficiently wide to ensure that the actual volume of resources is included.

3. ***Dependencies among plays being aggregated to the province level*** - In most cases, plays will be independent by definition. However, shared factors, such as a common source for hydrocarbons, indicate a dependency that should be recognized and accommodated by the model. This concern was addressed by the program used to aggregate play results in the 1995 assessment, which helped ensure reasonable output ranges by allowing assessors to specify the degrees of dependencies among plays, from total independence to total dependence (see Chapter 9, FASPAG program). Total independence has the narrowest range of output results, whereas total dependence has the widest output distribution.

The fourth concern expressed by the National Academy of Sciences was that economic constraints were inadvertently imposed on the conventionally recoverable resources. For the 1995 assessment, minimum values for the distributions of geologic variables were based solely on geologic criteria, without consideration of economic viability. In earlier assessments, entire prospects were deleted from the databases by economic screens. Deleted prospects were deemed subeconomic for several reasons: they had insufficient acreage or net pay to be economically viable; they were located at a depth considered too shallow (less than 3,000 feet), requiring too many costly wells or platforms; or they were too deep (greater than 20,000 feet) with high drilling costs. In the 1995 assessment, all prospects were retained and economic constraints were applied only in the economic model. This allowed highly speculative plays to contribute to the geologic resource endowment. Also, removing economic criteria from geologic risking increased the geologic chance of success for most plays and provinces. As a result, estimates of risked, conventionally recoverable resources increased significantly in the 1995 assessment. Resource volumes from smaller pools were eliminated only after a discounted cash flow analysis showed a negative present worth. Specific modeling changes are described in Chapter 9, Computer Models Used to Calculate Oil and Gas Potential.

The changes suggested by the National Academy of Sciences and incorporated by the MMS enhanced the 1995 assessment by providing a more expansive interpretation of the geologic potential and showing the effects of economics over a spectrum of prices. Another area of enhancement is the wider variety of presentation results, including the customary tabular outputs, pool size rank plots, complementary cumulative curves, and price-supply curves.

COMPARISONS: UNDISCOVERED, CONVENTIONALLY RECOVERABLE RESOURCES

The 1995 estimates of undiscovered, ***conventionally recoverable*** oil and gas resources are the most appropriate numbers for comparison with past assessments, because they are not distorted by the additional variability introduced by engineering and economic factors. However, any comparison must be tempered by a number of methodology changes that occurred between the 1987 and 1995 MMS assessments of conventionally recoverable resources. Although both assessments report a range of possible values with corresponding probabilities, the most statistically valid points of comparison are the risked mean results.

The risked mean, conventionally recoverable oil increased from 3.84 billion barrels (Bbbl) in 1987 to 24.31 Bbbl in 1995 (table 4.2). Similarly, risked mean, conventionally recoverable gas increased from 16.75 trillion cubic feet (Tcf) in 1987 to 125.93 Tcf in 1995 (table 4.3). Figures 4.1 (oil) and 4.2 (gas) graphically display the differences for individual provinces between the two assessments. Factors contributing to these changes include the following:

- The conventionally recoverable resources were assessed in 1995 with a new computer program having a significantly different conceptual model. The program incorporates an assumption that the larger pool sizes are discovered first. This underlying assumption is based on the observation that large pools are often discovered early in the exploration of a frontier basin, with progressively smaller pools discovered over time. In previous MMS models, prospect probability of success was independent of computed resource size. The previous models established an inventory of resources at a specific time and under specific conditions. Finding rate was not a consideration. Probabilities were based on frequency of prospect success, rather than probability of discovery. In general, one of the impacts of adopting the assumptions associated with the new model is that larger prospects have higher probabilities and hence the play has a greater likelihood of containing at least one economic pool.
- The 1995 assessment included more plays and more prospects, both mapped and unmapped (or speculative resources).
- A concerted effort was made in the 1995 assessment to ensure that geologic resources were not biased by perceived economic effects. Prospects were included regardless of their location or their possible economic viability. The 1995 database is less restrictive and includes prospects that conceivably could be developed but would not be economic under any reasonable price expectations owing to extremely high development costs associated with their location, reservoir depth, low resource volume, or poor reservoir characteristics.
- Geologic risks were generally lower for the 1995 assessment of conventionally recoverable resources. Marginal probabilities (that is, chance of success) for a play were often 1.0, indicating a certainty of at least one oil or gas accumulation capable of flowing to a well bore, regardless of rate or size implications. "Success" was defined in the 1995 assessment by existence of the resource, not by its economic viability. Figure 4.3 compares the province chances of success for the 1987 and 1995 assessments.
- In the 1995 assessment, the minimum values of distributions for geologic variables were permitted to reflect geologic minima that might yield subeconomic pools. In 1987, minimum values in distributions for geologic variables were selected to approximately reflect the minimum quantities required for a pool of commercial size. If maximum values are held constant, lowering the minimum value has the effect of lowering the mean of the distribution. In provinces where 1995 results were lower than 1987 results, much of

the decrease in estimated resources occurred because of the different approach to creating probability distributions for geologic variables.

Between the 1987/1990 and 1995 assessments, the resource endowments of the Chukchi shelf and Beaufort shelf provinces increased dramatically, and these two provinces are primarily responsible for the overall increase in Alaska offshore resources. Between the 1990 and 1995 assessments, all exploratory drilling in the Alaska OCS was confined to the Beaufort shelf (7 new wells) and Chukchi shelf (4 new wells). Some of these wells, though classified as "dry" or unable to produce oil or gas in *commercial* quantities, provided geologic information that reduced the geologic risks for some plays, increasing the estimates of conventionally recoverable resources.

According to 1995 results, the Chukchi shelf and Beaufort shelf provinces contain 90 percent of both the conventionally recoverable and economically recoverable oil resources of the Alaska OCS. (Proportionally, this is consistent with earlier assessments. Combined Chukchi shelf and Beaufort shelf resources comprised 87 percent of the 1987 Alaska OCS assessment and 93 percent of the 1990 assessment). Furthermore, they contain about 76 percent of the conventionally recoverable natural gas resources. The resource changes in the Chukchi shelf and Beaufort shelf provinces result mostly from increases in the numbers of prospects and increases in the fractions of prospects believed to contain oil or gas (more optimistic risking). Given their overwhelming contribution to the total resources, the estimates for these two provinces are provided for comparison on tables 4.4a (Chukchi) and 4.4b (Beaufort).

The increase in the numbers of prospects in Chukchi and Beaufort shelf provinces is related to three factors: (1) more seismic mapping; (2) the addition of subeconomic prospects precluded from the 1987 study by minimum guidelines relating to areal extent, thickness, or reservoir characteristics; and (3) supplementing the inventory of mapped prospects with additional numbers of unmapped or speculative prospects that are not yet identified because of insufficient data.

The changes to the number of prospects assessed in the Chukchi shelf over time can provide a sense of scale that can be extrapolated to the entire assessment. The 1987 assessment of the Chukchi shelf included 4 plays containing 90 mapped prospects and another 80 speculative prospects or leads. The 1990 assessment of the Chukchi shelf assessed 10 plays containing 243 mapped prospects; another 157 identified closures were not included, because they failed to pass economic screens (Cooke, 1991, p.5). The 1995 assessment of the Chukchi shelf includes 22 plays. The number of prospects assessed includes 745 mapped and 1,638 unmapped (speculative), for a maximum of 2,383. (Additional information on "unmapped" prospects and their characteristics is provided in Chapter 13).

The fractions of prospects modeled as "successful" increased in 1995 because of a major shift in the risking philosophy. In 1995, a "success" was defined as any pool of hydrocarbons capable of flowing unassisted into a wellbore; a "successful" pool could be from either the economic or subeconomic fractions of the total hydrocarbon endowment. This definition of success generally resulted in estimates of the overall chances of success at the prospect, play, and province levels that were much higher than the 1987 estimates (fig. 4.3). This effect has a direct and significant impact on the risked estimates that are appropriate for comparing 1987 and 1995 results. Potential oil and gas volumes are discounted by risk to reflect the chance that the province may fail to contain any (conventionally or economically) recoverable hydrocarbons. Statistically valid comparisons between provinces (or any other assessment levels) must be made using *risked* volumes. A much more conservative risking approach was taken in the 1987 assessment, such that the

TABLE 4.4: COMPARISON of PREVIOUS MMS ASSESSMENTS
Key Provinces

TABLE 4.4a: CHUKCHI SHELF

ASSESSMENT	1987	1990	1995
CONVENTIONALLY RECOVERABLE	2.22 BBO 6.33 Tcfg	NA	13.02 BBO 51.84 Tcfg
ECONOMICALLY RECOVERABLE (BASE CASE)	0.59 BBO 0 Tcfg	1.36 BBO 0 Tcfg	1.14 BBO 0 Tcfg
ECONOMICALLY RECOVERABLE (ALTERNATIVE HIGHER CASE)	1.03 BBO 2.52 Tcfg	1.69 BBO 4.46 Tcfg	2.84 BBO 0 Tcfg

TABLE 4.4b: BEAUFORT SHELF

ASSESSMENT	1987	1990	1995
CONVENTIONALLY RECOVERABLE	1.27 BBO 8.26 Tcfg	NA	8.84 BBO 43.50 Tcfg
ECONOMICALLY RECOVERABLE (BASE CASE)	0.21 BBO 0 Tcfg	0.38 BBO 0 Tcfg	2.27 BBO 0 Tcfg
ECONOMICALLY RECOVERABLE (ALTERNATIVE HIGHER CASE)	0.38 BBO 2.38 Tcfg	0.67 BBO 2.45 Tcfg	3.22 BBO 0 Tcfg

RISKED MEAN VOLUMES:
Billion Barrels of Oil (BBO); Trillion Cubic Feet of Gas (Tcfg)
NA - Not Assessed

1987 data from Cooke and Dellagiarino, 1989, MMS 89-0090, p.43 (conv. rec.); p.34 (econ. base.); p.39 (econ. high).
--Base case starting price: $18/bbl; $1.80/Mcf
--Higher case starting price: $30/bbl; $3.00/Mcf
1990 data from Cooke, 1991, MMS 91-0051, p. 20 (econ. base.); p. 27 (econ. high).
--Starting prices unchanged from 1987 assessment.
1995 data - this publication
--Base case starting price: $18/bbl; $2.11/Mcf
--Higher case starting price: $30/bbl; $3.52/Mcf

general effect was much lower risked volumes of oil and gas than those estimated in 1995.

COMPARISONS: UNDISCOVERED, ECONOMICALLY RECOVERABLE RESOURCES

Estimates for risked mean, undiscovered, ***economically recoverable*** oil and gas resources for the Alaska offshore also increased dramatically from 1987 values of 0.92 billion barrels (Bbbl) of oil and no (0.00) economic gas to 1995 values of 3.75 Bbbl of oil and 1.11 Tcf of gas (tbls. 4.2, 4.3). Figure 4.4 compares the province estimates of undiscovered, economically recoverable oil resources for the 1987 and 1995 assessments. The most significant increases among economic oil resources are the estimates for the Chukchi and Beaufort shelf assessment provinces.

Important technical and philosophical differences must be recognized when comparing MMS economic assessment results from 1984 through 1995. These differences are summarized below:

- The key geologic factors contributing to the overall increase in economically recoverable resources in the 1995 assessment over prior assessments are the increase in prospect numbers and the higher chances of geologic success.
- Different versions of the computer program to assess economic resources were used for the 1984, 1987/1990, and 1995 assessments, each version becoming progressively more detailed and sophisticated. The program used for the 1995 assessment modeled the development and production of each pool and used an internal discounted cash flow program to evaluate the pool's economic worth. Resources from pools having a positive net economic value contributed to the total economic resources, whereas resources for pools with negative economic worth were set to zero and did not contribute to the total (the economic modeling is described further in Chapter 9). Prior to the 1995 assessment, an external economic program was used to estimate minimum economic field sizes, which were entered into the assessment program as single point estimates at the prospect level. Frequently, the same minimum economic field size was applied to all prospects in a play.
- The 1984, 1987, 1990, and 1995 assessments had unique estimates for economic variables (e.g., discount rates, costs, inflation rates, gas discount factors), each reflecting the financial climate at the time.
- Different price paths were used for each assessment. For example, the 1984 assessment used a starting oil price of $29 per barrel (bbl) and a starting gas price of $4.56 per thousand cubic feet (Mcf). Following the 1986 price crash, the 1987 assessment used a starting oil price of $18/bbl and a starting gas price of $1.80/Mcf. An alternative, higher case was also assessed, using starting prices of $30/bbl for oil and $3.00/Mcf for gas.
- The 1995 assessment presents economic results in an entirely new format. In addition to traditional tables of results, the 1995 economic assessment results are presented as price-supply curves. The user can select any starting price and read the corresponding resource amount from the curve. (The computer program can also be run for a single price to obtain detailed output under that specific set of economic assumptions).
- The earlier assessments used "ramped" prices (incorporating real increases), whereas the 1995 assessment assumes "flat" pricing (without real increases, only reflecting nominal increases).
- Development strategies changed considerably over time, from a philosophy of giant fields and correspondingly massive development infrastructure, to smaller fields, having fewer wells, smaller platforms, and lower costs. Cost files accessed by the computer program were modified to reflect

this change to industry development strategy.

- Assessment area boundaries varied among the different assessments. The 1987 conventionally recoverable resources were based on the assessment of geologic provinces. The 1987 and 1990 economically recoverable resources were based on administrative planning areas, because these estimates were most appropriate for lease sale planning purposes. The 1995 assessment of both conventionally recoverable and economically recoverable resources are based on geologic province boundaries. These province boundaries do not coincide exactly with all planning area boundaries, so adjustments to the estimates are required for individual lease sales. The most direct comparison of the different assessments is at the total area level or the subregion level (Arctic, Bering Sea, and Pacific Margin Subregions).

Given all of the changes incorporated into the 1995 National Assessment, only the broadest comparisons with previous estimates of economically recoverable resources are appropriate. Although estimates for specific economic variables have changed, *each assessment of economically recoverable resources represents the most likely expectation under the economic conditions existing at the time.* Certain variables, such as price, will have a greater impact than others. In fact, the sensitivity of resources to price, coupled with the volatility of oil prices, led to presenting the results as price-supply curves. The different economic assessments can be compared (on a total basis), given the understanding that they represent a snapshot of the resource potential at a specific time. Key factors contributing to the changes over time can then be identified.

Risked means for economically recoverable resources are compared in tables 4.2 and 4.3, and show a considerable increase in 1995 results as compared with previous assessments. Most of the increase can be attributed to changes in the geologic models, as described above.

The economic results for 1995 are more completely described by price-supply curves (provided in Chapter 27, Economic Assessment Results). In the 1987 assessment, only two economic cases, a "primary" case ($18/bbl oil price) and an "alternative" case ($30/bbl oil price) were reported (Cooke and Dellagiarino, 1989). In the 1995 assessment, instead of just two cases, the price-supply curves report a spectrum of economic resources as continuous functions of commodity prices ranging from $0 to $50 (or more) per barrel. At very high prices, perhaps greater than $50/bbl, economically recoverable volumes approach the estimates of undiscovered, conventionally recoverable volumes as a limit.

The price-supply graphs allow readers to find the potential economic resources of an offshore province by using their own estimate of commodity prices. The price-supply curves provide a much more complete summary of the ranges of economic potential and they highlight the high-risk/high-reward potential that attracts exploration investment in frontier areas.

SUMMARY

The 1995 assessment of the Federal offshore incorporates significant changes to the databases, models, and methods used in earlier assessments. Earlier assessments were appropriate for the mission and responsibilities of the time, but were more conservative and limiting. Previously, the severe impact of Alaskan economics subconsciously pervaded database construction, leading to increased risk and conservative results. Divorcing minimum values based on economic criteria from the ranges of geologic distributions required a paradigm shift for staff geologists. With the emphasis on economic accumulations, earlier assessments focused on large and easily defined prospects. The 1995 assessment also included prospects difficult or impossible to map with the existing grid of seismic data, because of either small size or subtle geology. The ability of the geologic model to assess speculative plays inspired more creative thinking in the 1995 assessment.

In addition to changes in the geologic assessment, the economic assessment methodology was revised to incorporate discounted cash flow analysis of individual pools. The methodology changes effectively linked the geologic and economic models, providing more consistent data sets and increased flexibility through an expanded suite of results. The revised assessment methods expand MMS capabilities to respond to a broad array of future questions.

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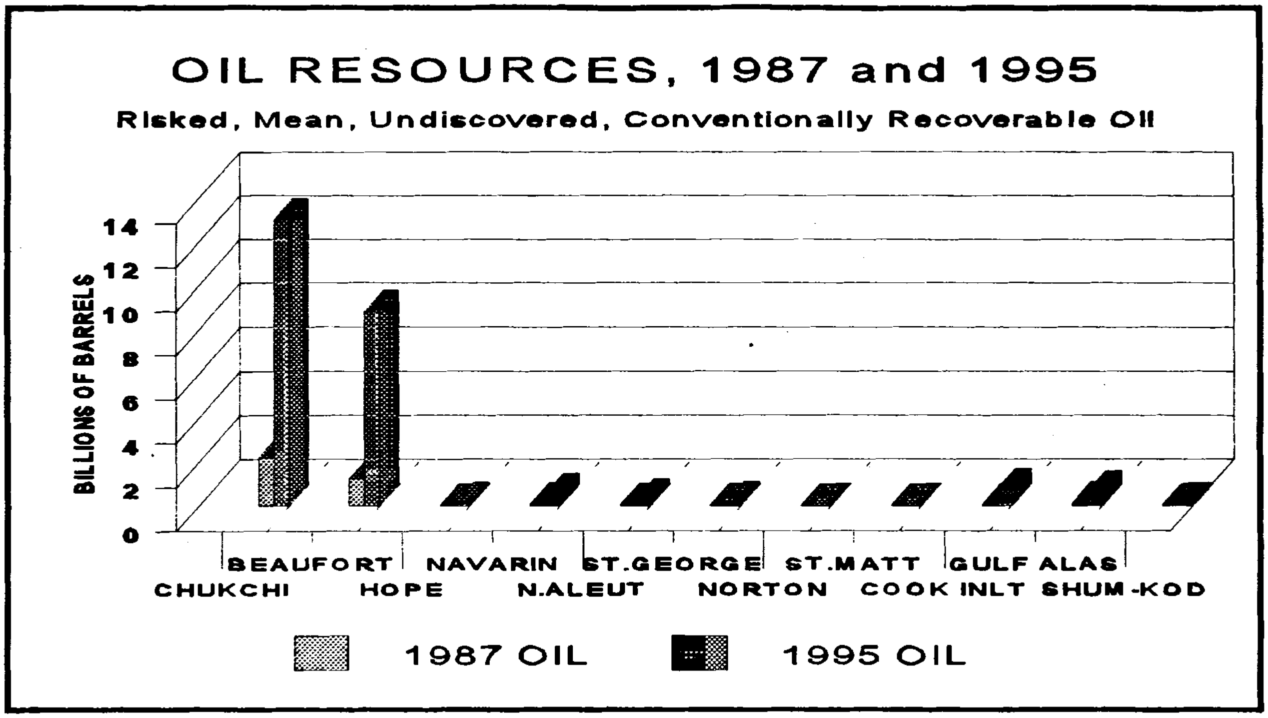

Figure 4.1: Comparison of Province Undiscovered, Conventionally Recoverable Oil Resources, 1987 and 1995.

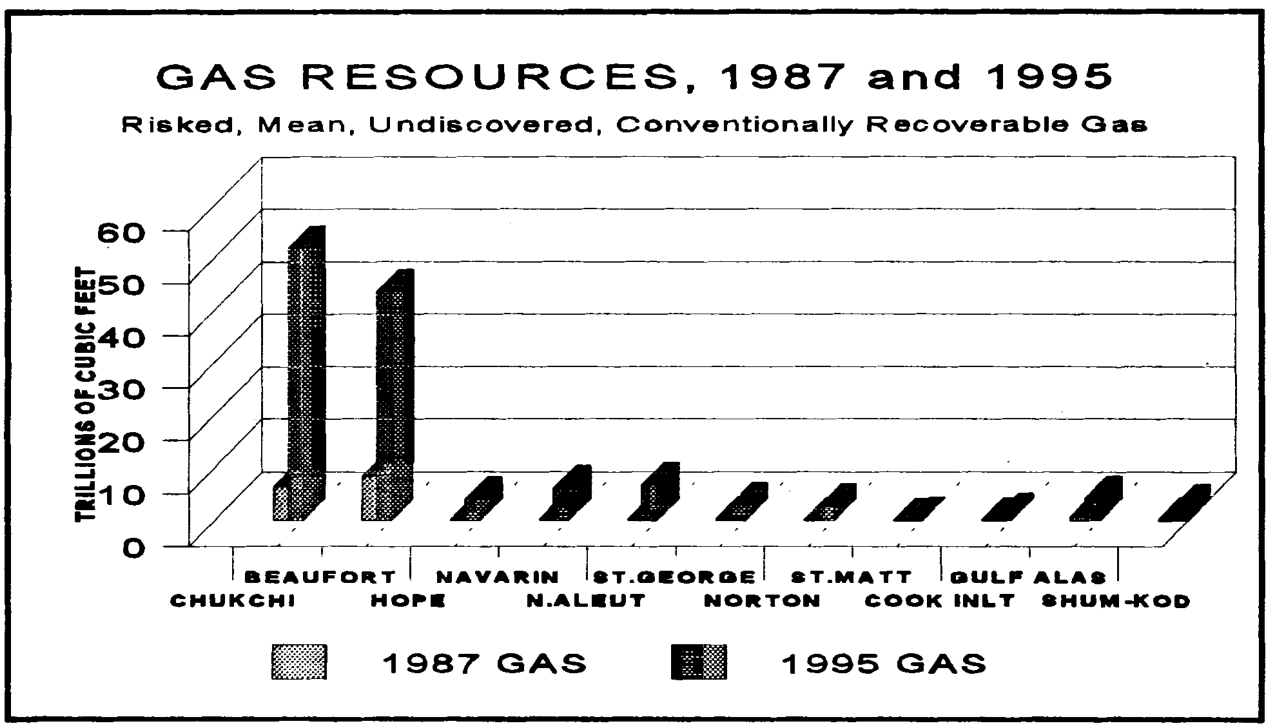

Figure 4.2: Comparison of Province Undiscovered, Conventionally Recoverable Gas Resources, 1987 and 1995.

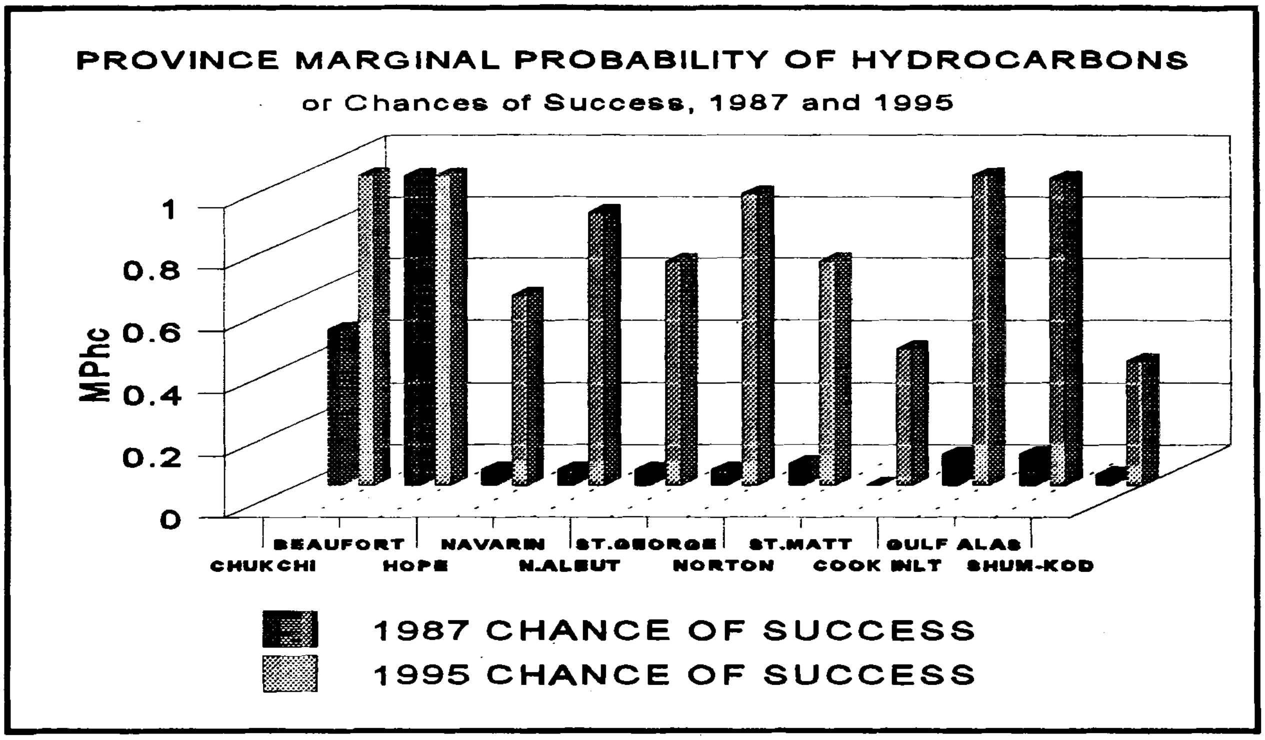

Figure 4.3: Comparison of Province Chances of Success, 1987 and 1995.

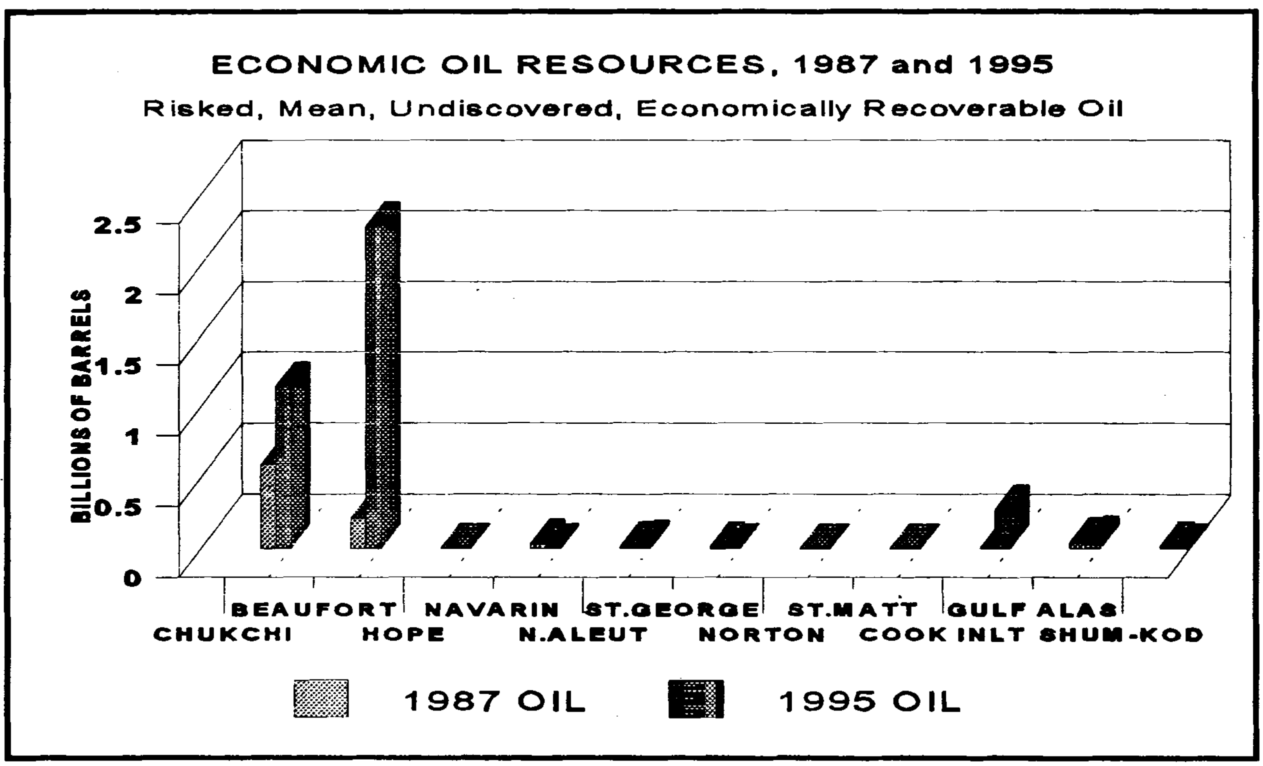

Figure 4.4: Comparison of Province Undiscovered, Economically Recoverable Resources, 1987 and 1995.

INTRODUCTION

INTRODUCTION
1995 National Resource Assessment
Alaska Federal Offshore
U.S. Minerals Management Service

by

Kirk W. Sherwood, James D. Craig, and Larry W. Cooke

5. PURPOSE OF ASSESSMENT AND LOCATION OF ASSESSMENT AREA

This assessment of the Alaska Federal offshore was conducted as part of a national appraisal of all Federal offshore lands of the United States that was performed by the Minerals Management Service (MMS) concurrently with a U.S. Geological Survey (USGS) assessment of all onshore lands and submerged lands in State waters (USGS, 1995). The MMS assessments are conducted periodically (Cooke, 1985, 1991; Cooke and Dellagiarino, 1989; Sherwood and others, 1996; MMS, 1996), and the results are used to guide management of leasing and exploration policies and programs in the Federal offshore.

The U.S. (Federal) submerged lands partly surround Alaska, starting at the U.S.-Canadian maritime boundary in southeastern Alaska, then extending west and clockwise to the U.S.-Russia maritime boundary in the Bering Sea, and then northeast to the U.S.-Canadian maritime boundary in the Beaufort Sea (fig. 1.1; pl. 1.1). The areas of Federal jurisdiction in these waters extend from the limit of State of Alaska waters, generally 3 miles offshore, to the farther of two limits as defined by either Federal Outer Continental Shelf (OCS) planning areas or the 200-mile Exclusive Economic Zone. These offshore U.S. lands cover an area of over 1.8 million square miles. Because submerged Federal lands extend 200 miles or farther offshore, they include all of the continental shelves as well as large areas of the continental slopes and deep abyssal plains of the north Pacific Ocean, and the Bering, Chukchi, and Beaufort Seas.

6. IDENTIFICATION OF ASSESSMENT PROVINCES IN THE ALASKA FEDERAL OFFSHORE

For purposes of the 1995 assessment, the Federal waters offshore Alaska were divided on geological grounds into 17 assessment provinces, as shown in figure 1.1 and plate 1.1. The areas of the 17 assessment provinces of the Alaska Federal offshore are listed in table 6.1. Because Federal waters may extend 200 miles or farther offshore, they include all of the continental shelves as well as large areas of the continental slopes and deep abyssal plains of the north Pacific Ocean, and the Bering, Chukchi, and Beaufort Seas. Six of the 17 offshore assessment provinces embrace areas of deep water or unpromising geology that offer only negligible geologic potential for conventionally recoverable oil or gas. The five deep-water assessment provinces are the Chukchi Borderland, the Canada basin-Beaufort slope, the Bering shelf-margin basins, the Bering Sea deep-water basins, and the Aleutian trench and north Pacific abyssal plain (fig. 1.1; pl. 1.1). The sixth

TABLE 6.1
AREAS OF ASSESSMENT PROVINCES, ALASKA FEDERAL OFFSHORE

<table>
<tr><th colspan="3">ASSESSED CONTINENTAL SHELF SUBREGIONS AND PROVINCES</th><th colspan="2">PROVINCES WITH NEGLIGIBLE RESOURCES</th></tr>
<tr><th>Subregions</th><th>Province</th><th>Area (mi^2)</th><th>Province</th><th>Area (mi^2)</th></tr>
<tr><td rowspan="3">Arctic Subregion</td><td>Chukchi Shelf</td><td>44,580</td><td>Chukchi Borderland</td><td>27,600</td></tr>
<tr><td>Beaufort Shelf</td><td>34,430</td><td>Canada Basin-Beaufort Slope</td><td>100,000</td></tr>
<tr><td>Hope Basin</td><td>27,180</td><td>Bering Shelf-Margin Basins</td><td>61,700</td></tr>
<tr><td rowspan="5">Bering Shelf Subregion</td><td>Norton Basin</td><td>33,360</td><td>Bering Sea Deep-Water Basins</td><td>254,000</td></tr>
<tr><td>St. Matthew-Hall Basin</td><td>100,000</td><td>Aleutian Arc</td><td>92,500</td></tr>
<tr><td>Navarin Basin</td><td>50,750</td><td rowspan="2">Aleutian Trench and North Pacific Abyssal Plain</td><td rowspan="2">754,000</td></tr>
<tr><td>St. George Basin</td><td>85,200</td></tr>
<tr><td>North Aleutian Basin</td><td>50,710</td><td></td><td></td></tr>
<tr><td rowspan="3">Pacific Margin Subregion</td><td>Shumagin-Kodiak Shelf</td><td>74,100</td><td></td><td></td></tr>
<tr><td>Cook Inlet</td><td>8,370</td><td></td><td></td></tr>
<tr><td>Gulf of Alaska</td><td>43,200</td><td></td><td></td></tr>
<tr><td></td><td>SUM OF AREAS</td><td>551,880</td><td>SUM OF AREAS</td><td>1,289,800</td></tr>
<tr><td></td><td colspan="4">TOTAL AREA ALASKA FEDERAL OFFSHORE = 1,841,680 miles²</td></tr>
</table>

assessment province considered to have negligible potential for oil and gas is the Aleutian arc, which consists of an intra-oceanic volcanic arc of Tertiary age.

The 11 assessment provinces that offer any realistic potential for undiscovered conventional or economic oil and gas are confined to the continental shelves surrounding Alaska and cover approximately half a million square miles in area. These provinces are grouped into three subregions. The Arctic subregion includes the Beaufort shelf, Chukchi shelf, and Hope basin assessment provinces. The Bering shelf subregion includes the Norton basin, St. Matthew-Hall basin, Navarin basin, St. George basin, and North Aleutian basin assessment provinces. The Pacific margin subregion includes the Shumagin-Kodiak shelf, Cook Inlet, and Gulf of Alaska shelf assessment provinces.

7. GEOLOGIC SETTINGS OF ALASKA FEDERAL OFFSHORE ASSESSMENT PROVINCES

PACIFIC MARGIN SUBREGION

The assessment provinces located offshore southern Alaska overlie the modern Pacific convergent margin, where oceanic crust of the Pacific plate moves northward and is subducted beneath the Aleutian volcanic arc and the Shumagin, Kodiak, and Gulf of Alaska continental shelves. The compression and uplift resulting from the convergence of plates along this zone has controlled the geological development of the Pacific margin of Alaska.

The Aleutian volcanic arc, of Tertiary age and constructed entirely upon oceanic crust, extends eastward 1,300 km from Russian waters into a continental setting where it meets the Bering Sea continental margin (at approximately the southeast limit of the "Bering shelf-margin basins" assessment province, fig. 1.1; pl. 1.1). From the Bering margin northeast to the interior of southern Alaska, the modern volcanic arc is superposed upon older volcanic-arc systems ranging up to Jurassic (145 to 200 million years ago (or "Ma")) in age (Reed and Lanphere, 1973). East of Cook Inlet, the volcanic arc and convergent-margin tectonics gradually give way to the strike-slip fault tectonics that dominate the eastern Gulf of Alaska, where the Pacific plate moves northwest and laterally past the North American continental plate.

Most of the undiscovered oil and gas resources in the assessment provinces of the Pacific margin subregion are associated with forearc basins and shelf-margin wedges of Tertiary age (66 Ma and younger). Except in Cook Inlet, these Tertiary rocks are superposed on a deformed "basement" consisting of older volcanic-arc complexes and accretionary terranes that generally offer negligible hydrocarbon resource potential.

BERING SHELF SUBREGION

Western offshore Alaska is dominated by the 600-km-wide Bering Sea continental shelf. From Jurassic to earliest Tertiary time, the Bering shelf hosted one segment of a larger system of volcanic arcs extending from southeast Alaska to the Russian Sea of Okhotsk. This volcanic-arc system marked the northward descent of a southern oceanic (proto-Pacific) plate encroaching from the south. Continental fragments and volcanic arcs borne along with the southern oceanic plate collided with both Russian and Alaskan elements of the volcanic-arc system in earliest Tertiary time (Worrall, 1991). The collision(s) strongly deformed the rocks of most parts of the Bering shelf segment and other parts of the volcanic-arc system. Rocks deformed by these collisions, typically Cretaceous age or older (>66 Ma), offer only negligible potential for undiscovered oil and gas resources. The Aleutian arc was also established as a new plate boundary shortly after the collisions, trapping between it and northeast Siberia a small plate containing fragments of an old volcanic arc and oceanic crust that formerly were part of the southern oceanic plate of Marlow and others (1982). Subduction of a spreading ridge that lay within the southern oceanic plate reorganized plate interactions in the north Pacific and caused strike-slip faulting throughout southern Alaska in early Tertiary and later time (Atwater, 1970). Most of the Bering shelf basins (Norton, St. Matthew-Hall, Navarin, St. George, and North Aleutian basins) began to subside at this time as pull-aparts or related features along strike-slip fault systems passing through the Bering shelf. Most of the undiscovered oil and gas resources offshore western Alaska are associated with Tertiary rocks deposited in the Bering shelf basins formed during this period of strike-slip faulting.

ARCTIC OFFSHORE SUBREGION

Offshore areas north and northwest of Alaska are dominated by the broad (400-km) continental shelf of Chukchi Sea and the narrow (70-km) continental shelf of Beaufort Sea. In Paleozoic and Mesozoic time (ca. 360 to 115 Ma), these shelf areas and northern Alaska shared petroleum-rich geologic basins that were broken up or restructured in Early Cretaceous time (ca. 115 Ma) by continental breakup and rifting along the Beaufort shelf margin and the elevation of the Brooks Range (Craig and others, 1985; Moore and others, 1992; Warren and others, 1995). The fragmentation of the crust in northern Alaska and mountain-building in the Brooks Range gave rise to several new basins that received many thousands of meters of sediments during Cretaceous and Tertiary time (115 Ma to present). These events also created the geologic structures that later trapped the vast oil deposits (70+ billion barrels, in place) found in the Prudhoe Bay area of northern Alaska, as well as the undiscovered oil and gas resources thought to underlie the neighboring continental shelves of the Beaufort and Chukchi Seas.

8. PETROLEUM EXPLORATION AND DEVELOPMENT IN ALASKA AND THE ALASKA FEDERAL OFFSHORE

EXPLORATION OF SOUTHERN ALASKA AND THE OFFSHORE PACIFIC MARGIN SUBREGION

Petroleum exploration in Alaska began in the late nineteenth century, and the first field was discovered in 1902 by drilling at the site of oil seeps at Katalla along the coast of the eastern Gulf of Alaska (fig. 1.1 and pl. 1.1; AOGCC, 1994, p. 56). In the late 1950's and the 1960's, several commercial oil and gas fields were discovered in the Cook Inlet area. Many of the commercial-sized fields discovered during this time remain in production today (presently 7 oil fields, 7 gas fields). Altogether, 8 oil fields and 22 gas fields have been discovered in Cook Inlet, with total discovered oil resources of about 1.34 billion barrels of oil (BBO) and 9.33 trillion cubic feet of gas (TCFG) (AOGCC, 1994; OGJ, 1993; AKDO&G, 1995). Oil production from Cook Inlet fields peaked at 236,000 barrels of oil per day (BOPD) in 1970, but declined to 43,500 BOPD by 1994 (AOGCC, 1994). Total cumulative production from Cook Inlet by the end of 1994 was 1.19 BBO and 7.44 TCFG (AOGCC, 1994). Of the 7.44 TCFG produced in Cook Inlet, 2.73 TCFG were re-injected to aid oil recovery (and remain a future resource), with 4.70 TCFG, or 50 percent of discovered resources, actually delivered to market and consumed. Cook Inlet also hosts a liquefied natural gas (LNG) facility, which ships about 144 million cubic feet of gas per day to power utilities in Tokyo, Japan (AOGCC, 1994, p. 9 (N. Cook Inlet field); OGJ, 1993, p. 24).

No commercial production has occurred on any Federal submerged lands in the Cook Inlet area or any part of the offshore Pacific margin subregion. The first explorations of the Alaska Federal offshore began in the early 1970's with the scheduling of lease offerings in the Gulf of Alaska and Cook Inlet. A stratigraphic-test well was drilled in the Gulf of Alaska in 1975, and a second one was drilled in Federal waters of Cook Inlet in 1977. The first Federal offshore lease sale in Alaska waters was held in 1976 in the Gulf of Alaska. Three sales in the Gulf of Alaska from 1976 to 1981 leased 0.6 million acres for total high bonus bids of $670 million. Twelve exploratory wells on Gulf of Alaska leases in the period from 1977 to 1983 failed to locate commercial quantities of oil or gas. Two lease offerings in Federal waters of Cook Inlet in 1977 and 1981 leased 0.57 million acres for total high bonus bids of $403 million. Thirteen exploratory wells drilled on Cook Inlet leases in the period from 1977 to 1985 failed to find commercial quantities of oil or gas.

EXPLORATION OF WESTERN ALASKA AND THE OFFSHORE BERING SHELF SUBREGION

Petroleum exploration has been conducted since the early 20th century in various parts of western Alaska and the Alaska Peninsula. These efforts all failed to locate any significant quantities of oil or gas.

Petroleum exploration offshore western Alaska began in the early 1970's with the scheduling of lease sales on the Bering Sea shelf. Seismic data were gathered across large parts of the Bering shelf, and six stratigraphic-test wells were drilled from 1976 to 1983 in St. George, Norton, Navarin, and North Aleutian basins.

Four lease sales were held in these same basins in the period from 1983 to 1988, and 1.9 million acres were leased for total high bonus bids of $1.36 billion. Twenty-four exploratory wells were drilled in Navarin, Norton, and St. George basins. None encountered significant shows of oil or gas. Except for a stratigraphic-test well drilled in 1983, no exploratory drilling has occurred in North Aleutian basin.

EXPLORATION OF NORTHERN ALASKA AND THE ARCTIC OFFSHORE SUBREGION

Petroleum exploration in Arctic Alaska began with the reporting of oil seeps in the Cape Simpson area near the northernmost tip of Alaska by Leffingwell of the U.S. Geological Survey in 1917. In 1923, based on the presence of these seeps and prompted by fuel shortages in World War I, President Warren Harding established Naval Petroleum Reserve No. 4, later renamed the National Petroleum Reserve-Alaska (NPR-A, fig. 1.1 and pl. 1.1). Fuel shortages during World War II prompted the first intensive, publicly funded exploration program in NPR-A from 1944 to 1953, resulting in the discovery of several subcommercial oil and gas fields.

With passage of Alaska statehood in 1959, exploration shifted to the lands selected by the State of Alaska in the corridor between NPR-A on the west and the Arctic National Wildlife Refuge (ANWR, fig. 1.1 and pl. 1.1) on the east. State of Alaska lease sales in 1964 and 1965 were followed by the 1968 discovery of the largest oil field ever found in North America, the 12.4 BBO Prudhoe Bay field. The ultimate reserves recoverable from known commercial fields in the Prudhoe Bay area were approximately 16.4 BBO and new projects announced in recent weeks at the Alpine discovery, the West Sak pool in Kuparuk field, and the Schrader Bluff pool in Milne Point field bring the northern Alaska commercial reserve endowment to 17.7 BBO (Alaska Report, 1996; ADN, 1996b; ADN, 1996c). Untapped Prudhoe-area gas reserves are estimated at 28.2 TCFG (AOGCC, 1994; AKDO&G, 1995).

Construction of the Trans-Alaska Pipeline System (TAPS) began in 1974, and the first oil pumped through the pipeline arrived at the ice-free port of Valdez, Alaska, in 1977 for tanker shipment to the U.S. mainland (fig. 1.1 and pl. 1.1). Pipeline throughput peaked at 2.0 million barrels of oil per day (MMBOPD) in 1988. By May 1996, production was 1.5 MMBOPD and a total of 11.2 BBO had passed through the pipeline (R. Oliver, Alyeska Pipeline Co., pers. comm., 1996).

In response to concerns about oil shortages related to the 1973 embargo of the United States by the Organization of Petroleum-Exporting Countries, government-sponsored exploration of NPR-A resumed in 1975 after a 22-year hiatus. This second program resulted in 28 exploration wells and 14,800 miles of seismic data, but no significant discoveries. The first offerings of leases for private exploration occurred in 1981, followed by a single well drilled and abandoned in 1985. This well concluded the most recent cycle of petroleum exploration in NPR-A.

The first lease sale in the offshore Arctic subregion, offering mostly submerged lands of the Beaufort Sea near known fields in the Prudhoe Bay area, was conducted jointly by the State of Alaska and the Federal Government in 1979. Since 1979, most continental-shelf areas of the offshore Arctic subregion were offered in four additional lease sales in the Beaufort Sea and two lease sales in the Chukchi Sea. Northern parts of the Hope basin assessment province were offered in both Chukchi shelf sales but failed to attract any bids. In all seven sales, a total of 5.5 million acres of Federal lands were leased for total high bonus bids of $4.03 billion. An eighth sale, held in September 1996, attracted $14.6 million in high bids on 29 lease blocks (100,000 acres). A total of 32 exploratory wells were drilled in Arctic Federal waters between 1980 and 1993, resulting in the discovery of several subcommercial pools of oil (Northstar, Sandpiper, Liberty (Tern), Hammerhead, and Kuvlum).

Northstar (Seal Island) field, estimated by BP-Alaska to contain up to 145 million barrels of recoverable oil, straddles State of Alaska and Federal offshore lands about 10 miles north of Prudhoe Bay field and will provide the first-ever commercial production of oil from the Alaska Federal offshore. Commercial production from Northstar field could enter the Trans-Alaska pipeline as early as 1999 (ADN, 1996a, p. A1).

In the September 1996 lease sale, leases were re-acquired over a possible extension of the Liberty (Tern) pool. An exploration well in the 1996-97 drilling season was drilled to test the commerciality of the Liberty pool.

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RESOURCE ASSESSMENT MODELS

RESOURCE ASSESSMENT MODELS
1995 National Resource Assessment
Alaska Federal Offshore
U.S. Minerals Management Service

by

Larry W. Cooke, Kirk W. Sherwood, and James D. Craig

9. COMPUTER MODELS USED TO CALCULATE OIL AND GAS POTENTIAL

UNDISCOVERED OIL AND GAS RESOURCES: FUNDAMENTAL ASSESSMENT CONCEPTS

The assessment of the undiscovered oil and gas potential of the Alaska Federal offshore involved two separate tasks. The first task was to develop estimates of the undiscovered resources irrespective of any economic constraints. The second task was to determine how much of the undiscovered oil and gas would be profitable to produce under a range of possible commodity prices. This chapter describes the computer programs that were used by Minerals Management Service (MMS) to accomplish these tasks.

The method selected to assess undiscovered oil and gas resource potential is based on the specificity of available data and the purpose of the assessment. Assessment techniques are different for mature exploration provinces and frontier provinces. Evaluating a prospect for leasing is much different than assessing the potential of an entire geologic play. The method must be appropriate to the task. In the early stages of exploration in a frontier province, assessors must rely on scant data, often using analogs from similar geologic regimes, delphi (consensus based on expert opinion), areal yield, or other methods (White and Gehman, 1979). As seismic or drilling data are gathered in a province, more specific techniques can be used and the primary assessment unit becomes the geologic play. Geologic plays are defined as a population of pools[1] or prospects[2] having a common history of hydrocarbon generation, migration, reservoir development, and trap configuration. When sufficient data become available, assessment methods focus on individual prospects. Economic evaluations at the level of individual prospects provide necessary information for leasing or development decisions.

When assessing the undiscovered resource potential of a frontier province, two fundamental questions must be answered: Are there **any** undiscovered oil and gas accumulations in the area? If there are, **how much** oil and gas exists in these accumulations? The assessment methodology addresses these questions through the concepts of risk (any?) and uncertainty (how much?).

The first question (**any?**) requires an analysis of various geologic risk factors used to quantify the probability that oil and gas are absent. Risk can be assessed for individual prospects within a

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[1] *A pool is an accumulation of hydrocarbons, typically within a single stratigraphic interval, that is hydraulically separated from any other hydrocarbon accumulation.*

[2] *A prospect is an untested geologic feature having the potential for trapping hydrocarbons. A prospect contains one or more pools.*

geologic play, plays within a province, or for the entire province. Risk is one indicator of the relative resource potential of a province. For example, a "mature" exploration province with known oil and gas accumulations does not have geologic risk at the province level, although individual plays within the province may still be unproven, and individual prospects within the plays have their specific risks. In contrast, a "frontier" province requires additional exploration drilling to confirm whether all of the factors required to result in an oil or gas accumulation (hydrocarbon generation, migration paths to a reservoir, trapping mechanism, reservoir, and preservation) have occurred in the proper sequence. The resource potential for the frontier province is discounted relative to a mature province by applying a geologic risk factor. The risk factor associated with a specific prospect or play or province is computed through a process that requires assessors to estimate probabilities for contributing geologic factors (this risking process is described further in Chapter 10). The estimates for these factors can change based on the results of drilling or other new information.

The answer to the second question (**how much?**) is often highly uncertain because of the lack of data. The assessment method needs to incorporate techniques that reflect this uncertainty, so that the estimates do not convey a false sense of precision. Factors relating to the number of possible prospects and their sizes are typically represented as probability distributions, which relate values to the likelihood of occurrence. As new information becomes available through drilling or other geologic and geophysical surveys, the original values for uncertain variables can be adjusted.

Once an assessor is able to characterize uncertain variables as probability distributions, a statistical procedure is needed to combine these distributions to derive the resource estimates. These procedures are coded into steps or instructions executed by a computer. Two general techniques are commonly used, an *analytical process* or a *sampling process*:

- The *analytical process* reduces input probability distributions to representative statistics, such as the mean and standard deviation of the distribution. The distributions are combined statistically according to an algorithm used to calculate oil and gas resources. The model yields ranges of possible resource volumes in the form of probability distributions.
- The *sampling process* is based on a large number of computer trials, where each trial represents a possible state of nature. On an individual trial, all distributions are randomly sampled. These sampled variables are used to compute one simulation or possibility. On the second trial, all distributions are randomly sampled once again, and a second possible result is calculated. This process continues until a specified number of trials are completed. At the conclusion of the simulation process, a large number of possible results have been computed. These results are sorted, ranked, and presented as probability distributions for oil and gas resource volumes. This kind of random sampling method is called a Monte Carlo process. An important criteria is that enough trials are run to adequately sample the input distributions. This process requires extensive computer memory to store intermediate results and takes longer to run than an analytic process that requires about as much computing time as running a single Monte Carlo trial. The advantages of Monte Carlo sampling are that the distributions can be of any type or shape, and complex processes with numerous variables can be modeled. Both analytical and sampling processes were used by MMS in the current assessment.

In theory, the range of resource volumes derived from running the computer programs will bracket the volume that actually exists. However, the actual volume will only be known with certainty after all prospects are drilled, developed, and produced. In an active exploration province, this could require decades. Many frontier provinces may never be thoroughly tested. The range of volumes indicates the degree of uncertainty associated with the estimates. A well-explored, mature, exploration province would be expected to have a narrow distribution of resource volumes, as contrasted with a partially explored, frontier, exploration province, having greater uncertainty and a corresponding broad range of values.

OVERVIEW

From its inception in 1982, a key responsibility for the MMS has been the leasing of offshore tracts for exploration and possible development. The focus of the MMS Resource Evaluation Office has been to acquire, analyze, and interpret geologic, engineering, and economic data necessary for the evaluation of individual prospects offered for lease. Therefore, MMS has a substantial database of mapped prospects for all geologic provinces. Previously, MMS used an assessment method of prospect summation, where individual prospect volumes were summed to the geologic play level, and results for plays were summed to the province level. As described in Chapter 4, this focus on economic accumulations can be restrictive when considering the complete, undiscovered resource potential of a province. Therefore, MMS used a play assessment method for the 1995 National Resource Assessment. The assessment scope was widened to include all potential accumulations, mapped or unmapped, regardless of economic feasibility.

An overview of the MMS oil and gas resource assessment computer programs is shown on figure 9.1.

- The geologic model, **GRASP** (Geologic Resource Assessment Program), uses input data for geologic variables to compute ranges of values for individual pools within assessed geologic plays. These pool and play resources are aggregated to estimate the conventionally recoverable oil and gas resources at the province level. Output results are in the form of probability distributions, requiring pool level resources to be aggregated into play distributions and play level resources to be aggregated into province distributions.
- A program named **FASPAG** (Fast Appraisal System for Petroleum - Aggregation) is used for statistically aggregating probability distributions. Results at the province level are aggregated to the Subregion and Region levels using FASPAG.
- The output pool and play distributions from GRASP become the input to the economic evaluation program, **PRESTO** (Probabilistic Resource ESTimates - Offshore). PRESTO is used to estimate economically recoverable oil and gas resources under specified economic conditions. Running PRESTO under different economic scenarios results in distributions of economic resources, which can be compiled and presented in the form of price-supply curves. These curves display changes in recoverable resource potential corresponding to changing prices.
- PRESTO results at the province level are aggregated to the Subregion and Region levels using FASPAG.

The advantage to using probabilistic models is that individual subject matter specialists can be called upon to estimate probability distributions for uncertain geologic, engineering, and economic variables. A geology team comprised of geologists and geophysicists was assigned to each assessment province. The team determined values for inputs to the GRASP model, ran the model, reviewed intermediate results, verified outputs, and prepared final reports. An engineering team worked with the geology team for each province to provide inputs to the PRESTO engineering/economics model. The engineering effort required creating development and transportation scenarios, estimating engineering and cost variables, running the PRESTO model, verifying outputs, and preparing final reports.

The remainder of this chapter describes specific concepts associated with the individual MMS assessment programs.

GRASP - THE GEOLOGIC PROGRAM

Previous MMS resource assessments have been criticized by some within industry as too conservative. The concern is that by focusing on the practical aspects of leasing (and hence, looking for economic targets), MMS could have biased the assessment of geologic potential toward just the economic fraction. One of the goals of this assessment was for MMS assessors to expand their creative geologic thinking to consider conceptual or speculative plays regardless of their chance for commercial success. A speculative play could have high potential resource volumes, but only offer a minor contribution to the total resource endowment when adjusted by geologic risks. However, the assessment is more robust and comprehensive when these high risk plays are included. The expanded scope of this methodology can also indicate areas for future exploration or topics meriting further research.

Another goal of the assessment was to ensure that the geologic assessment was not constrained by economic considerations. For example, current development in an area may indicate that a field can be commercial only if the average net pay thickness exceeds 50 feet. However, many accumulations having lower average thicknesses can also exist within the play. Their potential contributions would be masked by using an economic screen to censor the distribution of thickness on the low end. The current geologic assessment allows the distribution of average thickness to extend to the minimum conceivable amount which could be completed and produced through a conventional well bore. The geologic program (GRASP) assesses the amount of resources that could exist, down to a minimum accumulation size of 1 million barrels of oil or oil-equivalent (gas converted to oil on an energy-equivalent basis of 5.62 Mcf/bbl). The economics program (PRESTO) uses this unconstrained geologic database for determining economic viability under various development conditions. Screening of subeconomic volumes through the economics program occurs as a separate operation. Separating these analyses computationally provides a clear focus for each, freeing the creative thought process, and resulting in a more complete sense of the resource potential that could exist in a province.

The desire for a separate analysis of the overall or "geologic" resources caused MMS to seek a different computer model with a primary focus on assessing geologic plays. Rather than develop a new, independent program, a review of the literature indicated that the Geological Survey of Canada (GSC) already had an assessment computer program that contained the major elements MMS wanted to adopt for this assessment (Procter and others, 1981; 1983; Lee and Wang, 1984; 1986, 1990; Podruski and others, 1988).

The Petroleum Resource Information Management and Evaluation System (PETRIMES) is the computer program currently used by the GSC for resource assessment. The GSC computer program both assessed geologic plays and provided resource estimates as probability distributions. MMS obtained a microcomputer-based version, named Petroleum Resources Appraisal System Software (PRASS), which was reviewed and tested for applicability to MMS assessment goals and criteria. When MMS decided to incorporate this approach into its assessment procedures, the PETRIMES computer code was adopted and modified to address specific MMS needs. The ultimate product of these modifications is a program titled Geologic Resource Assessment Program (GRASP).

One undesirable aspect of PETRIMES was that a play had to be assessed as either an all-oil play or an all-gas play, whereas in many cases the plays defined by MMS contained prospects with mixtures of both oil and gas in the reservoir (e.g., associated gas caps), as well as independent oil or gas pools. Therefore, MMS programmers modified the PETRIMES program code to allow pools to be all oil, all gas, or a mixture. MMS also developed a more user-friendly input processor to eliminate some of the operational structure that PETRIMES retained from its roots as a mainframe computer program. Otherwise, the PETRIMES computer code is fundamentally unchanged and is the core of the GRASP program. The user-friendly environment and fast operation of the program, combined with help screens and graphical outputs, provide a platform that encourages assessors to refine their inputs by analyzing intermediate results produced by the various GRASP modules.

The GRASP program, like PETRIMES, has two basic approaches, depending on the degree of exploration in a province: (1) a discovery method and (2) a subjective method.

- The *discovery* method is based on data from existing pools in an established play being assessed. An analysis of existing discoveries establishes a trend that is used in conjunction with a reserves matching process to estimate remaining undiscovered pools.
- The *subjective method* is used for conceptual plays having few or no discoveries and is the most suitable option for assessing the frontier provinces of the Alaska offshore. The subjective method uses all available information to determine probability distributions for the number of potential accumulations (pools) and their sizes.

The Alaska Region used the subjective method exclusively for the 1995 assessment. Additional information on the GRASP method as applied to a mature exploration area can be found in Lore and others, 1996. A conceptual flowchart for the GRASP subjective method is shown on figure 9.2.

GRASP is based on analytic probability theory, where distributions are represented by statistics and results are mathematically derived rather than approximated through a sampling procedure. As such, two underlying concepts, ***superpopulation*** and ***lognormality***, are incorporated.

A geologic play is a natural population of pooled hydrocarbons resulting from common geologic processes. Conceivably, these processes could have resulted in other populations of pools. A ***superpopulation*** is the full range of possible pool families that are possible under a given set of geologic conditions. The actual set of existing pools will be included in the hypothetical superpopulation, if modeled correctly.

Lognormality recognizes the tendency for pool volumes to be lognormally distributed. Figure 9.3a illustrates a lognormal distribution in the form of a probability density function that relates the magnitude of a random variable to its probability of occurrence (the area under the curve corresponds to a probability of 100 percent). In this example, that relationship is determined by a lognormal function, where most pools are small and the largest pools occur only rarely. The familiar bell-shaped normal (or Gaussian) curve is shown on figure 9.3b for comparison. For variables that tend to be lognormally distributed, the logarithms of the values for the variable will be normally distributed. This property allows certain computational efficiencies that are incorporated into the program code. Examples of variables which tend to be lognormally distributed include reservoir thickness, oil recovery (barrels per acre-foot), reserves per field, and core permeability. Core porosity tends to be normally distributed (Newendorp, 1975).

Although the pool volumes for all plays are not exactly lognormally distributed, this characteristic is sufficiently common to justify its application to the estimation of undiscovered pool sizes in conceptual plays (Kaufman and others, 1975). The lognormality assumption allows pool volumes to be simply described by two distribution statistics (mean and standard deviation). These statistics are distinctive for plays resulting from commonly shared geologic processes. For example, dispersed hydrocarbon habitats yield many small oil and gas pools of similar sizes, whereas concentrated habitats (possessing mechanisms for focusing hydrocarbon migration) tend to produce fewer pools that are larger in size and have greater size variance (Coustau, 1981). As a practical matter, lognormally distributed data plots as a straight line on a log probability graph (random variable versus probability for exceedance; see fig. 9.4). This characteristic is very helpful in constructing probability distributions for variables in the absence of abundant data, as long as the lognormal assumption is deemed appropriate. For example, if the extreme range of a variable is known and the probability distribution can be assumed to be lognormal, then a probability distribution can be constructed by drawing a straight line between the extreme values on a log probability plot. This technique was used by MMS in the 1995 assessment to construct probability distributions for many geologic variables. (The next chapter more fully describes specific aspects of the geologic assessment.)

The assessment process began with the analysis of available geologic data in a province to define possible geologic plays. All conceivable plays were identified and each was assigned a probability of success, which is the chance that the play contains at least one accumulation of hydrocarbons (pool). High potential plays were distinguished from low potential plays, and some plays were eliminated from numerical assessment because of perceived high risk and low potential. The play definition phase is critical to avoid play mixing, which might cause deviations from a lognormal distribution of resources.

Peer reviews of the play definitions were held at this stage to ensure that all plays had been identified and given unbiased consideration. Peer review meetings were conducted with participants from the petroleum industry, and State and Federal agencies (January 1995, in Anchorage, Alaska). Similar meetings were held with MMS consultants, management, and other geoscientists. These meetings enabled MMS assessors to receive feedback on play definitions prior to constructing numerical models and entering data to the computer programs.

Once plays were identified and defined, the assessors developed data necessary to estimate the undiscovered resources. The GRASP method focuses on developing distributions for (1) the **number of pools** in a play and (2) the **pool sizes** (fig. 9.2). These distributions are used to create individual pools of oil and gas, ranked in size, within a play. Pool level distributions of resources are then aggregated to probability distributions of play resources.

The distribution for the **number of pools** in a play (representing actual accumulations) is derived from risking the prospect number distribution (many prospects will be modeled as dry). Assessors develop a probability distribution for the number of prospects based on identified and mapped prospects, as well as an estimate of unmapped prospects that may exist in the play. Prospects may be unmapped for a variety of reasons. Unmapped prospects can be assumed to be present where geologic and geophysical information is scant or nonexistent. Some unmapped prospects are simply so small in size that they are not intersected by the grid of seismic lines. The assessors estimate the chance that the play has adequate geologic conditions for the formation of oil and gas pools. If exploration drilling has encountered producible hydrocarbons (capable of flowing to a conventional well bore) within the play, the chance of at least one pool existing in the play (play probability) becomes 100 percent. A prospect chance of success (or drilling success rate) is also estimated. The play chance and the prospect chance are combined to derive an *exploration chance*, the probability that a prospect will yield a discovery if drilled. The distribution for numbers of prospects and the various risk factors (expressed as the exploration chance) are entered into a module that computes a probability distribution for the number of pools.

The assessors then estimate probability distributions for geologic variables that contribute to the **pool sizes**. Three components are developed by separate calculations: *pool volume*, *oil yield*, and *gas yield*.

- *Pool volume* (acre-feet) is derived through an analytical process that combines probability distributions for the areas of individual prospects in the play, pay thickness, trap fill fraction, fraction of the pool that is oil-bearing, and fraction of the pool that is gas-bearing.
- *Oil yield* (barrels per acre-foot) is derived from probability distributions for porosity, oil saturation, oil formation volume factor, and recovery efficiency.
- *Gas yield* (million cubic feet per acre-foot) is derived from probability distributions for porosity, gas saturation, reservoir temperature and pressure, gas deviation or Z factor, shrinkage, and recovery efficiency.

Oil and gas yield distributions can be computed through a GRASP module that statistically combines the appropriate input distributions.

An intermediate module in GRASP combines the pool volume distribution with the number of pools distribution to create pore volumes (acre-feet) for all pools in a play, ranked from largest to smallest pore volume. At this point, the module computes the probabilities that a specific number of pools exists. That is, a probability is computed for the Rank #1 pool that one or more pools exist in the play; a probability is computed for the Rank #2 pool that two or more pools exist in the play; and so forth, through the maximum number of pools assessed for the play.

GRASP then executes a sampling procedure that determines the resource commodity for each pool, based on the estimated probabilities that a given pool contains all oil, all gas, or a mixture of oil and gas. Oil and gas resource distributions are computed for individual pools by statistically combining pore volume distributions and pool probabilities with oil and gas yield distributions. The resulting pool size distributions can be displayed as a rank plot, with resources for each pool displayed as a range of values rather than as a single number. The pool resource volumes are displayed in rank order, from largest to smallest. The pool size rank plot, as illustrated in figure 9.5, is similar in concept to a field size distribution for discovered reserves, making it easy to use and interpret.

Finally, all of the pool resources are aggregated into resource distributions for the play. Although volumes of crude oil, solution gas, nonassociated and associated gas, and condensate are computed separately, GRASP aggregates the components and reports total oil (all liquids), total natural gas (all gases), and total hydrocarbon energy (oil summed with gas in oil-equivalent units). In addition to the pool size rank plots, GRASP outputs include normal, tabular printouts showing pool level resource distributions at specific percentiles, and complementary cumulative curves by play. Complementary cumulative curves display resource volumes (horizontal axis) versus the probability that the resource is that amount or greater (vertical axis), as shown on figure 9.6.

The final results of GRASP modeling are the distributions of resources that are recoverable using conventional technology by pool, play, and province. This geologic assessment can indicate areas of high resource potential, where oil and gas accumulations may be sufficiently common and with sufficient potential to warrant consideration for future exploration. However, the true test of near-term economic potential requires a separate economic assessment, where constraints to development, such as the high capital costs to construct infrastructure, must be considered.

GRASP CONCLUSIONS

In the previous section, two goals for the 1995 assessment were identified: (1) to expand the creative geologic thinking to consider more conceptual or speculative plays and (2) to ensure that the geologic assessment was not constrained by economic considerations. Both of these goals were achieved in this assessment. Geologic thinking was expanded to consider more speculative, high risk plays. In some cases, these play concepts were abandoned without assessment because of extremely low resource potential, but the process was valuable as a catalyst for discussion among assessors considering the merits of a particular play concept. The goal of eliminating economic bias from the estimation of geologic parameters required a difficult change in perspective for MMS assessors accustomed to evaluating prospects for leasing. This change in perspective is reflected in the broader ranges of the input distributions and had a significant effect on variables such as the number of pools estimated in assessment provinces. Although the MMS geologic assessment is distinct from its economically based assessment reported for 1987, an economic overprint still shadowed many of the input distributions. By design, the foundation of the 1995 assessment was a more pure geologic assessment. The individual pool size distributions resulting from GRASP can be used to develop estimates of economically recoverable resources under a range of possible conditions (as described shortly), or can be used by others outside of MMS as a basis for further economic analyses.

In the Alaska offshore, 74 plays were identified and individually assessed for undiscovered, conventionally recoverable quantities of oil and gas. Specifics related to the development of ranges of values for individual parameters to the Alaska geologic assessment will be described in Chapter 10.

FASPAG - THE AGGREGATION PROGRAM

Once GRASP has been run for all plays in an area, the play results can be aggregated to the province level. PETRIMES, the predecessor to GRASP, had the capability of aggregating play level results to the province level, assuming complete independence of plays. Under the assumption of total independence, the discovery of hydrocarbons in one play does not impact the likelihood of hydrocarbons existing in other plays in the province. MMS felt that additional aggregation options were important to include.

In the previous National Assessment, MMS assessors worked with Dr. Robert Crovelli of the U.S. Geological Survey on the problem of aggregating probability distributions. He had developed a program named FASPAG (Fast Appraisal System for Petroleum - Aggregation), which characterizes distributions with key statistics, then aggregates the distributions using analytic techniques (Crovelli and Balay, 1986). The Crovelli program allows dependencies to be recognized among plays being aggregated. If the discovery of hydrocarbons in one play in the province improves the likelihood of resources in other plays (or conversely, if exploration failures in one play tend to increase geologic risks associated with other plays), this dependency should be incorporated into the estimation of total resources. The FASPAG program allows plays to be modeled as totally independent, totally dependent, or partially dependent, where the degree of dependency is estimated by the assessor.

MMS wanted to retain this capability rather than be forced into the assumption of independence as the only option, so the Crovelli program was incorporated into GRASP as a module. FASPAG was used to aggregate plays into assessment provinces, to aggregate the provinces into Alaska subregions (Arctic, Bering Shelf, and Pacific Margin Subregions), and finally to aggregate all areas into total Alaska resources.

PRESTO - THE ENGINEERING/ECONOMIC PROGRAM

The PRESTO (Probabilistic Resource ESTimates - Offshore) computer program has been a practical and evolving MMS assessment tool to estimate undiscovered economically recoverable oil and gas resources. The basic PRESTO concepts are described in Cooke and Dellagiarino (1989). Originally developed in the late 1970's, the current PRESTO version (generation 5) has been extensively modified. Significant changes to the program include:

1. Former PRESTO prospect inputs were changed to pool resources imported from GRASP.
2. Minimum Economic Field Sizes (MEFS) as economic screens were changed to a discounted cash flow (DCF) analysis for each pool.
3. Price-supply curves were added as a graphical output, summarizing results from numerous model runs.

PRESTO: "Prospects" to "Pools"

PRESTO was originally designed to model specific mapped prospects, as well as providing three options for assessing unidentified (that is, unmapped or speculative) prospects. However, for this assessment, geologic potential was modeled entirely by the GRASP program, whereas engineering and economic modeling became the focus of the PRESTO program. PRESTO was modified to accept pool size distributions and their associated probabilities as output from GRASP. The geologic model is created for PRESTO by GRASP, and the primary function of PRESTO is to determine the quantities of undiscovered ***economic*** resources. Also, certain geologic variables residing in the GRASP data files are imported into PRESTO to derive some engineering variables (for example, pool area divided by well spacing is used to compute the number of wells simulated on a trial). The creation of data transfer files is accomplished with a GRASP-PRESTO interface module, which is executed upon completion of the final geologic assessment computer runs. Each GRASP geologic play assessment in a province contributes to the PRESTO input file. Then, PRESTO evaluates the economic viability of each pool and play within the province.

PRESTO: MEFS to DCF

MMS used PRESTO, generation 3, for the previous National Assessment (1987, updated in 1990). At that time, PRESTO 3 was primarily a geologic model. Geologic resources were developed on a prospect basis. Economic viability was determined by comparing geologic resources computed in a trial for a prospect with a minimum economic field size (MEFS). If sufficient resources were available to support prospect development, the resources were considered economic and the individual values saved. The MEFS represented a minimum size that could be economic under a given (single) set of economic conditions. This volume was computed externally by a proprietary, discounted cash flow (DCF) program. Derivation of the MEFS was a very time- and labor-intensive part of the assessment effort. Generally, one to three MEFS's were computed for each assessment province.

A similar process was used in PRESTO 3 to determine economic viability at higher levels.[3] A different external program was used to develop either a minimum basin reserve (MBR) or a minimum area reserve (MAR), which represented a minimum resource volume to support infrastructure within a basin and a major

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[3]*Confusion can be caused by nomenclature changes that occurred between the use of PRESTO 3 in the 1987 assessment and PRESTO 5 in the 1995 assessment. The PRESTO hierarchy for both versions (3 and 5) allowed four levels to be assessed in a single run. The lowest level is the zone. Up to three zones can be modeled per prospect. Zones contribute to prospects. Zone and prospect terms are common to both versions. According to the 1987 nomenclature, prospects were included in "basins," and basins were included in the highest level, the "area." For the 1995 assessment, only one zone per prospect was assessed. A prospect which contains oil or gas is termed a "pool." According to the 1995 nomenclature, prospects are grouped into "plays", and plays are within the highest level, the "province". In essence, both versions provide four levels of organization for the assessor to use:*

1987: zone-prospect-basin-area
1995: zone-prospect-play-province

transportation system from an area. Resources for an entire basin or area on a trial were compared to the MBR or MAR. If sufficient resources were available to support the infrastructure and transportation systems, the resources were considered economic and the individual values saved. Otherwise, the resources were insufficient for economic development and resources for all prospects in the basin or area were set to zero on that particular trial.

MMS assessment requirements outgrew the MEFS/MBR/MAR concept, and the decision was made to add engineering and economic modeling into PRESTO for the current assessment. GRASP became the MMS geologic model, whereas the focus of PRESTO shifted from geology to engineering and economic modeling.

Many of the original PRESTO concepts still remain. A conceptual flow diagram of the current version of the program, PRESTO 5, is shown on figure 9.7. The program still addresses the concepts of risk and uncertainty by using ranges of values and a Monte Carlo sampling process.[4] This process runs a large number of evaluation trials (typically 1,000 trials), where each trial represents a possible state of nature (Trial Loop on fig. 9.7). For each trial, all pools are sampled and and those pools simulated as being productive are evaluated (as shown on Play Loop and Prospect Loop, between points "B" and "C" on fig. 9.7). The results from all of the trials yield a probability distribution of economically recoverable resources.

PRESTO 5 models the exploration, development, and production for every pool output by GRASP. In addition to the pool-specific geologic resources and risking information provided by GRASP, the evaluator must develop various cost, engineering, and economic input files. These data files are used by the program to schedule production volumes, costs, revenues, and taxes, which are necessary to compute present worth using the DCF analysis.

The cost input file for PRESTO 5 includes ranges for variables such as exploration wells; platforms; production wells; transportation (as pipeline capital costs or tariffs); operating costs; among many others (see Chapter 11). Cost matrices are established according to various elements (e.g., water depth, drilling depth, number of platform slots). Low, most probable, and high values are estimated for each step of the controlling element (e.g., ranges of exploratory well drilling costs for every 1,000 feet of drilling depth). The engineering input file schedules all drilling and development activities (e.g., design, fabrication, and installation time for platforms). An economics input file provides discount rates, inflation rates, royalty rates, real increases in prices and costs, and starting oil and gas prices. These various files are brought together under an input processor that executes the program and provides output options. Particulars for the economic modeling assumptions used in this assessment can be found in Chapter 11.

PRESTO: Computing Economic Resources

The structure of the PRESTO model can be broadly divided into four main activities: **risking; sampling; computation; and compilation of outputs.**

As mentioned previously, the **risking** structure for the geologic plays and pools within the geologic plays is established through GRASP and imported by PRESTO. On a given trial, PRESTO compares computer generated, *pseudo-*

[4] *The term Monte Carlo sampling is used in a generic sense. Although traditional Monte Carlo sampling is available as an option in PRESTO 5, a similar concept called* ***Latin Hypercube sampling*** *was used exclusively in this assessment. Latin Hypercube sampling results in a more complete sampling of distributions with fewer trials. Essentially, a probability distribution is divided into partitions of equal probability area, with the number of partitions equal to the number of trials. Each partition is randomly sampled without replacement until all trials are complete (and all partitions sampled). The LHS provides a program framework that supports code to impose variable correlations specified by the assessor.*

random numbers[5] with the risk factors to determine which plays contain oil or gas on the particular trial and which pools are hydrocarbon-bearing within the individual plays. PRESTO conducts all of the risking at one time to develop a "hit history" (a matrix of productive pools and plays over all trials). The matrix discloses the number of pools and plays that have resources on any given trial, as well as the number of successful trials for any given pool or play. All of the risking occurs in the beginning, so that Latin Hypercube Sampling (LHS) can be used. LHS requires the number of successful trials for pools before sampling can begin, because input distributions are divided into a number of partitions equal to the number of successful trials. A pool that is sampled as having oil or gas on 107 trials, for example, will have all of its input distributions divided into 107 partitions of equal probability area. Each input distribution will be sampled 107 times, with each partition of every distribution being randomly sampled one time. Other pools will have their own counts of successful trials where they were modeled as containing hydrocarbons, as a direct response to the individual pool risks.

Once the risking process is complete, **sampling** of the input variable distributions occurs. The entire variable sampling for each pool is performed at one time to be able to use the variable correlation features of the program. The initial sampling of all of the distributions for a pool over all of the trials assumes total independence of the variables. If no variable correlations are identified, the sampling process is complete. If the evaluator chooses to correlate certain variables (either positively or negatively), internal PRESTO algorithms rearrange the originally sampled values to ensure the specified degree of correlation. Correlations among the input variables are induced through a rank transformation process (for more information, see References, Correlations and Sampling). Once all variables have been sampled (and correlated, if appropriate), then the computation process can begin.

The **computation** process has become quite complex in PRESTO 5, which performs a discounted cash flow for each productive pool in a trial. A description of the conceptual modeling during ***a single trial*** will illustrate the capabilities of PRESTO 5. *First, all pools are evaluated individually for the trial:*

- A given pool is sampled to determine the areal extent of its reservoir on the specific trial (the area ultimately controls the number of development wells and platforms).
- The numbers of exploration and delineation wells are based on an input of the average number needed to appraise the drainage area for a platform.
- The number of platforms modeled for the pool on the specific trial will be controlled by the maximum number of well slots allowed for each platform.
- The number of development wells is determined (both producers and service wells) for each platform, based on the pool area and the well spacing variable.
- Drilling and production activities are scheduled.
- Costs associated with these development activities are determined from sampling the cost file.
- Reservoir parameters determine flow rates and a production schedule is computed.
- Economic inputs determine the price paths for oil and gas over time, which are used to estimate future revenues.
- Tax consequences are factored into the cash flow.
- All costs, revenues, taxes, and royalties

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[5]***Pseudo-random numbers*** *- a random number seed is used as a starting point in an algorithm that generates a sequence of "random" numbers (hence, "pseudo-random"). Computer runs can be reproduced exactly at some later time by using the same sequence of "random" numbers to sample distributions. Changing the random number seed will generate a completely different sequence of numbers. If a sufficiently large number of trials is used, changing the random seed should not have a significant impact on final model results.*

are accounted for in a discounted cash flow process, which yields annual future values of the cash streams.

- The future cash flows are discounted to current dollars and summed to a present worth value for the pool. If that value is negative, the resource is subeconomic and deleted from that specific assessment trial. These subeconomic trials constitute economic failure.
- The frequency of economic failure is added to the geologic risk to ultimately yield an output risk for the pool (as shown on fig. 9.7, Prospect Loop).

This process is repeated for all pools in the play. Economic resources for all pools are summed to the play level to determine if adequate resources are available to justify the costs of development infrastructure to support the play. If so, the resources are added to the tabulation of economically successful trials for the play. If the play cannot support the required infrastructure and transportation costs, the resources for all pools are set to zero on that trial. Unsuccessful trials increase the economic risk for that particular play. Province resources are calculated as the sum of economic resources for all plays in the province[6]. If the province resources are adequate to justify costs of development (economic value is positive), all results are stored for the trial. If not, all pool and play economic results for the province are set to zero for that trial.

At the conclusion of one trial, all pools in all plays have been tested to determine whether they contain oil or gas. If they do, a complete development simulation and cash flow analysis has been performed. Pool results are aggregated to the play level, and play level results are aggregated to the province level. Each trial may analyze several hundred pools in a province. Then, the process begins again for the next trial, until a sufficient number of trials (usually 1,000) are complete.

At the conclusion of all trials, the computation results for all trials are sorted and ranked to produce probability distributions of possible economically recoverable resources. A trial count is available for each pool, showing how many times it was "hit" (simulated as drilled and resources discovered), and how frequently it was economic to produce. Results for volumes of oil, gas, solution gas, condensate, total hydrocarbon energy (barrels of oil-equivalent), profit, royalty, and tax are reported (as risked means of distributions) at the pool, play, and province levels. Complete ***conditional*** and ***risked*** [7]probability distributions and statistics for economic results are reported at the play and province level. PRESTO 5 also reports statistics for net economic value, numbers of exploration wells, delineation wells, oil wells, gas wells, and platforms. In addition to this vast tabular output, various graphics are available for most model

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[6]*Oftentimes, only one pipeline transportation system is considered and that is at the province level, modeling a trunkline needed to support development in a new area. Individual pools support flow lines to the platforms, and specific plays support gathering lines into the main trunkline.*

[7]***Conditional*** *- resources conditioned on the resources being present and economic; based only on the number of trials meeting both conditions (no zero trials). Prospect conditional resource volumes are the expected amount if the prospect is actually productive. These volumes are necessary for the model to properly estimate production revenues, development and transportation infrastructure costs, and other components of the DCF analysis.* ***Risked*** *- resources discounted by geologic and economic risk. Based on all trials, including trials with zero values (zeroed because resources did not exist geologically or zeroed because the volume was determined to be too low to be economic after DCF evaluation). Risked estimates are statistically appropriate for comparison. They are used for constructing price-supply curves and appear in tables of estimates used for comparisons in this report. If the condition has been met (economically recoverable resources do exist), then conditional and risked results will be the same. Otherwise, the effect of incorporating the zero trials into the risked estimates is to lower them relative to the conditional estimates.*

elements (e.g., complementary cumulative curves, histograms).

All plays in a geologic province are evaluated in one PRESTO computer run. Aggregation of the plays occurs within PRESTO, which honors dependencies among plays if appropriate. FASPAG is used for the final aggregation of the economically recoverable resources for all of the provinces up to the subregion level and for the total Alaska offshore.

PRESTO: Price-Supply Curves

One of the most significant improvements incorporated into PRESTO 5 was the ability to construct price-supply curves. The discounted cash flow approach described above is for one set of possible economic conditions. In the previous National Assessment, MMS assessed the conventionally recoverable resources (no economics); and the economically recoverable resources under two sets of economic conditions.[8] For the 1995 assessment, MMS decided to provide economic results for a continuum of starting oil or gas prices. This information is reported in the form of price-supply curves.

The process described in the previous section was for a single PRESTO run, under a given set of economic conditions. Alternatively, PRESTO 5 can be run in "price-supply mode," where it continues making PRESTO runs in an iterative fashion, each time changing the starting prices. The first run has a high starting price ($50/bbl of oil, for example; specified by the user). The full complement of PRESTO trials are run, and all usual outputs are created and stored. The results from this initial high price run approach the GRASP endowment results, which do not contain any economic risk. The second iteration halves the first price and reruns the PRESTO program, once again storing the results. Prices continue to be halved and additional iterations run until a price floor is reached below which no resources are economic on any trials. The program then methodically increases prices and continues with additional runs to fill in remaining gaps in the curves. Typically, PRESTO 5 runs 20 to 25 iterations at different prices until a full suite of economic results are obtained, and smooth price-supply curves are constructed (as shown on fig. 9.7, final steps within the darker gray box).

The price-supply curves can display price versus mean (or average) values, or price versus resource values at other percentiles (such as a low value having a 95 percent chance of that amount or more occurring, or a high value having a 5 percent chance of that amount or more). A sample set of curves is shown on figure 9.8. If a horizontal line were extended from a given starting price, the values where the line intersected the low, mean, and high curves would correspond to the 95 percent, mean, and 5 percent values for economically recoverable oil on the specific PRESTO run for that price. It is easy to imagine similar curves at other percentiles existing between the plotted curves. Any random point on the price-supply diagram represents a unique combination of price, volume, and probability.

Although numerous tables of detailed data are available from PRESTO, the price-supply curves are a primary output for the assessment because they reduce an enormous amount of information to a single illustration. The curves simply show that increases in price drive corresponding increases in the volumes of oil and gas that can be economically recovered, primarily through the profitable development of progressively smaller fields.

Inspection of price-supply curves allows interpretation of economically recoverable volumes of oil or gas at any commodity price. They can be used to provide quick, approximate answers to "what if" scenarios: "What if price of oil increased to $25/bbl?" "Would there be exploration interest in this area if price drops to $15/bbl?" In a sense,

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[8] *A base case was assessed in 1987, with a starting oil price of $18/bbl, a starting gas price of $1.80/Mcf, and other assumptions reflecting the prevailing economic conditions at that time. An alternative case was also assessed, with a starting oil price of $30/bbl, a starting gas price of $3.00/Mcf, and more optimistic assumptions regarding economic conditions.*

the price-supply curves are timeless. The 1995 economic model did not apply real increases to oil prices, gas prices, or costs. To determine the resources associated with a price at some time in the future, the user must assume that inflationary effects on prices are mirrored in costs to the same degree. A reduction in costs that significantly alters the cost-price relationship would require changes to the cost file used by the program and warrant a new assessment.

PRESTO Conclusions

As a result of changes to the program, PRESTO 5 is much more complicated and sophisticated than previous versions, but produces graphical outputs that present vast amounts of information in a more convenient and easily understood format. If the results are more easily understood and interpreted, they can be used to provide answers to a wider variety of questions. Furthermore, the versatility of the price-supply curve analysis should extend the useful life of this assessment, because the estimates do not necessarily become obsolete when a sudden price change occurs.

SUMMARY

The 1987 MMS assessment of undiscovered oil and gas resources received several criticisms that have been addressed in the current assessment through changes in the assessment models; through adopting a more optimistic geologic perspective; and, through a more rigorous economic analysis of individual pools. Each MMS assessment has been an improvement over the previous one. The 1995 assessment represents a culmination of years of model evolution along with the interpretation of the most recent available data.

This chapter has presented the modeling framework that shaped the 1995 assessment. The next two chapters provide specific information on the data used for the geologic and economic assessments.

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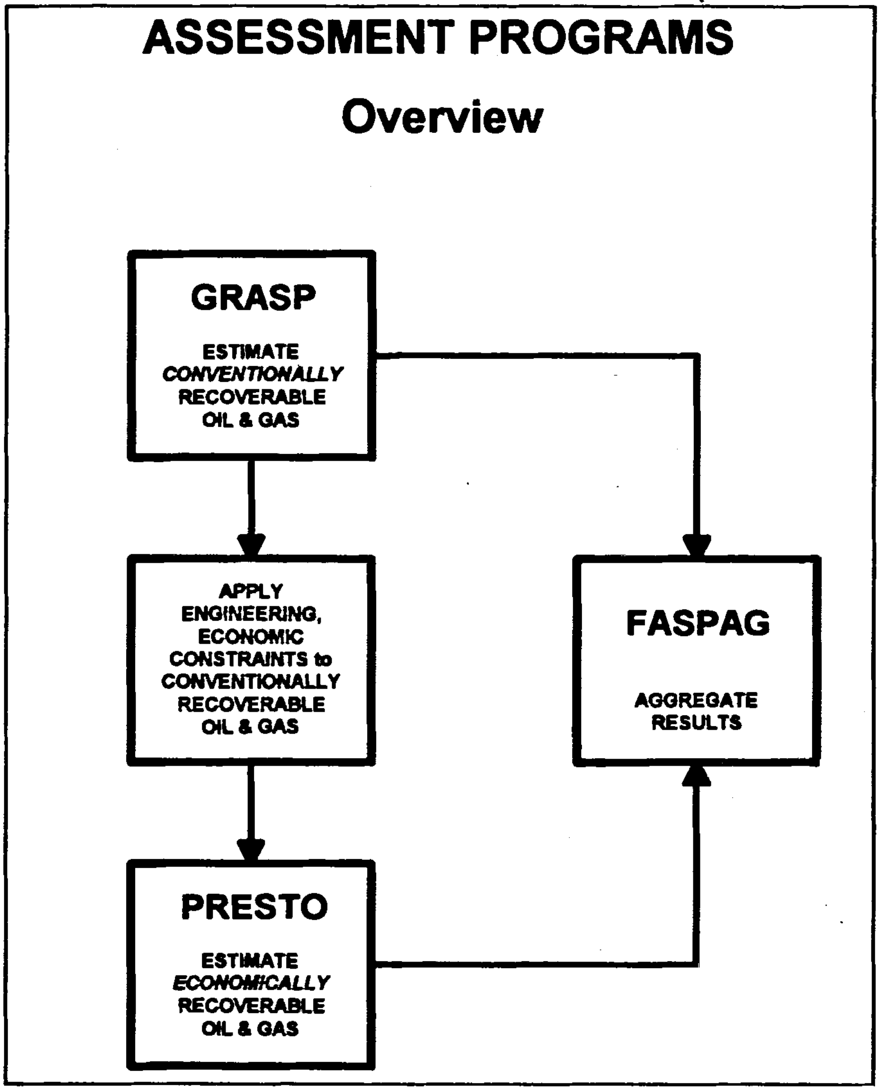


Figure 9.1: Overview of MMS oil and gas resource assessment computer programs.

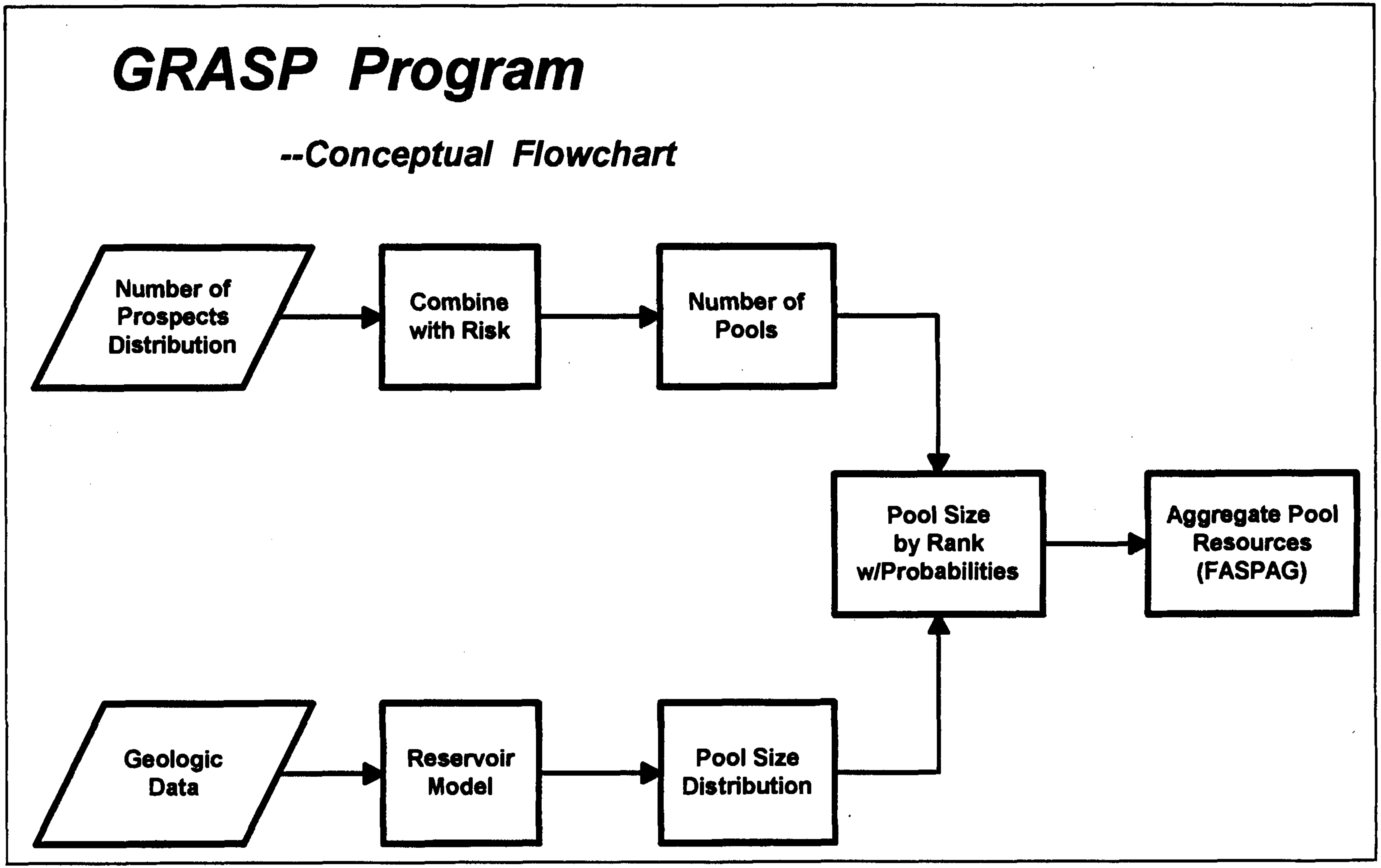
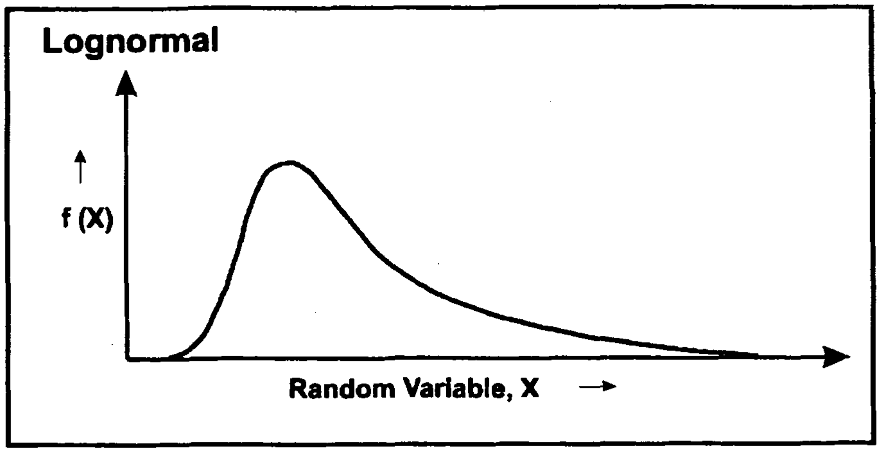


Figure 9.2: Conceptual flowchart for the GRASP program, used by MMS to assess conventionally recoverable oil and gas resources.

A.



B.

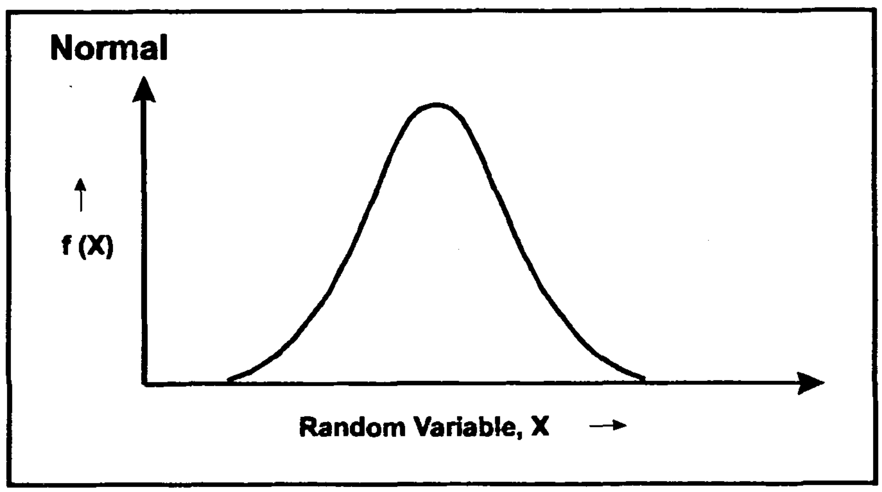


Figure 9.3: (A), Example of a **lognormal** distribution; and (B), example of a **normal** distribution, both shown as probability density functions.

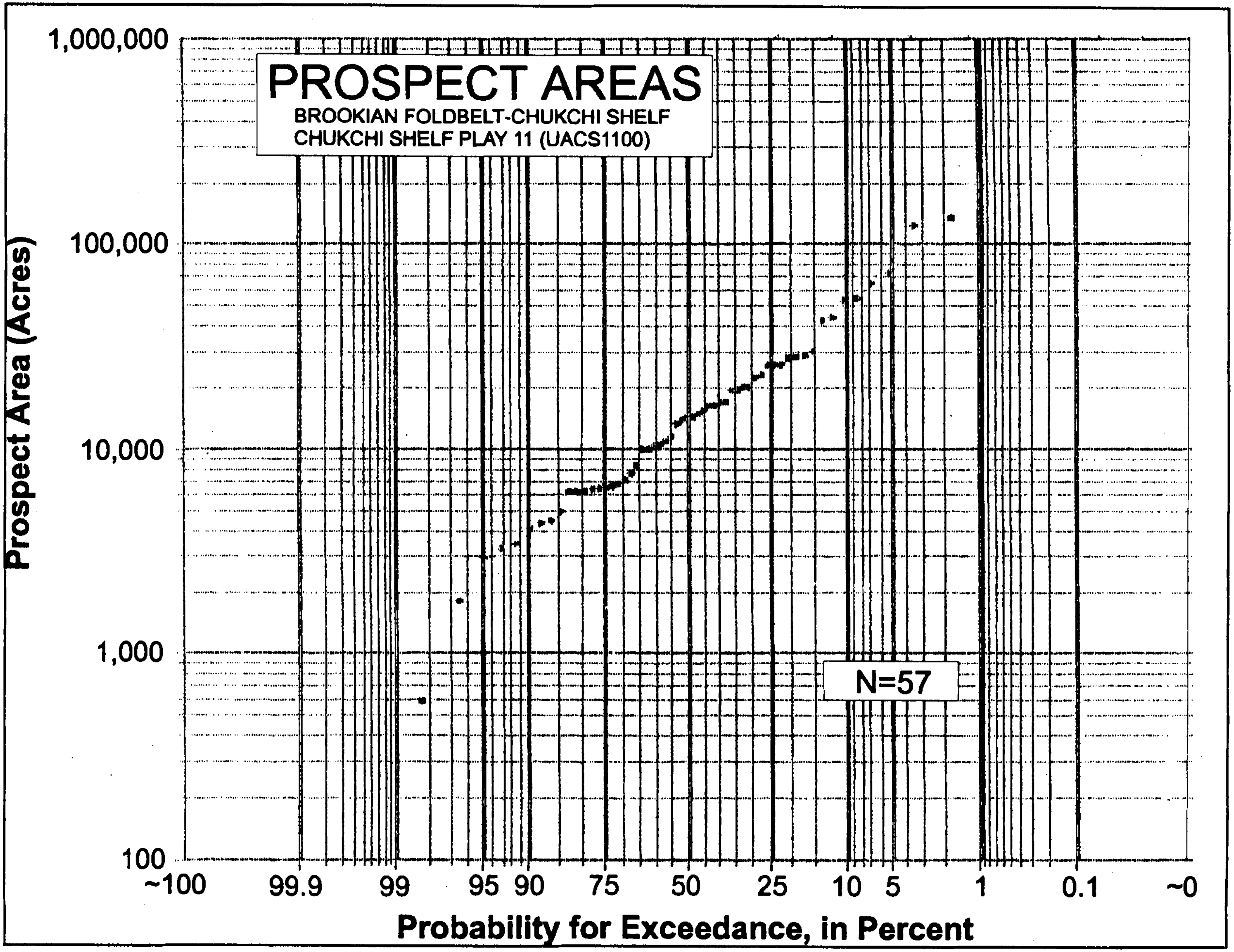


Figure 9.4: Example of lognormally distributed data displayed on a log probability plot (N is the number of prospect areas plotted on this example).

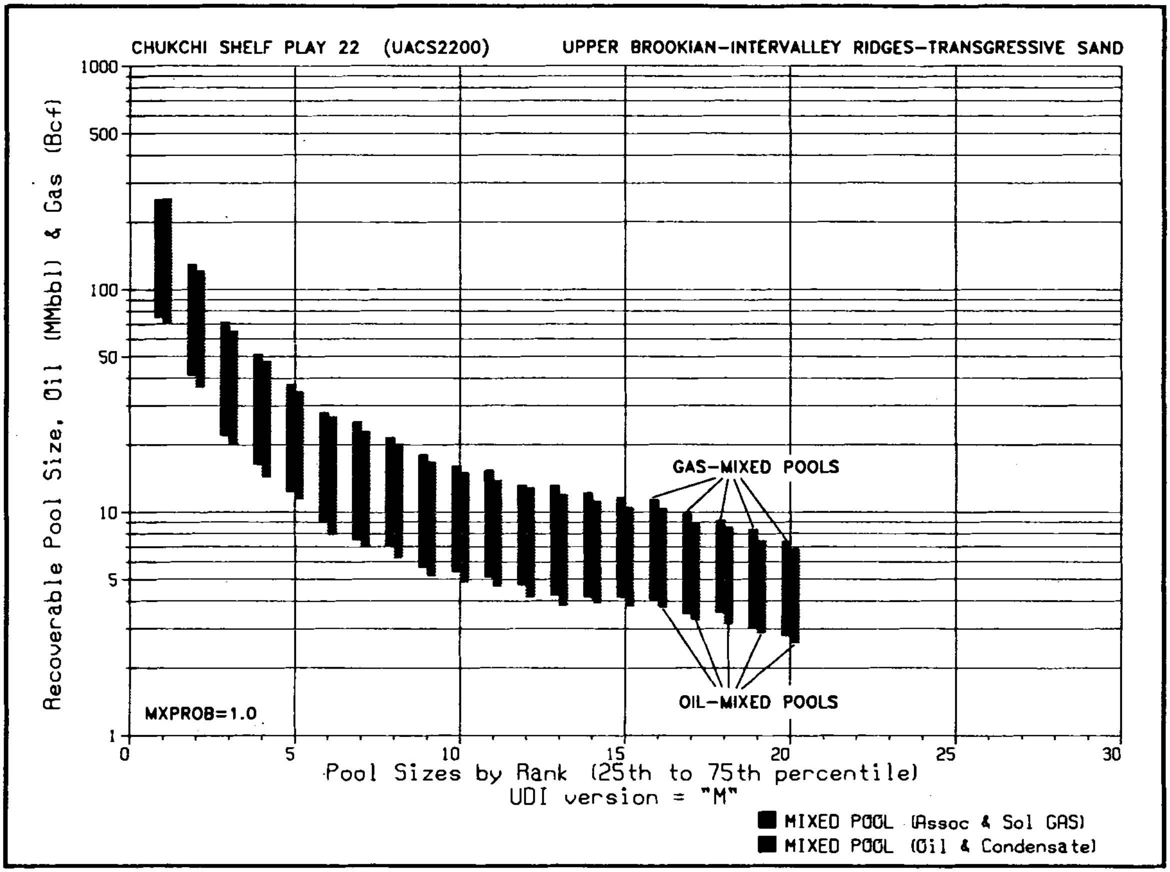


Figure 9.5: Example of pool size rank plot (pool resources versus size rank).

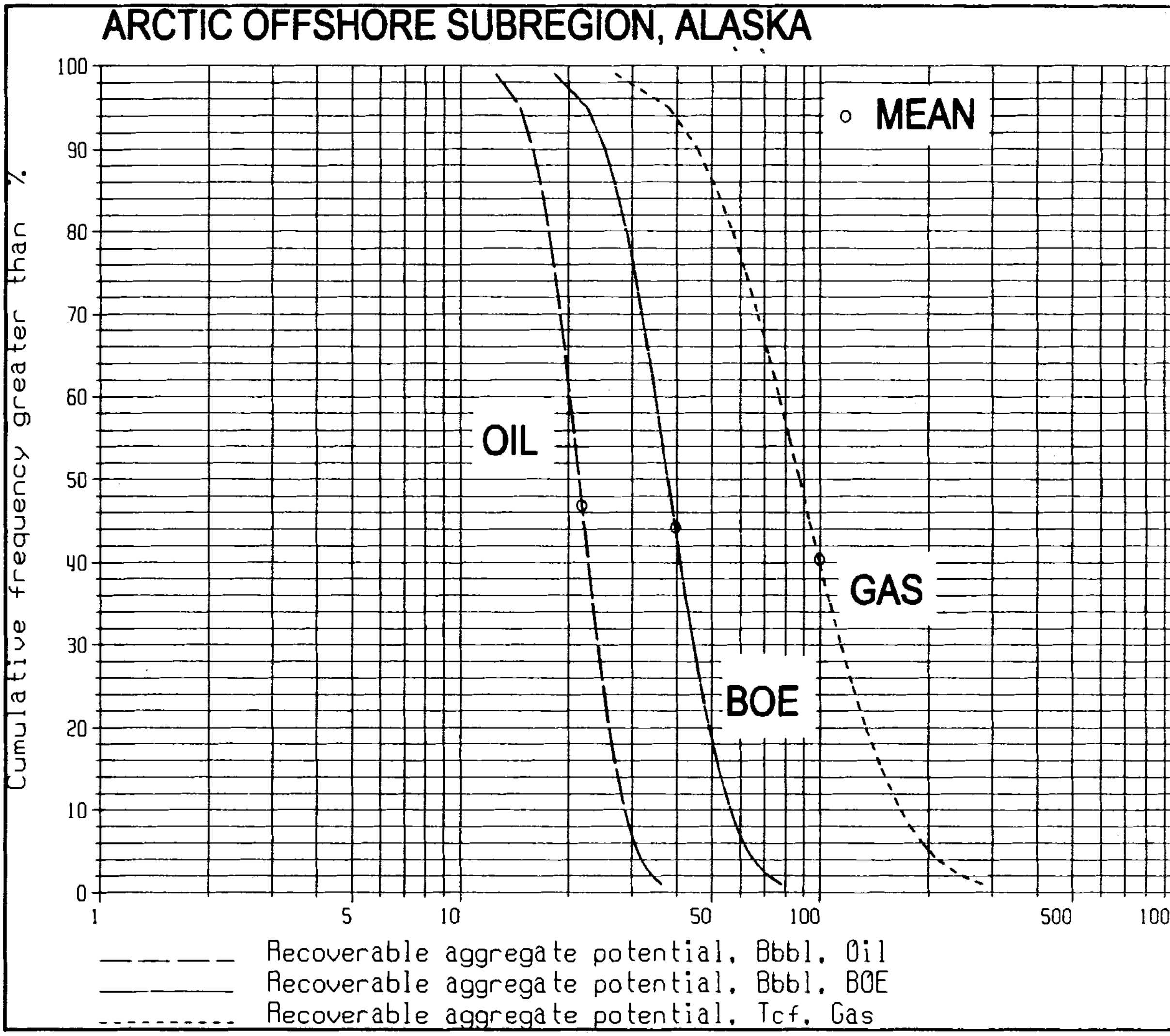


Figure 9.6: Example of complementary cumulative curves for undiscovered hydrocarbon resources of the Arctic offshore subregion. "Cumulative frequency greater than" on vertical axis can also be viewed as probability for exceedance.

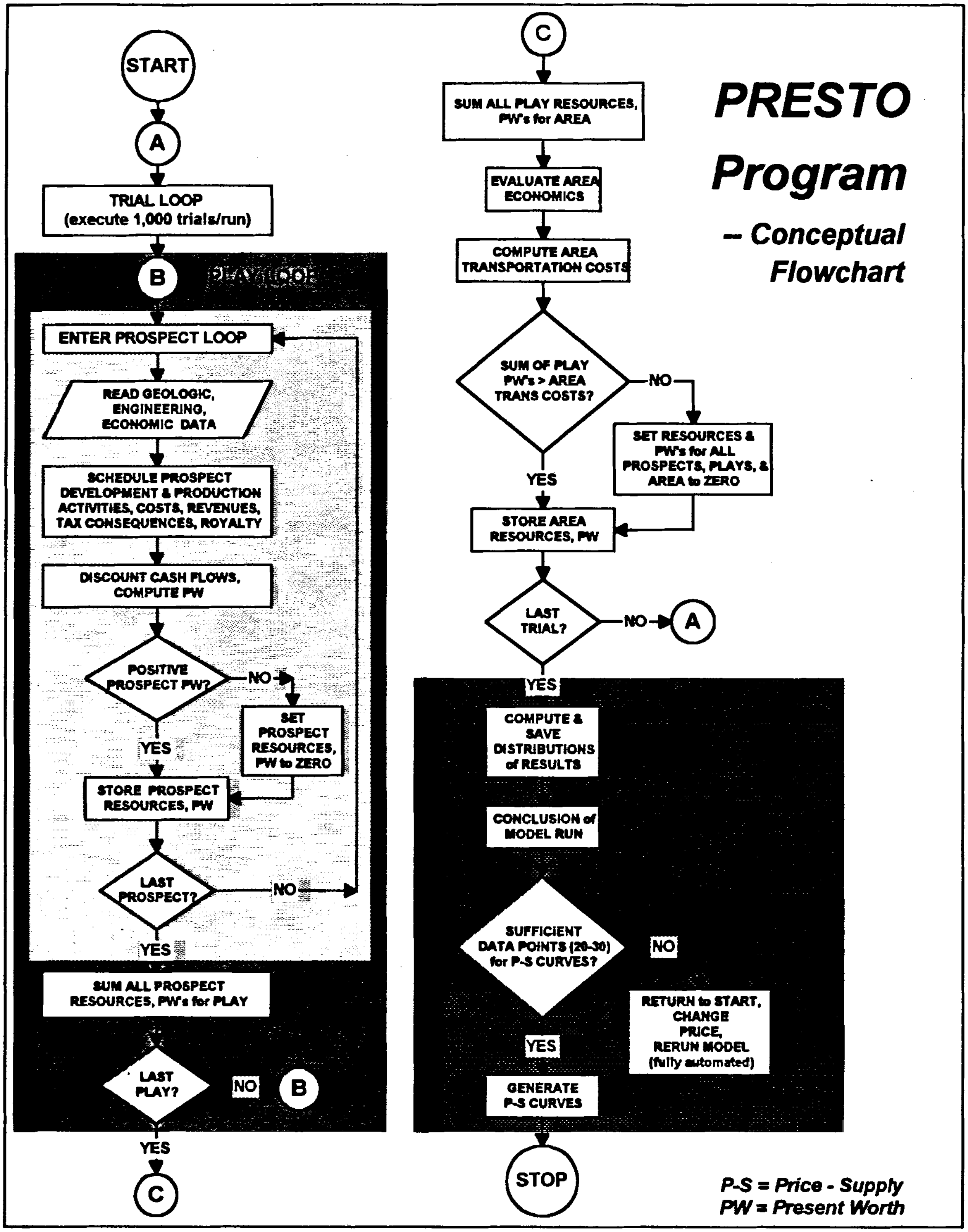


Figure 9.7: Conceptual flowchart for the PRESTO program, used by MMS to compute economically recoverable oil and gas resources.

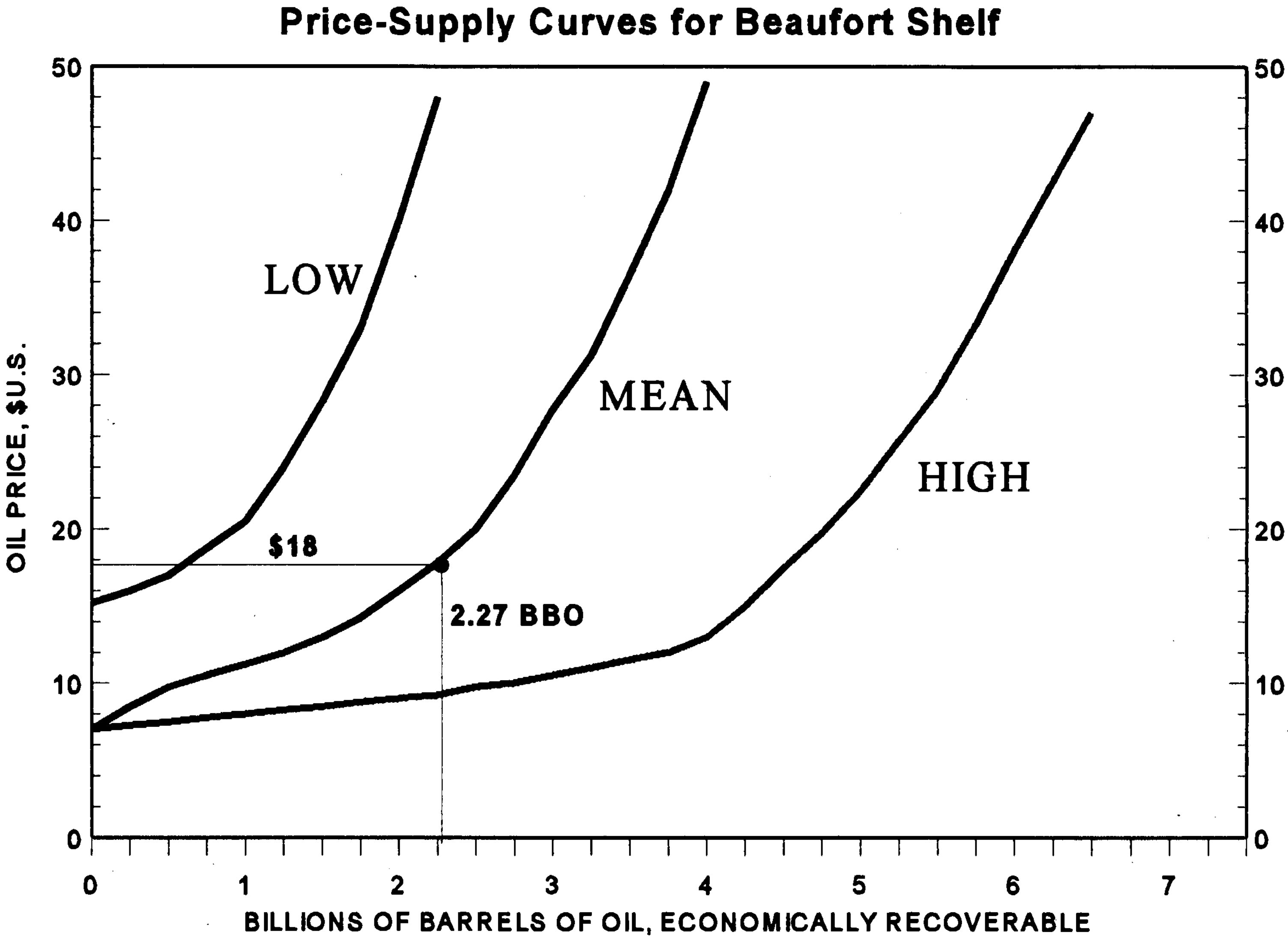


Figure 9.8: Example price-supply curves for Beaufort shelf, showing quantities of oil that are economically recoverable at different (1995) prices for oil. "Low" case refers to relatively small amounts of oil recoverable at high statistical confidence (95% probability for recovery). "Mean" case refers to the average amounts of oil recoverable at each oil price level. "High" case refers to the large amounts of oil recoverable with low statistical confidence (5% probablity for recovery). The graph shows that on average the Beaufort shelf offers 2.27 billions of barrels of oil that are economic to develop at an oil price of $18 per barrel.

10. GEOLOGIC DATA BASE FOR ASSESSMENT OF UNDISCOVERED, CONVENTIONALLY RECOVERABLE OIL AND GAS RESOURCES

RELIANCE UPON MAPPED PROSPECTS

The creation of the geologic data base used to calculate the undiscovered oil and gas resources of the Alaska offshore drew data from MMS seismic mapping, exploratory wells, producing fields, commercial data compilations (e.g., Petroconsultants, Inc.), and published literature. A complete tabulation of the geologic data base used to calculate the undiscovered resource potentials of the 74 plays identified in the Alaska Federal offshore is given in Appendix A.

Perhaps the greatest strength of the 1995 Alaska offshore assessment is the reliance placed upon the detailed seismic mapping conducted offshore over the past 20 years by the Alaska (Region) office of the Minerals Management Service. Over these two decades, nearly half a million line-miles of seismic data were acquired by this office from the industry grid in the Alaska offshore. Over the years, this data was used to proactively search out and map prospects in support of economic evaluations of bids for leases in offshore sales. By the time of the 1995 assessment, this mapping had identified the locations and sizes of 2,432 prospects in the Alaska offshore. This mapping was the basis for estimates of the ***numbers of prospects*** and the ***areal sizes of prospects***, elements of the data base that were particularly influential to calculations for the undiscovered oil and gas potential of the Alaska offshore.

PLAY IDENTIFICATION

The basic object of study in regional oil and gas assessments is the geologic ***play***[1], which is a genetic or familial grouping of petroleum accumulations and prospects. When prospects and fields are properly organized into ***geologic plays***, their sizes and numbers usually obey certain mathematic laws[2] that are utilized by the computer models as part of the process of estimating undiscovered resources (Kaufman, 1965; Baker and others, 1986; Schuenemeyer and others, 1990; Houghton and others, 1993).

In most Alaska offshore assessment provinces, the first test of genetic association was stratigraphic sequence. The geologic column for each basin was partitioned into the stratigraphic sequences that recorded the important events in the history of basin development. These stratigraphic sequences then united families of plays, each play representing the different structural or stratigraphic contexts of the stratigraphic sequence in different parts of the basin. For example, the "Lower Brookian" stratigraphic sequence blankets most of Chukchi shelf. In the south, Lower Brookian rocks are folded and these were set aside as a separate play. To the north, the same rocks are not folded but are dissected by dense arrays of transtensional faults. These faulted Lower Brookian rocks will offer distinctly smaller trap sizes and clearly should not be grouped in the same play as the folded rocks. We also recognize that potential reservoirs in the Lower Brookian sequence occur

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[1] *"A play is a group of prospects (potential field sites) and any known related fields having common oil or gas sources, migration relationships, reservoir formations, seals, and trap types" (White, 1993, p. 2049).*

[2] *generally **log-normal** or similar right-skewed distributions that predict that there are many small deposits and very few large deposits in the play*

in two highly dissimilar depositional settings: (1) turbidite sandstones deposited in deep water at the bases of deltaic slopes, and (2) sandstones deposited in fluvial to shallow marine settings near delta shorelines. These different depositional environments will produce quite different reservoirs in terms of thickness, continuity, and potential storage volumes, and, should therefore be grouped into separate plays. Lastly, Lower Brookian rocks are so deeply buried in some areas that only gas[3] will be present; elsewhere, these same rocks are likely to contain oil. The "gas-only" areas were set apart as separate plays because the relative proportions of oil and gas are important parts of the data models. The complex overlapping of depositional environments, structural settings, and petroleum types (gas vs. oil) in the end justified the identification of ***9 separate plays*** for the Lower Brookian sequence on Chukchi shelf. A similar analysis was conducted in each of the 11 assessment provinces that offered any potential for undiscovered, conventionally recoverable oil and gas resources. Altogether, 74 exploration plays were identified and quantitatively assessed in the Alaska offshore.

PLAY ANALYSIS, PEER REVIEW, AND MANAGEMENT OVERSIGHT

Comprehensive and rational play identification is the cornerstone of any oil and gas assessment. Early in the process of play identification, the MMS tried to draw upon all possible sources of expertise in this area. In March 1993 the Alaska (Region) office held a workshop where play concepts were reviewed by MMS headquarters management, representatives from other Federal agencies, and noted experts Dr. David White and Dr. Richard Procter, the latter brought into the project as contractors to the MMS. This meeting, and other less formal consultations in early stages of the project, helped shape the play concepts that later became fundamental to the assessment process.

In January 1995, after numerical models for plays had been constructed and preliminary results had been obtained from the computer models, a second peer review workshop was held. This second workshop, attended by geoscientists from other Federal agencies, the State of Alaska, and private oil and gas firms, provided an open forum in which model shortcomings could be identified and aired. Play concepts, input data, and preliminary estimates for oil and gas potential were presented. Reviewers attending this meeting were largely receptive to the proposed data bases and preliminary results. After incorporating the results of the peer review, new computer runs were conducted in Alaska through January and February of 1995. Several internal MMS review meetings where comparisons were made among results from all offshore areas (Atlantic margin, Gulf of Mexico, Pacific margin) were held throughout 1995. Assessment results were finalized in January 1996, nearly 3 years after the first play identification meeting in 1993, and at the conclusion of a long process of analysis, review, reconsideration, and model iterative computer model runs. The most important contribution of this extensive review process was to enlist the aid of the geoscientific community in capturing all possible play concepts for pooling of oil and gas resources in the Alaska offshore.

PROSPECT AREAS

Once geologic plays were identified and defined, mapped prospects in each basin were assigned to their respective plays. The areas of these prospects (areas of maximum closure) were measured and then statistically analyzed to develop probability distributions for input to computer models. The analysis consisted of assembling prospect areas as point data onto log-probability plots and then choosing a "best fit" line of some kind. The scatter plots for prospect areas typically formed linear arrays, revealing a

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[3] *temperatures too high for the preservation of oil*

fundamentally log-normal mathematic nature[4]. An example log-probability plot for prospect areas in one play is shown in figure 10.1, and it is evident that it would be easy to choose a "best-fit" line for the prospect areas for that particular play (Brookian foldbelt, Chukchi shelf). In general, assessors would inspect the plots and then draw a linear "fit" to the scatter plot, but the computer programs also offered a choice of data-fitting routines.

The interpreted "best-fit" line chosen by the assessor then became the probability distribution for prospect areas for that particular play. A ***linear*** fit could be aggregated with other log-normal distributions using the ***log-normal computational option*** in the computer programs. In the event that the prospect area data departed strongly from log-normality and the assessor felt assured that his data did not include more than a single play, a ***curved "best fit"*** on a log-probability plot could be defined. The probability distribution developed from a non-linear interpretation would be aggregated with other probability distributions using the ***Monte Carlo computational option*** in the computer models.

THE ASSUMPTION OF LOG-NORMALITY AND THE "FORCE-FIT" PROBABILITY DISTRIBUTION

The assumption of log-normality of probability distributions pervades the mathematic structure of the ***PRASS*** computer model and log-normal mathematics forms the preferred method of aggregation, although Monte Carlo sampling is also offered as an aggregation option. However, the paucity of geologic data in many areas forced assessors to create ***"force-fit"*** probability distributions based on estimates for minimum and maximum values and assumptions about the intrinsic mathematic nature of the probability distribution. Most probability distributions based on sparse data were assumed to be log-normal. **Accordingly, most input (probability) distributions developed for this assessment are approximately log-normal.** Input probability distributions are tabulated in Appendix A.

The input parameters required by the computer models are listed in the sample data forms shown in figures 10.2 and 10.3. In many assessment provinces with little or no exploratory drilling there are very little data available for many of these input parameters. However, in many cases, some data are available about the ***extreme ranges*** for any particular input parameter. For example, in the calculation of gas recovery yields, the reservoir temperature is an important variable (fig. 10.2) that varies greatly within and between plays according to burial depth and local geothermal gradients. One approach to constructing a probability distribution for reservoir temperatures is to first estimate the temperatures of the shallowest (coolest) and deepest (hottest) prospects, and then, to post the minimum temperature at the 99 percent probability and the maximum temperature at the 1 percent probability in a log-probability plot (like fig. 10.1). A straight line is then drawn connecting the two points (thereby invoking the assumption of log-normality) to create a probability distribution for reservoir temperature for the play. Newendorp (1975, p. 383) termed such constructions ***force-fit*** distributions. Many input probability distributions in the geologic data base for this assessment were created using this method.

COMPUTATION OF POOL AREAS

Probability distributions for pool areas were computed in the PORE module of either ***PRASS*** or ***GRASP*** by multiplying (the probability distribution for) ***prospect areas*** by (the probability distribution for) trap fill fractions. Prospect area

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[4]Log-normal functions form straight lines on log-probability plots. Departure from log-normality in these plots was taken as possible evidence that more than one play was represented in the plot and that narrower play definitions might be entertained.

data were compiled from seismic mapping in the manner described above. Trap fill data were instead drawn from a much more subjective analysis.

In Alaska, at the time of the 1995 assessment, all commercial oil fields, and most known accumulations, were located beneath State of Alaska lands, where the MMS does not have access to detailed seismic mapping. Therefore, we generally do not know the full sizes and extents of the structures occupied by the Alaskan oil fields and cannot estimate what fractions of the structures are filled with oil. It is generally understood from published accounts that Prudhoe Bay field must nearly fill the structure it presently occupies (Jones and Speers, 1976; Wadman and others, 1979), but fill fractions are generally not available for other northern Alaska fields or the fields in Cook Inlet.

The formulation of probability distributions for trap fill fractions therefore relied upon subjective analysis of each of the key elements controlling trap fill. Assessors first considered the charge potential for the play, that is, the extent to which hydrocarbons were made available to fill traps within the play. In plays understood to have easy access to abundant hydrocarbons migrating from areas of prolific oil and gas generation, trap fill fractions were permitted to rise to a maximum of 1.0 (100%). For example, plays favorably located along a regional arch (like Barrow Arch in northern Alaska) that is known to have acted as a regional gathering system for migrating petroleum, would be expected to generally offer more complete filling of prospects. Conversely, plays perceived to only have access to modest quantities of hydrocarbons were modeled with prospects incompletely filled. For plays requiring lengthy migration distances, even to acknowledged prolific generation centers, trap fill fractions were reduced in recognition of the potential high losses and risk of diversion incurred by long-distance migration.

Given access to some significant source of hydrocarbons for the play, attention was then turned to trap size, trap amplitude, trap type, and seal integrity. Trap size is an issue where limited hydrocarbons are available to fill high-volume traps. Trap amplitude becomes a factor when the vertical relief is very large, so large that differential pressures across seals[5] at the crests would probably rupture and allow the hydrocarbons to escape. In Navarin basin, for example, some structures offer thousands of feet of vertical relief (Turner and others, 1985, p. 53, fig. 13). The poorly-consolidated Tertiary shales invoked as seals for the Navarin basin structures certainly would not retain a petroleum column several thousands of feet in height no matter what quantity of hydrocarbons were available to charge the structure. Trap integrity is also a function of trap type. A trap sealed by one or more faults is probably at more risk for leakage than a simple anticline sealed by a single, continuous shale formation. Seal integrity is generally controlled by lithology and thickness. Even high-amplitude prospects could reasonably be allowed to be completely filled if sealed by thick, well-consolidated, clay-rich shales. Shales that can be shown to be geopressured also offer greater seal integrity and more complete filling of traps might be anticipated where such geopressured shales form the seals.

The subjective analysis is only credible when it results in probability distributions that reflect the assessor's perceptions about the relative statures of plays with regard to the particular aspect under appraisal, in this case, trap fill fractions. The absolute values in these distributions, though certainly important to the computations, are difficult to defend in the absence of local data. Probability distributions for trap fill fractions for all 74 plays , all the product of subjective analysis, are tabulated in Appendix A.

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[5] *created by contrasts between hydrostatic pressures in rocks saturated by relatively high-density water and excess pressures ("buoyant pressures") developed in columns of relatively low-density hydrocarbons*

COMPUTATION OF OIL AND GAS RECOVERY FACTORS

The *GRASP* computer model requires entries for recoverable petroleum per unit volume of petroleum-saturated reservoir. The sample data form in figure 10.3 lists these entries as "Oil Recovery Factor" (barrels per acre-foot of reservoir pool) and "Gas Recovery Factor" (millions of cubic feet of gas per acre-foot of reservoir pool). In the absence of local production experience, predicting these values for undiscovered pools is difficult because they are the product of complex interactions of many contributing factors. If one could find data for analogous reservoirs in comparable plays or geologic settings, that data might be confidently extended to the reservoir in the play under study. However, establishing credible analogs and finding data for them are both difficult tasks. In the end, most assessors chose to use the computer model to calculate these recovery factors using more fundamental information that is often readily available from regional studies or local well data, and then to compare results to any known credible analogs.

The data required to compute recovery factors are essentially the variables in the yield equations for oil and gas. These are listed in the sample data form in figure 10.2 and tabulated with the equations below:

<u>Oil Recovery Factor, or Oil Yield</u>:

a. Porosity
b. Hydrocarbon Saturation
c. Oil Formation Volume Factor
d. Oil Recovery Efficiency

Barrels Oil Recoverable per Acre-Foot of Pool Reservoir (BO)
= 7758.38 Bbl/acre-ft (a·b·d/c)

<u>Gas Recovery Factor, or Gas Yield</u>:

a. Porosity
b. Hydrocarbon Saturation
c. Reservoir Pressure (pounds per in^2)
d. Reservoir Temperature (in °Rankine= °F+460)
e. Gas Deviation Factor
f. Combustible Gas Fraction
g. Gas Recovery Efficiency

Millions of Cubic Feet of Gas Recoverable per Acre-Foot of Pool Reservoir (MMCFG)*
= [43,560 ft³/acre-ft] [a·b·f·g] [(60 °+460 °)/d·e] [c/14.73] [1/1,000,000]

* (at standard surface conditions of 60 °F and 14.73 pounds per in^2 [1 atmosphere])

Many of these variables, such as porosity, temperature, and pressure, are depth-dependent and can be predicted over the depth ranges of plays if geothermal, geopressure, and porosity-decline gradients, respectively, are known. These latter data are readily available from exploratory wells and can often be extrapolated with some confidence over large areas.

If reservoir texture can be estimated, hydrocarbon saturations can be predicted from porosity determinations (independently estimated from burial depth or similar means). Most assessors developed estimates for saturation by reference to White (1989, p. 3-15), or, by reference to a series of general tables and charts. The latter approach began by estimating the lithology and grain size of potential reservoirs and using these data to estimate bulk volume water using a published table (Asquith and Gibson, 1982, p. 98, tbl. 8). The value for bulk volume water was taken as equivalent to the "ϕS_{wi}" (porosity · irreducible water saturation) curves in a porosity-saturation cross plot published by Schlumberger (1991, p. 158, chart K-3). By pairing a porosity value (predicted from burial depth) with a "ϕS_{wi} " value (from textural considerations and the Asquith table), an estimate for irreducible water saturation (= 1-hydrocarbon saturation) can be read from the Schlumberger chart. In this way, minimum and maximum values for hydrocarbon saturations were determined for the play and used to construct "force-fit" probability distributions for entry to the computer models.

When oil is produced, it shrinks in volume because gases dissolved in the oil at reservoir pressures are released at surface pressures. This volume change is represented by the "Oil Formation Volume Factor" and it is dictated by the quantity of dissolved solution gas (gas-oil ratio, or GOR), which is in turn controlled by reservoir pressure, temperature and petroleum composition(s). The Formation Volume Factor was estimated by reference to nomographs by M.B. Standing (republished by both McCain [1973, p. 187, fig. 4-18] and White [1989, p. 3-20, 3-21]) and using estimates for GOR, oil and gas gravities, reservoir pressures, and reservoir temperatures. In the absence of local data for oil or gas gravities[6], assessors used data published by White (1989, p. 3-23, 3-24).

Ranges in oil and gas recovery efficiencies were estimated from local reserve studies and production histories, where available, or, by referring to recovery data for various combinations of reservoirs and drive mechanisms as published by White (1989, p. 3-29 to 3-31) or Arps (1967).

The gas "Z" factor, or "deviation" factor, was determined using charts published by Standings and Katz (1942; republished by Anderson, 1975, p. 155-156) and using estimates for gas gravities and reservoir temperatures and pressures.

Probability distributions for all of the variables in the yield equations, and appropriate unit conversion constants, were entered to the ***PRASS*** computer program and aggregated under independence[7] to calculate probability distributions for oil and gas recovery factors.

PROSPECT NUMBERS

Geophysical mapping conducted by the Alaska Regional office of MMS had identified a total of 2,432 prospects on the continental shelves of the Alaska Federal offshore by the time of the 1995 assessment. However, both here and in most petroleum provinces, it is generally conceded that large numbers of prospects remain unidentified, some even in the most thoroughly mapped areas. "Unidentified" prospects exist for a variety of reasons. Some prospects remain unidentified because some areas lack seismic data. Some smaller prospects may have been missed because they fall between widely spaced lines in the seismic grid. Other prospects may be missed because of lack of detail in stratigraphic analysis. Lastly, many prospects may remain unidentified because they are subtle or impossible to detect in seismic data, for example, porous sandstones sealed laterally by pore blockages unrelated to seismically-detectable structures or lithologic changes. It is generally acknowledged that unidentified prospects exist in all basins, that some fraction of the unidentified prospects probably contain petroleum, and that some of the unidentified prospects will ultimately be tested and discovered to contain pooled oil or gas, perhaps in commercial quantities. Therefore, unidentified prospects must be given account in the assessment of undiscovered oil and gas potential.

For each of the 74 exploration plays identified in the Alaska Federal offshore, assessors were asked to supplement the numbers of known prospects with some estimate of the numbers of prospects that might remain unidentified. The estimation process focused on the completeness

[6]*Most natural gas gravities range from 0.6 to 0.8 (density relative to air). The range of gas gravities reported for 27 Alaskan fields is 0.556 to 0.790, with an average of 0.584. Oil gravity data are also available for commercial oil fields (data from AOGCC, 1994).*

[7]*Aggregation under independence probably reduced the range, or variance, of the probability distributions for oil recovery factors. Conversely, some experimentation showed that aggregation under independence actually increased the variance of probability distributions for gas recovery factors. The choice of independent (versus dependent) aggregation does not materially affect the outcome at the median or mean, but does affect outcomes at extreme probabilities.*

of seismic information and the level of geological complexity. In thoroughly-mapped areas of simple geology, relatively few prospects are expected to remain unidentified. Conversely, in areas of complex geology or deficient analysis (sparse seismic data, or rudimentary seismic-stratigraphic analysis), very large numbers of prospects might reasonably be expected to remain unidentified. Both kinds of areas are represented in the Alaska Federal offshore.

Overall, Alaska Region assessors estimated that as many as ***3,450 prospects might remain unidentified*** in the 74 exploration plays in the half million square miles of the 11 assessment provinces involving the continental shelves of the Alaska Federal offshore. When added to the numbers of mapped prospects, we have a ***maximum endowment of 5,882 prospects*** that yielded a maximum endowment of 2,097 hypothetical pools[8] that contributed oil and gas volumes to overall assessment results.

When devising a prospect numbers probability distribution for a play, assessors first posted the number of mapped prospects at F99 (99% frequency of exceedance) on a log-probability plot (example plot type in fig. 10.1). To the number of mapped prospects the assessor added the number of unidentified prospects; this sum was then posted at the extreme right at ~F00 (approximately 0% frequency of exceedance) on the same log-probability plot. A line connecting these two data points then defined the probability distribution for prospect numbers for that particular play.

In some assessment provinces, some structures had been tested by exploration wells and found to be barren of hydrocarbons. Because our purpose was to estimate the ***undiscovered*** potential, it was necessary to remove these tested-and-barren structures from the overall trap endowment of the play. Of course, these unsuccessful tests contributed to a perception of elevated risk for the play, and, in this way, contributed to a reduction in overall potential. However, we wanted to explicitly remove these tested-and-barren structures from the data base. This was done by lowering the prospect numbers distribution by an amount equal to the number of barren structures in the play. The prospect numbers distributions were amended by subtracting the numbers of barren structures from both the numbers of mapped (F99) and total (~F00) prospects, posting the amended values, and then drawing a new prospect numbers distribution between the two amended values.

Structures that were tested and found to contain quantified[9] petroleum resources were removed from the overall hydrocarbon endowment by a separate process. Discovered resources were subtracted from the overall endowment by first matching[10] known or discovered pools to the hypothetical pools created by the model (e.g., ranked-pool plots of Appendix B). After matching discoveries to hypothetical pools, each matched hypothetical pool was then mathematically extracted from the overall play resource endowment. The removal of discovered pools in this manner was conducted only in the Beaufort shelf assessment province.

RISK ASSESSMENT

Analysis of risk for plays was carried out in the Alaska (Region) office along the lines suggested by White (1993) and using a risk analysis form (shown here as fig. 10.4) that was adapted from White's paper. Risk was assessed at two levels for each play. Risk was first assessed at the ***play level***, where the absence of a critical element could ***hazard the success of the entire play***. Secondly, risk was assessed at the ***prospect level***, where a critical element might be

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[8] *sum of maximum numbers of pools found for 74 plays, as reported in Appendix A*

[9] *Some structures have been found to contain petroleum (for example, 4 sites in Chukchi Sea), but no estimates for recoverable resources are available.*

[10] *using productive pore volumes (pool area · net pay), in MATCH module of **GRASP** computer program*

absent at some sites and cause ***failure of some fraction of the prospects*** in the play.

Estimates of prospect level chances of success are ***conditional*** upon success (i.e., success is assumed) at the play level because the ***play chance*** is ultimately ***multiplied against*** the ***prospect chance*** to obtain an ***"exploration" chance.*** The ***exploration chance*** is in turn used with the (probability distribution for) ***numbers of prospects*** to determine the (probability distribution for) ***numbers of pools***[11]. Chances for success at the prospect level are therefore analogous to drilling success rates or ratios, and, accordingly, are often modeled after known drilling success rates experienced in commercially successful plays in productive basins elsewhere in the world (examples provided by Clifford, 1986, p. 370).

Success of a play or prospect can be defined in different ways. Commercial success in oil prospecting is contingent upon finding sufficient reserves to permit the accumulation to be developed at a profit. However, some (or most) oil or gas pools, particularly in the Arctic, are too small to warrant commercial development. Nevertheless, these small pools represent "geologic" successes, proving that oil or gas must have been generated somewhere and was able to migrate to traps bearing porous media that could be filled with petroleum. In effect, the small pools, by their existence, prove that all components of the petroleum system are working properly.

In the 1995 assessment of the Alaska offshore, the condition for "geologic" success for a play was a single occurrence of conventionally pooled hydrocarbons capable of flowing to a wellbore. Any play known ***or believed*** to host such an occurrence was assigned a play level chance of success of 1.0. No attempt was made to formalize a specific minimum field size as part of the condition of "geologic" success. Although similar definitions for play success, in which no minimum pool sizes are specified, are advocated by some experts, (Capen, 1992; Rose, 1992), the practice is admittedly controversial and has been criticized by other prominent experts such as White (1993, p. 2050).

We note for the record that the very smallest pools found by the 1995 offshore assessment ranged down to approximately 100,000 barrels of oil and 700 million cubic feet of gas (see ranked pool plots in Appendix B). In this Arctic setting, as a matter of practicality, these sizes are not materially different from the minimum pool sizes (1 million barrels of oil, 6 billion cubic feet of gas) formally adopted by the U.S. Geological Survey in their 1995 assessment of the Alaska onshore (USGS, 1995). Even if this office had adopted the same minimum pool sizes as those adopted by the U.S. Geological Survey, it would have had no practical effect on the way we approached construction of our play data bases.

The construction of risk models for most plays in the frontier Alaska basins required a subjective appraisal of the factors underlying play success. Our subjective risk analysis focused upon each of the main elements required for successful creation and preservation of oil or gas accumulations, as listed in the sample risk analysis form of figure 10.4.

The key elements of risk were grouped into four major categories: 1) trap success; 2), reservoir success; 3) charge or source success; and 4) preservation success. Subsidiary elements of ***trap success*** include closure presence (risk related to seismic definition), seal presence (or integrity), and timing (of trap formation relative to hydrocarbon generation and migration). Subsidiary elements of ***reservoir success*** include reservoir presence (stratigraphic extent) and presence of porosity and permeability. Subsidiary elements of ***charge or source success*** include presence (stratigraphic) of source rocks, thermal maturity of source rocks, and migration (direction, distance). ***Preservation success*** becomes a factor, for example, where oil enters very shallow reservoir and becomes subject to

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[11] *actually performed in a mathematically complex process by the MPRO module of the* ***GRASP*** *computer program, as described by Bennett (1994)*

biological and chemical processes that may convert it to asphalt. Each element was analyzed at both play and prospect levels.

When devising ***play-level*** risks, most assessors respected White's (1993, p. 2052) admonition to focus only on the ***critical*** group risks—those particular factors that are ***most likely to cause the play to fail***. The assessor was also cautioned to avoid the practice of adding incremental risk simply to acknowledge incomplete information, for example, by entering "0.9" in each of the 9 play-level risk categories listed in figure 10.4, which, when multiplied, would yield an overall play chance of 0.39. This value is probably too low and the analysis clearly fails to identify the truly critical areas of risk for the play. "Over-risking" by this practice presents a further hazard in that it could cause the play to be removed from further consideration. If a play was so risky that the assessor felt that it had a play chance less than 0.10, as a matter of policy no further quantification of the play was undertaken.

In completing the risk analysis form (fig. 10.4), assessors were also advised to preclude the hazard of "double-risking" by simply avoiding, if at all possible, the practice of making entries in the same risk element at both the play and prospect levels (discussed by White, 1993, p. 2053).

White's (1993) practice in assessing risk is to estimate the chance that the play possesses a given volumetric variable (e.g., reservoir thickness, oil yield, prospect area, etc.) in quantity sufficient to exceed some externally-defined minimum value, as illustrated by his example rhetorical question: "What is the chance that the sandstone thickness will equal or exceed the specified 5 meter minimum?" In the 1995 assessment of the Alaska Federal offshore, we did not formally adopt any minimum quantities as criteria for success in a risk element. Instead, we analyzed the ***chance for existence*** at the play level and ***frequency of existence*** at the prospect level (i.e., chance of existence at any single prospect).

The subjective risk analysis, when completed, was compared to commercial exploration success rates in productive basins and plays as a test of overall reasonableness. However, judging "reasonableness" from such comparisons is difficult because we are analyzing "geologic" success rather than commercial success. Although commercial success rates in productive basins are widely available (e.g., Clifford, 1986), very little data are available for rates of ***geologic success*** among prospects in successful plays around the world. However, because "geologic" successes are presumably much more common than commercial successes, the probabilities for "geologic" success should be generally much higher. As a means of setting an upper limit, we assumed that ***prospect level chances of geologic success*** in the very best plays probably would approach ***commercial success rates*** for plays in areas where costs are very low and very small accumulations are economically viable. For example, two recent papers (Shirley, 1994; Durham, 1995) tout drilling ***discovery success rates ranging from 71 to 84 percent*** on carefully screened[12] prospects in areas with extensive infrastructure and low development costs. We took these values as the upper limits for geologic success in our high cost Alaska frontier basins. For example, prospect level chances for geologic success were permitted to rise as high as 0.81 in the best[13] of several Beaufort shelf plays offering long histories of spectacular commercial success in nearby areas onshore.

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[12]*with sophisticated three-dimensional seismic analysis and seismic modeling*

[13]*Rift sequence play-UABS0701: includes commercial oil fields at Kuparuk (2,500 mmbo), Point McIntyre (340 mmbo), Alpine (300 mmbo), Milne Point (220 mmbo), Niakuk (65 mmbo), and West Beach (4 mmbo), and, discoveries at Point Thomson (5 tcfg, 300 mmbo), Barrow (40+ bcfg), and Walakpa (30 bcfg)*

RELATIONSHIP OF GEOLOGIC MODEL TO ECONOMIC ASSESSMENT

After constructing a complete geologic data model for each play, assessors embarked upon computer runs to calculate the undiscovered oil and gas endowments for the plays. These endowments are the sum of the oil and gas contents of all of the hypothetical pools, ***large and small***, modeled as existing within the play. Because the geologic data base incorporates the full ranges for input variables, that is, without any "economic minimums", the results of the "geologic" assessment are ***total hydrocarbon endowments*** entirely free of economic constraints.

The results of the geologic modeling take two forms. First, the results are reported as probability distributions for (risked) oil, gas, and BOE resources for each play. These results are useful for reporting and comparing the ranges of possible resources offered by plays. Secondly, play results are reported as individual pools—that is, the oil and gas volumes for each of the hypothetical pools constructed from the geologic model. The ranges of potentials for each pool are also reported, allowing an appreciation of the "upside" potential of the largest pools—presumably the targets of any future explorations.

The economic model passes the results of the geologic assessment through an "economic screen" to identify those hypothetical pools that could be developed at a profit. Fundamentally, it is a process of separating the economic (large) pools from the subeconomic (small) pools. However, this characterization oversimplifies what is actually a quite sophisticated process. A hypothetical pool proposed from the geologic model is actually given the same economic scrutiny that would be given any new, potentially-commercial discovery. Overall pool size is only one of many important considerations. Pool areas and depths strongly control costs while pay thickness and yields (i.e., site richness) strongly control individual well recoveries and revenues. It is quite possible, therefore, that a very large pool of oil contained in a thin sandstone over a large area at shallow depths (requiring many development wells) will be unprofitable to develop. Conversely, in the same area, a small pool of oil in a thick, high-yield reservoir at depths allowing extraction from a minimum of surface installations may offer outstanding profitability. Therefore, all of the relevant data in the geologic model (***GRASP***), especially pool depths, pool areas, reservoir thicknesses, and reservoir yields, as well as the pool size results from ***GRASP***, must be drawn into the economic model (***PRESTO***) for use in calculating economic resources.

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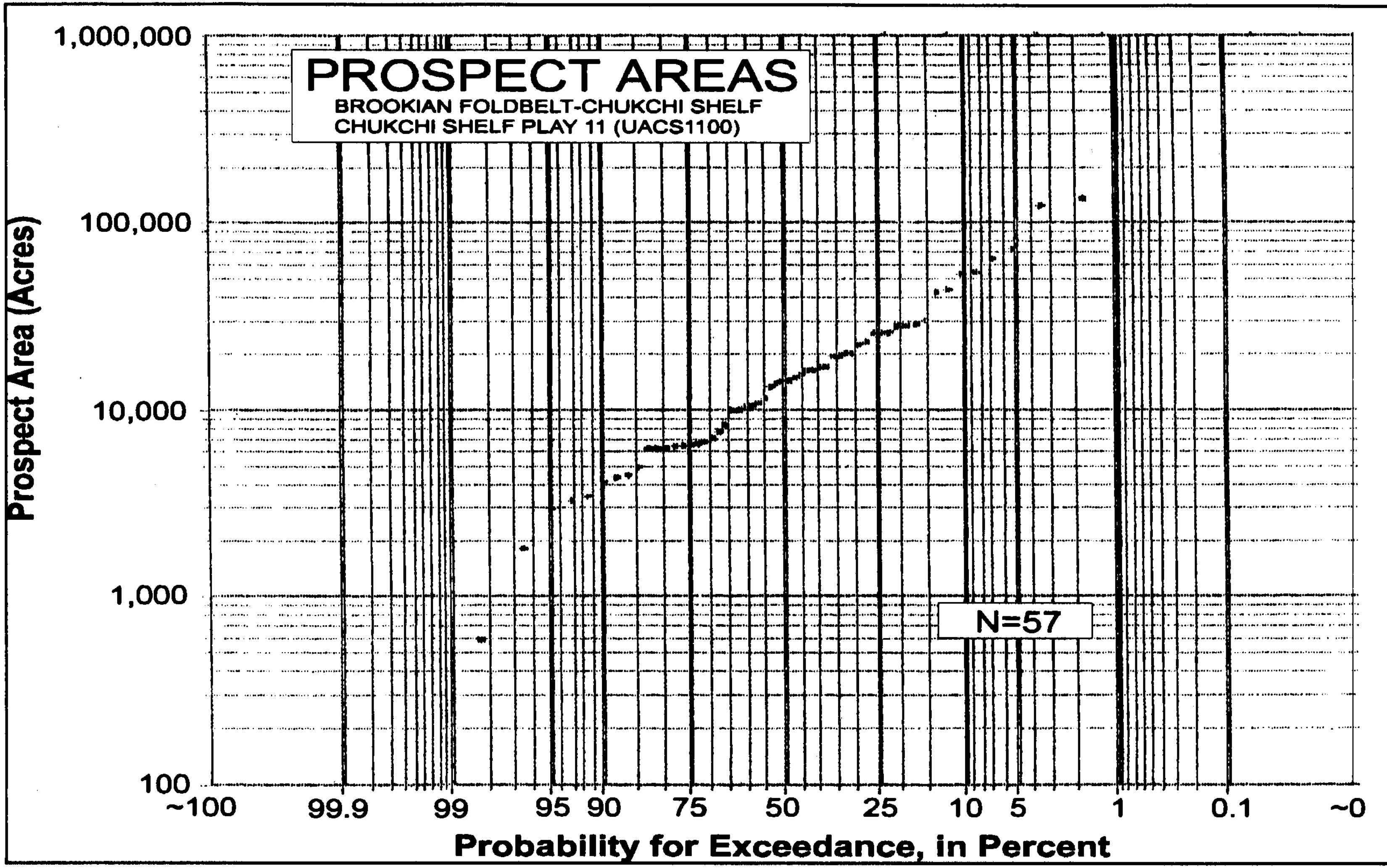

Figure 10.1: Log probability plot for maximum areas within closure, in acres, for 57 prospects identified by seismic mapping in play 11 in Chukchi shelf assessment province. Mapped prospects range from 588 to 135,278 acres in area, but the distribution predicts larger prospects at very low probabilities. The linear arrangement of the plotted points is consistent with a log normal probability distribution.

DATA FORM
1995 National Resource Assessment
________________ **Assessment Province**

Assessor ____________________ **Play:** ______ ______________
No. Name

Play Type: Oil___ Gas___ Oil and Gas___
Number of Discoveries ________ **Number of Structures Tested Dry** ________

	(Minimum Value) F_{100}	F_{99}	F_{95}	F_{75}	F_{50}	F_{25}	F_{05}	F_{02}	F_{01}	(Maximum Value) F_{00}[1]
Prospect Area	___	___	___	___	___	___	___	[ ]	___	___
Trap Fill	___	___	___	___	___	___	___	[ ]	___	___
Oil Fraction	___									___
Gas Fraction	___									___

	F_{100}	F_{99}	F_{75}	F_{50}	F_{25}	F_{02}	F_{01}	F_{00}
Net Pay	___	[ ]	[ ]	___	[ ]	___	[ ]	___
Porosity	___	[ ]	[ ]	___	[ ]	___	[ ]	___
Oil Saturation	___	[ ]	[ ]	___	[ ]	___	[ ]	___
Oil Fm. Volume Factor	___	[ ]	[ ]	___	[ ]	___	[ ]	___
Oil Rec. Efficiency	___	[ ]	[ ]	___	[ ]	___	[ ]	___
Gas Saturation	___	[ ]	[ ]	___	[ ]	___	[ ]	___
Reservoir Temp., °R	___	[ ]	[ ]	___	[ ]	___	[ ]	___
Reservoir Press., psi	___	[ ]	[ ]	___	[ ]	___	[ ]	___
Gas Z Factor	___	[ ]	[ ]	___	[ ]	___	[ ]	___
Gas Rec. Efficiency	___	[ ]	[ ]	___	[ ]	___	[ ]	___
Gas Shrinkage Factor[2]	___	[ ]	[ ]	___	[ ]	___	[ ]	___
Numbers of Closures	(no entry)	___	___	___	___	[ ]	___	___
Numbers of Untested Prospects[3]	(no entry)	___	___	___	___	[ ]	___	___

Play and Prospect Chance Factors[4]

Play Level
Explor. Success Ratio 2,20, ____
1, ___, ____ 1, ___, ____
1, ___, ____ 1, ___, ____
1, ___, ____

Prospect Level
Explor. Success Ratio 2,20, ____
2, ___, ____ 2, ___, ____
2, ___, ____ 2, ___, ____
2, ___, ____

Enter 1, 19, 1.0 If Play Chance = 1.0

---

[1] ____ (Entry Required) [ ] (Entry Optional)

[2] 1 - Fraction of Noncombustible Gases (H_2S, CO_2, N, He, etc.)

[3] Obtained from "Numbers of Closures" distribution by subtracting number of tested prospects (discoveries plus structures tested dry) at F_{01} and F_{99} to obtain "transformed" values for "Numbers of Untested Prospects" distribution.

[4] From Risk Analysis Form -

Figure 10.2: Play data sheet used for ***PRASS*** computer model by Alaska Region assessors. This computer model was generally used to compute probability distributions for ***pool area*** (prospect area · trap fill), ***oil yield*** (porosity · oil saturation · oil recovery efficiency/oil formation volume factor), and ***gas yield*** (porosity · gas saturation · reservoir pressure · gas recovery efficiency · gas shrinkage factor/[reservoir temperature · gas Z factor]). The results of these calculations were used as data entries to the ***GRASP*** computer model (fig. 10.3).

GRASP PLAY DATA FORM

______________________ ______________________

Assessment Province Play Number and Name

____

Assessor(s), Date

PORE

	F100	F50	F02	F00				
Pool Size (AC)								
Net Pay (FT)								

MPRO

	F99	F95	F75	F50	F25	F05	F01	F00	
Numbers of Prospects									

Play Level Chance __________ Prospect Level Chance __________ Exploration Chance__________

MONTE

	F100	F99	F95	F75	F50	F25	F05	F01	F00
Oil Recovery Factor (B/AC-FT)									
Gas Recovery Factor (10^6CFG/AC-FT)									
Solution Gas/Oil Ratio (CFG/B)									
Condensate Yield (B/10^6CFG)									

Proportion of Pools All Oil__________ Proportion of Pools All Gas__________

Proportion of Pool Volume Attributed to Oil in Mixed Case__________

Figure 10.3: Play data form used for *GRASP* computer model by assessors in Alaska OCS Region office.

RISK ANALYSIS FORM

1995 National Resource Assessment
Alaska OCS Region

Assessment Province ____________________ Play: ___ ____________
No. Name

Assessor ____________________ Play U.A.I. No. ____________

EXPLORATION SUCCESS RATIO = 2,20,___
(From exploration success rate within play, exploration success rate in productive analog, or prospect grading)

PLAY CHANCE FACTORS
(Complete and enter to PRASS only if play is not known to be successful, or, if Overall Play Level Chance is less than 1.0)

CONDITIONAL PROSPECT CHANCE FACTORS
(Complete and enter to PRASS only if Exploration Success Ratio Not Available. Must assume success of same factor at play level. No entry needed if equal to 1.0)

	TRAP - SEAL - TIMING	
1,01,___	CLOSURE PRESENCE (reliability of map size or definition)	2,01,___
1,04,___	SEAL PRESENCE (top, lateral; role of faults; number of seals required)	2,04,___
1,05,___	TIMING (relative to petroleum migration)	2,05,___
	RESERVOIR - POROSITY	
1,02,___	RESERVOIR PRESENCE (areal distribution as limited by deposition, facies changes, truncation at regional unconformities)	2,02,___
1,03,___	POROSITY (primary, secondary, fracture; not plugged or cemented)	2,03,___
	SOURCE - MATURATION - MIGRATION	
1,06,___	SOURCE PRESENCE (organic quantity and quality, areal extent, thickness, total organic carbon)	2,06,___
1,07,___	MATURATION (sufficient time, temperature)	2,07,___
1,11,___	MIGRATION (timing; primary (expulsion) and(?) secondary (source to trap); migration route vs. prospects; migration distance)	2,11,___
	PRESERVATION/HC QUALITY - RECOVERY	
1,08,___	PRESERVATION (risk of flushing, biodegradation, diffusion, thermal overmaturation of pooled oil and cracking to gas; processes yielding viscous, high-sulfur, possibly unproducible oil)	2,08,___

****

Calculate the Following as a Check on Results-Do Not Enter into PRASS

A.___ **OVERALL PLAY LEVEL CHANCE** (Product of all play chance factors)

B.___ **OVERALL PROSPECT LEVEL CHANCE** (Exploration Success Ratio, **or** product of all Conditional Prospect Chance Factors. Must be $\leq$ Overall Play Level Chance.)

A·B = ___ = EXPLORATION CHANCE

Figure 10.4: Risk analysis form used by assessors in Alaska OCS Region, adapted largely from White (1993, p. 2051, fig. 1).

11. ECONOMIC MODELING

The economic phase of the 1995 National Resource Assessment was conducted using the Probabilistic Resource Estimates Offshore model, referred to by the acronym PRESTO. This computer model was developed by MMS, and in its current form (version 5) represents the evolution from a relatively simple geologic assessment tool to a complex discounted cash flow model based on simulated development of hundreds of oil and gas pools. The modeling input for PRESTO is tied directly to the output of another new MMS assessment model (GRASP), which estimates the pool characteristics and calculates the volumes of conventionally recoverable resources. PRESTO determines the economic viability of individual pools within the geologic plays of a province. When aggregated, the economically recoverable resource potential of each province represents the undiscovered volumes of oil and gas that could be recovered profitably under realistic economic conditions and engineering assumptions.

PRESTO-5 MODEL

The methodology used in the economic assessment is based on a typical sequence of events progressing from the discovery of a hydrocarbon-bearing pool to the delivery of the commodity to a market destination. Generally, this sequence would be as follows:

1. A group of prospects are tested by exploration drilling, leading to a discovery.
2. Delineation wells are drilled to define the pool size and appraise its reservoir.
3. If commercial volumes are present, engineering and project development plans begin.
4. Production facilities are installed, and development wells are drilled.
5. Transportation infrastructure is designed and constructed.
6. Oil and/or gas is produced and transported to market destinations.

The parameters and assumptions used in the PRESTO model to simulate these events are contained in four main computer input files, listed as follows:

- Geologic-engineering input
- Cost file
- Engineering-schedule file
- Economic file

The following description of modeling methodology is organized according to these files. The discussion will cover the general parameters incorporated in the assessment, with more specific comments regarding engineering scenarios for individual provinces given in Chapter 26.

Geologic-Engineering Input

Numerous geologic and engineering variables are combined to simulate developments in each assessment province. The geologic input variables to the PRESTO model were largely obtained from the GRASP model. The two MMS assessment models (GRASP and PRESTO) were linked together in san Interface program for data transfer and data input functions. Engineering variables were formulated according to the geologic variables to achieve realistic simulation models. For discussion purposes, the geologic and engineering variables are segregated into categories, although all of these parameters are entered in the PRESTO program in one large data file.

It is important to recognize that the geologic characteristics of reservoirs were defined by the modeling concepts adopted by the geologic assessment teams. The economic assessment was built on the preceding geologic assessment. The reason that some provinces are economically viable and others are not was basically predetermined by pool size, reservoir attributes, and hydrocarbon type (oil/gas). Small pool volumes or low grade reservoirs usually can not overcome the high development costs in harsh environmental settings in offshore Alaska.

Geologic Variables

The number of undiscovered pools, their areal size, and the volumetric mixture of associated and non-associated oil and gas in each assessment play were transferred directly into PRESTO from GRASP.

- *Productive pool area* was used by PRESTO to determine the number of wells required to develop the pool. The pool area divided by the well drainage area (or well spacing) defines the number of production wells. Allowance was made for additional service wells for total production well costs. Typically a factor of 1.3 was used, or 30 percent of the total wells are used for injection and disposal.
- *Net pay thickness and recovery factor* (bbl/ac-ft) were not entered directly into PRESTO. However, they were used in external spreadsheet programs to model reservoir performance variables (for example, flow rates), which were important input variables to the economic model.
- *Gas/oil ratio* and *condensate yield* were not entered directly into PRESTO. The oil and gas content of pools was previously determined by GRASP, and pool volumes were directly input from GRASP to PRESTO. However, these variables were considered in the engineering infrastructure.
- *Geologic risk* controls the sampling frequency for pools within each play, where pools with lower risks (higher chance of success) are sampled more often than high risk pools. Whereas all pools in a province are eventually simulated for development, they are not necessarily evaluated in a single PRESTO trial. Geologic risk was entered directly into the PRESTO model from GRASP.

Exploration Variables

Exploration variables were used to define the cost for discovery for each pool.

- *Average number of wells to justify a production platform,* includes the discovery wells for each pool. Only the cost of successful exploration (wells and seismic) is included in the PRESTO model. Individual pools are not burdened by regional exploration costs leading to the discovery.
- *Average number of delineation wells for each production platform* includes the wells required to appraise the size and reservoir characteristics of a pool. The number of exploration and delineation wells was assigned according to pool characteristics (area, reservoir depth). Typically, an accurate appraisal of a platform drainage area would require 2-4 wells.
- *Number of wells to condemn a province* is used in estimating the costs to unsuccessfully test a province. This condemnation cost is used in calculating the net economic value of the province. Typically, we assumed that each play would contain 2 dry wells before abandonment, including all previously drilled-and-dry exploration wells in the province.
- *Average exploration and delineation well depth* is used to determine exploration well costs. Although pools in a play typically range broadly in depth, a representative well depth was chosen because this parameter was entered as a constant.
- *Delay to exploration* is defined on a play-basis and entered as a range (in years). This variable is used to control the discovery sequence for all plays in a province. Typically, resource-poor plays containing high risk pools are delayed in the discovery

sequence relative to resource-rich plays and containing lower risk pools. Although all pools in a play are eventually tested by the PRESTO model, sampling rates are tied to conditional probability sampling. The delay to exploration variable promotes a more realistic sequence of drilling in a province.

- *Time to drill exploration well* is defined by constants (months). This variable is controlled largely by reservoir depth, but also considers drilling location and logistics. For example, if exploration wells were drilled to test prospects at 10,000 feet subsurface depths in the Beaufort and Cook Inlet provinces, the Beaufort well might require 2-3 months to drill and test, whereas the Cook Inlet well might require 1-2 months. A remote setting and more difficult operating conditions combine to add time to mobilization, rig installation on-site, drilling/testing operations, and weather downtime.

Development Variables

These variables are used in conjunction with infrastructure data to define overall development costs for pools within each play.

- *Minimum and maximum number of platforms for each pool* is defined as 1 and 99, respectively, for all plays in the Alaska assessment. These are merely limits to the development simulation. The actual number of platforms installed depends on the number of wells required to fully develop the pool.
- *The maximum number of wells per platform* is a key variable that controls the number of production platforms required for pool development. In determining this variable, we considered the platform type likely to be used. Platform type is constrained by both water depth and environmental conditions. Generally, bottom-founded platforms are used in relatively shallow water (< 150 feet) and can be designed to hold 48-60 well slots. Floating production systems are used in deep water (> 150 feet) and can hold fewer well slots (48 or less) because of buoyancy restrictions. Gravel islands in very shallow water (< 50 feet) can be constructed to hold 60-90 wells.
- *Production well depth* is entered as a range in measured depth. To accommodate deviated wellbores, a series of scaling factors was used to convert the average true vertical depth (TVD) to a range of measured depths (MD) for development wells. Shallow reservoirs generally assumed higher measured/true vertical depth factors to minimize the requirements for extra platforms. For example, a pool at 6,000 ft TVD would have a triangular distribution of 6,000; 9,000; 12,000 ft MD. A pool at 15,000 ft TVD would have a triangular distribution of 15,000; 19,500; 24,000 ft MD.
- *Water depth* is entered as a triangular distribution for each play. Water depth is used as a cost scaling factor to adjust platform and pipeline costs. Exploration/delineation well costs were based on drilling depth, not water depth.

Production Variables

Reservoir performance was modeled using production variables for oil and gas recovery. A spreadsheet program was used to balance reservoir characteristics (net pay thickness, oil and gas recovery factors) with production variables (well spacing, flow rates) to ensure that realistic values were input into the PRESTO model. Three of the four variable sets discussed below were used in combination by PRESTO to calculate the production profile of each well in a simulated pool development. Different combinations of variable sets were used for individual plays according to data for pool characteristics.

- *Oil and gas well spacing* defines the drainage for each production well in a trial simulation. These variables determine the number of wells required to fully develop a pool, and they influence the flow rates from individual wells. Increasing the well spacing (or drainage area) will increase the flow rate when all other reservoir characteristics are unchanged. Typically, oil well spacing was entered as a triangular distribution of 80; 160; 240 acres, where the high end includes the possibility of horizontal completions. Typical gas well spacing distribution was 240; 320; 640 acres. Considerations were given to the thickness, permeability, and lateral continuity of reservoirs in each play. Oil and gas well spacing variables were adjusted accordingly. For example, a thin, laterally discontinuous oil play might have its well spacing distribution lowered to 40; 80; 160 acres.

- *Initial oil and gas well production rates* are important variables in defining the production profile of each well. These input variables were tuned in relation to the other production variables using an external spreadsheet program. Initial flow rates are most closely correlated to reservoir thickness. For typical oil reservoirs, initial well flow rates (bbl oil per day, BOPD) are approximately 10 times the reservoir thickness, where a 150- foot thick sand would have initial flow rates of 1500 BOPD. For typical gas reservoirs, initial well flow rates are approximately 100 times the reservoir thickness, where a 100 ft gas sand would have initial production rates of 10 million cubic feet per day (MMCFD).
- *Fraction of total oil or gas produced before flow rates start to decline* is different for oil and gas reservoirs. Typically, oil pools have smaller fractions produced before decline (0.9; 0.12; 0.15), and gas pools have a larger fractions (0.60; 0.80; 1.0). These characteristics are related to reservoir properties and drive mechanisms. These variables were entered as triangular distributions (minimum, most likely, maximum).
- *Exponential declines for oil and gas streams* were used in the 1995 assessment. Typically, oil stream decline coefficients are low (0.10; 0.15; 0.20) compared to gas stream decline coefficients (0.40; 0.50; 0.60). These variables were entered as triangular distributions.

Transportation Variables

Transportation costs are generally divided into two categories: capital costs and tariffs. New pipelines are treated as capital costs scaled on a per-mile basis. Pipeline sizing is calculated within the PRESTO program based on sampled production rates for each trial. Transportation costs to utilize existing pipeline systems are entered as tariffs. The pipeline models for each province represent a typical development case, and specific infrastructure systems are discussed in Chapter 26 (Infrastructure Scenarios).

- *Flowlines* are small diameter pipelines connecting platforms within a field or between individual fields and a central gathering point for the play. Generally, these distances are relatively short (few tens of miles). These pipeline costs are supported by individual fields.
- *Play pipelines* are larger diameter lines that gather oil or gas from the play area to the main trunk pipelines in the province. Because of the size of many Alaska provinces, these pipeline distances are considerably longer than flowlines (perhaps tens to hundreds of miles). The costs of play pipelines are shared by all of the productive fields in the play.
- *Basin pipelines* are the main trunk pipelines carrying oil/gas resources to regional export centers. Often, the export terminals are in southern Alaska, resulting in new trunklines hundreds of miles in length. The cost of basin pipelines is supported by all production occurring in the province (all commercial pools and plays).

Cost file

The estimated capital and operating costs for exploration, development, and production activities are included in a series of tables specifically formulated for each assessment province. The tables include costs scaled by key factors (for example, slot count and water depth for production platforms). These tables typically employ ranges of 50 percent surrounding most-likely costs from the MMS-Alaska database. This cost database was gathered from both public and proprietary sources, and it is periodically updated to reflect changing technology. Publically available references are provided at the end of Chapter 26.

For each modeling simulation, various combinations of costs for different components of the project are randomly selected from these costfile tables by monte carlo sampling. Distributions for cost and engineering variables are employed because of the inherent uncertainties of the modeling. Several factors are listed below:

1. Data are limited for actual offshore operations in Alaska.
2. Considerable differences are likely between companies with respect to strategies and costs to develop new fields in frontier areas.
3. Each activity will have a "learning curve" for each activity, where initial operations will be improved with experience and later projects may be more cost efficient.
4. New technology is expected to be developed to lower production costs. The cost benefits realized by new technology could occur over decades in the life of a field.

Capital Costs

Cost matrix tables are included for the following project components:

- Exploration and delineation well costs
- Platform costs (includes support structure or "jacket" and topside production equipment)
- Production well drilling and completion costs
- Shorebase facility costs (Oil and gas facilities are in separate tables.)
- Pipeline costs (Oil and gas pipeline costs are separate tables.)

Operating Costs

Platform operating costs are scaled according to the number of production wells, reflecting the overall size and complexity of the platform. Field operating costs vary for each province, from high operating costs in the remote Arctic offshore to relatively low operating costs in offshore southern Alaska. In comparison to operations in the Gulf of Mexico, operating costs in offshore southern Alaska were higher by factors of 4 to 5, provinces in the Bering Sea were higher by factors of 6 to 8, and the offshore Arctic was higher by factors of 8 to 10. The operating cost differentials are caused by severe environmental conditions and difficult logistics for grassroots projects in these remote provinces.

Operating costs are included for province infrastructure, such as trunk pipeline systems, shorebase facilities, liquefied natural gas (LNG) processing plants, and offshore loading terminals. These operating costs vary according to the size and throughput of the facility. Because both capital and operating costs incorporate the economy of scale, and each PRESTO run could result in different resources and production rates, we used assumed production rates for play- and province-level development based on the mean conventionally recoverable resource volumes.

- *Peak annual oil production is 10 percent of mean recoverable resource volume.*
- *Peak annual gas production is 5 percent of mean recoverable resource volume.*
- *Annual operating costs for infrastructure are 3.5 percent of original capital cost,* where capital cost is scaled by throughput using the above annual production rate assumptions.

Transportation Costs

Transportation scenarios to move oil and gas from production platforms to market destinations are separated into two categories: capital costs and tariffs. Generally, new transportation infrastructure components (such as pipelines and terminals) were included as capital costs. The costs to use existing infrastructure (trunk pipelines) or other components (tankers) were included as tariffs.

Transportation within the Alaska region usually assumed that offshore pipelines would be constructed. New pipeline systems were included as capital costs incurred by producers, with costs scaled to simulated production rates. If regional pipeline systems were available, transportation costs were input as per-barrel tariffs from published rates. For example, the Trans-Alaska Pipeline System (TAPS) tariff is $3.25/bbl (1995).

Export scenarios from Alaska assumed that ocean tankers would be used (no overland pipelines). Shipping costs to transport oil to the U.S. West Coast or gas (as LNG) to Japan are input as tariffs charged on a per-bbl or per-Mcf basis. Oil transport to the West Coast was based on published tanker tariffs for Alaska North Slope Crude from Valdez, Alaska, to Los Angeles, California. These tankers average 125,000 deadweight tons (DWT) (approximately 836,000 bbl) capacity and the cost is $1.40/bbl (1995) for the 2,400 mile route (tariff, $.58/bbl-1,000 miles). For this study, it was assumed that Alaska oil (blended with condensates) would be transported to the West Coast on U.S. flag ships with American crews.

LNG transportation costs are more uncertain for many reasons, including actual routes to Pacific Rim ports, ownership of fleet and its crews (foreign or U.S.), as well as the size and cost of new LNG carriers. Using published data for the LNG trade, we assumed a tariff of $.20/Mcf-1,000 miles for ships of approximately 250,000 DWT. This LNG tariff converts on a barrels-of-oil-equivalent (BOE) basis to $1.12/BOE-1,000 miles, or nearly twice that of the oil transportation tariff ($.58/bbl-1,000 miles). The LNG tariff is based on the assumption that foreign flag ships (and crews) will be contracted to deliver LNG to buyers in Asia. Because the commodity price is defined as the "landed price", additional costs at the delivery point are carried by the buyer and are not included as costs to the producers. Delivery point costs could include construction and operations at receiving terminals, temporary storage, and regasification processing. The centrally located port of Yokohama, Japan was selected to represent a typical Pacific Rim destination.

Scenarios for some remote, deepwater provinces assumed that shuttle tankers would be used to transport oil from offshore storage and loading systems to overseas export terminals in southern Alaska. Shuttle tankers are smaller (less than 40,000 DWT), generally shallower draft, and probably ice-reinforced. Because these specialized ships would be purpose-built and could serve several production operations, they were assumed to be operated by an independent company. A factor of 1.5 applied to the general oil transportation tariff was used to scale the costs of the shuttle tankers ($.87/bbl-1,000 miles) Likewise, if smaller, ice-reinforced ships were used to transport LNG from northern Alaska provinces, the 1.5 factor was applied ($.30/Mcf-1,000 miles).

Engineering Schedule

An important component of net present worth evaluations is the timing of expenditures in relation to income from production. In the PRESTO model, representative schedules were generated to define the timing of activities associated with installation of infrastructure supporting the simulated development of new offshore fields.

The data used in the 1995 Assessment reflect ongoing efforts to incorporate available industry information from comparable operating areas (for example, the North Sea) and periodically update this information to account for new technology or experience in Alaska. Recognizing that there are significant differences in the environmental conditions for offshore Alaska provinces, a set of general Engineering-Schedule input files were developed. These are: the offshore Arctic (Beaufort, Chukchi); Sub-Arctic (Hope, Norton), deep Bering Sea (Navarin, St. George), and southern Alaska (North Aleutian, Kodiak-Shumagin, Cook Inlet, and Gulf of Alaska).

Although refinement of these generalized schedules is possible, it should be recognized that petroleum production occurs only in the Beaufort and Cook Inlet provinces, so project scheduling in the other frontier provinces has no historical basis.

Data for project scheduling are entered into the PRESTO model through matrices or probability distributions. The key variables in the Engineering-Schedule file are discussed below:

- *Platform design, fabrication, and installation (DFI)* are defined in a matrix relating DFI time to platform slot count (representing overall platform size) and water depth. For example, a small, 18-slot platform in shallow water (30 ft) could be installed in 2 years, whereas a larger, 60-slot platform in deeper water (125 ft) could be installed in 4 years. DFI times include engineering design, construction, towing, site preparation, setting the platform, and installation of topside production equipment. We assumed no long-lasting legal or regulatory delays.
- *Platform starts* matrix defines the delay (in years) between multiple platform installations on a pool. This matrix relates platform starts to water depth, not platform size. Using the example above, two 60-slot platforms could be installed in a deeper water site in a period of 6 years (4 years for DFI and 2 year delay between platform starts). For the assessment, we assumed an aggressive, full field development for discovered pools, which often involved multiple production platforms. A staggered, incremental development strategy, now commonly employed for marginal fields, was not modeled.
- *Fractional yearly expenditures for infrastructure* were included in a matrix relative to total years to completion. Using the above example, platform costs for a 4-year platform DFI schedule would be expensed using fractions of 0.2, 0.2, 0.3, and 0.3. If capital costs for platform installation were $200 MM, the annual expenses would be $40 MM, $40 MM, $60 MM, and $60 MM.
- *Number of platform wells* matrix sets the number of production and service wells to be drilled and completed each year. The number of wells drilled is dependent on measured drilling depth, where well completions are more frequent to shallower drilling depths. Considerations were given to platform size, type, and location in assigning the number of rigs operating on each platform. Typically, floating platforms have less topside area in addition to center-of-mass limitations, so provinces requiring this platform type assumed 1 drilling rig per platform. Bottom founded platforms, or gravel islands, have less restrictions, and 2 rigs were usually assumed on these platform types if over 30 wells were expected to be drilled.

Economic Input

To maintain consistency between MMS regional offices, the economic variables and assumptions used in the 1995 National Assessment were established by MMS Headquarters. Using consistent parameters allowed an accurate aggregation of resource estimates to national levels. The following is a listing of key economic variables:

- *Discount rate = 12 percent*; Discount rate is used to scale future cash flows to a present value basis. Development projects with positive net present value are defined as commercially viable (or "economic"). The discount rate represents the minimum acceptable rate of return on investment considering the cost of capital and alternative investments. Higher discount rates provide a greater comfort factor for risky investments.
- *Inflation = 3 percent*; Inflation is the rate of price increase for goods and services. For the modeling simulations, both the commodity prices and development/production costs were assumed to inflate equally at a constant rate. Future cash flow is inflated and then deflated to a base year (1995) to account for

the effects of depreciation on large-cost items.

- *Royalty = 12.5 percent*; Royalty is a fee paid to the landowner (Federal government) on production. Typically, lower royalty rates are assigned to deepwater and frontier leases, and alternative royalty systems are assigned to more favorable economic environments.
- *Federal tax = 35 percent;* Development costs were divided into tangible (depreciating assets) and intangible (expendable items) fractions. For the Alaska assessment, the tangible fractions assumed were: exploration/delineation, 0.0; platform and production facilities, 0.50; production wells, 0.25. No State taxes were included (income, severance, ad valorem taxes).
- *BOE conversion factor = 5.62 MCF/bbl*; This factor is used to convert gas resources to barrels-of-oil-equivalent (BOE) units. A gas conversion factor is often based on British Thermal Unit (BTU) energy content which is related to gas composition, and BTU conversion factors can vary 50 percent above or below this value. Without speculating on gas composition for undiscovered resources, we used a standard conversion factor for all plays.
- *BTU equivalency factor = 0.66*; Oil and gas prices are linked in the PRESTO model, as well as in the marketplace as alternative energy commodities. Typically, transmission gas is sold in the continental United States at a price discount to oil. In the Pacific Rim, LNG is often sold at a price premium to oil. Although Alaska gas was modeled as LNG exported to the Pacific Rim, a BTU equivalency factor (0.66) was assumed for consistency in gas resource aggregation to the national level. However, this assumption decreases the potential value and lowers the estimates for economically recoverable gas resources in Alaska to some extent.

Commodity price is perhaps the single most important factor in determining economic viability. As discussed previously, PRESTO results are given in the form of price-supply curves which show that increasing volumes of resources are economically recoverable at higher commodity prices. As a further refinement, PRESTO allows price adjustments based on oil gravity differences among the geologic plays. The price adjustment followed a standard formula:

No price adjustment was made for gravities above 40° API.
From 40° and 34° API, the price adjustment was $0.10/degree;
Below 34° API, the price adjustment was $0.15/degree.

Price adjustments were made relative to 32° API World Oil. World Oil price represents the composite refiners' acquisition price for landed crude oil for domestic markets. For example, a typical Alaska North Slope (ANS) crude oil with 28° API gravity would receive a gravity price adjustment of -$.60/bbl (32° minus 28° @ -$0.15/degree). If World Oil price is $18.00/bbl, the ANS landed price would be $17.40/bbl. For higher gravity oil example (38°), the price adjustment would be +$0.70/bbl (34° minus 32° @ +$0.15/degree plus 38° minus 34° @ +$0.10/degree), resulting in a landed price of $18.70/bbl.

All transportation costs were subtracted from the landed price to determine the wellhead price to the producer. Price-supply curves show economically recoverable resource volumes at landed prices, with gas and oil linked by the BTU equivalency factor (0.66).

GEOLOGIC ASSESSMENT

Arctic Alaska Offshore

Bering Shelf

Pacific Margin

GEOLOGIC ASSESSMENT
1995 National Resource Assessment
Alaska Federal Offshore
U.S. Minerals Management Service

ARCTIC ALASKA OFFSHORE ASSESSMENT PROVINCES

12. INTRODUCTION

by

Kirk W. Sherwood

United States (U.S.) waters offshore Arctic Alaska were divided on geologic grounds into five provinces that framed the estimates of undiscovered oil and gas potential for the 1995 National Resource Assessment. All U.S. waters offshore Arctic Alaska are assessed, including deep water areas of doubtful potential. However, most of the oil and gas resources identified in the Arctic offshore by this study are associated with the Outer Continental Shelf (OCS) areas of Chukchi and Beaufort Seas. The five offshore Arctic assessment provinces adopted for the MMS study are outlined in figure 12.1.

The Beaufort shelf assessment province extends from the 3-mile limit of State of Alaska waters northward to the 500 m isobath. This isobath was adopted as a mappable reference approximating the present practical limit for petroleum development in Beaufort Sea. Beyond the 500 m isobath, extreme water depths and ice conditions essentially preclude exploration and development using existing technologies.

North of the 500 m isobath in Beaufort Sea lie the very deep waters of the Beaufort continental slope and rise and the abyssal plain of the Canada basin, all ice-bound throughout much of the year. United States lands that extend into this deep water area, at least north to the U.S. Exclusive Economic Zone (or *EEZ,* extending 200 miles offshore), are here set apart as the Canada basin-Beaufort slope assessment province. The Canada basin-Beaufort slope assessment province extends west to the 3,700 m isobath along Northwind Escarpment (fig. 12.1), which we arbitrarily adopted as the east margin of Chukchi Borderland assessment province. Assessment province boundaries depart from the 3,700 m, 100 m, and 500 m isobaths where joined near the south end of Northwind Escarpment (fig. 12.1).

The Chukchi shelf and Beaufort shelf assessment provinces meet along the 71° north latitude and 162° west longitude lines formerly adopted by the MMS as the political boundaries between the Beaufort Sea and Chukchi Sea OCS Planning Areas. Planning Areas are political land units defined for purposes of funding environmental surveys, conducting impact studies, and leasing properties for petroleum exploration and development. Naturally, planning area boundaries do not necessarily correspond to geologic boundaries and several geologic plays overlap both the Beaufort shelf and Chukchi shelf assessment provinces in this area.

Chukchi Borderland is a large subsided continental block north of Chukchi shelf that lies at water depths mostly in excess of 1,000 m (Perry and Fleming, 1986). A small part of this large geologic feature lies in U.S. waters and is here set apart as the Chukchi Borderland assessment province. This province is bounded by 169° west longitude on the west, the 100 m isobath on the south, the 3,700 m isobath on the east, and the traditional northern limit of the Chukchi and Beaufort Sea OCS Planning Areas along 75° north latitude on the north.

Hope basin and Chukchi shelf assessment provinces are sited on Chukchi shelf in water depths typically 50 m or less. Both provinces extend from the three-mile offshore limit of State of Alaska waters to Russian waters west of 169° west longitude. Hope basin and Chukchi shelf assessment provinces are separated by the Herald arch, a thrusted uplift that forms the north margin of Hope basin. Chukchi shelf assessment province extends north from Herald arch to the 100 m isobath. The 100 m isobath was adopted as a mappable reference for the northern limit for conventional exploration and development technology, mostly because it roughly corresponds to the line of maximum northward retreat of the Arctic ice pack (Grantz and others, 1982, fig. 2).

GEOLOGICAL POTENTIAL OF NORTHERN ALASKA AND THE ARCTIC ALASKA OFFSHORE

The continental shelves beneath Beaufort and Chukchi Seas are in many ways simply direct geological extensions of (onshore) northern Alaska. Northern Alaska is a rich commercial petroleum province, with a discovered *total-hydrocarbon* or in-place endowment of approximately 77 billion energy-equivalent barrels, mostly oil (Bird, 1994) and commercial oil reserves of at least 16.4 billion barrels (AKDO&G, 1995). Northern Alaska discovered resources are scattered among 32 or more oil and gas fields, but most resources occur in the several oil fields in the Prudhoe Bay area (located in fig. 12.1). Many, but not all, of the key oil-source and reservoir sequences of northern Alaska (highlighted in fig. 12.2) extend directly into offshore assessment provinces. For this reason, and because of the abundance of untested potential traps in the offshore, the Beaufort and Chukchi shelf assessment provinces are considered high potential areas. This study estimates that their collective potential approaches 22 billion barrels of recoverable[1] oil. Offshore Arctic Alaska offers nearly half of the 46 billion barrel undiscovered oil endowment of the U.S. offshore (MMS, 1996, tbl. 1; Sherwood and others, 1996, tbl. 1).

The Hope basin assessment province is geologically isolated from onshore Alaska north of the Brooks Range and the Arctic offshore north of Herald arch. Hope basin therefore lacks most of the key geological attributes that are known to have proved so immensely favorable to creation of petroleum deposits in northern Alaska. Hope basin in U.S. waters is filled with rocks of Cenozoic age with qualities that suggest gas will be the dominant resource. Cretaceous rocks, possibly more oil-prone, may floor Hope basin in Russian waters, but these do not extend in volume into U.S. waters. U.S. Hope basin is therefore viewed primarily as a gas basin.

In this assessment we conclude that the Canada basin-Beaufort slope assessment province offers only negligible quantities of undiscovered, conventionally recoverable oil and gas resources. However, we freely acknowledge the potential existence of *technically unrecoverable* conventional resources, perhaps mostly gas pooled in widespread stratigraphic traps and deep diapiric folds. Anomalies in seismic data that suggest the presence of gas deposits are widespread across the Beaufort continental slope (mapped by Grantz and others, 1987, fig. 20). Diapiric folds that might contain gas pools are found primarily beneath the eastern Beaufort continental slope (Grantz and others, 1987, fig. 20). Unconventional hydrocarbon deposits, such as gas hydrates, also appear to be abundantly present on the continental slope in the Canada basin-Beaufort slope assessment province. Acoustic anomalies that may reveal these gas

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[1]*risked, mean, undiscovered, conventionally recoverable oil*

hydrate deposits are observed in seismic records across large areas of the Beaufort continental slope. Beaufort slope gas hydrates offer an estimated geological (presently technically inaccessible) potential of 10^{15} cubic meters (35,500 trillion cubic feet) of methane (Kvenvolden and Grantz, 1990).

The Chukchi Borderland is perpetually covered by the Arctic ice pack and is navigable only seasonally and only with the most powerful modern icebreaking vessels. Chukchi Borderland assessment province therefore offers only negligible potential for conventionally recoverable oil and gas resources. However, unconventional resources, such as gas hydrates like those widely interpreted in seismic data on the Beaufort continental slope, may be abundantly present here as well. Conventional petroleum deposits may also be present in the Chukchi Borderland assessment province, but cannot be reached with present-day technology.

REGIONAL GEOLOGY OF NORTHERN ALASKA AND THE ARCTIC ALASKA OFFSHORE

Northern Alaska and the adjacent continental shelves are underlain by sedimentary rocks that represent one fragment of a large basin that once was continuous across a single "supercontinent" now represented by several independent continental masses separated by the Arctic oceanic basin (Chukotka, northern Alaska, northern Canada, and perhaps others; Jackson and Gunnarsson, 1990; Embry, 1990). This "supercontinent" broke up about 100 Ma (million years ago) into fragments that were dispersed by expansion of the Arctic oceanic basin. The former assemblage of the now-dispersed continental masses is suggested by strong similarities between rock sequences deposited in a large, continuous basin that extended across the supercontinent before the breakup event. In fact, the rocks that record the pre-breakup basin in northern Alaska are generally grouped under the term "Ellesmerian sequence" because of their striking resemblance to rocks of the same age exposed on Ellesmere Island in northern Canada near Greenland, now 2,100 km distant (Grantz and others, 1975). Correlative rocks are found on several circum-Arctic continents, and the Ellesmerian sequence as most broadly defined ranges in age from about 360 to 175 Ma (fig. 12.2).

In many areas of the Arctic, Ellesmerian rocks or correlative sequences rest upon a group of highly deformed rocks of Devonian and older ages. In northern Alaska and northern Canada, these rocks are assigned to a group of rocks called the "Franklinian" sequence. Franklinian rocks host oil and gas deposits in northern Canada (Stuart Smith and Wennekers, 1977). Two oil and gas plays in the Arctic Alaska offshore (Beaufort shelf plays 0101, 0200) are associated with Franklinian rocks.

In the Arctic, the breakup of the old supercontinent that hosted deposition of Ellesmerian rocks is marked by younger sedimentary deposits that are peculiar to the rift zones along which the old supercontinent fragmented. In this report, these deposits are referred to as either the "Rift" sequence (terminology of Craig and others, 1985), or the roughly correlative and comparable "Beaufortian" sequence described by Hubbard and others (1987) along the Beaufort margin. These rocks range from about 175 to 115 Ma in age (fig. 12.2).

Continental fragmentation and dispersal began a phase of active expansive growth of the Arctic oceanic basin at mid-ocean rifts or spreading centers. These movements inevitably caused collisions between dispersing breakup fragments and outlying independent continental masses or volcanic arcs. These collisions in turn caused uplifts of new mountain systems with complementary basins that received sedimentary debris shed from the mountains. In northern Alaska, the rocks that record this event are termed the "Brookian" sequence, in deference to their obvious ties to the Brooks Range of northern Alaska. Rocks correlative to the

Brookian sequence of Alaska are found on all of the circum-Arctic continents, but can be quite varied owing to their independent origins in many different types of basins. Brookian rocks in northern Alaska range in age from about 115 Ma up to the present (fig. 12.2).

PETROLEUM POTENTIAL OF ARCTIC STRATIGRAPHIC SEQUENCES

The Trans-Alaska pipeline system (TAPS) is currently shipping about 1.5 million barrels of oil per day, about 25 percent of U.S. daily production, south from the several fields in the Prudhoe Bay area (located in fig. 12.1). Most of this oil (1.2 million barrels per day) is being extracted from reservoirs in the Ellesmerian sequence (Prudhoe Bay, Lisburne, and Endicott fields; AOGCC, 1993). Fields in Rift sequence reservoirs (Kuparuk, Milne Point, Pt. McIntyre, and Niakuk) account for about 0.3 million barrels per day, or 20 percent of northern Alaska production. In 1993, Brookian rocks contributed only about 3,000 barrels per day (0.2% of total) to TAPS (Schrader Bluff pool, Milne Point field; AOGCC, 1993). These stratigraphic sequences and their associated petroleum deposits are illustrated in the geologic column of figure 12.2.

The fact that the most prolific oil production has historically been associated with Ellesmerian sequence reservoirs is mostly due to the exceptionally thick and porous Triassic (Ivishak Fm.) sandstones that form the reservoir at the spectacular 12.4 billion barrel Prudhoe Bay field. Because of their proven performance as commercial petroleum reservoirs, Ellesmerian targets, especially the Triassic strata, have traditionally formed the chief exploration objectives in northern Alaska and the Arctic Alaska offshore. Reservoir formations with qualities comparable to the best Ellesmerian reservoirs are only rarely found within the younger Rift and Brookian sequences.

Organic-rich shales and limestones within the Ellesmerian and Rift sequences are the sources (identified as "Key Oil Source Rocks" in fig. 12.2) for an estimated 98 percent of the discovered oil endowment of northern Alaska (Bird, 1994). Twenty to forty billion barrels (in place) of heavy oil are lodged in Brookian sequence reservoirs (West Sak, Ugnu) near Prudhoe Bay (Thomas and others, 1991, tbl. 2-5), but all of this oil, like that in deeper Ellesmerian and Rift sequence reservoirs, was generated from these key oil source rocks.

Ellesmerian and Rift sequence rocks have clearly played a critical role in the success of northern Alaska as a commercial petroleum province. Seismic mapping and well data have established that these key reservoir and oil-source rocks also occur beneath the adjoining continental shelves of Chukchi Sea and Beaufort Sea. The presence of these rocks offshore was a critical consideration in assessing the offshore oil and gas potential. In the Chukchi shelf assessment province, plays associated with Ellesmerian and Rift sequence rocks contain 67 percent of the province endowment in energy-equivalent barrels (BOE) and 75 percent of the oil endowment. These rocks are less widespread beneath Beaufort shelf, which is dominated seaward by thick wedges of Brookian rocks. Yet in the Beaufort shelf, Ellesmerian and Rift sequence plays still account for 50 percent of the province BOE endowment and 34 percent of the overall oil endowment.

ELLESMERIAN![2] PETROLEUM SYSTEM OF NORTHERN ALASKA AND THE ARCTIC ALASKA OFFSHORE

The geologic events that created the vast oil deposits already discovered by drilling in northern Alaska are fairly straightforward. From about 230 to 115 Ma, shaly rocks rich in fatty or oil-prone organic matter were deposited across the Beaufort and Chukchi shelves and northern

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[2] *(!) denotes a known or well documented system (Magoon and Dow, 1994, p. 12).*

Alaska at least as far south as the present Brooks Range (fig. 12.1). Uplift of the Brooks Range from about 115 to 60 Ma then created a complementary downwarp (Colville basin) on the north that was quickly filled with over 6 km of Brookian strata laid down atop the older organic-rich shales. By about 100 Ma, the organic-rich shales beneath Colville basin had reached depths and temperatures sufficient to convert organic matter to oil. The oil was expelled into porous carrier beds that guided it northward and up stratal dip beneath impermeable beds (rising buoyantly over relatively dense water) toward a structural high called Barrow arch along the modern Beaufort Sea coast (located in fig. 12.1). Great quantities of this oil were ultimately captured by several traps along the Barrow arch near Prudhoe Bay. Bird (1994) has termed this oil generation, migration, and entrapment system the Ellesmerian! petroleum system and estimates its total generative potential at ***8 trillion barrels of oil***.

The geochemistry of some offshore oil deposits indicates that at least some fraction of the immense 8 trillion barrels of oil generated by the Ellesmerian! petroleum system must have reached the offshore as well as the known onshore deposits. Other petroleum generating systems, particularly north of Barrow Arch, may contribute additional resources to some parts of the offshore assessment provinces.

Only about 1 percent, or 70 billion barrels, of the 8 trillion barrels of oil generated by the Ellesmerian! petroleum system is presently known and accounted for (as total or in-place oil) in discovered fields in northern Alaska (Bird, 1994, p. 340). The sum of undiscovered, conventionally recoverable oil for the entire Alaska Arctic (onshore and offshore) is about 31 billion barrels[3], less than half a percent of the 8 trillion barrels of oil generated by the Ellesmerian petroleum system. The ability of this petroleum system to create oil clearly far outstrips the accessible trap volume within the system. This prolific oil generation and trap charging system is the chief geological asset of the U.S. Arctic petroleum provinces north of the Brooks Range.

OFFSHORE PLAY ORGANIZATION AND IDENTIFICATION

The larger petroleum deposits in northern Alaska partly owe their exceptional sizes to the presence of some very thick reservoir formations offering high quality pore systems.[4] These key reservoir formations are unique to certain stratigraphic sequences. Each of the major stratigraphic sequences (Ellesmerian, Rift, Brookian) record distinct tectonic events in the geologic history of the Arctic. Because sedimentation is a response to tectonism, tectonic events of distinct types characteristically produce distinct sedimentary deposits. Tectonics particularly control the thicknesses, textures, and geographic distributions of the coarse clastic sediments that become petroleum reservoirs. For this reason, we have chosen the stratigraphic sequence as our most fundamental level of organization of petroleum plays in the Arctic Alaska offshore.

We recognize three principal play groups, representing the Ellesmerian, Rift, and Brookian sequences (fig. 12.2). (In some areas, basement rocks or unique older rocks also offer potential petroleum reservoirs, and these are identified as separate plays.) Each play group contains several petroleum plays, with distinctions variously based on unique attributes such as individual reservoir facies or stratigraphic units within the sequence, trap

[3]*The sum of the mean quantities of risked, undiscovered, conventionally recoverable oil presently estimated for northern (onshore) Alaska (7.41 + 1.12 BBO), Chukchi shelf (13.09 BBO), and Beaufort shelf (8.91 BBO) = 30.53 BBO. Estimates for northern Alaska are from USGS (1995).*

[4]*Quality is governed by size, quantity, and communicability of the internal void spaces that actually house the petroleum.*

type, structural setting, or anticipated reservoir content (oil versus gas, if exclusive). The criteria used to distinguish plays are given in detail within the following chapters that describe the Chukchi shelf, Beaufort shelf, and Hope basin assessment provinces.

OIL AND GAS ENDOWMENTS OF ARCTIC ALASKA PROVINCES

Forty-five petroleum plays are recognized in Chukchi and Beaufort shelf provinces, with 8 of these plays overlapping both provinces (but evaluated independently). Several plays extend directly onshore to equivalent plays among the 11 plays independently recognized there by the U.S. Geological Survey (USGS, 1995). Four plays are recognized in Hope basin, bringing the total number of independently quantified plays in the Arctic Alaska offshore to 49, and the total for the Arctic (onshore and offshore) to 60. Resource endowments of offshore provinces and northern Alaska are summarized in table 12.1. Cumulative probability distributions for the undiscovered oil, gas, and BOE resources of the Arctic Alaska offshore subregion are plotted in figure 12.3..

COMPARISON OF RESULTS FOR NORTHERN ALASKA (ONSHORE) TO ARCTIC ALASKA OFFSHORE PROVINCES

The Chukchi shelf and Beaufort shelf assessment provinces together offer 21.86 billion

TABLE 12.1
RESOURCES OF THE ARCTIC OFFSHORE SUBREGION AND NORTHERN ALASKA
RISKED, UNDISCOVERED, CONVENTIONALLY RECOVERABLE OIL AND GAS

AREA	OIL (BBO)			GAS (TCFG)			BOE (BBO)			MPhc
	F95	MEAN	F05	F95	MEAN	F05	F95	MEAN	F05	
CHUKCHI SHELF	6.80	13.02	21.94	9.81	51.84	141.75	8.59	22.24	44.75	1.00
BEAUFORT SHELF	6.28	8.84	11.96	20.10	43.50	79.15	10.29	16.58	24.84	1.00
HOPE BASIN	0.00	0.11	0.34	0.00	4.06	12.67	0.00	0.83	2.59	0.61
CHUKCHI BORDERLAND	NEGLIGIBLE			NEGLIGIBLE			NEGLIGIBLE			0.00
CANADA BASIN-BEAUFORT SLOPE	NEGLIGIBLE			NEGLIGIBLE			NEGLIGIBLE			0.00
ARCTIC SUBREGION	14.68	21.96	31.18	38.02	99.41	201.13	22.52	39.65	63.25	1.00
NORTHERN ALASKA	na	8.63	na	23.27	63.50	124.33	nr	nr	nr	1.00

*BBO, billions of barrels (oil values include both crude oil and natural gas liquids); TCFG, trillions of cubic feet; BOE, total oil and gas in billions of energy-equivalent barrels (5,620 cubic feet of gas=1 energy-equivalent barrel of oil); reported **MEAN**, resource quantities at the mean in cumulative probability distributions; **F95**, the resource quantity having a 95-percent probability of being met or exceeded; **F05**, the resource quantity having a 5-percent probability of being met or exceeded; **MPhc**, marginal probability for hydrocarbons for basin, i.e., chance for the existence of at least one pool of undiscovered, conventionally recoverable hydrocarbons somewhere in the basin; **na**, crude oil and natural gas liquids not aggregated; **nr**, not reported. Resource quantities shown are risked, that is, they are the product of multiplication of conditional resources and MPhc. Data for **NORTHERN ALASKA** from USGS (1995). Mean values for provinces may not sum to values shown for subregions or region because of rounding.*

barrels of undiscovered oil[5], over twice the 8.63 billion barrels of undiscovered oil estimated by the U.S. Geological Survey (USGS) for the equivalent onshore province (Northern Alaska in tbl. 12.1). At first glance, it may seem that the endowment of the Arctic offshore is disproportionately large. However, when discovered resources are added to undiscovered resources to obtain the total endowments, we observe a more logical balance between onshore and offshore Arctic subregions, as illustrated in figure 12.4.

Discovered oil resources in the Arctic Alaska offshore are presently tallied[6] at 0.4 billion barrels (MMS, 1996, tbl. 3). This represents only about 2 percent of the total offshore endowment, estimated to be ***22.3 billion barrels*** when undiscovered resources are included (fig. 12.4).

Total original commercial oil reserves for northern Alaska are at least 16.4 billion barrels (AKDO&G, 1995). BP-Alaska has recently speculated that perhaps an additional 5.0 billion barrels might be extracted from undeveloped pools in the Prudhoe Bay area (Nelson, 1996). To these quantities we then add the USGS estimate of 8.63 billions of barrels of undiscovered oil and obtain a total recoverable onshore oil endowment of ***30.0 billion barrels*** (fig. 12.4).

If the onshore and offshore subregions of Arctic Alaska are taken as a whole, the proportion of the overall oil endowment allotted to the ***offshore*** is about 43 percent, while the proportion of the overall geographic area occupied by the ***offshore*** is about 40 percent. The undiscovered oil resources estimated for the ***offshore*** are therefore consistent with the physical size of the offshore subregion and its geological ties to the onshore.

A much larger fraction of the ***onshore*** oil endowment has been discovered (fig. 12.4), but exploration of the onshore began in 1944, 35 years before the first well was drilled in offshore Federal waters. The assessment results for offshore provinces indicate a large, undiscovered potential for the Arctic offshore provinces that is consistent with the exploration experience in the more mature petroleum province of northern Alaska onshore.

COMPARISON OF RESULTS FOR CHUKCHI SHELF AND BEAUFORT SHELF

Chukchi shelf assessment province offers a resource endowment[7] of 13.02 BBO and 51.84 TCFG, ranging from 47 percent to 20 percent larger, respectively, than the 8.84 BBO and 43.50 TCFG estimated for Beaufort shelf assessment province (tbl. 12.1). This markedly larger resource endowment for Chukchi shelf is partly because Chukchi shelf province is 17 percent larger than Beaufort shelf province in areal size. However, Chukchi shelf has the larger resource endowment mainly because ***prospects are more numerous beneath Chukchi shelf than Beaufort shelf***. At the time of completion of the assessment (January 1995), seismic mapping had identified 331 prospects in Beaufort shelf and 745 prospects beneath Chukchi shelf. Although other differences exist in the assessment data bases for these two provinces, prospect numbers alone could entirely account for the observed differences in assessment results.

[5]*mean, risked, undiscovered, conventionally recoverable oil resources; "oil" includes both crude oil and natural gas liquids.*

[6]*several discovered pools were not tested for flow capacity and remain unevaluated*

[7]*mean, risked, undiscovered, conventionally recoverable oil and gas*

COMPARISON OF RESULTS FOR ARCTIC ALASKA OFFSHORE SUBREGION TO RESULTS FOR BERING SHELF AND PACIFIC MARGIN SUBREGIONS

With 92 percent of undiscovered offshore oil resources and 79 percent of undiscovered offshore gas resources, the Arctic offshore subregion dominates the overall Alaska offshore potential. The dominance of Arctic offshore subregion results from several factors that are reflected in both the data prepared for the assessment models and the computational results:

- Arctic Alaska offshore assessment provinces have the majority of prospects and the greatest chances for success; therefore they have the majority of pools.
- Arctic Alaska offshore assessment provinces have larger prospects. Several in Chukchi shelf assessment province approach the size of the 12.4 BBO Prudhoe Bay field—the largest oil field ever found in North America.
- Beaufort and Chukchi shelf assessment provinces are geologically linked to the immensely successful petroleum province of northern Alaska.

Prospect and Pool Numbers

The geology of the Arctic offshore subregion is very complex because of the long history of repeated tectonic disturbances. These events shaped the crust, creating many faults and structures that may have trapped migrating petroleum. This assessment predicts that an average of 500 pools of oil and gas, of all sizes, remain undiscovered in all of offshore Alaska. Of these, an average of 330 pools (or 66 percent of all offshore Alaska) are expected to occur in just the Beaufort shelf and Chukchi shelf assessment provinces.

Prospect Sizes

The typical prospects that underlie the Arctic offshore subregion are markedly larger than the prospects seismically mapped within the Pacific margin and Bering shelf subregions. In Chukchi shelf, Beaufort shelf, and Hope basin assessment provinces, median values of prospect area distributions (for plays) range from 8,000 to 11,000 acres. Most other provinces have prospect area distributions (for plays) with median values ranging from 3,000 to 7,000 acres.

Chukchi shelf is particularly well-endowed with large undrilled prospects. Forty prospects beneath Chukchi shelf range from 50,000 to 100,000 acres in size, and 18 range from 100,000 to 130,000 acres, approaching Prudhoe Bay field at 151,000 acres.

Most Known Oil Resources of Alaska Occur in the Arctic

Of the 24 BBO and 126 TCFG estimated for the entire Alaska Federal offshore, 22 BBO (92 percent) and 99 TCFG (79 percent) are found in the Arctic offshore provinces. This high Arctic proportion is identical to the proportion of Alaskan commercial oil reserves that have been discovered onshore in northern Alaska. Ninety-two percent of Alaska's (original) commercial oil reserves are found in northern Alaska, mostly in Prudhoe Bay and nearby fields. The remaining 8 percent of Alaskan oil reserves once filled the now nearly-depleted oil fields of Cook Inlet (and the small field found at the turn of the century at Katalla in the Gulf of Alaska). The dominance of the Arctic resource endowment, in onshore Alaska and offshore waters, is graphically illustrated in figure 12.5.

The results of the 1995 resource assessment of the Arctic Alaska offshore provinces indicate a very large, untapped geologic potential. The assessment results are quantitatively consistent with the 95-year exploration experience in onshore Alaska and point to a sustained future for petroleum exploration in all of the Arctic regions of Alaska.

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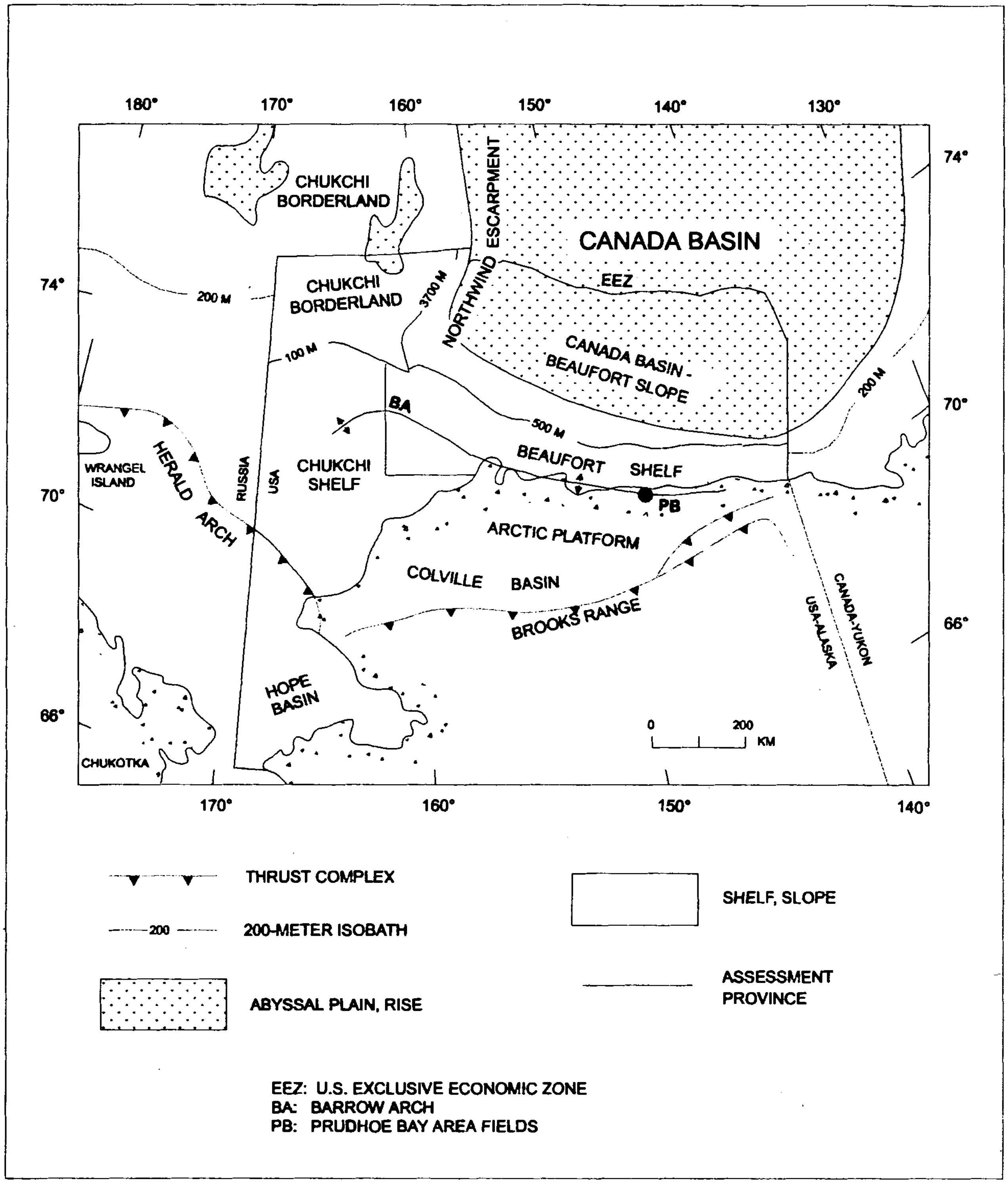

Figure 12.1: Map showing locations of assessment provinces within the Arctic subregion of the Alaska offshore region. Only the Chukchi shelf, Beaufort shelf, and Hope basin assessment provinces offer potential for undiscovered, conventionally recoverable oil and gas. The Chukchi Borderland and Canada basin—Beaufort slope assessment provinces offer negligible conventionally recoverable hydrocarbon resources.

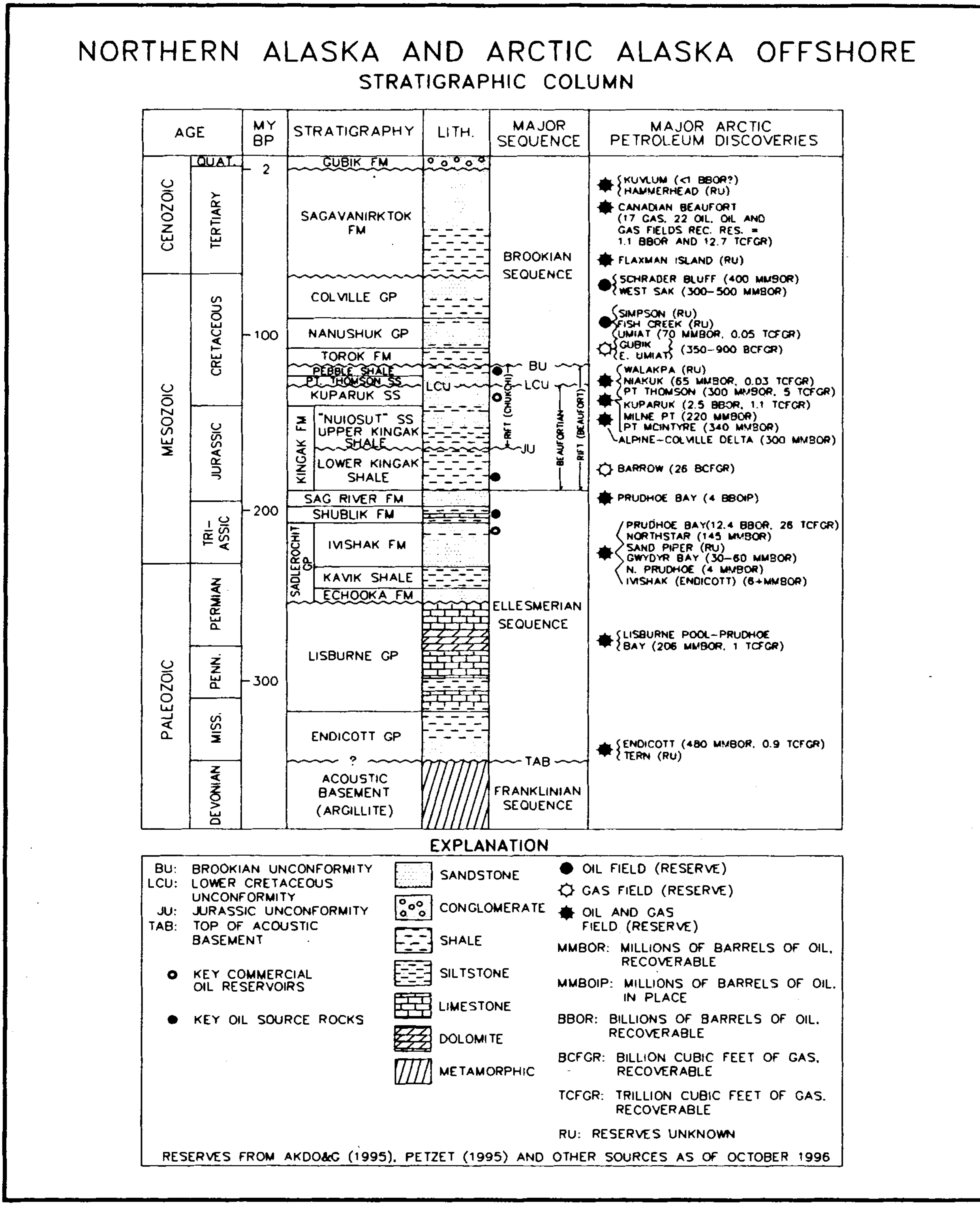

Figure 12.2: Generalized stratigraphic column for northern Alaska and Arctic Alaska offshore assessment provinces. Beaufortian sequence after Hubbard and others (1987).

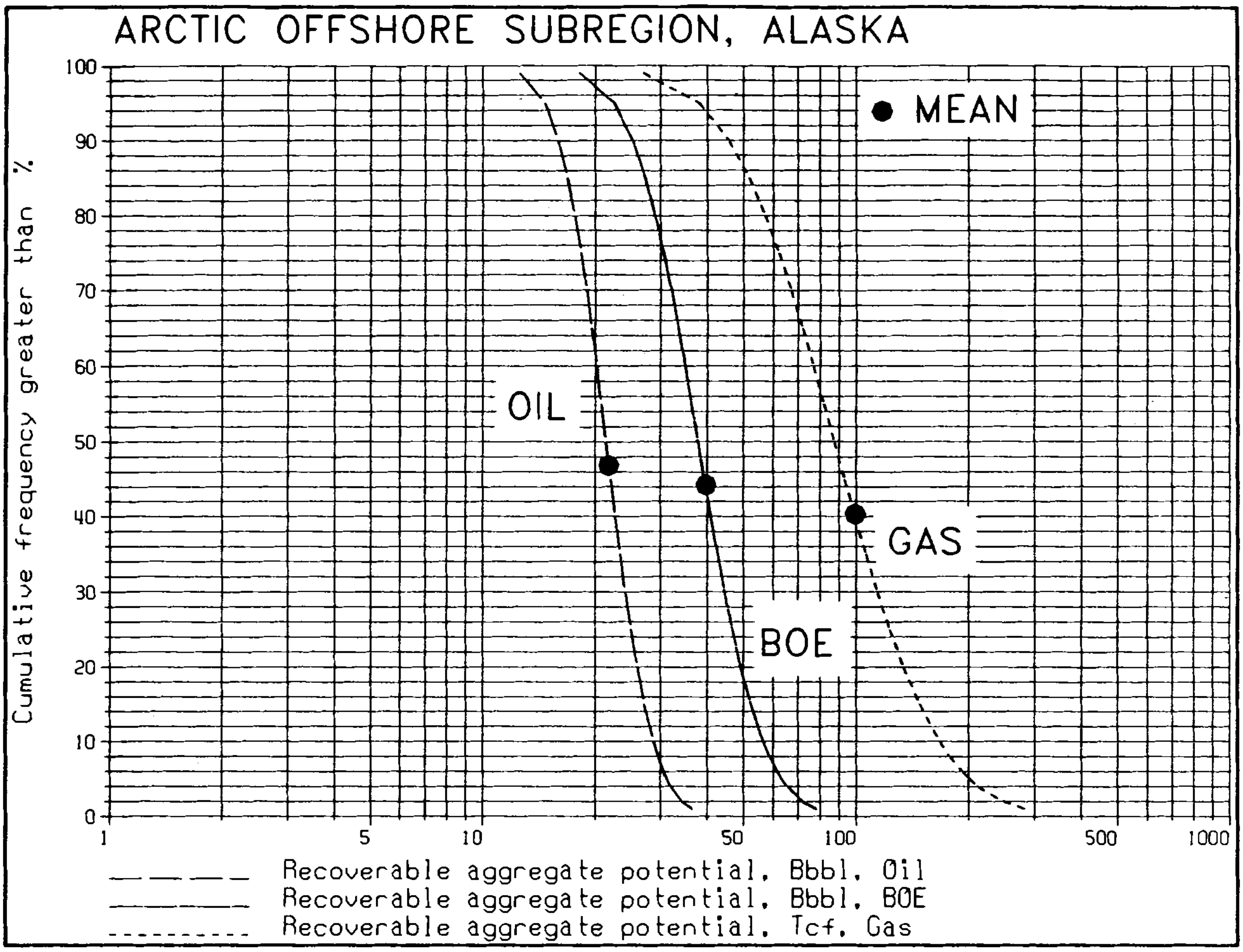

Figure 12.3: Cumulative probability distributions for risked, undiscovered, conventionally recoverable oil, gas, and total hydrocarbon energy in BOE (barrels of oil-equivalent, 1 barrel of oil=5,620 cubic fet of gas) for Arctic offshore subregion (aggregation of Chukchi shelf, Beaufort shelf, and Hope basin assessment provinces). **Bbbl**, billions of barrels (oil); **Tcf**, trillions of cubic feet (gas).

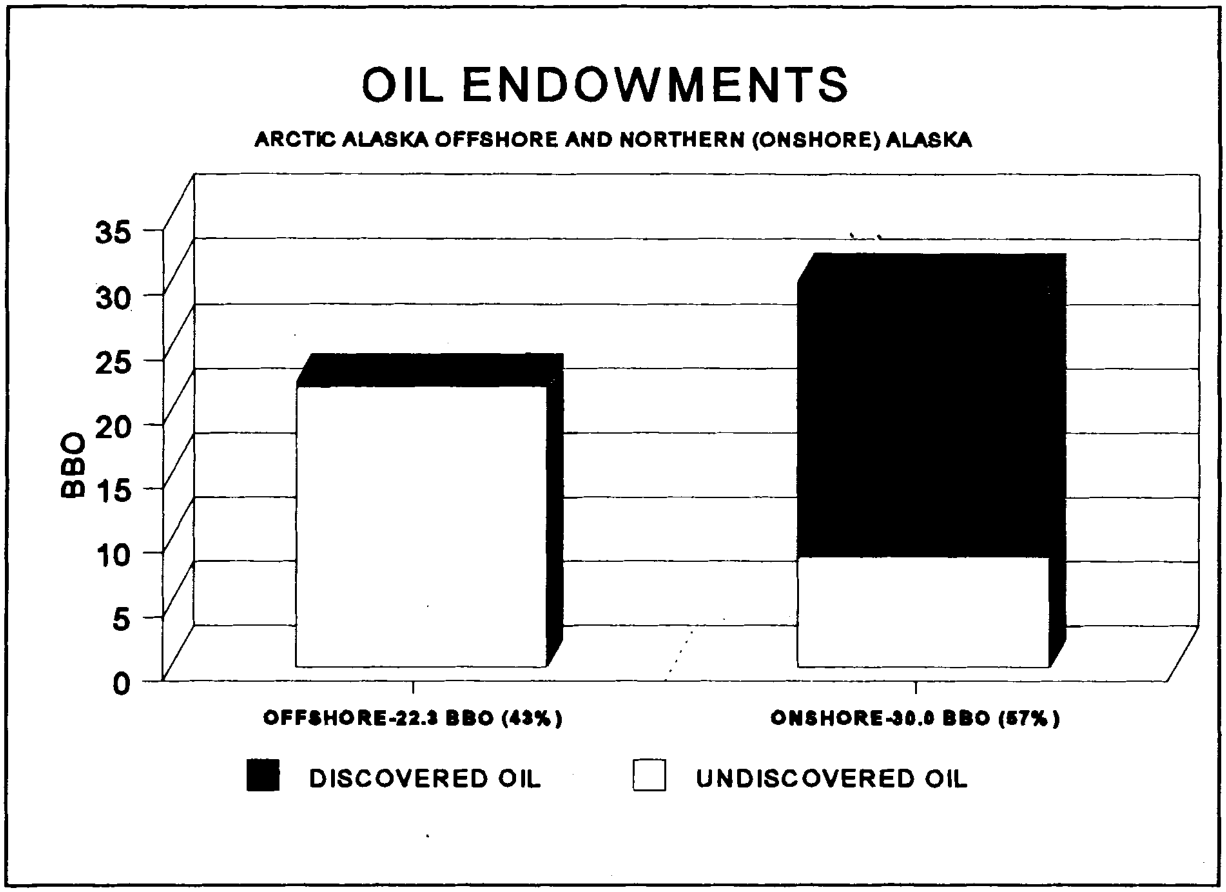

Figure 12.4: Bar charts comparing total (discovered and undiscovered) endowments of recoverable petroleum liquids for offshore (Chukchi and Beaufort shelf assessment provinces) and onshore (northern Alaska) Arctic subregions of Alaska. **Offshore areas offer 43 percent of the liquid petroleum endowment within 40 percent of the total area.** Discovered reserves offshore are 0.40 BBO; undiscovered oil resources are 21.86 BBO. Discovered reserves onshore (northern Alaska) include 16.4 BBO commercial reserves and 5 BBO speculative additional reserves identified by BP-Alaska (Nelson, 1996); undiscovered oil resources are 8.63 BBO (USGS, 1995).

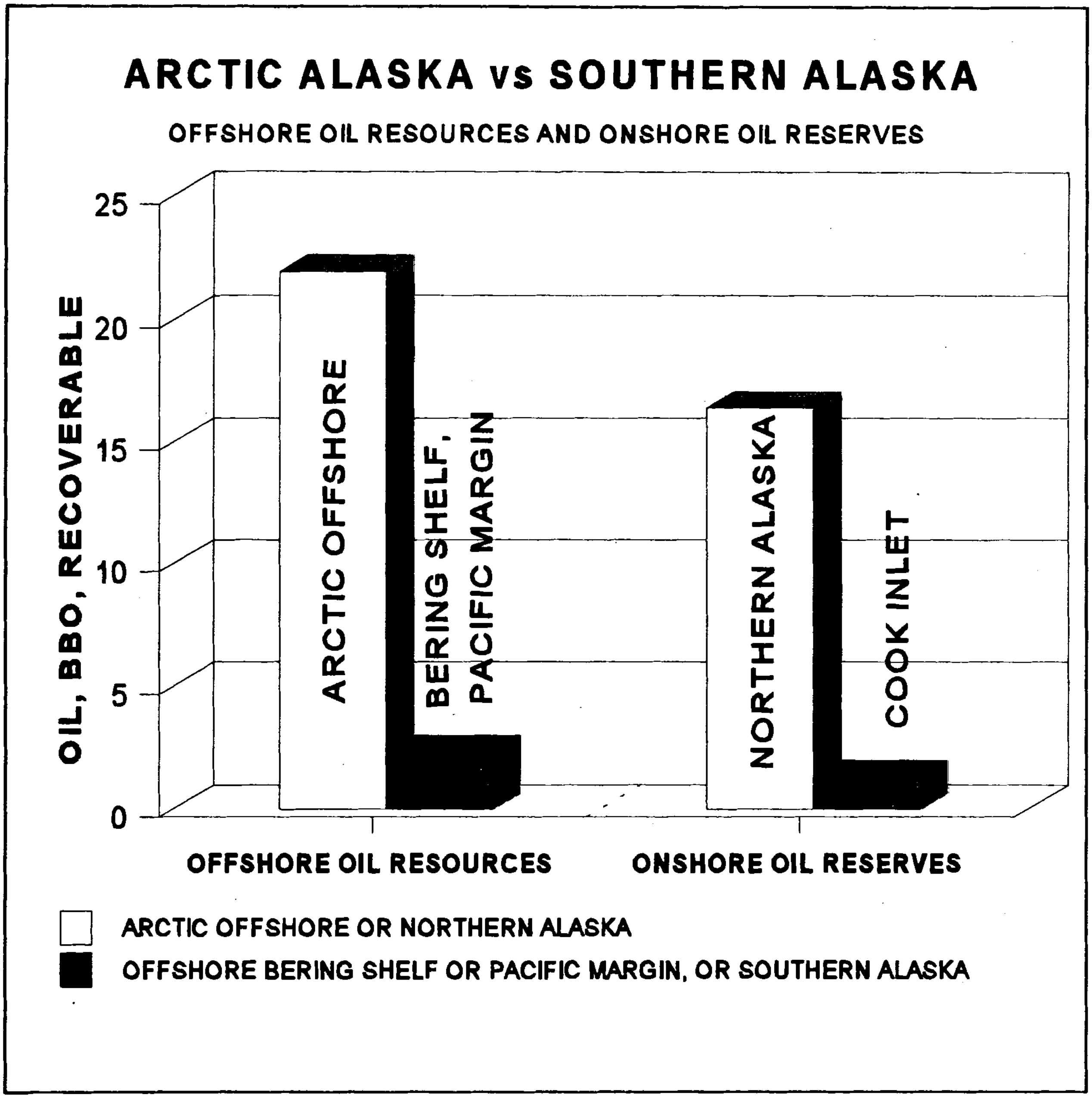

Figure 12.5: Bar charts comparing distribution of **offshore undiscovered oil resources** between Arctic offshore provinces (21.96 BBO) and Bering shelf/Pacific margin offshore provinces (2.35 BBO), and comparing distribution of **onshore commercial oil reserves** between northern Alaska (16.4 BBO) and southern Alaska (1.34 BBO; primarily Cook Inlet). In both cases, 92 percent of oil resources or reserves are associated with the Arctic regions of Alaska.

GEOLOGIC ASSESSMENT
1995 National Resource Assessment
Alaska Federal Offshore
U.S. Minerals Management Service

13. CHUKCHI SHELF ASSESSMENT PROVINCE

by

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INTRODUCTION

Chukchi shelf assessment province lies offshore northwestern Alaska in waters typically 50 m or less in depth, extending from the three-mile offshore limit of State of Alaska waters to Russian waters west of 169° west longitude, and north from Herald arch to the 100 m isobath. The 100 m isobath, near 73° north latitude, was chosen as a map reference for the north boundary because it roughly corresponds to the maximum northernmost retreat of the Arctic ice pack (illustrated in Grantz and others, 1982a, fig. 2), and therefore represents the northern practical limit for conventional hydrocarbon exploration and development technology.

The Chukchi shelf assessment province meets the Beaufort shelf assessment province along the geographic lines formerly (prior to 1996) adopted by the U.S. Minerals Management Service as the political boundaries between the Beaufort Sea and Chukchi Sea OCS Planning Areas[1] (71° north latitude, 162° west longitude). Several geologic plays overlap the assessment province boundaries along 71° north latitude and 162° west longitude, and are described here with correlative Chukchi shelf plays, but were independently assessed as part of the Beaufort shelf assessment province. The Chukchi shelf assessment province is outlined in figure 13.1.

LEASING AND EXPLORATION HISTORY

Four lease sales were held for different parts of Chukchi shelf in 1988 and 1991. Two lease sales (109, 126) were held in the U.S. Chukchi Sea Outer Continental Shelf (OCS) Planning Area. Two sales were also held in 1988 and 1991 in the adjacent Beaufort Sea OCS Planning Area (97, 124). The four sales issuing leases on Chukchi shelf together collected $512 million in total high bids on 483 tracts (approximately 2.7 million acres). All leases ever issued on Chukchi shelf (1988 to 1991) are shown in figure 13.2. None of these leases remain active at present.

Apparently extending the lessons of success won in Arctic Alaska, 93 percent of total high bids in the four sales were spent to lease Chukchi shelf prospects with targets correlative to reservoir formations housing the commercial oil fields in the Prudhoe Bay area. The remaining 7 percent of high bids in Chukchi shelf lease sales targeted five anticlines in a Cretaceous foldbelt in southern Chukchi Sea ($17 MM) and 6 fault structures involving Tertiary and Cretaceous

[1]*Beaufort Sea and Chukchi Sea Planning Areas now meet at 156° west longitude*

rocks in North Chukchi basin ($13MM). Some structures involving Devonian and older rocks in Northeast Chukchi basin were also leased.

Industry, primarily Shell Oil, invested heavily on just a few of the 42 prospects leased on Chukchi shelf. In fact, 85 percent of the $512 MM spent in all four sales went for just the five prospects that were eventually drilled (Burger, Klondike, Crackerjack, Popcorn, Diamond; fig. 13.2). Success in exploring Chukchi shelf was clearly viewed as highly dependent upon commercial success at these five large, favorably situated prospects. Although the five Chukchi shelf wells encountered favorable geology, none discovered commercial quantities of oil or gas.

Through subsequent years and successive rounds of relinquishments, industry leaseholdings gradually diminished, and of the 483 leases active on Chukchi shelf in 1992, none remain active today (December, 1996).

In the period 1989-1991, 5 exploratory wells were drilled on Chukchi shelf (fig. 13.2). Although some wells encountered promising geology and significant quantities of hydrocarbons, none found commercial pools of oil. Only very large pools would justify commercial development on Chukchi shelf. In fact, the Department of Energy (DOE) (Thomas and others, 1991, p. 3-66) estimated (using NES[2] price path, oil at $20.40 in 1989 dollars by 1995) that the minimum volume for an economic field in the Chukchi Sea would be 2.6 billion barrels of oil. The DOE estimate is corroborated by Dees (1991, fig. 7) of ARCO, who estimated that economic development of a single pool in Chukchi Sea might require 1 to 3 billion barrels of oil.

Industry investigations of the U.S. Chukchi shelf prompted by the 1988 and 1991 lease offerings resulted in the collection of 100,000 line-miles of high quality seismic reflection data. In addition, comprehensive gravimetric, magnetic, thermal, and geochemical surveys were also conducted on the U.S. Chukchi shelf. These data form the basis for the present study.

Previous investigations of the Chukchi and contiguous Arctic continental shelves were carried out primarily by Arthur Grantz and colleagues of the U.S. Geological Survey. These pioneer studies, including those of Grantz and others (1975; 1979; 1981; 1982a; 1982b; 1987, 1990), Grantz and Eittreim (1979), Grantz and May (1982, 1987), and Eittreim and Grantz (1979) established the framework from which all subsequent studies have been extended. Published studies based on industry data by Thurston and Theiss (1987), Craig and others (1985), and Hubbard and others (1987) have improved our understanding of the region.

STRATIGRAPHIC ELEMENTS OF CHUKCHI SHELF

The rocks that underlie Chukchi shelf may be simplified into four main groups for purposes of introduction to regional stratigraphy (fig. 13.4). In northern Alaska and most of U.S. Chukchi shelf, seismic and economic basement is represented by deformed and metamorphosed rocks of Late Devonian and older age. The highly-deformed, low-grade metamorphic rocks which form acoustic basement beneath Arctic Alaska are generally assigned to the ***Franklinian sequence*** (Lerand, 1973), shown as synonymous with acoustic basement in figure 13.4. The Franklinian rocks which underlie the Arctic platform were deformed by a regional event, widely recognized in many parts of Arctic North America, termed the Ellesmerian orogeny (Late Devonian). Northeastern Chukchi shelf is underlain by an anomalous area of relatively undeformed rocks apparently belonging to the Franklinian sequence. This enigmatic feature was termed the Northeast Chukchi "basin" by Craig and others (1985) and is so labeled on figure 13.3. However, Northeast Chukchi basin is fault-bounded and appears to be a tectonic fragment of

[2]*Oil price schedules (low, NES, and high) from National Energy Strategy Study, described in Thomas and others (1991, p. 3-20).*

the Franklinian basin of Arctic Canada, with which it was once continuous, but now is isolated because of rifting, continental breakup, and formation of the Canada oceanic basin (Sherwood, 1994).

Deposition of the ***Ellesmerian sequences*** began in Late Devonian or Early Mississippian time, and in Arctic Alaska, Ellesmerian strata rest unconformably upon deformed Franklinian rocks, identified as geologic unit "F" in figure 13.5. The east-trending basin in which Ellesmerian strata accumulated is termed the Arctic Alaska basin (located in fig. 13.3). Beneath Chukchi shelf, the Ellesmerian sequence fills a north-trending rift basin or aulacogen called Hanna trough[3] (located in fig. 13.3; Grantz and others, 1982a). Hanna trough began to subside in Late Devonian(?) or Early Mississippian time, with an early (rift) phase of fault-driven subsidence (Late Devonian to Permian time) corresponding to the ***Lower Ellesmerian sequence***. When faulting ceased, a second phase of subsidence related to cooling and thermal contraction (Permian to Late Jurassic time) governed deposition of the ***Upper Ellesmerian sequence***. These events in Hanna trough are illustrated in figures 13.5A and 13.5B. Hanna trough subsidence and the Ellesmerian cycle of sedimentation is capped by a regional unconformity we term the "Jurassic unconformity", or "JU", that marks the base of the overlying "Rift" sequence (fig. 13.4).

Rifting along the Beaufort continental margin extended into the northern Chukchi shelf in mid-Jurassic time and opened a new rift that ultimately became North Chukchi basin (fig. 13.5C). Tectonic disturbance of the crust near the active rift zone influenced patterns of sedimentation far to the south of the zone. Grabens and flexural downwarps near the rift were filled with thick sequences of clastic sediments, some probably of local derivation and possibly rich in detritus recycled from Ellesmerian rocks exposed on uplifts within the rift zone (fig. 13.5C). These strata represent a distinct tectonic process and have been variously distinguished as the ***Rift sequence*** (Craig and others, 1985), the Beaufortian sequence (Hubbard and others, 1987), or the Barrovian sequence (Carman and Hardwick, 1983). Because it is more general, we adopt the term "Rift sequence" for rocks deposited during the rifting in northern Chukchi shelf. The Rift sequence ranges in age from Late Jurassic to Early Cretaceous (Aptian to Albian) on Chukchi shelf and we extend the term to include rocks deposited at the same time to the south and beyond the influence of the rift zone (fig. 13.5C).

The Brookian-Chukotkan orogeny, ranging in possible age from Middle Jurassic to Early Cretaceous (ca. 175 to 115 Ma), ended the Jurassic to Cretaceous rift-controlled phase of sedimentation south of North Chukchi basin and completely reorganized the tectonic framework of northern Alaska and Chukchi shelf. Cretaceous and Tertiary rocks of the ***Brookian sequence***, consisting mostly of sediments shed from mountain belts created during the Brookian-Chukotkan orogeny, fill several (Colville, Hope, North Chukchi) basins beneath Chukchi shelf (figs. 13.3, 13.4). Continuing deformations folded the rocks in southern Colville basin and reactivated north-trending faults (established earlier during subsidence of Hanna trough) that complexly structured Brookian strata on Chukchi platform (illustrated in figs. 13.5E, 13.5F, and 13.9).

ELLESMERIAN ROCKS AND BASINS (LATE DEVONIAN[?] TO JURASSIC)

Arctic Alaska Basin and Hanna Trough

Ellesmerian rocks in northern Alaska were deposited on a south-facing continental shelf on a passive margin that was created by breakup of an earlier, larger landmass during Late Devonian time (Moore and others, 1992). This margin hosted the deposition of sediments derived from

[3] *alternatively termed the "Central Chukchi basin" by Thurston and Theiss (1987)*

exposed lands to the north until Early Cretaceous time, when the shelf was rifted away from the northern lands and then inundated by sediment derived from mountains elevated on the south by the Brookian-Chukotkan orogeny.

In northern Alaska during the early phase of Ellesmerian sedimentation, this south-facing margin was embayed by the north- and northwest-trending Meade and Umiat-Ikpikpuk basins, in which Ellesmerian rocks may quadruple in thickness, reaching aggregate thicknesses of 20,000 feet (Bird, 1988, fig. 16.21; Moore and others, 1992, figs. 12, 16).

During Triassic time, shoreline systems along the north edge of the Arctic Alaska basin controlled the deposition of thick (up to 600 ft) sandstones of the Sadlerochit Group - the petroleum reservoir at Prudhoe Bay field (AOGCC, 1993, p.89). Prudhoe Bay field, at 12.9 billion barrels, (Thomas and others, 1991, table 2-1) of recoverable oil, is the largest oil field known to exist in North America. This supergiant accumulation owes its spectacular size to the coincidence of a large trap with the thick sandstones deposited in fan delta and shoreline systems in Triassic time along the north edge of the Arctic Alaska basin.

Nearshore and fluvial environments in Ellesmerian rocks along the north edge of the Arctic Alaska basin generally grade into deep-water, shaly, marine rocks in southern parts of the basin. There, rocks rich in organic carbon, like the Shublik, Kingak, and Otuk Formations, were deposited. These rocks were later deeply buried and heated, ultimately generating the large volumes of oil and gas that migrated to Prudhoe Bay and nearby fields (Bird, 1994).

Because of stratigraphic thinning and subaerial exposure and erosion, Ellesmerian rocks are absent along parts of the Barrow Arch at the north edge of the Arctic Alaska basin (fig. 13.3, zero Ellesmerian line).

The Arctic Alaska basin passes west and offshore beneath Chukchi shelf, where it is transformed into the north-trending Hanna trough (fig. 13.3). Hanna trough subsided as a highly-faulted rift basin in Late Devonian(?) or Early Mississsippian time (Thurston and Theiss, 1987; Haimila and others, 1990; Herman and Zerwick, 1994), and locally accumulated up to 28,000 feet of Ellesmerian strata.

Structure at the top of acoustic basement, illustrated in plate 13.1, strongly reflects the northerly trends of faults that controlled the rift phase of subsidence in Hanna trough. Chukchi platform was fragmented into a series of arcuate, north-trending horsts and grabens that controlled early sedimentation patterns and the shapes of large stratigraphic traps where horsts are truncated by younger unconformities.

Hanna trough is bounded on the west by Chukchi platform (fig. 13.3), which was elevated during early phases of Ellesmerian sedimentation, as evidenced by stratigraphic wedging and internal angular unconformities along the east flank (Thurston and Theiss, 1987, p. 40). Basement rises to within 3,000 feet of the seafloor along the U.S.-Russian boundary on Chukchi platform (pl. 13.1). As along Barrow arch, Ellesmerian strata are completely absent from parts of Chukchi platform along the U.S.-Russian boundary (fig. 13.3, "zero Ellesmerian" line).

At its north end, the axis of Hanna trough is apparently offset or transformed west about 80 miles across a west-trending accomodation zone, north of which it passes north beneath North Chukchi basin (pl. 13.1; fig. 13.3). Major horsts and grabens on Chukchi platform clearly bend northeasterly and northwest-trending transverse faults become more prominent within 75 miles of the accomodation zone, probably formed in response to a right-lateral shear couple along the accomodation zone during rift opening of Hanna trough.

The accomodation zone is crossed by a younger arch that parallels the hinge line that defines the south margin of North Chukchi basin (fig. 13.3). This arch, analogous to Barrow arch, is of Jurassic to Cretaceous age and separates North Chukchi basin on the north from Colville basin on the south.

Beneath North Chukchi basin, the northern arm of Hanna trough now lies at burial depths too great to permit recognition in seismic data. The presence of a northern arm of Hanna trough beneath the thick North Chukchi basin fill is suggested by the identification of a westward-thickening wedge of Ellesmerian rocks on the west flank of North Chukchi high (Grantz and others, 1990, fig. 9; Lothamer, 1994, fig. 4). Embry (1990) in fact speculates that Hanna trough may have extended some hundreds of kilometers farther north to the rifted Beaufort margin and that it once formed a seaway linking the Sverdrup (Canada) and Arctic Alaska basins, severed since Cretaceous time by opening of the Canada oceanic basin.

Jurassic-Cretaceous (Brookian-Chukotkan) Deformation Belt

Rocks correlative to the Ellesmerian sequence were apparently deposited in varying thicknesses over most of Arctic Alaska, the Chukchi shelf, and Chukotka (Kos'ko and others, 1993, p. 61). However, in Alaska south of the north edge of the Brooks Range, and on U.S. Chukchi shelf south and west of Herald arch (fig. 13.3), Ellesmerian rocks have been strongly deformed and variably metamorphosed. Ellesmerian rocks in this deformation belt are now part of a tectonized basement that offers negligible potential for oil and gas.

Ellesmerian rocks in the Brookian-Chukotkan deformation belt are exposed in several areas. Metamorphosed Upper Triassic and older rocks partly age-equivalent to the Ellesmerian sequence of Arctic Alaska are described from Wrangel Island by Kos'ko and others (1993). Jurassic argillite at a vitrinite reflectance of 1.76 percent was sampled by a corehole on Herald arch south of Herald thrust in U.S. waters (Fugro-McClelland, 1985, located as "USGS-7" in figs. 13.19, 13.20, and 13.21). Highly deformed Mississippian through Jurassic rocks equivalent to the Ellesmerian sequence are also exposed on the Lisburne Peninsula north of Point Hope, Alaska (Martin, 1970; Moore and others, 1984). Rocks equivalent to the Ellesmerian sequence occur in several allochthonous thrust sheets in the Brooks Range of Alaska (Mayfield and others, 1988).

Kos'ko and others (1993, p.56, 63) date the deformation of Ellesmerian rocks on Wrangel Island as ranging between Middle Jurassic and Late Early Cretaceous. Youngest K-Ar dates at 115 Ma on Wrangel Island may reflect culmination of orogenesis and uplift. In the Lisburne Hills, where Herald arch extends onshore into Alaska (fig. 13.3), Martin (1970) recognized the onset of Brookian-Chukotkan deformation in Late Jurassic to Early Cretaceous time (160 to 100 Ma), followed by the culmination of deformation in Late Cretaceous to Tertiary time (ca. 65 Ma). In a review of the literature for the Brooks Range of Alaska, Miller and Hudson (1991, p. 788) concluded that an early phase of thrusting began perhaps as early as 180 Ma (Early Jurassic) and was largely completed by 131-119 Ma (age of Hauterivian-Barremian unconformity at base of Fortress Mountain Formation). The emplacement of thrust sheets was followed by renewed, but relatively modest, thrusting in Late Cretaceous to early Tertiary time in the Brooks Range.

Discovered Oil and Gas Endowments of Ellesmerian Rocks

The Ellesmerian petroleum generation, migration, and entrapment system of Arctic Alaska is responsible for most of the 77 billion energy-equivalent barrels of total, or in-place, hydrocarbons (mostly oil), and certainly all of the commercial oil deposits, presently known to occur in northern Alaska (Bird, 1994). Recoverable reserves in Ellesmerian reservoirs in northern Alaska total approximately 17.7 billion barrels of oil and 32 trillion cubic feet of gas. In addition, most of the 26 to 45 billion barrels of in-place oil lodged in shallow Brookian reservoirs in northern Alaska (Thomas and others, 1991) were generated by Ellesmerian source rocks (Bird, 1994).

Because of the spectacular success of the

Ellesmerian petroleum system in northern Alaska, the presence of thick sequences of Ellesmerian rocks beneath large areas of Chukchi shelf suggests that large deposits of oil and gas exist there as well.

RIFT SEQUENCE (JURASSIC TO EARLY CRETACEOUS)

Rift Sequence Tectonic Provinces

Rifting that ultimately led to sea floor spreading and formation of Canada basin apparently began along the Beaufort margin as early as 215 Ma or in the Late Triassic (Hubbard and others, 1987). This timing is estimated from the oldest deposits that are inferred to floor early-formed grabens associated with the rifting along the Beaufort margin. The rift extended northwest around North Chukchi high (following the "hinge line" of fig. 13.3) and into northern parts of Chukchi shelf assessment province, ultimately creating North Chukchi basin (Grantz and others, 1979, fig. 4). The time of earliest subsidence of North Chukchi basin is not well constrained owing to very deep burial (beneath seismic records) of the oldest stratigraphic sequences beneath the basin, and this subsidence may have occurred after a period of uplift associated with the onset of rifting. The Jurassic unconformity, marking extensive erosion mostly on northern Chukchi platform, is of Late Jurassic age (overlain by Oxfordian to Kimmeridgian rocks; Micropaleo Consultants, 1989a; 1989b; 1990a; 1990b) and may represent a rift-shoulder unconformity of the type identified by Falvey (1974, fig. 1) or modeled by White and McKenzie (1988, fig. 3). If so, the age of this unconformity suggests a minimum age of pre-Oxfordian (pre-Late Jurassic, or pre-160 Ma) for the onset of rifting in the area that later became North Chukchi basin.

The Rift sequence beneath Chukchi shelf encompasses those stratigraphic units between the submarine scour at the base of the Torok Formation that we term the Brookian unconformity or "BU" and the unconformity at the base of the upper Kingak Formation that we term the Jurassic unconformity or "JU" (fig. 13.4; pl. 13.4). As such, the Rift sequence in Chukchi shelf includes rocks equivalent to the following units described from Arctic Alaska by Carman and Harwick (1983, fig. 6). Beginning at the top, these include the Aptian-Albian "Highly Radioactive Zone", or "HRZ", and Pebble Shale (or Kalubik Formation), Neocomian sandstones and shales equivalent to the Kuparuk Formation, and Upper Jurassic (Chukchi only) to Neocomian shales equivalent to upper parts of the Kingak Formation (along Beaufort margin, the Miluveach Formation). This differs from the "Beaufortian" sequence of Hubbard and others (1987), which extends from the base of the Kingak Formation to the Lower Cretaceous unconformity, or "LCU", as shown in figure 12.2.

The rift that created North Chukchi basin created a 110-mile wide zone of abrupt isopach variation in the Rift sequence near the present south margin of North Chukchi basin. Abrupt variation in thickness is observed in all units included within the Rift sequence, and the sequence as a whole ranges from 1,000 to 10,000 feet in thickness. Some of the variation in Rift sequence thickness among Chukchi shelf wells in the zone is illustrated in the stratigraphic correlation panel of plate 13.4 (compare Popcorn, Crackerjack, and Burger). The pattern of isopach variation is hypothesized to reflect local grabens or flexural depressions (isopach thicks) and intervening uplifts (isopach thins) formed along the rift shoulder. The zone of abrupt isopach variation is set aside as the "active margin" area in figure 13.6. During early stages of rifting, the "active margin" presumably represented the tectonically-active flank of a rift system active beneath North Chukchi basin to the north.

The zone of abrupt isopach variation grades southward into what was apparently a tectonically stable area now characterized by regionally smooth isopach variation, where the Rift sequence varies only from 1,000 to 2,000 feet in thickness. We interpret this area as a "stable shelf" that faced a deep-water area or "basin plain" in southeastern Hanna trough (fig. 13.6). A shelf edge (southernmost advance) mapped in rocks correlative to the Rift sequence in western Arctic Alaska by Bird (1988, fig. 16.15) can be extended west and offshore to the east flank of Chukchi platform, where it turns south and follows the platform edge as the "shelf edge" in figure 13.6. Along Chukchi platform, the shelf edge appears to be flanked on the east by a lowstand wedge or prograding complex. The shelf edge and lowstand wedge are approximately located in figure 13.6. In the "basin plain", southeast of the shelf edge in deep waters along axial parts of Hanna trough, shales and turbiditic sandstones were presumably deposited.

Rocks representing the basinal setting adjacent to the lowstand wedge are possibly exposed onshore as a 300-foot sequence of quartzitic turbidite sandstones of Early Cretaceous (Neocomian) age, in the Tingmerkpuk Mountain area (located in fig. 13.6) as described by Crowder and others (1995) and Mull and others (1995). These authors, and Mowatt and others (1995), note that the high lithic quartz contents of the Tingmerkpuk Mountain turbidites are unlike any clastic rocks known to have sources in the Brooks Range and probably point instead to a provenance to the north, on the Arctic platform (fig. 13.6).

We speculate that an alternative source for the quartz-rich detritus in the Tingmerkpuk sandstones may have lain to the west on Chukchi platform. The western shelf edge is physically much closer to the Tingmerkpuk exposures and large parts of Chukchi platform were at least episodically exposed in Oxfordian-Kimmeridgian (Late Jurassic) and Hauterivian-Barremian (Neocomian) times, as marked by the Jurassic and Lower Cretaceous unconformities (pl. 13.4; Micropaleo Consultants, 1989b). If so, much thicker sequences of quartz-rich turbiditic sandstones may occur in the lowstand wedge on the east flank of Chukchi platform. Quartz-rich sandstones are generally favored as reservoir objectives because they are more resistant to porosity loss. In addition, the lowstand wedge directly overlies thermally mature Triassic oil source rocks and would have ready access to any petroleum migrating from those sources.

Rift sequence structure is illustrated in plate 13.2 with a structure map for the Lower Cretaceous unconformity, or "LCU", which lies within the Rift sequence (stratigraphic position shown in fig. 13.4). The structure is dominated by a large depression on the south, where Rift sequence rocks have been buried beneath up to 24,000 feet of Brookian rocks in Colville basin. A north-trending sag also reflects some reactivation of Hanna trough, probably driven by the loads imposed on the south by Colville basin. Complex structuring on the north partly reflects deformations in those areas close to the Jurassic to Early Cretaceous rift zone now buried beneath North Chukchi basin.

Discovered Oil and Gas Endowments of Rift Sequence Rocks

Oil and gas have been discovered within Rift sequence reservoirs at ten sites[4] in Arctic Alaska. Commercial oil production amounting to about 20 percent of TAPS throughput is occurring at four Rift sequence pools in the Prudhoe Bay area. These producing fields include Kuparuk River, Milne Point, Point McIntyre, and Niakuk fields. Kuparuk River field, with original recoverable reserves of 2.5 BBO, is the second largest producing field in the United States. The estimated ultimate reserves for the four producing Rift sequence fields in the Prudhoe Bay area are about 3.1 BBO (Thomas and others, 1991; Petzet, 1995; for Milne Point, 220 MMBO, ADN, 1995). The newly announced Alpine field in Colville Delta may hold additional reserves of 300 MMBO (Alaska Report, 1996), raising the Rift sequence commercial endowment to 3.4 BBO.

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[4]*South Barrow, East Barrow, Barrow, Kuparuk River, Milne Point, Point Thomson, Walakpa, Niakuk, Colville Delta (or Alpine) and Point McIntyre fields.*

Walakpa and Barrow-area fields, approximately 200 miles west of the Trans-Alaska pipeline system, contain several tens of billions of cubic feet of gas and have been developed for use by the village of Barrow. A 5 TCF gas field (with 300 MMBO oil and condensate) at Point Thomson remains undeveloped.

BROOKIAN (CRETACEOUS AND TERTIARY) BASINS ON CHUKCHI SHELF

North Chukchi Basin

North Chukchi basin trends northwesterly for nearly 1,000 km along the northern edge of the Chukchi and Eastern Siberian shelves, with only a small part extending into Chukchi shelf assessment province (fig. 13.3). North Chukchi basin formed in response to Late Jurassic to Early Cretaceous rifting along the northern edge of the Arctic Alaska margin during opening of the Canada basin and partly represents a western continuation of the Nuwuk basin on the Beaufort shelf (fig 13.6; Grantz and others, 1979). North Chukchi basin was abandoned by the Canada Basin-Beaufort rift system by Late Cretaceous time, when the basin was filled to baseline with over 20,000 feet of Cretaceous, and perhaps older, strata (fig. 13.5D). Renewed subsidence in Paleocene time, related to transtensional faulting originating from a compressional belt to the south, accommodated an additional 26,000 feet of sediments of Tertiary age (fig. 13.5E; Lothamer, 1994; Sherwood, 1992). North Chukchi basin contains over 20,000 feet of Cretaceous to Quaternary strata in its western parts (Kos'ko, 1984), and at least 45,000 feet of Cretaceous to Quaternary strata in its eastern part (Lothamer, 1994).

North Chukchi basin extends west, into the Russian Chukchi and East Siberian shelves, where it is called the Vil'kitsky basin by Russian authors (Warren and others, 1995). Generally, the basin has an asymmetric profile, with a gentle southern slope formed by a structural flexure zone correlative to the Beaufort margin "hinge line" of Grantz and May (1982) and a steep, broken northern flank formed by fault blocks of the paleoshelf edge and the North Chukchi rise (Pol'kin, 1984). North Chukchi basin terminates on the east at North Chukchi high (Thurston and Theiss, 1987; Johnson, 1992). The western limit of the basin is only poorly defined as the De Long rise (Pol'kin, 1984).

The North Chukchi basin fill is divided into two groups reflecting the two main subsidence events. First, the deeply buried Rift sequence and Lower Brookian sequence, deposited, respectively, in response to Jurassic to Early Cretaceous rifting followed by Early to Late Cretaceous age post-rift thermal sagging, the latter begun after severing mechanical continuity with the "Beaufortian" rift system along the Beaufort margin (fig. 13.6). Second, the Upper Brookian sequence of Late Cretaceous to Paleocene and younger ages, reflecting Paleocene east-west transtensional faulting, followed by thermal sagging when faulting ceased in late Paleocene or early Eocene time.

The two groups of rocks representing the two cycles of subsidence are separated by a Late Cretaceous to Paleocene unconformity that we term the ***mid-Brookian unconformity***, or "MBU" (fig. 13.4; pl. 13.4). The mid-Brookian unconformity is interpreted to mark the culmination of filling of North Chukchi basin to baseline at the end of the Jurassic to Late Cretaceous cycle of subsidence (fig. 13.5C, 13.5D). The mid-Brookian unconformity is now highly fragmented by transtensional faults related to the second (Paleocene) cycle of subsidence. The Upper Brookian sequence may be further subdivided into lower and upper parts by a prominent, regional unconformity that separates Late Eocene and Late Oligocene rocks at 1,041 feet in Popcorn well (pl. 13.4) and that is widely observed in seismic data in North Chukchi basin (horizon "UB", Lothamer, 1994).

Shale diapirs with their source in Early Cretaceous deposits have been reported in the

North Chukchi basin (Grantz and others, 1975). Along the south edge of the North Chukchi basin, in a fault-bounded trough west of Popcorn well, the static load imposed by 14,000 to 20,000 ft of Tertiary sediments prompted the rise of evaporite diapirs from underlying Ellesmerian rocks (Thurston and Theiss, 1987; Thurston and Lothamer, 1991).

The structure of North Chukchi basin is dominated by the north-trending horsts and grabens formed during the Paleocene transtensional event. Plate 13.3 is a structure map for the base of Tertiary, or "mid-Brookian unconformity", or "MBU" (stratigraphic position shown in fig. 13.4) that forms a prominent reflector throughout North Chukchi basin and the shelf terrace to the south. The north-trending structures in North Chukchi basin are largely extensions of the north-trending faults that dominate the structure of Chukchi platform on the south. These faults were termed wrench faults by Thurston and Theiss (1987), but isopach maps published by Lothamer (1994) show no evidence for significant lateral offsets. Most of these faults are actually reactivated normal faults of great length that originated during Paleozoic rifting in Hanna trough. Their primary displacements during reactivation were fundamentally dip-slip in nature, but some lateral strains are suggested by fault style, orientations of subsidiary faults (the "flower" structures described by Thurston and Theiss, 1987), and manner of interactions with a detached foldbelt on the south (fig. 13.11; Sherwood, 1992). Where these faults cross the hinge line and enter North Chukchi basin, they seem to have acted as "scissors" faults, with null points at the hinge line, that accommodated differential down-to-the-north rotations between elongate, north-trending fault blocks in the basin.

The Paleocene foundering of North Chukchi basin appears to have been geologically catastrophic, with subsidence occurring so quickly that the seafloor was actually shaped by the rotated fault blocks and bounding scarps. This is evidenced in seismic profiles by patterns of sedimentary drape as sediments filled the north-trending seafloor valleys or grabens with little erosional rounding of fault scarps (Lothamer, 1994, fig. 4). Most of this bathymetric complexity was drowned by sediments by late Eocene time, when the basin entered a sag phase of thermal subsidence (Lothamer, 1994, p. 252).

The Paleocene transtensional event not only created the most prominent prospects within North Chukchi basin, but also set up one of the most important sedimentary plays. Drilling south of North Chukchi basin has shown that the fault-bounded valleys created by Paleocene transtensional faulting on Chukchi platform are floored by thick sequences of coal-bearing nonmarine sandstones. These sandstones record fluvial systems that fed sediment north into North Chukchi basin, where, presumably, the clastic material was carried farther north by turbidity currents into the deep seafloor valleys. Much of the onlapping fill above the mid-Brookian unconformity in the north-trending grabens in North Chukchi basin probably consists of sandstones deposited in submarine fan complexes that prograded northward into the basin from the hinge line. These submarine fan complexes are probably quite sand-rich near the hinge line, becoming more shaly in distal settings to the north.

Coarse-grained, quartz-rich detritus recycled from unmetamorphosed Ellesmerian rocks exposed to erosion on the northern edge of Chukchi platform, Barrow arch, and North Chukchi high may significantly increase the reservoir potential in proximal parts of the basin, particularly within the submarine fan complexes near the base of Tertiary rocks. Prospectiveness of reservoir rocks in distal parts of North Chukchi basin may be reduced by the probability that they are dominated by clay, silt, and fine-grained sand. Sag-phase strata of late Eocene or younger age are dominated in seismic records by highly continuous, parallel reflections consistent with a mostly pelagic sequence. These rocks probably offer modest reservoir potential at best.

Six fault structures (horsts) in North Chukchi basin (U.S.) were leased in 1988 for aggregate high bonus bids of $13.2 million, but none were tested by exploratory wells. Leased blocks on these structures are located in fig.13.2 (north of 72° 10', west of 166° 30'). Most mapped prospects are horsts or fault traps related to the north-trending Paleocene transtensional fault system illustrated in plate 13.3 and by Lothamer (1994).

Colville Basin

Colville basin is a foredeep or foreland basin that developed in response to the load imposed on the lithosphere by stacking of thrust sheets in the Brooks Range during the Brookian-Chukotkan orogeny (fig. 13.5D; Nunn and others, 1987; Coakley and Watts, 1991; Bird and Molenaar, 1992). The Colville basin is superposed on the older Arctic Alaska basin (figs. 13.3, 13.5D). Passive margin sedimentation of the Ellesmerian and Rift sequences ceased in Jurassic-Early Cretaceous time when the margin collided with an oceanic island arc arriving from the south (Moore and others, 1992). The collision caused the compression and stacking of thrust sheets that elevated the Brooks Range and drove subsidence of Colville basin from Middle Jurassic to late Tertiary time (only in east). The structure of the floor of Colville basin in northwest Alaska and Chukchi shelf is illustrated by the "LCU" structure map in plate 13.2.

Older parts of the Colville fill (Jurassic and earliest Cretaceous) are turbidites and basinal deposits that record earliest phases of basin subsidence concommitant with Brookian-Chukotkan thrusting. As illustrated in figure 13.5C, these tectonic deposits have corresponding deposits on the south-facing shelf that persisted to the north on the Arctic platform until Early Cretaceous time, when it was finally completely inundated by Brooks Range debris (Bird and Molenaar, 1992, fig. 4). Most of the fill in the western part of Colville basin is Albian to Cenomanian (ca. 115-90 Ma) in age (Moore and others, 1992). These rocks reach thicknesses of 24,000 feet offshore of Point Lay (pl. 13.2). The approximate western limit of Colville basin can be seen in plate 13.2 at about the 12,000 ft contour where the Colville fill abruptly thickens at a hinge east of Chukchi platform. Rocks equivalent to Colville basin fill, and, ranging from 3,000 to 12,000 feet in thickness, extend across the shelf terrace that separates Colville and North Chukchi basins. Rocks equivalent to the Colville basin fill exceed 20,000 feet in thickness in North Chukchi basin.

The filling of Colville basin progressed along the basin axis from west to east, reflecting dominance of a mountainous sediment source in Chukchi Sea west of Chukchi platform, probably uplifts along the Brookian-Chukotkan orogenic belt now buried beneath the Cretaceous-Tertiary Hope Basin (fig. 13.2). This western sediment source produced a distinct wedge named the "Corwin delta" because of the uncommonly thick and coarse-grained conglomerates and sandstones exposed along Corwin bluffs on the north side of the Lisburne Peninsula (north of Point Hope), Alaska (Ahlbrandt and others, 1979, p.17). In most areas, the Colville basin fill consists of a lower, downlapping, clinoformal sequence of prodelta shales and turbidite sandstones (Torok Formation) capped by deltaic sandstones, coals and shales (Nanushuk Group).

Following the filling of Colville Basin, a second phase of Brooks Range thrusting folded the rocks in western Colville basin (Bird and Molenaar, 1992, p. 378). The age of this folding is not well constrained. The youngest folded rocks offshore are 92 Ma (Phillips and others, 1988) and the overlap sequence is Pleistocene in age. However, transtensional faults that were active during folding extend north and control margins of shallow Paleocene basins on the shelf terrace and Chukchi platform north of the foldbelt (illustrated in pl. 13.3). This suggests a Late Cretaceous to early Tertiary age for the folding, consistent with the previous age determinations of Martin (1970) and Grantz and others (1975, p. 681).

The basic elements of the deformation belt in southern Colville basin are schematically illustrated in figures 13.7 and 13.8. The southernmost element is Herald thrust, which emplaced a Jurassic and older basement complex (exposed at seafloor along Herald arch) upon highly deformed Brookian rocks to the north. Herald thrust dips 30 degrees to the south near Russian waters, but shallows to 19 degrees where it passes into the exposed "Lisburne" thrust complexes on Cape Lisburne (Sherwood, 1992). On Cape Lisburne, the thrust system places highly deformed Lisburne and Endicott rocks on Brookian rocks to the east (Martin, 1970). Herald thrust zone contains Brookian rocks so highly deformed that only fragments of folds, mostly syncline axes, remain visible in seismic reflection data. Individual folds, especially anticlines, cannot be mapped in seismic data in Herald thrust zone, although Herald fault and the decollement that floors the thrust zone (fig. 13.8) are clearly observed in seismic data.

Seismic mapping has identified many anticlinal prospects in the fold and thrust belt north of Herald thrust zone (fig. 13.9), some of which may be correlated with folds exposed and mapped onshore to the east by Chapman and Sable (1960). The detached foldbelt ("Foldbelt" in figs. 13.7, 13.9) in Colville basin on U.S. Chukchi shelf narrows to the west and terminates near the U.S.-Russia maritime boundary along 169° west longitude. West of this termination, all of the compressional deformation is apparently accommodated by the system of thrust faults and steep folds in the Herald thrust zone, which widens to the west (fig. 13.9). Sherwood (1992) attributed the westward loss of the detached foldbelt to the westward termination of an overpressure cell in Cretaceous rocks. The overpressure cell, recognized in wells in western Alaska and Chukchi shelf, promoted detachment folding throughout western Colville basin. West of 168° west longitude, the Colville basin fill is less than 6,000 feet thick, and projections of well data suggest that the overpressure cell is absent. The projected termination of the overpressure cell coincides with the termination of the detached foldbelt.

Dense swarms of transtensional faults extend north-northeast into Chukchi platform from the northern edge of the foldbelt (fig. 13.9). These faults also pass at depth beneath the foldbelt, but are isolated from it by the basal decollement, and rise into shallow rocks only in areas north of the foldbelt. Major swarms of these transtensional faults intersect the foldbelt at points of abrupt contraction in foldbelt width and apparently accommodated differential contractive movements between foldbelt segments (Sherwood, 1992).

Discovered Oil and Gas Endowments of Brookian Rocks

Oil and gas have been discovered in Cretaceous and Tertiary rocks at 62 sites across Arctic Alaska and the Mackenzie delta of Canada, with minimum aggregate known reserves (no estimates are available for many pools) of 2.7 billion barrels of oil and 12.4 trillion cubic feet of gas (*Canada* [Dixon and others, 1994, table 1], *Alaska* [Simpson, Umiat, West Sak, and Schrader Bluff pools; respectively: Thomas and others, 1991, table 2-5; ADN, 1996a; ADN, 1996b]). In Arctic Alaska, most of the known pools of oil and gas in Cretaceous or Tertiary rocks appear to have been derived from the underlying Ellesmerian source rocks (Bird, 1994). On the other hand, in the Mackenzie delta area of Canada, most of the oil and gas appears to have actually arisen from Cretaceous or Tertiary source rocks (Brooks, 1986). The Mackenzie delta area is gas-dominated overall but also clearly offers substantial potential for large oil accumulations like the 500 million barrel Amauligak field (Dixon and others, 1994, fig. 47).

Oil and gas have been discovered at seven anticlinal structures in the Colville basin in Arctic Alaska. Umiat oil field, 250 miles east of the Chukchi coast and the largest discovery, is estimated to contain 70 million barrels of oil. The largest gas field in the foldbelt, Gubik field, is adjacent to Umiat field and is estimated to contain 0.6 trillion cubic feet of gas (Thomas and others, 1991, table 2-5). Surface oil seeps are known in folded rocks in western parts of the Colville basin (Chapman and Sable, 1960). The Union Oil Tungak Creek No. 1 well, near Point Lay, tested gas from a number of sandstones, noted abundant oil shows, and for purposes of this study, is treated as a gas discovery. This well tested an anticlinal trap (fig. 13.9) and is the westernmost exploration well in the foldbelt. Foldbelt oil and gas fields are located in figure 13.3.

Although five foldbelt anticlines were leased (fig. 13.2, south of 70.5° N. Lat.) for total high bids of $17.1 million in 1988 on Chukchi shelf, none were tested by exploratory wells. Anticlinal folds in western parts of Colville basin are quite large, some traceable for 110 mi along their axes and with mapped closures for single culminations ranging up to 135,300 acres.

RESULTS OF EXPLORATORY DRILLING

Regional Stratigraphy and Play Sequences

Figure 13.4 shows the play stratigraphy of Chukchi shelf and the extent of stratigraphic sampling obtained by the five Chukchi shelf wells drilled in the period 1989-1991. The heavy vertical bars in the "LITH" column indicate the sampled intervals. A regional stratigraphic correlation section that shows the detailed stratigraphy for all Chukchi shelf wells is presented in plate 13.4.

We recognize six major groups of rocks offshore, including basement. All, including basement, contain oil or gas deposits somewhere in Arctic Alaska or the Beaufort Sea, as shown in the column for hydrocarbon discoveries on the right in figure 13.4.

The Upper Brookian sequence is of Tertiary age and overlies an Upper Cretaceous to Paleocene "mid-Brookian" unconformity (mBU) marking regional uplift of the Chukchi shelf. True Colville-equivalent ***Upper Cretaceous rocks*** are absent by unconformable truncation at all Chukchi drill sites, and may be present ***only in North Chukchi basin***. The maximum penetrated thickness of the Upper Brookian sequence is about 5,000 ft at Popcorn well (pl. 13.4), but the sequence reaches thicknesses up to 26,000 ft in North Chukchi basin (Lothamer, 1994).

The Lower Brookian sequence is represented offshore by a deltaic complex consisting of the prodelta Torok Formation and the marginal marine to delta plain Nanushuk Group, which reach a collective thickness of 24,000 feet offshore in Colville basin. At Burger and Diamond wells, and across most of southern Chukchi shelf, Nanushuk Group rocks subcrop at the seafloor. At Popcorn, Crackerjack, and Klondike wells, Nanushuk rocks are unconformably overlain by Tertiary rocks (pl. 13.4). The base of the Lower Brookian sequence is located at a submarine scour we call the Brookian unconformity ("BU" in fig. 13.4), which overlies the Pebble Shale at all drill sites. The HRZ or "Highly Radioactive Zone" of Carman and Hardwick (1983, fig. 6), widely present in northern Alaska, is present at the top of the Pebble Shale only in Diamond well (pl. 13.4).

All wells sampled some part of the Rift sequence, extending from the Brookian unconformity down to the Jurassic unconformity ("JU" in fig. 13.4). The Jurassic unconformity is apparently Late Jurassic (Oxfordian to Kimmeridgian) in age at Klondike, Crackerjack, Burger, and Popcorn[5] wells. The JU truncates Ellesmerian strata across the western parts of Chukchi shelf assessment province and forms the regional seal for many structural and stratigraphic traps.

The Upper Ellesmerian sequence extends downward from the Jurassic unconformity (JU) to the Permian unconformity (PU) at the base of the Echooka Formation. The upper- and lower-most parts of the Upper Ellesmerian sequence were

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[5]some of the Jurassic fossil material above the Jurassic unconformity in Popcorn well was thought by Micropaleo Consultants (1989b) to be reworked and incorporated into Lower Cretaceous rocks; our correlations indicate that these strata are probably of Jurassic age.

sampled by the Chukchi shelf wells. However, the lower part of the Kingak Formation and the Sag River Formation, although both are surely present on Chukchi shelf, were absent at all well sites except Burger well, which reached total depth after penetrating 567 feet of Lower Jurassic shales beneath the Jurassic unconformity. Four of the five Chukchi shelf wells targeted and sampled rocks roughly equivalent to parts of the Sadlerochit Group, which forms the spectacular petroleum reservoir at Prudhoe Bay field.

Of the Lower Ellesmerian sequence, the wells sampled Mississippian to Permian carbonates and shales of the Lisburne Group. The wells encountered an expanded Permian sequence of carbonates and shales at the top of the Lisburne Group that may be age-correlative and lithologically similar to the Joe Creek member of the Echooka Formation as described by Detterman and others (1975). However, beneath Chukchi shelf, this Permian sequence appears to be a transitional unit at the top of the Lisburne Group (pl. 13.4). Popcorn well sampled a complete section of Pennsylvanian carbonates equivalent to the Wahoo Formation (upper part of Lisburne Group; Tupik Formation of Sable and Dutro, 1961, p. 587) and a partial section of Mississippian carbonates equivalent to the Alapah Formation (lower part of Lisburne Group; Utukok Formation of Sable and Dutro, 1961). No wells on Chukchi shelf were drilled deep enough to sample the Endicott Group or acoustic basement.

Exploration Drilling Targets and Results

Klondike well (OCS Y 1482 No. 1): Klondike well was drilled to test Sadlerochit-equivalent rocks truncated beneath the Jurassic unconformity in a large anticline on the east flank of Chukchi platform. The test failed because Sadlerochit-equivalent rocks are in a shale facies and no reservoir is present. Oil was swabbed into the wellbore from rocks equivalent to the Fire Creek or Shublik Formations. A Rift sequence (Kuparuk) sandstone at 9,000 feet appears (logs and shows) to contain oil pay and oil shows were associated with turbiditic Brookian sandstones near the base of the Torok Formation. Minor oil shows were noted in several sandstones below 2,800 feet (pl. 13.4).

Burger well (OCS Y 1413 No. 1): Burger well was drilled to test Rift sequence rocks equivalent to the Kuparuk Formation in a large dome on the east flank of Hanna trough. This feature was originally identified as the "Wainwright dome" by Thurston and Theiss (1987, fig. 22, pl. 4). Burger well discovered and sampled a pool of gas, possibly with multi-TCF reserves, within a Kuparuk-equivalent Rift sequence sandstone 110 feet in thickness (Craig and others, 1993). A deltaic Brookian sandstone 36 feet in thickness within the Nanushuk Group also appears (logs, shows) to contain gas pay (pl. 13.4). Burger well was abandoned at 8,202 feet after encountering lost circulation in a breccia containing tar 800 feet or more above the top of the Shublik Formation as projected from seismic mapping (fig. 13.22).

Popcorn well (OCS Y 1275 No. 1): Popcorn well targeted Sadlerochit-equivalent and older rocks on a horst along the arch that separates North Chukchi and Colville basins (fig. 13.3). The test failed because no reservoir was present. Sadlerochit-equivalent rocks are truncated at the Jurassic unconformity that seals the prospect and Permian carbonates and shales of the Lisburne Group were instead found directly beneath the unconformity. Gas and condensate were recovered from a (Rift sequence) sandstone 20 feet thick that lies directly upon the Jurassic unconformity. Oil shows were noted in turbiditic sandstones of the Torok Formation and within Permian and Pennsylvanian carbonates of the Lisburne Group (pl. 13.4).

Crackerjack well (OCS Y 1320 No. 1): Crackerjack well targeted Sadlerochit-equivalent rocks in a stratigraphic wedge beneath the Jurassic unconformity on the flank (1,700 feet below the crest!) of the tilted fault block that forms Crackerjack structure. The test was unsuccessful because no reservoir is present. Sadlerochit-equivalent rocks are mostly truncated at the Jurassic unconformity. Spiculitic siltstones equivalent to the Permian Echooka Formation (Micropaleo Consultants, Inc., 1990a) appear (logs) to contain gas pay. In addition, turbiditic sandstones near the base of the Early Cretaceous Torok Formation appear (logs) to contain oil pay. Minor oil shows were also noted in Nanushuk Group sandstones (pl. 13.4). No sampling for formation fluids was conducted on the apparent pay zones in either the Echooka Formation or the Torok Formation in Crackerjack well.

Diamond well (OCS Y 0996 No. 1): Diamond well targeted Sadlerochit-equivalent rocks in a stratigraphic wedge trap truncated and sealed beneath the Lower Cretaceous unconformity (LCU) on the east flank of Hanna trough. Although reservoir rocks of the Sadlerochit Group (mostly Permian Echooka Formation) were present in abundance, the prospect failed because insufficient petroleum migrated to the trap. Trace oil shows were logged in sandstones of the Torok Formation, Ivishak Formation, Echooka Formation, and carbonates of the Lisburne Group.

Key Geological Findings of Chukchi Shelf Exploratory Drilling

The major geological findings of the 1989-91 Chukchi drilling program are summarized here.

1. **Probable failure of Sadlerochit play west of Hanna trough.** One of the major plays in Chukchi shelf in earlier years was based on the concept that thick sandstones equivalent to the Sadlerochit Group were deposited in source-proximal settings along the west margin of Hanna trough, roughly along the zero edge for the Ellesmerian sequence shown in fig. 13.3. This concept draws upon analogy to the north margin of Arctic Alaska basin in the Prudhoe Bay area, where Sadlerochit Group sandstones (reservoir for Prudhoe Bay field) reach gross thicknesses in excess of 600 feet (Jones and Speers, 1976, p. 33) in a fan-delta complex that fringed a more northern landmass. However, drilling results in Chukchi shelf suggest that a western proximal sandstone facies, if ever developed, lay west of the well sites and has probably been lost to subsequent erosion events on Chukchi platform.

   Klondike well, within 33 miles of the western truncation of the Sadlerochit Group, encountered a complete (age-equivalent) Sadlerochit sequence, yet entirely in a shale facies. A sequence of sandy siltstones up to 525 feet thick occurs with shales correlative to the Kavik Formation and may represent a distal (eastern) facies of a sand body deposited farther west, but now lost to erosion at the Jurassic unconformity.

   Only the very base of the Sadlerochit Group was preserved at Crackerjack well, which is located only 6 miles east of the regional truncation of the Sadlerochit Group at the Jurassic unconformity. Spiculitic siltstones of Permian age, possibly equivalent to the Echooka Formation at the base of the Sadlerochit Group, reach a gross thickness of about 500 feet in Crackerjack well (pl. 13.4). These may represent an eastern, distal, offshore facies of a more sand-rich facies to the west, but the latter now would probably be lost to erosion at the Jurassic unconformity.

   Reservoir sequences of commercial qualities (coarse and porous) and thicknesses (probably 300+ ft) are therefore probably not present in the Upper Ellesmerian play sequence on the west flank of Hanna trough. However, up to 10,000 ft of the Endicott Formation, the lowermost part of the Lower Ellesmerian sequence, remains untested by any well on either flank of Hanna trough. This unsampled interval is correlative to the commercial oil reservoir at Endicott field near Prudhoe Bay in Arctic Alaska.

2. Thick, porous sandstones at the base of Tertiary rocks. All wells found highly porous and permeable sandstones resting upon the mid-Brookian unconformity at the base of Tertiary rocks. At Popcorn well, these sandstones are 540 feet (net) thick, evidently with excellent reservoir qualities (average porosity=31%, average (geometric mean) permeability of 564 millidarcies, percussion sidewall cores).

3. Thermally mature oil source rocks over 1,000 feet thick. Klondike well penetrated a continuous sequence of oil-prone source rocks over 1,000 ft in thickness within the upper Ellesmerian sequence. These oil source rocks are partly correlative to the source rocks that generated most of the oil in known deposits in the Arctic Alaska basin (Prudhoe Bay, Kuparuk, and related oil fields). Mapping of isograd and formation structure shows that roughly 10 billion acre-feet of these oil source rocks beneath southeast Chukchi shelf have been sufficiently heated to have generated and expelled oil. The burial event that heated these rocks to oil generation temperatures was the filling of the Colville basin with up to 24,000 ft of sediment at approximately 92 Ma (tuff at top of sequence dated by Phillips and others, 1988). This timing is important because many large potential traps in Ellesmerian rocks on Chukchi platform existed at this time and could have trapped migrating hydrocarbons.

4. Pooled gas and oil were encountered at most wells. Four of the five Chukchi wells encountered pooled and probably recoverable oil and gas, but in reservoir formations far too thin to warrant commercial exploitation. Gas with some condensate was recovered from Popcorn well and Burger structure probably contains a gas pool with reserves of several trillions of cubic feet (Craig and others, 1993). Oil was recovered from Klondike well and logs suggest pooled oil at Crackerjack well (J. Craig, pers. comm., 1994).

Biomarkers and isotopic data suggest that the Klondike oil was derived from source rocks resembling, but more highly mature, than the oil source rocks actually penetrated at Klondike well, suggesting that the oil is migrated rather than indigenous (Sherwood and others, 1994). The recovery of this oil at Klondike well confirms that a regional petroleum system in U.S. Chukchi Sea has successfully generated, migrated, and trapped oil. The oils feature low sulfur contents (< 0.18%) and high gravities (>35 degrees API) and therefore would command premium prices on the world market.

5. Most traps in southern Chukchi shelf are not thermally overmature. Most rocks penetrated by the wells now lie at their maximum burial depths and feature levels of thermal maturity below those at which oil is converted to gas. Prior to exploratory drilling, there was some concern that most Chukchi shelf prospects, particularly the large features on Chukchi platform, might have been much more deeply buried and heated to levels sufficient to destroy pooled oil. Fortunately, well data indicate that this is not the case, except within deepest parts of Colville and North Chukchi basins and along Herald arch.

6. Widespread regional seals favor trap integrity and focused lateral migration of hydrocarbons. Four of the five exploratory wells encountered a regional overpressure cell with the hydraulic top-seal occurring within thick shales of the Torok Formation or Pebble Shale between 4,000 and 8,000 feet (Sherwood, 1992). The top-seal occurs slightly above regional stratigraphic seals at the Lower Cretaceous and Jurassic unconformities. The widespread existence of the overpressure top-seal above these regional unconformities predicts high sealing competence for the unconformities. These unconformities are widespread and seal many large stratigraphic traps on Chukchi platform.

It is noteworthy that overpressure cells appear to control the spatial distributions of oil and gas deposits in some productive basins. For example, in the Gulf of Mexico, most petroleum deposits reportedly occur within a few thousand feet (above and below) the local tops of cells of overpressured rocks (Timko and Fertl, 1971). The top of overpressure in Chukchi shelf wells is posted in plate 13.4.

GEOPHYSICAL MAPPING AND PROSPECT SIZE DATA

Over 100,000 line miles of seismic data are available for prospect identification on Chukchi shelf, with grid densities typically 0.5 X 0.5 mi, but ranging up to 5.0 X 5.0 mi in a few isolated areas in the extreme north. Mapping by MMS staff on Chukchi shelf was generally conducted on a 3.0 X 3.0 mi grid at minimum, but often on a denser grid in closure-critical, highly faulted, or problematic areas. At least 22 different seismic horizons have been defined and mapped by MMS staff in the Chukchi shelf assessment province, with several seismic horizons, typically those bounding major tectonostratigraphic sequences, interpreted across the entire province (e.g., pls. 13.1, 13.2, 13.3, and fig. 13.22).

Geophysical mapping in Chukchi shelf has resulted in an inventory of 745 prospects mapped at scale 1:96,000 or less. These prospects, once organized into their respective plays, formed the basis for preparation of prospect area distributions that played a very powerful role in the outcome of this assessment. Prospect areas within a play are assumed (here) to be log-normally distributed, or arrayed linearly in a log-probability plot. Therefore, using actual data for total closure areas of seismically-mapped prospects, we created a scatter plot for each play on log-probability graph paper and then devised a straight line that best fit the data. This line then defined the probability distribution for play prospect area (reported in Appendix A1) used in subsequent volumetric modeling. The prospect area probability distributions strongly controlled the pool sizes and endowments calculated for the plays. ***Prospect area distributions*** were joined with ***fill fraction distributions*** to obtain ***pool area distributions***.

For each Chukchi shelf play, we tried to estimate the number of additional prospects that might remain unidentified as a consequence of indetectibility in seismic reflection data, insufficient density of interpreted seismic grid, or insufficiently detailed seismic-stratigraphic analysis. Most of the unidentified prospects were perceived by the Chukchi shelf team to be stratigraphic traps of two sorts: 1) mappable traps that were missed owing to wide (vertical) spacing of interpreted seismic horizons; or 2) unmappable stratigraphic traps formed by seismically subtle facies changes that created sealed volumes. Stratigraphic traps, mostly unconformity truncations at major sequence boundaries, already form a large part of the mapped prospect inventory. However, for most plays, we could admit the possibility of many additional traps at minor unconformities and unseen porous-bed terminations <u>within</u> the major sequences. For each play, the Chukchi shelf assessment team considered the play geology and the likelihood for occurrence of unidentified traps, and then estimated the maximum number of unidentified prospects.

Among the 22 plays distinguished in Chukchi shelf assessment province, we propose a maximum of 1,638 unidentified prospects for this assessment. When added to the 745 mapped prospects, we arrive at a maximum possible inventory of 2,383 prospects for the assessment province. This prospect inventory does not include the extensions of some plays into the Beaufort shelf assessment province.

Because most of the unidentified prospects are anticipated to share the complete range of sizes of mapped prospects, we made no corrections to prospect area distributions. However, if most unidentified prospects were thought to have been quite small and simply "missed" by a wider seismic grid, then a correction to the prospect area distribution, reducing the average prospect area, would be required.

After estimating the numbers of unidentified prospects in each play, probability distributions for prospect numbers were constructed. The distributions were constructed by posting two points on log-probability paper: 1) the number of mapped prospects at F_{99}; and 2) the sum of mapped plus unidentified prospects at F_{00}. A line connecting these two points, a "force-fit" distribution as described by Newendorp (1975, p. 383), then became the probability distribution for prospect numbers for the play. The numbers of mapped and unidentified prospects for each play are given in table 13.1. F_{99} and F_{00} values used for construction of prospect numbers distributions are also reported in Appendix A1. The ***probability distributions for prospect numbers*** for each play were coupled with ***risks*** in a ***GRASP*** program module (***MPRO***) to construct ***probability distributions for pool numbers*** for each play. Probability distributions for pool numbers are reported in Appendix A1.

RESERVOIR THICKNESSES

Probability distributions for reservoir thicknesses for each play were extracted from published literature for Arctic Alaska (Carman and Hardwick, 1983; Wadman and others, 1979; Jamison and others, 1980; Jones and Speers, 1976; AOGCC, 1993) or from control wells within the province or in western Arctic Alaska. Formation thicknesses (gross sand) were reduced by some appropriate net-to-gross ratio as observed in developed pools onshore and the values were directly entered as "net pay". Typically, distributions were constructed as force-fits between maximum (F_{01}) and minimum (F_{99})

TABLE 13.1
MAPPED AND UNIDENTIFIED PROSPECTS, CHUKCHI SHELF PLAYS

PLAY NO.	MAPPED PROSPECTS	UNIDENTIFIED PROSPECTS	PLAY NO.	MAPPED PROSPECTS	UNIDENTIFIED PROSPECTS
1	35	105	12	41	123
2	10	20	13	93	93
3	39	39	14	54	99
4	86	344	15	60	31
5	32	32	16	47	141
6	32	32	17	3	12
7	33	66	18	9	18
8	24	72	19	20	40
9	16	32	20	12	48
10	2	100	21	27	108
11	57	57	22	13	26

observed thicknesses, or perhaps, from typical (median, F_{50}) and maximum thicknesses observed in areas of drilling experience. Reservoir ("pay") thickness distributions are reported in Appendix A1.

RESERVOIR POROSITY MODEL

It has been well known for many years that the porosities of sandstones in most basins decline in some regular manner with increasing depth. This decline in porosity concerns oil producers and explorers because it lowers the productivity of petroleum reservoirs and can ultimately determine the maximum depth for commercial exploitation in a basin. The ability to predict porosity decline, therefore, has important economic ramifications. It is also clearly an important consideration in resource assessment.

It has been a common practice in many basins to use well data to develop estimates for rate of porosity loss with depth. However, depth is a positional reference that only crudely indexes the physical processes that actually cause porosity reduction. These processes or conditions include overburden pressure, temperature, or thermal maturity, among others. Therefore, depth, in itself, is a specious predictor of porosity loss in the subsurface. A method that relates porosity loss more directly to the controlling physical processes is clearly preferable.

Several empirical studies in the past two decades (Van de Kamp, 1976; Lyons, 1978, 1979 [cited in Schmoker and Hester, 1990, p. 53]; Schmoker, 1984; and Schmoker and Gautier, 1988) have concluded that sandstone and carbonate porosity declines most predictably as a function of rising thermal maturity. Researchers tentatively surmise from this apparent relationship that the kinetics of porosity reduction processes are approximately paralleled by the kinetics of thermal maturation of organic matter, that is, the cumulative effect of time-temperature exposure on chemical reactions. These same studies have found that the decline of porosity with rising thermal maturity (in most cases indexed by vitrinite reflectance) is best described by a power law function of the form $\Phi = aR_o\%^b$ (where Φ = porosity and $R_o\%$ = vitrinite reflectance).

The rate of porosity decline with rising thermal maturity is observed to vary locally within and between basins, sandstone facies, sandstone compositions, and perhaps in reaction to basin fluid dynamics and chemistries. However, collective statistical treatment of large, multibasin data sets provides for cancelling interference among these presumably more random, non-kinetic factors and reveals the more systemic law of porosity loss driven by time-temperature exposure. The study by Schmoker and Hester (1990) incorporated over 4,300 data points from all kinds of sandstones in many different basins. This study identified broad statistical groupings in the data from which porosity decline functions at certain levels of probability could be constructed.

The statistical analysis conducted by Schmoker and Hester (1990) first assigned each sandstone or sandstone sequence to a data cell (associated with a fixed R_o) for which a cumulative frequency (or "box") plot was constructed. Porosity values at select percentiles from each cumulative frequency plot were then segregated from other percentile values and assembled into Φ-R_o (log-log) plots representing each percentile group (P_{10}, P_{25}, P_{50}, P_{75}, and P_{90}). The Φ-R_o data representing each percentile group were then statistically fit with a power law function of the form given above. In this manner, a porosity decline function was constructed for each percentile group. The five resulting porosity decline functions (P_{10}, P_{25}, P_{50}, P_{75}, and P_{90}) predict the frequency or probability distribution of sandstone porosity at any given R_o in the subsurface. The P_{10}-P_{90} curves of Schmoker and Hester (1990) are shown in figure 13.10. Mathematic functions for the Schmoker-Hester functions are given in table 13.2.

We evaluated the appropriateness of the Schmoker-Hester curves for prediction of sandstone porosities in Chukchi shelf basins by graphically superposing them on actual porosity-R_o data prepared by J. Craig from five Chukchi-area control wells. These wells as a group sampled a

TABLE 13.2
Equations of Schmoker-Hester Porosity Decline Curves:
(General form $\Phi = aR_o\%^b$)

P_{90}	$\Phi = 10.90\ R_o\%^{-0.870}$
P_{75}	$\Phi = 9.30\ R_o\%^{-0.960}$
P_{50}**	$\Phi = 7.70\ R_o\%^{-1.050}$
P_{25}	$\Phi = 5.80\ R_o\%^{-1.150}$
P_{10}	$\Phi = 4.10\ R_o\%^{-1.340}$

***Equation not provided by Schmoker and Hester paper, but developed from power fit to points picked from 50th percentile line shown in figure 7 of same paper.*

comprehensive R_o spectrum, ranging from 0.32 percent to 4.00 percent, that embraces the full range of thermal maturities of (mapped) prospects in plays in the Chukchi shelf assessment province. A compilation of these data is illustrated in figure 13.11. We observe that porosity-R_o data for the control wells mostly cluster between the P_{10} and P_{90} Schmoker-Hester porosity decline functions, with only sparse trails of data points extending outside the P_{10}-P_{90} envelope. We conclude from this compilation that the Schmoker-Hester porosity decline functions adequately describe the loss of porosity with rising vitrinite reflectance observed in Chukchi Sea control wells, and presumably, the Chukchi shelf at large.

We note some important deviations between the Schmoker-Hester functions and the Chukchi shelf data, particularly the anomalously high (secondary?) porosities between vitrinite reflectances of 1.0 and 1.5. However, because the five Chukchi control wells form a very limited sample set, predictive functions obtained from statistical analysis of the Chukchi well data alone might introduce sampling bias and thereby poorly represent the shelf at large. Therefore, for the assessment, we elected to rely upon the more robust Schmoker-Hester data base for porosity prediction in Chukchi shelf plays.

The uppermost curve in figures 13.10 and 13.11, designated "P_{99}", is an arbitrarily-drawn line that captures the 50 percent surface porosity value and most (excluding some of the high values between 1.0 and 1.5 R_o%) of the highest porosity measurements across the R_o spectrum samples by the Chukchi-area wells. Unlike the statistically-based P_{10} to P_{90} functions, the "P_{99}" function is an arbitrary construct and is not based on statistical analysis. The equation of the P_{99} line is: $\Phi = 21.05R_o\%^{-0.620}$

Vitrinite reflectance isograd mapping based on the well data from Chukchi shelf provides a basis for predicting the thermal maturity of any prospect with a known location and depth. Most of the 22 plays recognized in the Chukchi shelf province contain prospects that are spread across a very large range of depths and thermal maturities. Therefore, it was necessary to first determine the range of reservoir vitrinite reflectances within each play before proceeding to construct a porosity distribution for the play.

For each play, we determined the thermal maturities of several prospects near the limits of the prospect depth range and in this way identified the two prospects associated with the extreme values of vitrinite reflectance for the play. Extremes in thermal maturity for each play are given in tables 13.3 and 13.4. In most cases, as one might expect, the deepest prospects are associated with highest vitrinite reflectances and the shallowest prospects are associated with lowest vitrinite reflectances. However, some exceptions crop up because of the great structural relief on isograd surfaces across some play areas (illustrated in figs. 13.19-13.21). Inevitably, there are areas where prospects are at shallow depths, but where isograds also lie very near the surface, indicating high thermal maturities for the prospects.

The extreme values for vitrinite reflectance were used to define porosity extremes for the play. Once determined, the extreme values for

TABLE 13.3
RANGES IN PROSPECT THERMAL MATURITY, CHUKCHI SHELF PLAYS
Thermal Maturities Reported as Vitrinite Reflectances
Estimated from Isograd Mapping

PLAY*	LEVEL OF MATURITY	PROSPECT		ISOGRAD DEPTHS AT PROSPECT				Ro%*** PROSPECT
		NO.	DEPTH	0.60**	1.35	2.00	8.0	
1	MINIMUM	17	6,700	[6,000	13,000]	17,000	25,000	0.65
	MAXIMUM	76	16,200	7,200	[13,500	16,500]	25,000	1.92
2	MINIMUM	8	3,000	[3,500	9,200]	12,000	20,000	0.56
	MAXIMUM	3	13,609	4,500	[11,000	14,000]	22,000	1.90
3	MINIMUM	31	5,000	[4,000	9,500]	13,000	21,000	0.70
	MAXIMUM	62	18,000	7,500	14,500	[18,000]	30,000	2.00
4	MINIMUM	123	11,110	brch'd	[2,000	10,000]	15,000	2.11
	MAXIMUM	139	37,160	3,500	[10,000	12,500	30,000	14.9(>8.0)
5	MINIMUM	199	9,000	2,500	[8,000	13,700]	20,000	1.45
	MAXIMUM	186	17,000	7,100	[14,300	17,800]	31,000	1.83
6	MINIMUM	166	3,600	[3,000	7,600]	11,000	20,000	0.67
	MAXIMUM	176	14,200	5,800	[13,000	17,000]	30,000	1.52
7	MINIMUM	241	2,600	[3,000	8,000]	11,000	19,000	0.56
	MAXIMUM	751	12,000	[6,400	13,700]	17,400	31,000	1.12
8	MINIMUM	761	3,500	[1,000	8,000]	14,000	22,000	0.80
	MAXIMUM	264	13,140	5,800	[12,000	13,800]	31,000	1.73
9	MINIMUM	770	9,108	brch'd	[1,000	8,800]	16,000	2.03
	MAXIMUM	784	22,775	brch'd	[6,700	10,500	26,000]	6.00
10	Herald Arch and Thrust Zone-No Mapped Prospects							
	MINIMUM	Ro%=1.00 at Surface Along Northeast Margin						1.00
	MAXIMUM	--	20,000	Thickness of Complex Over Decollement				4.30

* *Plays 1-4, Lower Ellesmerian; plays 5,6, Upper Ellesmerian; plays 7-9, Rift (Kuparuk) Sequence; play 10, Lower Brookian.*

** *"brch'd" indicates that isograd is breached or projects above surface at the prospect site.*

*** *estimated by interpolation using exponential function ($R_o\%=Ae^{(b \cdot depth)}$) fit to enclosing isograd datums (shown in brackets[]), or, projection using two (or three, if R_o>2.0%) nearest isograd datums.*

TABLE 13.4
RANGES IN PROSPECT THERMAL MATURITY, CHUKCHI SHELF PLAYS
Thermal Maturities Reported as Vitrinite Reflectances
Estimated from Isograd Mapping

PLAY*	LEVEL OF MATURITY	PROSPECT		ISOGRAD DEPTHS AT PROSPECT				Ro%*** PROSPECT
		NO.	DEPTH	0.60**	1.35	2.00	8.0	
11	MINIMUM	556	7,410	[3,000	9,700]	13,100	25,000	1.02
	MAXIMUM	544	5,600	brch'd	[6,500	10,600]	25,000	1.24
12	MINIMUM	476	3,500	[1,000	7,500]	14,000	22,000	0.82
	MAXIMUM	428	19,000	[7,300	19,100]	27,000	37,000	1.34
13	MINIMUM	492	1,600	[1,800	7,500]	14,000	22,000	0.58
	MAXIMUM	437	16,500	7,900	[15,500	20,000]	30,000	1.47
14	MINIMUM	460	1,650	[3,000	7,800]	10,700	18,000	0.48
	MAXIMUM	369	15,500	6,100	[13,400	16,000]	25,000	1.85
15	MINIMUM	365	9,914	[6,800	14,700]	17,000	30,000	0.83
	MAXIMUM	354	28,500	11,000	[20,000	30,000]	40,000	1.89
16	MINIMUM	524	9,108	brch'd	[1,000	8,800]	16,000	2.03
	MAXIMUM	795	22,775	brch'd	[6,700	10,600	25,000]	6.46
17	MINIMUM	589	8,400	[5,600	13,400]	15,100	31,000	0.80
	MAXIMUM	587	8,800	[5,700	13,000]	14,400	30,000	0.85
18	MINIMUM	573	4,768	[5,500	12,000]	13,400	30,000	0.55
	MAXIMUM	574	6,095	[6,100	12,200]	13,600	30,000	0.60
19	MINIMUM	682	2,551	[7,800	16,200]	23,000	30,000	0.36
	MAXIMUM	681	10,412	[7,800	16,000]	22,500	30,000	0.78
20	MINIMUM	632	14,460	[7,200	15,000]	17,700	30,000	1.28
	MAXIMUM	617	25,000	12,000	[20,000	30,000]	40,000	1.64
21	MINIMUM	679	2,472	[7,900	16,000]	24,000	30,000	0.35
	MAXIMUM	643	12,000	[8,000	15,600]	20,000	30,000	0.92
22	MINIMUM	657	1,600	[4,100	10,000]	13,000	23,000	0.43
	MAXIMUM	634	7,500	[9,500	19,000]	26,000	36,000	0.51

* *Plays 11-18, Lower Brookian; plays 19-22, Upper Brookian.*

** *"brch'd" indicates that isograd is breached or projects above surface at the prospect site.*

*** *estimated by interpolation using exponential function ($R_o\%=Ae^{(b \cdot depth)}$) fit to enclosing isograd datums (shown in brackets[]), or, projection using two (or three, if R_o>2.0%) nearest isograd datums.*

vitrinite reflectance for a play were posted on a plot of the Schmoker-Hester porosity-R_o functions. The highest anticipated porosity for the play was defined to correspond to the P_{99} porosity value at the play R_o minimum. A near-minimum anticipated porosity for the play was arbitrarily defined to correspond to the P_{10} porosity value at the play R_o maximum. A line was then drawn to join these porosity extremes. This line was used to interpolate the porosity values at intermediate probabilities by noting the intersections of the line with the P_{25}, P_{50}, P_{75}, and P_{90} porosity-R_o functions in figure 13.10. The porosity values at each of these intersections can be read directly from the graph or calculated mathematically. The probability values were inverted to fractiles ($1-P_m$), and the porosity values paired with each fractile were assembled on a log-probability plot. These plotted data were fit with a line that then became the porosity distribution for the play. Porosity distributions obtained in this way and used for calculation of play resources are listed in table 13.5. The porosity distributions played a key role in the quantitative calculations for reservoir recovery factors or yields.

ESTIMATION OF RESERVOIR RECOVERY FACTOR OR YIELD

Recovery factor, or yield, in units of barrels of oil per acre-foot of reservoir, or, millions of cubic feet of gas per acre-foot of reservoir, were required by the assessment software for calculations of pool sizes. Probability distributions for recovery factors were calculated for each play by statistical aggregations of probability distributions for the following volumetric factors:

Oil Recovery Factor, or Oil Yield:

a. Porosity
b. Hydrocarbon Saturation
c. Oil Formation Volume Factor
d. Oil Recovery Efficiency

Barrels Oil Recoverable per Acre-Foot of Pool Reservoir (BO) = $(7758.38\ Bbl/acre\text{-}ft)\ (a \cdot b \cdot d/c)$

Gas Recovery Factor, or Gas Yield:

a. Porosity
b. Hydrocarbon Saturation
c. Reservoir Pressure
d. Reservoir Temperature
e. Gas Deviation Factor
f. Combustible Gas Fraction
g. Gas Recovery Efficiency

Millions of Cubic Feet of Gas Recoverable per Acre-Foot of Pool Reservoir (MMCFG)

$$= [43{,}560\ ft^3/acre\text{-}ft]\ [a \cdot b \cdot f \cdot g]\ [(60^\circ + 460^\circ)/d \cdot e]\ [c/14.73]\ [1/1{,}000{,}000]$$

Porosity distributions were obtained from the porosity model described in the preceding section. Hydrocarbon saturation distributions were constructed by estimating the high and median values for saturation that would be paired with the respective high and median porosity values. Hydrocarbon saturations were estimated from porosities by first estimating the bulk volume water values characteristic of the grain size of the proposed reservoir (table from Asquith, 1982, p. 98). Reservoir bulk volume water, taken to equal irreducible water saturation (Sw_i), was cross-plotted against the high and median porosity values on a standard chart (Schlumberger, 1988, K-3, K-4, p. 138-139) to obtain high and median values for hydrocarbon saturation. A force-fit hydrocarbon saturation distribution was then constructed on log-probability plots between the minimum (F_{99}) and maximum (F_{01}) values.

Pressure and temperature extremes for each play were estimated from the extremes in prospect depths (using appropriate gradients from well data) and these in turn were used to estimate the ranges in oil shrinkage factor and gas deviation factor (Z) using standard charts published by Standings and Katz (1942; replicated in Anderson, 1975, p. 155-156). In all of these between minimum (F_{99}) and maximum (F_{01}) values.

Ranges in recovery efficiencies were estimated from data published by White (1989, p. 3-29, 3-31) or Arps and others (1967). These also were graphically drawn between extreme values to obtain log-normal probability distributions.

Standard atmospheric pressure (14.73 psi) was used as the abandonment pressure for gas reservoirs. The use of atmospheric pressure in the calculation essentially yielded an in-place gas volume that was then coupled with recovery efficiency to obtain a gas recovery factor or yield.

Lastly, some plays (especially carbonates at great depths) were viewed as potentially containing gas mixtures rich in non-combustible gases such as carbon dioxide, nitrogen, hydrogen

TABLE 13.5
PLAY POROSITY DISTRIBUTIONS
Constructed from Ranges in Reservoir Vitrinite Reflectances for Plays (Tbls. 13.3,13.4)

PLAY NUMBER	PLAY POROSITY DISTRIBUTIONS					
	F100	F50	MEAN	F02	F01	F00
1	0.01	0.06	0.07	0.22	0.26	0.50
2	<0.01	0.07	0.08	0.25	0.30	0.50
3*	<0.01	0.04	0.05	0.13	0.15	0.35
4	<0.01	0.02	0.024	0.10	0.13	0.42
5	<0.01	0.04	0.05	0.14	0.16	0.37
6	<0.01	0.07	0.08	0.22	0.26	0.50
7	0.01	0.09	0.10	0.25	0.29	0.50
8	0.01	0.07	0.08	0.20	0.23	0.47
9	<0.01	0.02	0.03	0.10	0.12	0.37
10	<0.01	0.04	0.05	0.17	0.21	0.50
11	0.02	0.08	0.084	0.18	0.20	0.36
12	<0.01	0.06	0.07	0.20	0.23	0.50
13	<0.01	0.07	0.09	0.25	0.29	0.50
14	<0.01	0.08	0.09	0.28	0.33	0.50
15	<0.01	0.06	0.07	0.20	0.24	0.50
16	<0.01	0.02	0.03	0.10	0.12	0.37
17	0.02	0.09	0.10	0.22	0.25	0.45
18	0.04	0.135	0.143	0.28	0.30	0.49
19	0.03	0.14	0.15	0.33	0.37	0.50
20	<0.01	0.05	0.055	0.14	0.16	0.33
21	0.02	0.13	0.15	0.34	0.39	0.50
22	0.06	0.165	0.172	0.30	0.32	0.49

* *based on ranges observed in well penetrations of Lisburne Group on Chukchi shelf and northwestern Alaska, and, average for productive intervals (10%) in Lisburne pool of Prudhoe Bay field (AOGCC, 1993, p.89)*

sulfide, or helium. To estimate the potential contents of non-combustible gases, we applied our estimates for extreme ranges in reservoir temperatures for plays to the empirical data published by Burruss (1992, figs. 7-1, 7-2). Most plays are predicted to have greater than 90 percent combustible gas at minimum. However, deep plays involving carbonates, such as plays 3 and 4, could have combustible gas fractions (minima of distributions) approaching zero. Minimum (F_{99}) and maximum (F_{01}) values for combustible gas fractions were used to develop force-fit distributions on log-probability plots.

All distributions were aggregated under independence using ***PRASS*** (a supplied agency software) to obtain recovery factor or yield distributions. The assumption of independence is a weakness in the modeling, as some contributing factors (e.g., porosity, hydrocarbon saturation, and recovery efficiency) are usually (though not always) dependent or correlative.

PETROLEUM SYSTEMS AND CHARGING OF PLAYS

Source Rocks Recognized Beneath Chukchi Shelf

Rocks equivalent to most of the oil source sequences recognized in northern Alaska were penetrated and sampled by the five exploratory wells on Chukchi shelf. These include the Lower Cretaceous ***Pebble Shale***, the Jurassic to Cretaceous ***Kuparuk and upper Kingak Formations***, and the Upper Triassic ***Shublik Formation***. One important unit that was not sampled is the lower part of the Jurassic Kingak Formation (fig. 13.4). These rocks, surely present in abundance in Hanna trough, were simply missed at drilling sites because of truncation at those sites by the overlying Jurassic unconformity (JU).

Klondike well obtained the most complete sampling of all potential source units, including important Triassic oil source rocks. Much of the discussion will therefore focus on Klondike well, with exceptions noted where appropriate.

From the standpoint of organic carbon content, most shale sequences at Klondike classify as "fair" to "excellent" sources. In most cases, the shales at Klondike well are somewhat richer in organic carbon than correlative shales in northern Alaska. The thin bars with a central diamond symbol in figure 13.12 signify the range and average of values, respectively, of samples from these sequences in northern Alaska. Data from Klondike well are shown with a heavier bar indicating range and a dot signifying the average. Among the major shale sequences at Klondike well, only the Pebble Shale offers an average organic carbon content that is lower than that reported for northern Alaska.

In figure 13.13, organic carbon content is crossplotted against generation potential (S1 + S2, from Rock-Eval pyrolysis). The geometric symbols are from Klondike well, and represent averages of all analyses for each stratigraphic unit. The stippled areas are data clouds representing some of the same stratigraphic units from northern Alaska.

It should be noted that the generation potentials for the Arctic Alaska samples in the stippled areas of figure 13.13 represent less than full original potential because many of those samples are thermally mature to overmature (Ro%>>0.60) and have already exhausted some fraction of their capacity for oil generation. At most sites in western Arctic Alaska, these rocks have been completely expended and it is impossible to determine what their original generation potential might have been. In fact, the Klondike well represents a rather unique sampling of organic-rich rocks equivalent to the Shublik Formation in a state of low thermal maturity.

In figure 13.13, four stratigraphic units at Klondike well clearly stand out as potential oil sources. These include carbonate and shale members of the Upper Triassic Shublik Formation, shown as two diamonds, shales equivalent to the Lower Triassic Fire Creek Formation of the Sadlerochit Group, represented by the hour glass, and some shales equivalent to the Lower Triassic Ledge or Ivishak Formation of the Sadlerochit Group, shown as a dot. All other shales penetrated by Klondike well, including the Kingak Formation and Pebble Shale, are primarily gas sources.

Figure 13.14 assembles modified Van Krevelen plots for Tertiary rocks (A), shales of the Nanushuk Group (B) and Torok Formation (C), and the Pebble Shale (D). All are dominated by type III kerogens and would be primarily gas sources, confirming the gas-prone character suggested by figure 13.13.

Figure 13.15 assembles modified Van Krevelen diagrams for the Kuparuk/Kingak shale (A), four Triassic oil source units (B,C), and the Permian Kavik shales (D). The vitrinite reflectances for samples from Klondike well are profiled in figure 13.16. The Shublik, Fire Creek, and Ivishak (equivalent) Formations have vitrinite reflectances ranging between 0.66 and 0.78 percent (R_o%), indicating that the samples retain most of their original potential to generate oil and gas. The pyrolysis yields shown in figure 13.15 therefore approach original generative capacities.

The Shublik carbonates and shales (fig. 13.15B) and the Fire Creek (equivalent) shales (fig. 13.15C) all have hydrogen indices well in excess of 300 and should be excellent oil sources. Ivishak-equivalent shales (fig. 13.15C) have hydrogen indices in the range from 200 to 300, and should form modest sources for liquid hydrocarbons.

At Klondike, these oil source units are together quite thick. The three richest units are altogether 465 feet thick, and when the Ivishak-equivalent rocks are included, we obtain a total of 1,030 feet of oil-prone source rocks. Parts of the Triassic oil source rock sequence can be correlated into Tunalik well (fig. 13.17), where they have been subjected to very high temperatures and now record vitrinite reflectance values (R_o%) between 3.0 and 4.0 percent.

The only other offshore penetration of Triassic source units was at Diamond well, 100 miles northeast of Klondike. There, Rock-Eval analyses found hydrogen indices for Shublik Formation shales and carbonates scarcely reaching 150. At Diamond, unlike at Klondike, the Ledge- or Ivishak-equivalent rocks are mostly sandstones and offer no source potential. With a vitrinite reflectance of 0.84%, the Triassic rocks at Diamond are thermally mature and have surely lost some of their generative potential. By analogy to Baird's (1986) model for fractional generation in the North Sea, these source rocks may have already lost 40% of their original generation potential. This means that the hydrogen indices may have originally been in the range from 250 to 300. However, even accounting for losses due to thermal maturation, we must acknowledge that these rocks are considerably less rich oil sources than their counterparts to the southwest at Klondike well.

At Diamond, in addition to being leaner sources, the Shublik and Fire Creek units are also rather thin. The Shublik Formation is mostly truncated at the Lower Cretaceous unconformity or "LCU" (pl. 13.4). As a consequence, the Shublik Formation at Diamond is only 120 feet thick, although the unit is 275 to 425 feet thick in the nearest onshore wells. When we include the Fire Creek-equivalent shale sequence, we have altogether only 205 feet of quite marginal oil source rocks.

The apparent northward decline in organic richness from Klondike well to Diamond well is consistent with the facies mapping within the Shublik Formation published by Judith Parrish. Parrish (1987) recognized a northern, "glauconitic" facies characterized by glauconitic sandstones and shales poor in organic carbon. The glauconitic facies is succeeded to the south by rocks rich in phosphate nodules. South of the "phosphatic" facies, the Shublik Formation is dominated by organic-rich shales, which form Parrish's "Organic-Rich" facies. The "Organic-Rich" facies probably extends south to include the carbon-rich Early Triassic to Middle Jurassic Otuk Formation exposed in the Brooks Range (Blome and others, 1988; Bodnar, 1989). Parrish (1987) ascribed the development of these facies belts to the existence of an upwelling zone centered above the belt of phosphatic Shublik rocks in Triassic time.

The Shublik Formation at Klondike (and probably at Tunalik) is clearly in Parrish's "Organic-Rich" facies, and the presence of Lower to Middle Triassic (Ivishak-equivalent) source rocks is unique to the two well sites and the Otuk Formation of the Brooks Range. Containing neither phosphate nor glauconite in prominent quantities, it is difficult to assign the Triassic rocks at Diamond well to any of Parrish's facies belts. However, the occurrence of Triassic rocks relatively poor in organic carbon and oil generation potential at Diamond is consistent with the regional pattern of northward decline of source potential in the Shublik Formation.

Structure of Thermal Maturity Isograds Beneath Chukchi Shelf

Based on statistical fits of exponential functions to vitrinite reflectance data in the offshore wells (fig. 13.18; tbl. 13.6), and incorporating the interpretations of onshore wells (tbl. 13.7) by Johnsson and others (1993), we have mapped the structure of key isograds offshore. This mapping is presented in figures 13.19 through 13.21, representing structure of isograds at the top of the oil generation zone (0.60 R_o%), the base of the zone of oil generation (1.35 R_o%), and the floor for oil preservation (2.00 R_o%). These maps formed the basis for estimating the thermal maturities of prospects (for porosity modeling) and for mapping exhaustion levels in key oil source rocks. All isograd structure maps are dominated by a synclinorium that plunges northwest into the North Chukchi basin. All isograds are breached at the seafloor offshore along the Herald thrust and onshore along the front of the Brooks Range thrust belt. Rather than regional variations in thermal gradients, most of the structure of these isograd surfaces is clearly the result of post-catagenic tectonic uplifts in the areas of North Chukchi high, Northeast Chukchi basin, Herald thrust and Herald thrust zone, and the Brooks Range.

Figure 13.22 is based on MMS seismic mapping offshore and USGS mapping onshore and unites in one map the regional structure of the top of the Shublik Formation (offshore) and the top of the Sadlerochit Group[6] (onshore). The general pattern is one of southward and eastward dip toward a depth maximum of 30,000 feet just offshore from Point Lay. On the west, the sequence is truncated at the Jurassic unconformity (JU). On the northeast the sequence is truncated at the Lower Cretaceous unconformity (LCU) or simply laps out against basement, as in the Barrow area.

We have mapped the lines of intersection between the key isograd surfaces and the Triassic source rocks in order to define levels of thermal maturity or fractional exhaustion within the source rock sequence. South of the 1.35 percent vitrinite isograd in figure 13.22 the Triassic oil source rocks are completely expended with respect to generation of oil. Given gravitational drainage up present-day structure (mostly established by 92 Ma), at least some of the oil expelled from the exhausted Triassic oil sources should have migrated west and north, respectively, into traps on Chukchi platform and the Arctic platform.

Oil Generation Potential of Triassic Oil Source Rocks and Charge Analysis

Resource assessments commonly investigate the potential volumes of oil that might have been generated by thermal maturation of source rocks in a basin. Basins with high potential volumes of generated oil usually possess large commercial reserves as well. In addition, comparisons between volumes of generated oil and volumes of potential traps help estimate how many traps might be filled with oil. Such comparisons are termed "charge analysis." A charge analysis of Chukchi shelf was undertaken as part of the 1995 resource assessment.

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[6]*corresponds to base of Shublik Formation*

TABLE 13.6
ISOGRAD DEPTHS IN CHUKCHI SHELF WELLS

WELL	KB (ft)	MATURATION* TREND SEGMENT	A(Ro)**	B(10^{-5})**	r^2**	[VITRINITE REFLECTANCE ISOGRAD***] 0.25	0.60	1.35	2.00	4.00
BURGER	42	0-5,020 (BU)	0.405	7.095	0.280	-6,834	--	--	--	--
		5,020-8,202	0.366	9.879	0.319	--	4,978	13,168	17,147	24,163
CRACKERJACK	42	0-7,485 (BU)	0.279	8.876	0.768	-1,286	--	--	--	--
		7,485-9,573	0.260	11.226	0.509	--	7,406	14,630	18,131	24,305
DIAMOND	42	0-4,215 (BU)	0.370	16.176	0.832	-2,471	2,941	--	--	--
		4,215-6,745	0.275	23.996	0.864	--	--	6,580	8,218	11,107
KLONDIKE	41	0-9,400 (JU)	0.330	7.636	0.756	-3,667	7,798	--	--	--
		9,400-12,008	0.116	18.294	0.750	--	--	13,394	15,542	19,331
POPCORN	42	0-5,000 (MBU)	0.306	6.478	0.489	-3,180	--	--	--	--
		5,000-10,202	0.280	11.585	0.931	--	6,549	13,550	16,943	22,926
PEARD****	103	0-6,195 (BU)	0.426	9.280	0.881	-5,857	3,577	--	--	--
		6,195-10,225	0.263	15.172	0.755	--	--	10,674	13,265	17,833

* *BU: trend break at Brookian unconformity; JU: trend break at Jurassic unconformity; MBU: trend break at mid-Brookian unconformity. Depths given are depths below kelly bushing (KB).*

** *Regression parameters for Ro% = $Ae^{(B \times depth)}$ or Ln Ro% = LnA + (B X depth); A is Ro% at KB elevation, B is slope for depth in feet, r^2 is coefficient of determination.*

*** *Depths in feet relative to sea level. Above sea level if negative, underlined if projected beyond data field.*

**** *Re-interpreted from Johnsson and others (1993).*

TABLE 13.7
ISOGRAD DEPTHS IN ARCTIC ALASKA WELLS
(after Johnsson and others, 1993)

WELL	KB (FT)	MATURATION* TREND SEGMENT	A(Ro)**	$B(10^{-5})$**	r^2**	0.25	0.60	1.35	2.00	4.00
						[VITRINITE REFLECTANCE ISOGRADS***]				
AKULIK	1,224	0-5,689	0.444	27.98 (8.53)	0.90	-1,701	309	--	--	--
		5,689-17,038	0.899	9.85 (3.00)	0.91	--	--	4,636	10,267	20,170
EAGLE CREEK	1,990	0-12,051	1.520	6.26 (1.91)	0.96	N/A	-23,148	-4,690	4,245	19,982
TUNALIK	110	0-6,624	0.513	5.02 (1.53)	0.27	-20,513	4,337	--	--	--
		6,021-10,542	0.154	32,45 (9.89)	0.95	--	--	9,423	--	--
		9,941-19,811	0.468	18.00 (5.49)	0.94	--	--	--	11,388	16,875
TUNGAK CREEK	118	0-8,212	0.546	3.90 (1.19)	0.82	--	3,227	--	--	--
KUGRUA	85	0-8,481	0.423	14.28 (4.35)	0.87	-5,333	3,403	--	--	--
		6,929-10,699	0.110	40.51(12.35)	0.90	--	--	8,735	10,117	--
		9,758-12,350	0.972	10.74 (3.27)	0.51	--	--	--	--	18,684

* *Depth of trend break, in feet, as measured from KB.*

** *Regression parameters (from Johnson and others, 1993, tbl. 2). Ro% = $A(10^{(B \times depth)})$; A is Ro% at KB elevation; B is slope for depth in meters (parens, slope for depth in feet); r^2 is coefficient of determination.*

*** *Depths in feet below sea level, calculated from Johnsson regression parameters, incorporating borehole deviation data. Underlined if projected beyond data field; negative values signify projection above sea level.*

To estimate the oil-generation potential of the area of thermally mature (charge area) Triassic rocks beneath Chukchi shelf, we mapped the regional variation in source potential index. The source potential index, employed here along the lines described by Tissot and others (1980) and Demaison and Huizanga (1991), simply combines thickness and richness at a well site into a single mappable factor, corrected for losses due to present thermal maturity, that can be posted on a map with other well sites and contoured. In this way, regional variations in petroleum-generating capacities may be identified. The equation may be written as follows:

Source Oil Potential Index (SOPI)*

SOPI = (Thickness) (Yield/TOC) (TOC) (Maturation Loss Factor) (Rock Density) (1/Oil Density) (K) = 10^3m^3 Oil/km^2 Source Rock

* *Variables include:* ***Thickness*** *of stratigraphic or organic unit in meters; total organic carbon (TOC) and* ***Yield*** *from pyrolysis (mean values for organic unit);* ***Maturation Loss Factor*** *to restore to original potential oil yield (taken as 78.2% of total HC yield; Baird, 1986, tbl. 1);* ***Rock Density*** *from density logs (g/cc);* ***Oil Density*** *from well recovery at Klondike (0.85 g/cc for 35 °API oil); and* ***K*** *to handle unit conversions.*

Table 13.8 lists the values for source oil potential index, in millions of cubic meters of oil per square kilometer, that were obtained for four control wells.

Some assumptions were required in order to perform the SOPI calculation for Tunalik well, where the Triassic rocks are fully expended and at vitrinite reflectances between 3.00 and 4.00 percent (R_o%). The correlation presented in figure 13.17 implies that most of the key oil source units in Klondike well extend intact as organic units into Tunalik well. To estimate the SOPI for Tunalik, we united ***yield data*** from Klondike well with ***thickness data*** from Tunalik well. The assumption that Klondike yield data can be extended to correlative sequences at Tunalik is probably not unreasonable, given that correlative units offer comparable levels of organic carbon (after correction at Tunalik) and given that both wells are on depositional strike within Parrish's (1987) "organic-rich" facies for the Shublik Formation. However, the apparent absence (or highly condensed presence) of both the lower Shublik shale member and Fire Creek-equivalent rocks at Tunalik (fig. 13.17) resulted in a diminished source oil potential index at that site. In all probability, within axial parts of Hanna trough, which intervenes between these wells, we may expect a Triassic source rock sequence even thicker and richer than that observed at Klondike well. Potential Jurassic sources not sampled at Klondike well (or any other Chukchi shelf wells) are probably present within Hanna trough as well and offer additional oil generation potential. The present model is therefore probably conservative in its estimate of overall generative potential.

TABLE 13.8
SOURCE OIL POTENTIAL INDEX
Chukchi Shelf Control Wells
(10^6m^3 Oil/km^2)

WELL	SOPI
KLONDIKE	10.4
TUNALIK	8.3
DIAMOND	0.5
PEARD	0.5

Figure 13.23 is a contoured map for SOPI for the Triassic oil source rock sequence in the charge area for Chukchi shelf[7]. Figure 13.23 also contains an overlay for values of fractional

[7] *that area of thermally mature source rock so structured that generated oil might migrate by gravitational drainage to some part of Chukchi shelf*

TABLE 13.9
RECOVERABLE OIL ESTIMATED* FROM GENERATION POTENTIAL
Hanna Trough Charge Area, Chukchi Shelf

GENERATED OIL (10^{12} BBL)	EFFICIENCY LEVEL	MIGRATION EFFICIENCY	TRAP EFFICIENCY	RECOVERY EFFICIENCY	RECOVERABLE OIL (10^{9} BBL)
2.97	Minimum	0.15	0.07	0.20	6.2
2.97	Typical	0.25	0.14	0.40	41.6
2.97	Maximum	0.42	0.28	0.70	244.5

* *Migration and trap efficiencies from Meissner (1984).*

conversion, or exhaustion of generation potential, based on modeling studies in the North Sea published by Baird (1986). The fractional conversion estimates are based on vitrinite reflectances for Triassic rocks as mapped in figure 13.22, but also incorporates a 1.00 R_o% isograd not shown here. The Baird study suggested (fractions in his table 1, normalized to 100% depletion at 1.35 R_o%) the following equivalences between vitrinite reflectance and fractional conversion (or percent exhaustion of oil generation potential): 0.6 R_o%, 20 percent converted; 1.00 R_o%, 65 percent converted; and 1.35 R_o%, 100 percent converted. These are the fractional conversion values mapped in figure 13.23.

The two data sets (SOPI, fractional conversion) divide the charge area into 31 cells (fig. 13.23) with unique combinations of area, SOPI, and fractional conversion. The intermediate values associated with each cell were multiplied and the sum of the 31 products became the integrated oil generation potential for the entire charge area.

Altogether, we have about 10 billion-acre feet of mature Triassic source rocks in the charge area for Chukchi shelf. Integration of the generation potentials for the 31 cells in figure 13.23 yields an estimate for total generation potential of 2.97 trillion barrels of oil.

Given lateral migration, present-day structure would guide the migration of this oil updip beneath the regional seals toward the western and northern margins of the generative area. How much of this oil might have reached traps in that area is not known. Most (90 to 99 percent) of the oil generated in most basins is typically lost before reaching a production well. A large fraction of the generated oil is lost to migration and an even larger share simply never finds a trap and escapes to the surface. Finally, 30 to 80 percent of the oil that actually fills traps becomes locked into reservoir pore systems as irreducible (unrecoverable) saturations.

Table 13.9 sets the 2.97 trillion-barrel generation potential of the Hanna trough charge area against some efficiencies for migration, trapping, and recovery reported by Meissner (1984). These calculations indicate that only ***6 to 245 billion barrels*** of the generated oil might be technically recoverable from Chukchi shelf. Nevertheless, these quantities far exceed the estimate for oil-charged trap volume ***(7 to 22 billion barrels)*** calculated for Chukchi shelf in the present (1995) assessment. We may conclude that the quantity of oil generated and available to fill traps in the basin far outstrips the storage volume offered by those traps.

The charge area for Triassic source rocks centered in Hanna trough is merely the western third of an oil generation system extending across Arctic Alaska that Bird (1994) terms the

"Ellesmerian![8] petroleum system, estimated to offer a total oil generation potential of ***8 trillion barrels of oil***.

For purposes of this assessment, we recognize three separate hydrocarbon generation and migration systems that might have charged petroleum plays in Chukchi shelf. The areas where each of these systems might dominate are mapped as "charge areas" in figure 13.24.

Hanna Trough Play Charging System

Most of the plays in the Chukchi shelf assessment province are considered to be charged by this petroleum system, which we term the "Hanna trough charge area" in figure 13.24 to distinguish it from the more regional Ellesmerian! petroleum system of Bird (1994). Based on the charge analysis summarized above, the Hanna trough play charging system is viewed as the most robust and prolific of the three proposed systems. Little is known about either the North Chukchi basin or Colville basin charge areas mapped in figure 13.24, but they are probably endowed with smaller volumes of oil source rocks. Also, the source rocks in the North Chukchi basin and Colville basin charge areas formed in deltaic systems with high sedimentation rates, and, are probably generally more gas-prone and lean with respect to convertible organic matter.

Colville Basin Play Charging System

In the area of the foldbelt in southern Chukchi shelf, Colville basin is filled with up to 24,000 feet of Early Cretaceous strata. The upper half of this sequence consists of folded deltaic sandstones that form the main reservoir objective in the foldbelt play. The lower half of the basin fill consists of overpressured shales (of the Torok Formation), which, along with deep structural decollements, isolate the shallower deltaic sandstones from oil sources in the underlying Ellesmerian sequence.

Petroleum expelled from the Ellesmerian rocks probably migrated laterally westward or northward beneath the overpressured and impermeable Torok shales, rather then rising vertically into the overlying detached foldbelt.

Umiat oil field in the foldbelt onshore 270 miles to the east contains oil that has been geochemically linked to the Torok shales and perhaps the underlying Pebble Shale that floors Colville Basin (Magoon and Claypool, 1988, p. 543). In addition, all discoveries in the foldbelt west of Umiat have been gas fields, also consistent with a gas-prone Torok Formation or Pebble Shale as the dominant source.

L.B. Magoon of the U.S. Geological Survey has speculatively termed the Colville basin system the "Torok-Nanushuk(.)[9] petroleum system", with the name reflecting the source-to-reservoir coupling (in Bird, 1994, p. 341). This system is assumed to be the dominant prospect-charging agent for the foldbelt in southern Chukchi shelf. The western part of this system is mapped in figure 13.24 as the "Colville basin charge area", to distinguish it from the more regional "Torok-Nanushuk(.) petroleum system" of Arctic Alaska.

North Chukchi Basin Play Charging System

Geologic plays within North Chukchi basin are isolated from both Hanna trough and Colville basin by the structural arch along the south margin of North Chukchi basin. North Chukchi basin plays must, therefore, be charged by petroleum generated within the basin.

North Chukchi basin contains Tertiary and Cretaceous strata exceeding 45,000 feet in thickness. We know nothing about the source potential of these rocks, except that correlative rocks sampled in the Chukchi shelf wells to the south are gas sources. However, rocks of the same geologic age in a depocenter with comparable sediment thicknesses occur in the Mackenzie delta of northwest Canada.

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[8] *(!) denotes a known, or well documented source to trap system (Magoon and Dow, 1994, p. 12).*

[9] *(.) denotes a hypothetical petroleum system (Magoon and Dow, 1994, p. 12).*

There, Cretaceous and Tertiary rocks have generated, migrated, and trapped ***recoverable reserves*** of 1.7 BBO and 11.7 TCFG and additional ***undiscovered resources*** 5.4 BBO and 53.3 TCFG (Dixon and others, 1994, p. 43, mean estimates). In North Chukchi basin, immense volumes of sediment, including at least 25,000 feet of mostly Cretaceous rocks, have passed through the thermal window for oil generation and are now oil-expended (floor mapped in fig. 13.20). These thermally mature rocks may include Upper Cretaceous rocks (ca. 92 to 65 Ma) that are notably absent from western Colville basin and the Chukchi shelf exploratory wells. Rocks of this age, however, are probably preserved in North Chukchi basin. If present, such rocks would be age-equivalent to prominent ***regional oil sources*** like the Aptian to Maestrichtian Hue Shale of northeastern Alaska, or, the Santonian to Campanian Smoking Hills Formation of the southern Mackenzie delta area (Magoon and others, 1987, p. 142; Brooks, 1986, p. 492; Dixon and others, 1992, p. 930).

We conclude that it is reasonable to speculate that North Chukchi basin may have generated sufficiently large quantities of oil and gas to charge reservoirs in plays within the basin. The approximate area of dominance of the proposed North Chukchi basin charge area is mapped in figure 13.24. The southern boundary is drawn as a line passing along the crest of North Chukchi high and then along the structural ridge (extension of Barrow arch?) separating Colville and North Chukchi basins.

Controls Exerted by Play Charging System on Resource Assessment

For puposes of the 1995 assessment, each Chukchi shelf play was considered to have primary access to one of the three proposed play charging systems, each offering a different oil-gas mix and a different ability to generate petroleum to fill traps. These differences affect play quantification in two areas of input volumetric parameters: 1) the oil-gas mix for the play (gas-dominated versus oil dominated); and 2) the fill fraction distributions (proportion of available trap volume filled with petroleum). Model data linked to dominant play charging systems are listed in table 13.10.

The oil-gas mix is modeled into the analysis as four separate fractions (or probabilities): 1) OPROB, the fraction of pools completely charged with oil; 2) MXPROB, the fraction of pools charged with both oil and gas (segregated into a cap); 3) OFRAC, the fraction of the pay volume in mixed pools that is assignable to oil; and 4) GPROB, the fraction of pools completely charged with gas.

Fill fraction distributions primarily reflect the perceived richness or petroleum generating capacity of the source rocks charging the play. The differences among them are only valid in a

TABLE 13.10
MODELS FOR PLAY CHARGING SYSTEMS

CHARGE SYSTEM	OIL-GAS MIX				PROSPECT FILL FRACTION	
	OPROB	GPROB	MXPROB	OFRAC	F50	F00 (MAX)
North Chukchi Basin	0.34	0.43	0.23	0.50	0.25	0.60
Hanna Trough	0.00	0.00	1.00	0.70	0.43	1.00
Colville Basin	0.36	0.64	0.00	0.43	0.25	0.50

relative manner. For example, because the Hanna trough play charging system is viewed as the most prolific, prospects in plays charged by it are permitted the highest fill fractions.

The oil-gas mix for the North Chukchi basin play charging system is based on a field count in the Mackenzie delta (17 gas, 9 mixed oil and gas, 13 oil; Dixon and others, 1985, p. 20). Our fill fractions are also taken from data developed for Mackenzie delta (Wilson, 1978, graph 8), which shows a maximum fill fraction of 60 percent, probably reflecting some limitations for charge capacity and perhaps seal integrity.

The oil-gas mix for the Hanna trough play charging system is based on the fields in the Prudhoe Bay area, excluding the West Sak-Ugnu deposits. Most fields have gas caps (MXPROB=1.0), and the recoverable BOE oil-gas ratio overall is about 70 percent oil and 30 percent gas (OFRAC=0,70). Because the system has such a prolific generation capacity, fill levels for prospects charged by Hanna trough petroleum are permitted to rise to 100 percent.

In the foldbelt, the field count yields 1 oil field and 6 gas fields (includes Tungak Creek test). However, the one oil field contains 36 percent of the collective recoverable BOE endowment of the known fields. The oil-gas mix modeled for the Colville basin play charging system tries to recognize both the observed segregation of oil and gas into separate fields and the BOE contribution of the oil by substituting the 36 percent as the proportion of fields all oil (OPROB). Because of the high amplitudes of some folds, concerns about seals, and the overall poor generative capacity of Torok shales in Colville basin, we propose a fill fraction maximum of 0.50. The median of the proposed fill fraction distribution (0.25) falls between the medians (0.10, 0.30) for two fill fraction distributions for correlative Colville basin plays onshore assessed in 1987 by the USGS (Nanushuk II and III; Bird, 1988, p. 91-92).

PLAY ORGANIZATION

At the most fundamental level, plays are organized around the five major tectonostratigraphic sequences recognized beneath Chukchi shelf, shown in the "major sequence" column in figure 13.4. These major sequences are the basis for collecting into ***play groups*** all prospects involving reservoirs formations occurring within the sequences. We therefore recognize the ***Lower Ellesmerian, Upper Ellesmerian, Rift, Lower Brookian, and Upper Brookian play groups***.

Within each play group, individual ***plays*** are distinguished on the basis of paleogeographic setting (opposite sides of basin, with different sediment source terranes), reservoir facies (e.g., carbonates versus various types of clastic deposits), structural setting (trap type), play petroleum charging system, or reservoir fluid content (plays offering only gas are set apart). The distinguishing attributes of each play are given below with individual play descriptions.

Of the 22 plays proposed for Chukchi shelf assessment province, 15 were sampled by wells offshore or along the west coast of Arctic Alaska. Only 7 of the sampled plays, however, were actually tested within closed volumes (prospects) at the sites of the wells. Klondike well tested prospects in plays 5, 8, 12, and 13, encountering pooled oil in plays 5, 8, and 12. Burger well tested prospects in plays 7 and 18 and found gas pools in both. Popcorn well tested prospects in plays 3 and 7, encountering pooled gas in play 7. Crackerjack well tested a prospect in play 5, encountering pooled gas in play 5 and pooled oil in an unmapped stratigraphic trap in play 12.

PLAY DESCRIPTIONS

Play 1. Lower Ellesmerian: Endicott Clastics-Chukchi Platform (UAI[10]: UACS0100). Reservoir objectives primarily include Late

[10] *UAI is the "Unique Assessment Identifier" for each play, and is the principal guide to GRASP data files.*

Devonian(?) to Mississippian sandstones deposited in marginal marine to fluvial environments in western Hanna trough during the early rift or fault-driven phase of subsidence. Trap types on the east flank of Chukchi platform include early-formed horsts and areally-large stratigraphic wedges that were possibly disrupted by Paleocene transtensional faults. This play is charged by the Hanna trough play charging system, with petroleum generated from Triassic sources in Hanna trough migrating laterally westward beneath regional seals to large stratigraphic traps on Chukchi platform (fig. 13.24). Play 1 was not tested by any wells. The area of play 1 is shown in figure 13.25.

Play 2. Lower Ellesmerian: Endicott Clastics-Arctic Platform (UAI: UACS0200). Reservoir objectives primarily include Late Devonian(?) to Mississippian sandstones deposited in marginal- to non-marine environments in eastern Hanna trough during the early rift phase of subsidence. Early-formed horst and stratigraphic wedge traps have been buried to greater depths than their Chukchi platform counterparts in play 1 and are therefore associated with higher levels of thermal maturity and reduced chances for reservoir success. The play is charged by the Hanna trough play charging system. Most identified prospects lie considerably deeper than the primary regional source rock (Shublik Formation), and high thermal maturity of traps suggests the hydrocarbon endowment is largely dry gas. Play 2 is therefore modeled with a higher gas content than the other plays charged by the Hanna trough play charging system. Play 2 was not tested by any wells. The area of play 2 is shown in figure 13.25 and extends into western parts of Beaufort shelf assessment province, where it was assessed as Beaufort shelf play 1800.

Play 3. Lower Ellesmerian: Lisburne Carbonates (UAI: UACS0300). Reservoir objectives include Mississippian to Permian carbonates that were deposited on a stable marine shelf, with perhaps deeper water facies in the southeast part of the province in axial parts of Hanna trough (mostly in play 4). Porosity in Lisburne carbonates is associated with sparse porous zones in limestones and thin dolomite beds. No reef facies have been documented within the Lisburne carbonate assemblage, which ranges in age from Mississippian to Permian. The play is primarily charged by stratigraphically-younger rocks of the Hanna trough play charging system (fig. 13.24), with possible minor contributions from interbedded organically-lean and gas-prone shales. Incomplete penetrations of the Lisburne carbonates occurred at Popcorn, Crackerjack, and Diamond wells, which encountered carbonates with porosities ranging from 0 to 14 percent. Trace oil shows were noted in Lisburne carbonates in Popcorn and Diamond wells. The area of play 3 is shown in figure 13.25 and extends into western parts of Beaufort shelf assessment province, where it was assessed as Beaufort shelf play 1900.

Play 4. Ellesmerian Sequence: Overmature "Deep Gas" (Lower and Upper Ellesmerian Sequences) (UAI: UACS0400). Reservoir objectives include all potential reservoirs in both Lower Ellesmerian and Upper Ellesmerian sequences (reservoir strata described in plays 1,2,3,5, and 6). Prospects in play 4 occur at subsurface depths beneath the oil floor (2.0% vitrinite reflectance) and would contain only gas. High thermal maturities have a detrimental effect on reservoir properties and multi-cycle tectonic history combined with extremely deep burial at present (to 38,000 ft) result in high exploration risks for play 4. Play 4 was penetrated at Tunalik well in northwestern Alaska with minor gas shows in the Shublik Formation (pl. 13.4). The areas of play 4 are shown in figures 13.25 (overmature Lower Ellesmerian prospects) and 13.26 (overmature Upper Ellesmerian prospects). At the level of Lower Ellesmerian rocks, play 4 extends into western parts of Beaufort shelf assessment province, where it was assessed as Beaufort shelf play 2000.

Play 5. Upper Ellesmerian: Sadlerochit Group-Chukchi Platform (UAI: UACS0500). Reservoir objectives lie within Late Permian to Jurassic marine strata deposited on the western side of Hanna trough, mostly during a "sag" or thermal phase of subsidence that followed the fault-driven subsidence that controlled Lower Ellesmerian sedimentation in Hanna trough. The only potential reservoirs encountered in wells are spiculitic mudstones and cherts offering sparse moldic porosity, and some marine sandstones (Klondike well, Kavik(?) sandstone, 11,100-11,625 ft). More proximal (nearshore, littoral) sandstones postulated to have been deposited to the west may have been lost to truncation at Mesozoic unconformities. The potential absence of a western, proximal, reservoir-quality sandstone facies, as now suggested by well data, forms a major risk element for this play. Hydrocarbons are primarily derived from Triassic source beds of the Hanna trough play charging system, with migration paths to the west beneath regional seals into areally large stratigraphic traps (fig. 13.24). Early-formed stratigraphic traps were disrupted by Paleocene transtensional faults in some areas (fig. 13.9, pl. 13.3) and trap integrity may be an additional risk element for this play. Play 5 was penetrated by Crackerjack and Klondike wells, both of which encountered pooled hydrocarbons within the play sequence (pl. 13.4). The area of play 5 is shown in figure 13.26.

Play 6. Upper Ellesmerian: Sadlerochit Group-Arctic Platform (UAI: UACS0600). Reservoir objectives primarily include marginal to shallow marine sandstones that were deposited on the south-facing shelf that existed on the Arctic platform from Late Permian to Jurassic time. Triassic sandstones of the Sadlerochit Group are the primary targets, but reservoir sandstones like the Sag River or Simpson sandstones found onshore (pl. 13.4, Peard well) may also occur in Jurassic strata. Diamond well, offshore on the east flank of Hanna trough, encountered over 500 feet of potential reservoir strata that are correlative to the Permian Echooka Formation (pl. 13.4) at the base of the Sadlerochit Group. Primary trap styles include stratigraphic wedges and fault traps, with hydrocarbons migrating northward into traps from the Hanna trough play charging system to the south (fig. 13.24). A prospect in play 6 was tested by Diamond well, which encountered trace oil shows in sandstones of the Ivishak and Echooka Formations (pl. 13.4). At Barrow, gas production is occurring from Lower Jurassic ("Barrow") sandstones that are apparently unique to the Barrow area Several wells in northwestern Alaska penetrated the parts of the play sequence that extend offshore, but encountered no pooled hydrocarbons. The area of play 6 is shown in figure 13.26. Play 6 extends into western parts of Beaufort shelf assessment province and was assessed there as Beaufort shelf play 2100.

Play 7. Rift Sequence: Active Margin Clastics (UAI: UACS0700). Reservoirs are primarily Upper Jurassic to Lower Cretaceous sandstones (equivalent to the Kuparuk Formation) that were deposited in a zone of active faulting and flexural subsidence near an active rift that lay beneath what is now North Chukchi basin. This tectonic environment produced a pattern of abrupt thickness changes among component stratigraphic units. Areas of great thickness of the Rift sequence may correspond to great (and possibly commercial) thicknesses of sandstone reservoirs within the sequence. This inferred correspondence draws upon analogy to the abrupt expansion in thickness of Kuparuk sandstones that is observed in fault-bounded depressions in the Prudhoe Bay area. Kuparuk sandstones are 50 to 100 feet thick in most areas, including Kuoaruk field, but expand to 450 gross feet in the fault-bounded depression hosting Point McIntyre field near Prudhoe Bay (AOGCC, 1993, p.102). During Rift sequence deposition, tectonic depressions evidently accomodated greater thicknesses of strata, including reservoir sandstones. Play 7 is charged by the Hanna trough play charging system (fig. 13.24). Three offshore wells (Burger, Crackerjack, Popcorn) penetrated play 7. Burger and Popcorn wells encountered gas (with condensate) in sandstones ranging up to 115 feet in thickness at Burger (pl. 13.4). Burger structure probably houses a multi-TCF gas pool, although no accurate estimate is yet available. At Crackerjack well, no sandstones are preserved within the Rift sequence because most of the sequence is truncated at the Lower Cretaceous unconformity (pl. 13.4). The area of play 7 is shown in figure 13.27.

Play 8. Rift Sequence: Stable Marine Shelf (UAI: UACS0800). Reservoirs are primarily Late Jurassic to Early Cretaceous sandstones equivalent to the Kuparuk Formation of northern Alaska. Unlike the Rift sequence in the tectonically active rift zone (play 7) to the north, the Rift sequence in play 8 was instead deposited on a tectonically stable shelf and slope that rimmed a deep water "basin plain" area in southernmost Hanna trough (located in fig. 13.6). On the stable shelf and slope, we anticipate fine-grained marine shelf sandstones that are probably thinner than their counterparts in tectonic depressions in play 7. This play is charged by the Hanna trough play charging system. A prospect within the play was incidentally tested while drilling to a deeper target by Klondike well, encountering pooled oil (inferred from logs) in a sandstone 80 feet thick (pl. 13.4). Diamond well encountered no sandstones in the Rift sequence (only the Pebble Shale was present) and was barren of hydrocarbons. The Rift sequence was associated with minor gas shows at Peard No. 1 well onshore (pl. 13.4). The sequence hosts a gas field at Walakpa (fig. 13.27) that is produced for use by the community of Barrow. The area of play 8 is shown in figure 13.27 extending into large parts of Beaufort shelf assessment province west of Point Barrow, and was there assessed as Beaufort shelf play 2200.

Play 9. Rift Sequence: Overmature "Deep Gas" (UAI: UACS0900). This play includes prospects that lie at subsurface depths beneath the oil preservation floor (2.0% vitrinite reflectance) and that would therefore contain only gas. Reservoir objectives would be primarily thin, basin-floor turbidite sandstones deposited in the basin plain area south of the stable shelf sedimentary province of the Rift sequence (fig. 13.6). However, in western Arctic Alaska, shelf deposits in the play sequence (e.g., at Tunalik well) enter the gas window as well. The anticipated hydrocarbon mix is 100 percent gas, probably derived from underlying, oil-expended Shubik source beds of the Hanna trough play charging system, or marine shales (upper Kingak Formation, Kuparuk Formation, Pebble Shale) within the Rift sequence. High levels of thermal maturity for prospect reservoirs are expected to have an adverse effect on reservoir properties (tbl. 13.5), which primarily accounts for the small endowment of this play. Play 9 was penetrated at Tunalik well, which encountered pooled gas (logs) in a Kuparuk-equivalent sandstone at 12,508 feet within the play sequence (pl. 13.4). The area of play 9 is shown in figure 13.27.

Play 10. Lower Brookian: Herald Arch and Thrust Zone (UAI: UACS1000). This play involves highly-deformed Cretaceous and older (i.e., Lower Brookian, Ellesmerian) rocks that comprise acoustic basement beneath Herald thrust zone and Herald arch north of the limit for Tertiary strata in Hope basin (figs. 13.7, 13.8). Although fragments of axial areas of synclines are visible in some seismic profiles in Herald thrust zone, no traps can be reliably mapped. However, we speculate that traps in unseen anticlinal closures between synclines are present, but generally small in size consistent with the small fold wavelengths suggested by the synclines observed in seismic data. High levels of thermal maturity (1.76 percent vitrinite reflectance in Jurassic argillite cored at the seafloor south of Herald fault; Fugro-McClelland, 1985; located as USGS-7 in fig. 13.21) suggest that any pooled hydrocarbons will be only gas. This play was apparently tested at Eagle Creek and Akulik wells onshore, both of which recovered minor quantities of gas in drill stem tests from structurally complex Nanushuk or Torok Formation sandstones. The area of play 10 is shown in figure 13.28.

Play 11. Lower Brookian: Foreland Basin Foldbelt (UAI: UACS1100). Reservoir objectives are primarily deltaic sandstones of the Nanushuk Group deposited in Colville basin in Early Cretaceous time and subsequently deformed by north-verging Brooks Range deformation in earliest Paleocene time. Structural deformation increases toward the south, and broad unfaulted anticlines in the northern part of the play area grade into steep-limbed, thrust-faulted, and often breached anticlines to the south (fig. 13.8). Potential reservoir sandstones in the folded sequence are charged by the Colville basin play charging system (fig. 13.24). Play 11 was not tested offshore. Onshore exploratory drilling of about 30 anticlinal prospects over about 50 years discovered 6 sites of pooled gas (Tungak Creek(?), Wolf Creek, Gubik, Meade, Square Lake, and East Umiat) and one oil field (Umiat) with estimated reserves of 70 million barrels (Thomas and others, 1991, table 2-5). The area of play 11, and the area of overlap of play 11 and the deeper play 16, are shown in figure 13.28.

Play 12. Lower Brookian: Torok Turbidites-Chukchi Platform Wrench Zone (UAI: UACS1200). Potential reservoirs are primarily turbidite sandstones within Lower Cretaceous Torok Formation shales deposited in a prodelta system on the shelf terrace between Colville and North Chukchi basins and on Chukchi platform. A sequence of turbiditic sandstones over 300 ft thick (gross) was encountered at the base of the Torok Formation in Crackerjack well (pl. 13.4). Prospects are fault traps and faulted anticlines along transtensional faults that were active in early Tertiary time. The transtensional faults lie in several discrete north-trending, densely-faulted zones, as mapped in detail for southern parts of the play area in figure 13.9 and for northern parts of the play area in plate 13.3. Several evaporite diapirs pierce this play and create traps against diapir flanks in a narrow graben just west of Popcorn well (structure mapped and diapirs located in pl. 13.3). This play is charged by the Hanna trough play charging system, with some hydrocarbons possibly re-migrating into Brookian sandstones from deeper Ellesmerian stratigraphic traps disrupted by Paleocene faults. The play was penetrated at three wells, with pooled oil apparently present (logs) at Crackerjack and Klondike wells and minor oil shows present in a turbidite sandstone at Popcorn well (pl. 13.4). The area of play 12 is shown in figure 13.28.

Play 13. Lower Brookian: Nanushuk Topset-Chukchi Platform Wrench Zone (UAI: UACS1300). Potential reservoirs are primarily sandstones of the Albian-Cenomanian Nanushuk Group that were deposited in delta-plain and nearshore environments on the shelf terrace between Colville and North Chukchi basins, and, on Chukchi platform. The play was penetrated by two wells (Crackerjack and Klondike), which encountered only very sparse sandstones, some traces of oil, and no pooled hydrocarbons (pl. 13.4). Prospects are fault traps, faulted anticlines, and diapir-flank traps, as in (the underlying) play 12. This play, like play 12, is charged by the Hanna trough play charging system, with some hydrocarbons possibly re-migrated out of deeper Ellesmerian stratigraphic traps disrupted by faults. The area of play 13 is shown in figure 13.28.

Play 14. Sand Apron-North Chukchi High (Upper and Lower Brookian sequences) (UAI: UACS1400). Potential reservoirs are inferred to consist primarily of shallow marine to fluvial sandstones of Early Cretaceous to Tertiary age that are hypothesized to have been deposited in littoral systems that fringed North Chukchi high, an area of recurrent uplift throughout Albian-Aptian (post-Brookian unconformity) and later time (Johnson, 1992). Play 14 therefore includes both Lower and Upper Brookian sequences. The play is probably charged primarily by the North Chukchi basin play charging system on the west (fig. 13.24). Play 14 was not tested by any well.

The areas of play 14, which extend into western parts of Beaufort shelf assessment province (assessed there as Beaufort shelf play 2300), are shown in figures 13.28 and 13.29 (Lower and Upper Brookian sequences, respectively).

Play 15. Lower Brookian: Cretaceous Topset-North Chukchi Basin (UAI: UACS1500). Potential reservoirs are hypothesized to be deltaic sandstones of Cretaceous (possibly Late Cretaceous?) age that concluded an early cycle of filling of North Chukchi basin (concept illustrated in fig. 13.5D). We speculate that these deposits represent the filling of the basin to baseline prior to a second cycle of subsidence begun in Paleocene time. Traps are primarily north-trending horsts formed during early Tertiary time. The play is presumed to be charged by the North Chukchi basin play charging system (fig. 13.24). No rocks correlative to the proposed Upper Cretaceous(?) reservoir sequence of play 15 are present in any well on Chukchi shelf. The play was not tested by any Chukchi shelf well. The area of play 15 is shown in figure 13.28.

Play 16. Brookian Sequence (Upper and Lower Brookian): Overmature "Deep Gas" (UAI: UACS1600). Potential reservoir objectives include mostly Cretaceous and Tertiary sandstones in both Colville and North Chukchi basins that lie at depths below the oil floor, at thermal maturities exceeding 2.0 percent vitrinite reflectance. Play 16 therefore includes mostly rocks of the Lower Brookian sequence in both the Colville and North Chukchi basins. Rocks of the Upper Brookian sequence also exceed 2.0 percent vitrinite reflectance in a small, deep graben in North Chukchi basin. All pools within this play are modeled as consisting completely of gas. In Colville basin, the traps are primarily located in the undeformed plate below the regional decollement at the base of the foldbelt play (11). The subthrust plate probably consists of Torok Formation shales and turbiditic sandstones. This play was not tested by any well. The areas of play 16 are shown in figures 13.28 and 13.29.

Play 17. Lower Brookian: Torok Turbidites-Arctic Platform (Unstructured) (UAI: UACS1700). This play addresses the unstructured area of the Arctic platform that lies south of Barrow arch, east of the wrench fault province of western Chukchi shelf (equivalent play 12), and north of the foldbelt (play 11). Play 17 overlaps western parts of the Beaufort shelf assessment province and was assessed there as Beaufort shelf play 2400. Potential reservoirs are turbidite sandstones within the Lower Cretaceous Torok Formation. Exploratory drilling at Diamond and Berger prospects has shown that sandstone is quite sparse within the Torok Formation in this play. Reservoir presence is therefore one important risk element for the play. Low-relief anticlines (possibly related to compaction), mounded fan complexes, and slope turbidites (isolated within slope shales) form the primary anticipated trap types, few of which are readily observable in seismic data. The play is modeled as predominately charged by the Hanna trough play charging system, although some contribution from the gas-rich Colville basin system is also possible, particularly in southern parts of the play area (fig. 13.24). The play was tested by Burger and Diamond wells, the latter noting minor oil shows. Peard and Tunalik wells encountered abundant gas shows in turbiditic sandstones of the Torok Formation. The area of play 17 is shown in figure 13.28.

Play 18. Lower Brookian: Nanushuk Topset-Arctic Platform (Unstructured) (UAI: UACS1800). Like play 17, play 18 addresses the unstructured area of the Arctic platform that lies south of Barrow arch, east of the wrench fault province of western Chukchi shelf (equivalent play 13), and north of the foldbelt (play 11). Play 18 overlaps western parts of the Beaufort shelf assessment province and was assessed there as Beaufort shelf play 2500. Reservoir objectives include delta-plain and nearshore sandstones of the Lower Cretaceous Nanushuk Group. Low-relief anticlines possibly related to differential compaction and stratigraphic terminations of homoclinally south-dipping sandstones form the primary trap types. Like play 17, the play is modeled as predominately charged by the Hanna trough play charging system, although some contribution from the gas-rich Colville basin system on the south is possible (fig. 13.24). The play was tested at Diamond and Burger wells. A gas-charged sandstone 36 feet thick was encountered at Burger well, which is located within several miles of a fault that passes 3,500 feet below into a gas pool in a Rift sequence sandstone (pl. 13.4). This fault may have formed a migration conduit for gas escaping upward from the pool in the Rift sequence sandstone. The area of play 18 is shown in figure 13.28.

Play 19. Upper Brookian: Upper Tertiary Sag Phase-North Chukchi Basin (UAI: UACS1900). Potential reservoirs include Eocene and younger marine sandstones deposited in North Chukchi basin during the post-rift thermal or "sag" phase of basin subsidence (concept illustrated in fig. 13.5E). Some sandstones in this sequence may be associated with a late Eocene (and younger) regression now marked by an unconformity overlain by Late Oligocene to Miocene strata at 1,041 feet in Popcorn well (pl. 13.4) and widely observed and mapped in seismic data in North Chukchi basin (surface "UB", Lothamer, 1994). Prospects include fault traps, faulted anticlines, and diapir-flank traps, the latter in a graben west of Popcorn well. This play is mostly charged by the North Chukchi basin play charging system (fig. 13.24). Play 19 was tested in a proximal setting by Popcorn well, which encountered only very sparse sandstone in the Eocene sequence (1,041 to 3,235 feet) but abundant sandstones in shallow, unlogged parts of the well above 1,300 feet (pl. 13.4). Reservoir presence is therefore considered a major risk element for this play. The area of play 19, which is complexly overlapped by several other play areas, is shown in figure 13.29.

Play 20. Upper Brookian: Lower Tertiary Turbidites-North Chukchi Basin (UAI: UACS2000). Potential reservoirs are mostly turbidite sandstones hypothesized to have been deposited within north-trending, faulted-bounded seafloor grabens formed during Paleocene transtensional rifting in North Chukchi basin. Play 20 is charged by the North Chukchi basin play charging system (fig. 13.24). This play was not tested by any well. The area of play 20 is shown in figure 13.29.

Play 21. Upper Brookian: Lower Tertiary Paleovalley Fill (UAI: UACS2100). Potential reservoirs are primarily fluvial sandstones deposited in paleovalleys (developed over grabens bounded by transtensional faults) that emptied northward from Chukchi platform into North Chukchi basin in Paleocene time. The fluvial sandstones lie at the base of a transgressive Paleocene sequence that records progressive drowning of the valleys. This play was tested at Popcorn, Crackerjack, and Klondike wells. All wells encountered highly porous sandstones at the base of Paleocene rocks, with the maximum observed sandstone thickness reaching 540 feet at Popcorn well. Traps are primarily stratigraphic pinch-outs or fault truncations of the fluvial sandstones along the north-trending valley margins. Minor diapir-flank traps occur in a narrow graben west of Popcorn well. The play is modeled as predominantly charged by the Hanna trough play charging system, although some parts of the play extend north into North Chukchi basin and may be charged by hydrocarbons migrating from that area. No shows or zones of pooled oil or gas were encountered in Upper Brookian sandstones in any of the three wells that penetrated the sequence. The areas of play 21, which mark the north-trending grabens south of North Chukchi basin, are shown in figure 13.29.

Play 22. Upper Brookian: Tertiary Basal Transgressive Sand-Intervalley Uplifts (UAI: UACS2200). Potential reservoirs include transgressive-lag sandstone reservoirs deposited on wrench-fault-bounded structural ridges or horsts in Paleocene time. Because of the transgressive nature of the sandstones and the low inclination of flooding surfaces at the crests of intervalley uplifts, reservoirs are modeled as thin relative to play 21 (see discussion of transgressive sand thicknesses by Abbott, 1985, p. 158). The play is modeled as predominantly charged by the Hanna trough play charging system. This play was not tested by any well. The areas of play 22, which mark north-trending horsts south of North Chukchi basin, are shown in figure 13.29.

RISK ANALYSIS

Analysis of risk for plays was carried out along the lines suggested by White (1993). Risk was assessed at two levels for each play: 1) at the play level, where the absence of a critical element could hazard the success of the entire play; and 2) at the prospect level, where a critical element might fail for only some fraction of the prospects in the play.

The occurrence within a play of conventionally pooled hydrocarbons capable of flowing to a wellbore meant that the play was geologically successful. Such a play was assigned a play level chance of success of 1.0.

Estimates of prospect level chances of success are ***conditional*** upon success (i.e., success is assumed) at the play level because chances for success at both prospect and play levels are ultimately multiplied to obtain an "exploration" chance for success. The ***exploration chance*** is in turn multiplied by the numbers of prospects to determine the fraction (of prospects) that succeed in becoming petroleum pools. Chances for success at the prospect level are therefore much like measurable success rates or ratios, and, accordingly, are often modeled after known drilling success rates experienced in successful plays in productive basins.

Success of a play or prospect can be defined in different ways. Economic success in oil prospecting is contingent upon finding sufficient reserves to permit the deposit to be developed at a profit. However, some (or most) oil or gas pools, particularly in the Arctic, are too small to warrant commercial development. Nevertheless, these small pools represent "geologic" successes, proving that oil or gas must have been generated somewhere and was able to migrate to traps bearing porous media that could be filled with petroleum. In effect, the small pools, by their existence, prove that all components of the petroleum system are working properly.

The 1995 assessment focused on the entire petroleum endowment, rather than just that minority fraction occurring in large, commercial-sized deposits. For this reason, risk assessments were developed for the case of "geologic" success, which includes the small deposits, rather than commercial success. Because "geologic" successes are more common than commercial successes, the probabilities for "geologic" success are generally much higher. Although commercial success rates in productive basins are widely available (e.g., Clifford, 1986), there is very little data available for rates of ***geologic success*** among prospects in successful plays around the world. As a means of setting an upper limit, we assumed that ***prospect level chances of geological success*** in the best plays probably would approach ***commercial success rates*** for plays in areas where costs are very low and very small accumulations are economically viable. For example, two recent papers (Shirley, 1994; Durham, 1995) tout drilling ***discovery success rates ranging from 71 to 84 percent*** on prospects drilled after careful screening (with sophisticated three-dimensional seismic analysis) in areas with extensive infrastructure and low development costs. We took these values as the upper limits for geological success in our high cost Arctic frontier basins. For example, prospect level chances of success (or success rates) were permitted to rise as high as 0.64 in the best Chukchi shelf plays.

In one Chukchi shelf play (11), actual success rates from a 50-year exploration history provide a basis for estimating prospect level chance of success (7 successes (all subcommercial) out of about 30 tests, or chance =7/30= 0.23). All other plays in Chukchi shelf required a much more subjective appraisal of the individual elements underlying play success. Our subjective risk analysis was constructed around all of the main elements required for successful creation and preservation of oil or gas deposits.

The key elements of risk were grouped into four major categories: 1) trap success; 2) reservoir success; 3) charge or source success; and 4) deposit preservation success. Subsidiary elements of ***trap success*** include closure presence (risk related to seismic definition), seal presence (or integrity), and timing (of trap formation relative to hydrocarbon generation and migration). Subsidiary elements of ***reservoir success*** include reservoir presence (stratigraphic extent) and presence of porosity and permeability. Subsidiary elements of ***charge or source success*** include presence (stratigraphic) of source rocks, thermal maturity of source rocks, and migration (direction, distance). Subsidiary elements of ***deposit preservation success*** include biodegradation, thermal degradation, and asphaltification. Each element was analyzed at both play and prospect levels. The results of risk analysis for Chukchi shelf plays are listed in tables 13.11 and 13.12.

PLAY DEPENDENCY MODEL

The 22 plays in Chukchi shelf assessment province were aggregated with dependencies using ***FASPAG***, an aggregation software provided by the project leadership for that purpose to the Alaska Region Office of Resource Evaluation.

Play dependencies were developed with the view that they formed a measure of the frequency of geological coincidence or "pairing" of accumulations. Geological coincidence is taken to mean that accumulations are within sufficient proximity to imply linked geological origin, mostly sharing a petroleum migration and delivery system. A dependency between two plays therefore implies that there exists a certain frequency with which accumulations in one play are paired with accumulations in other plays.

In constructing play dependencies, we considered the fractional overlap of areas of stacked (overlying stratigraphic sequences) plays, the frequency of coincidence of multiple play sequences in shared structures (e.g., separate play sequences both deformed in the same anticline), and the potential for migrating hydrocarbons to pass form one play sequence into another. For example, in the area of transtensional faulting on Chukchi platform, continuous faults pass through three or more play sequences and might have simultaneously conducted migrating hydrocarbons into fault-contact traps in all play sequences. These plays are therefore highly dependent in this faulted area. On the other hand, the foldbelt play (play 11) overlies several plays involving deeper, underlying sequences. Nevertheless, play 11 is modeled as independent of these deeper plays because it is isolated from them by a thick sequence of overpressured shale that is probably impermeable to migrating hydrocarbons.

The dependency model used to aggregate plays in the Chukchi shelf assessment province is assembled in table 13.13, which shows the aggregation groups in tiers that define aggregation steps as conducted serially from left to right.

RESULTS OF RESOURCE ASSESSMENT

Chukchi shelf assessment province is estimated to offer undiscovered, conventionally recoverable oil and condensate resources ranging between 6.8 and 21.9 billion barrels, with an average expectation of 13.0 billion barrels. Undiscovered, conventionally recoverable gas resources are estimated to range between 9.8 and 141.8 trillion cubic feet of combined solution gas,

TABLE 13.11
RESULTS OF RISK ANALYSIS FOR CHUKCHI SHELF PLAYS 1-11

PLAY NO.	RISK LEVEL	CLOSURE PRESENCE	SEAL PRESENCE	TIMING	RESERVOIR PRESENCE	PORE SYSTEM	SOURCE PRESENCE	SOURCE MATURITY	MIGRATION	PETROLEUM PRESERV.	OVERALL CHANCE	EXPLORATION CHANCE
1	PLAY					0.8			0.9		0.72	0.37
	PROSPECT	0.8			0.8				0.8		0.51	
2	PLAY					0.5			0.8		0.40	0.02
	PROSPECT		0.5		0.2				0.5		0.05	
3	PLAY				0.7				0.7		0.49	0.05
	PROSPECT	0.5				0.4			0.5		0.10	
4	PLAY					0.6				0.9	0.54	0.05
	PROSPECT	0.5			0.2						0.10	
5	PLAY										1.00	0.32
	PROSPECT	0.8			0.5				0.8		0.32	
6	PLAY								0.6		0.60	0.14
	PROSPECT		0.6			0.8			0.5		0.24	
7	PLAY										1.00	0.64
	PROSPECT	0.8							0.8		0.64	
8	PLAY										1.00	0.64
	PROSPECT	0.8							0.8		0.64	
9	PLAY										1.00	0.15
	PROSPECT	0.5				0.3					0.15	
10	PLAY	0.6				0.6				0.6	0.22	0.02
	PROSPECT	0.2				0.8			0.5		0.08	
11	PLAY										1.00	0.23
	PROSPECT										0.23	

TABLE 13.12
RESULTS OF RISK ANALYSIS FOR CHUKCHI SHELF PLAYS 12-22

PLAY NO.	RISK LEVEL	CLOSURE PRESENCE	SEAL PRESENCE	TIMING	RESERVOIR PRESENCE	PORE SYSTEM	SOURCE PRESENCE	SOURCE MATURITY	MIGRATION	PETROLEUM PRESERV.	OVERALL CHANCE	EXPLORATION CHANCE
12	PLAY										1.00	0.14
	PROSPECT	0.6			0.3				0.8		0.14	
13	PLAY		0.7						0.7		0.49	0.02
	PROSPECT		0.2		0.4				0.5		0.04	
14	PLAY		0.8							0.8	0.64	0.08
	PROSPECT		0.2		0.9				0.7		0.13	
15	PLAY					0.5					0.50	0.21
	PROSPECT	0.7			0.6						0.42	
16	PLAY					0.3					0.30	0.04
	PROSPECT	0.4			0.3						0.12	
17	PLAY					0.5					0.50	0.02
	PROSPECT	0.4			0.3				0.4		0.05	
18	PLAY										1.00	0.06
	PROSPECT	0.4			0.4				0.4		0.06	
19	PLAY				0.4						0.40	0.02
	PROSPECT	0.5				0.2			0.5		0.05	
20	PLAY		0.8			0.8					0.64	0.26
	PROSPECT		0.5		0.8						0.40	
21	PLAY		0.7								0.70	0.11
	PROSPECT	0.3							0.5		0.15	
22	PLAY		0.6			0.8					0.48	0.13
	PROSPECT	0.7			0.8				0.5		0.28	

TABLE 13.13
DEPENDENCY* MODEL FOR AGGREGATION
Chukchi Shelf Assessment Province

TIER 1	TIER 2	TIER 3	TIER 4 (FINAL)
Group 1 Plays 9 and 16 ***DEP=0.9***	Group 7 Groups 2 and 3 ***DEP=0.0***	Group 8 Groups 6 and 7 ***DEP=0.1***	Final Group (9) Groups 1, 4, 5, 8 ***DEP=0.0***
Group 2 Plays 1, 5, 12, 13, 21, 22 ***DEP=0.5***			
Group 3 Plays 2, 6, 17, 18 ***DEP=0.2***			
Group 4 Plays 15, 19, 20 ***DEP=0.5***			
Group 5 Plays 4, 10, 11, 14 ***DEP=0.0***			
Group 6 Plays 3, 7, 8 ***DEP=0.0***			

* *DEP represents degree of mutual dependence, or frequency of geological coincidence, among petroleum pools in plays forming the dependency groups. A DEP value of 1.0 indicates complete dependency. In a group consisting of two plays, this would imply that every petroleum pool in one play would be accompanied, in geologic proximity, by a second petroleum pool in the other play in the group. A DEP value of 0.0 indicates complete independence, or no correlation, among petroleum pools within the play group. Independence typically implies geographic isolation or absence of hydraulic communication (migrating hydrocarbons) between plays (for example, stacked plays separated by an unbreached regional seal).*

gas cap gas, and non-associated gas, with an average expectation of 51.8 trillion cubic feet.

The ranges given above represent the 95 percent and 5 percent fractiles of the cumulative probability distributions shown in figure 13.30. However, our results show that even greater quantities of oil and gas could occur in Chukchi shelf assessment province. The cumulative probability distributions of figure 13.30 show that at extremely low probabilities, very large resource endowments are possible. For example, there is a 1 percent chance that the Chukchi shelf assessment province may contain over 28 billion barrels of oil and 250 trillion cubic feet of gas.

Oil and gas endowments for the 22 plays assessed in Chukchi shelf assessment province are listed in table 13.14. Just four plays (1, 7, 8, and 14) carry 76 percent of the province oil endowment and 69 percent of the gas endowment. These four plays dominate the resource endowment because they offer many large prospects, ready access to petroleum charging systems, broad areas of shallow burial with commensurate extensive preservation of reservoir pore systems, and in some cases (7 and 8), proven geological success. These four plays will likely form the primary objectives of any future exploration programs on Chukchi shelf. Cumulative probability distributions for play resources and ranked plots for oil and gas pools (for each play) are shown in Appendix B1.

TABLE 13.14
OIL AND GAS ENDOWMENTS OF CHUKCHI SHELF PLAYS

PLAY NO.	PLAY NAME (UAI* CODE)	OIL (BBO)			GAS (TCFG)		
		F95	MEAN	F05	F95	MEAN	F05
1.	Endicott-Chukchi Platform (UACS0100)	0.000	3.001	6.696	0.000	9.762	19.377
2.	Endicott-Arctic Platform (UACS0200)	0.000	0.002	0.006	0.000	0.035	0.133
3.	Lisburne Carbonates (UACS0300)	0.000	0.041	0.149	0.000	0.137	0.509
4.	Ellesmerian Deep Gas (UACS0400)	0.000	0.016	0.049	0.000	0.629	1.962
5.	Sadlerochit-Chukchi Platform (UACS0500)	0.257	0.537	1.098	1.478	2.993	5.823
6.	Sadlerochit-Arctic Platform (UACS0600)	0.000	0.660	1.818	0.000	1.935	5.314
7.	Rift - Active Margin (UACS0700)	2.385	4.136	7.770	5.314	8.547	14.204
8.	Rift - Stable Shelf (UACS0800)	0.910	1.645	3.121	3.118	5.026	8.193
9.	Rift - Deep Gas (UACS0900)	0.0003	0.003	0.007	0.012	0.108	0.269
10.	Herald Arch (UACS1000)	0.000	0.00002	0.00008	0.000	0.0006	0.003
11.	L. Brook. Foldbelt (UACS1100)	0.149	0.265	0.430	2.328	4.491	8.225
12.	L. Brook. Turbidites/Wrench Zn (UACS1200)	0.054	0.147	0.331	0.240	0.635	1.384
13.	L. Brook. Topset/Wrench Zn (UACS1300)	0.000	0.110	0.371	0.000	0.326	1.376
14.	N. Chukchi High/Sand Apron (UACS1400)	0.000	1.182	3.497	0.000	13.082	36.046
15.	L. Brook. Topset/N. Chukchi Basin (UACS1500)	0.000	0.099	0.283	0.000	1.491	4.564
16.	Brookian Deep Gas (UACS1600)	0.000	0.006	0.028	0.000	0.237	1.076
17.	L. Brookian/Turbidites/Arct. Plat. (UACS1700)	0.000	0.003	0.021	0.000	0.008	0.053
18.	L. Brookian/Topset/Arctic Platform (UACS1800)	0.000	0.045	0.173	0.000	0.034	0.121
19.	U. Brookian/Sag Phase/N. Chuk. Bsn. (UACS1900)	0.000	0.002	0.012	0.000	0.038	0.171
20.	U. Brookian/Turbidites/N.Chuk.Bsn. (UACS2000)	0.000	0.027	0.068	0.000	0.484	1.306
21.	U. Brookian/Paleovalleys (UACS2100)	0.000	0.886	2.283	0.000	1.637	3.961
22.	U. Brookian/Intervalley Highs (UACS2200)	0.000	0.204	0.697	0.000	0.203	0.740
	FASPAG AGGREGATION	*6.801*	*13.015*	*21.943*	*9.808*	*51.840*	*141.754*

* *Unique Assessment Identifier, code unique to play.*

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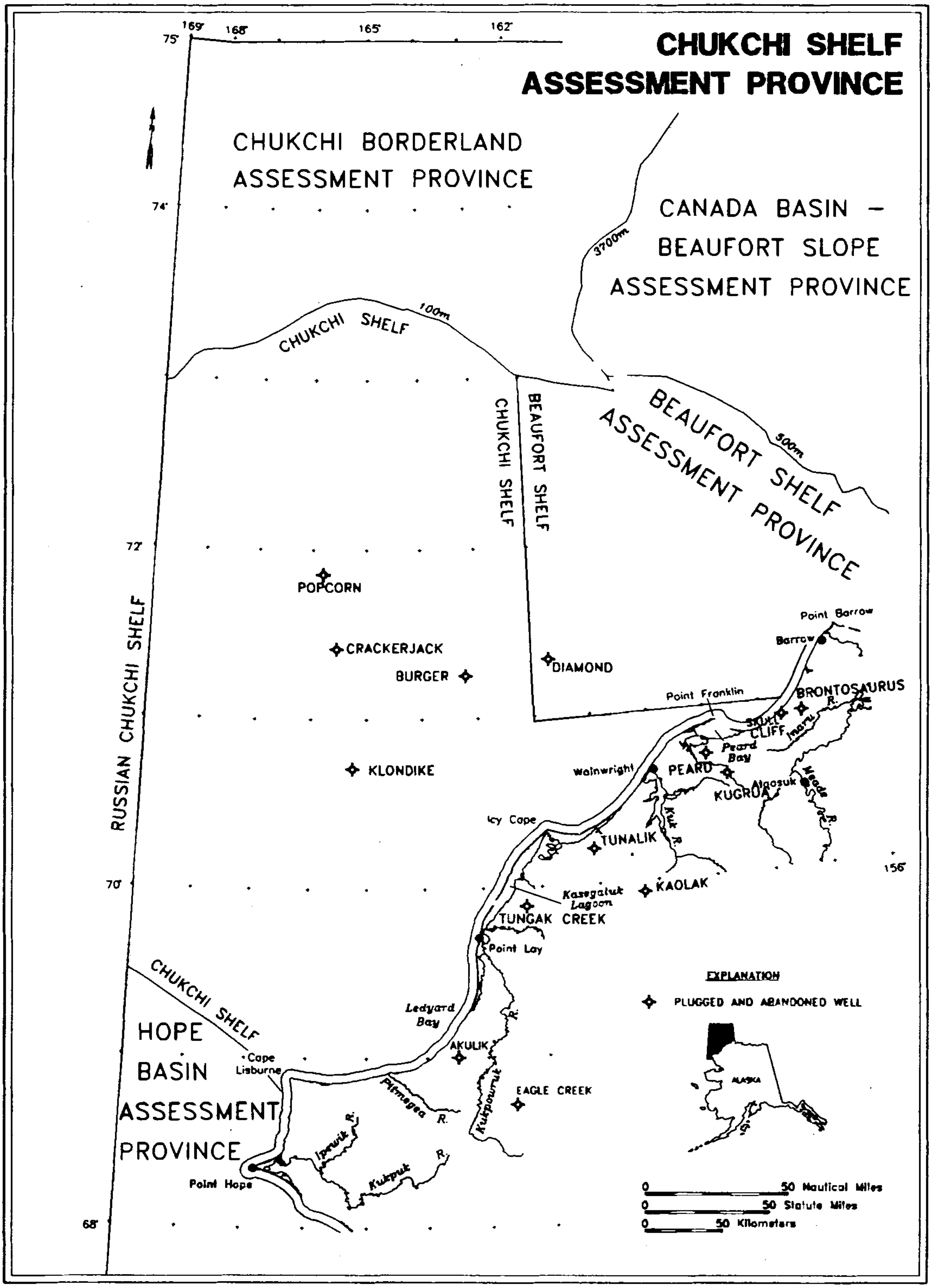

Figure 13.1: Chukchi shelf and adjoining assessment provinces, 1995 National Resource Assessment.

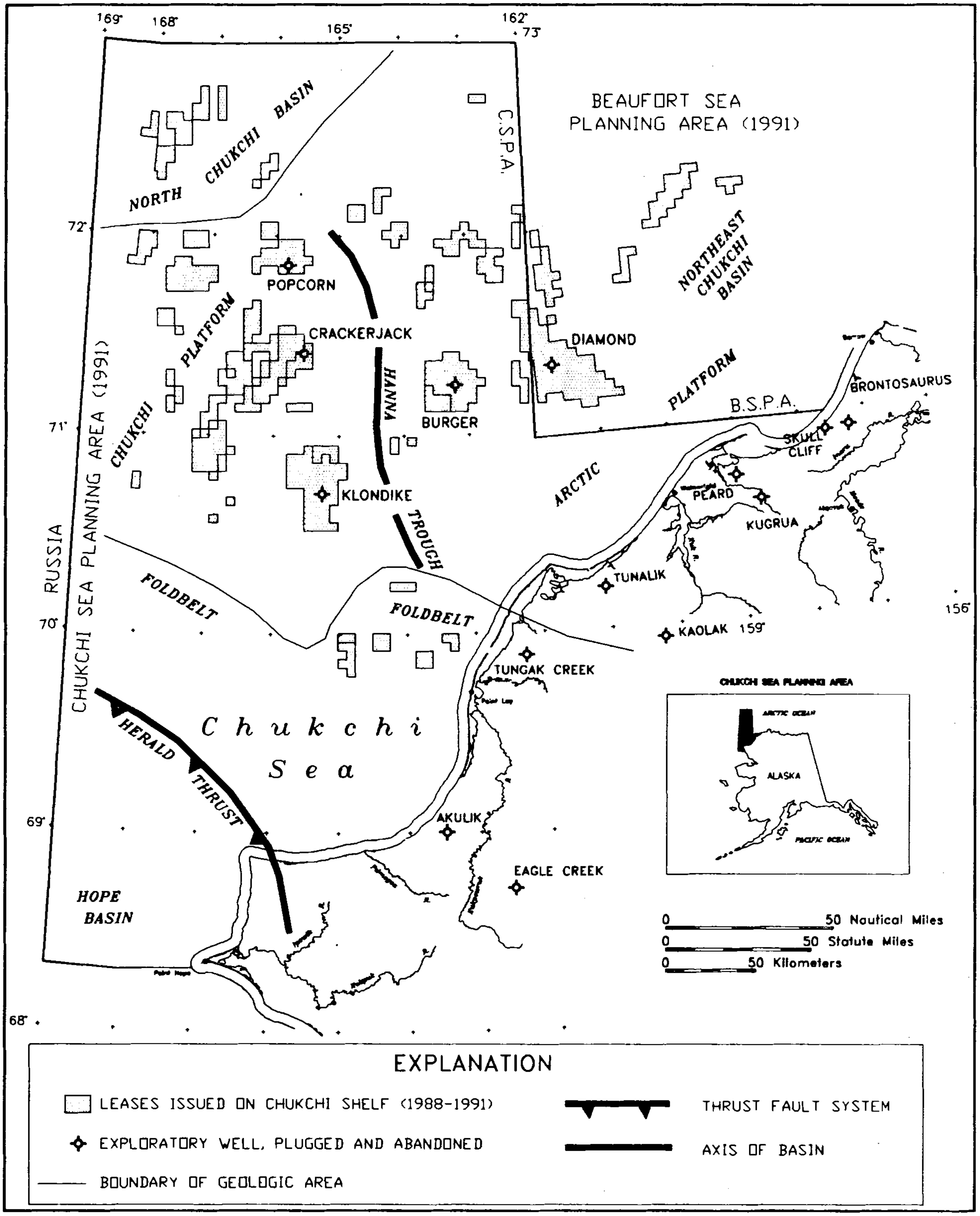

Figure 13.2: Leases issued on Chukchi shelf (OCS Lease Sales 97, 109, 124, and 126) and wells drilled from 1989 to 1991. As of December, 1996, all Chukchi shelf leases have been relinquished and are no longer active.

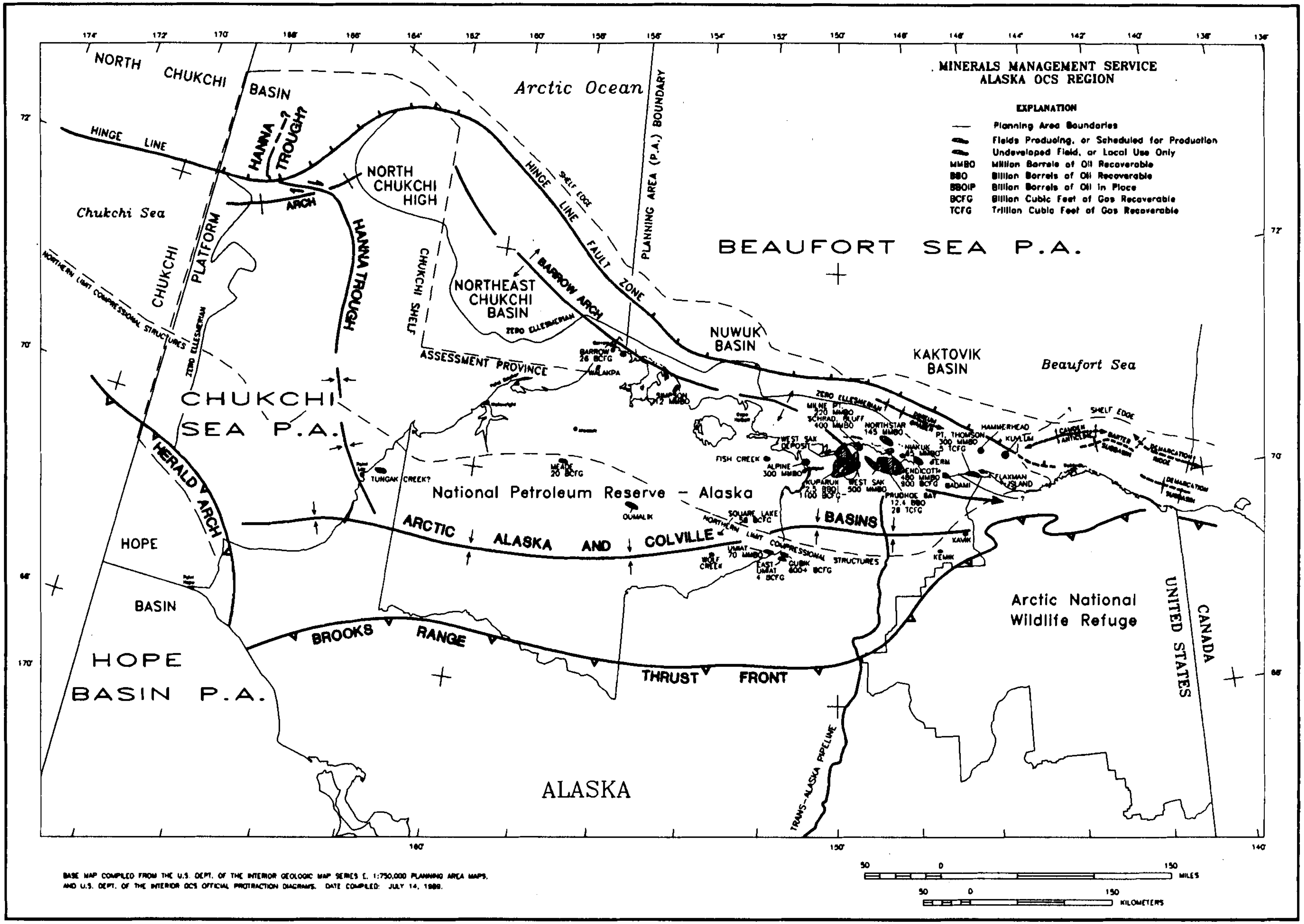

Figure 13.3: Regional geological elements of northern Alaska and Arctic Alaska offshore.

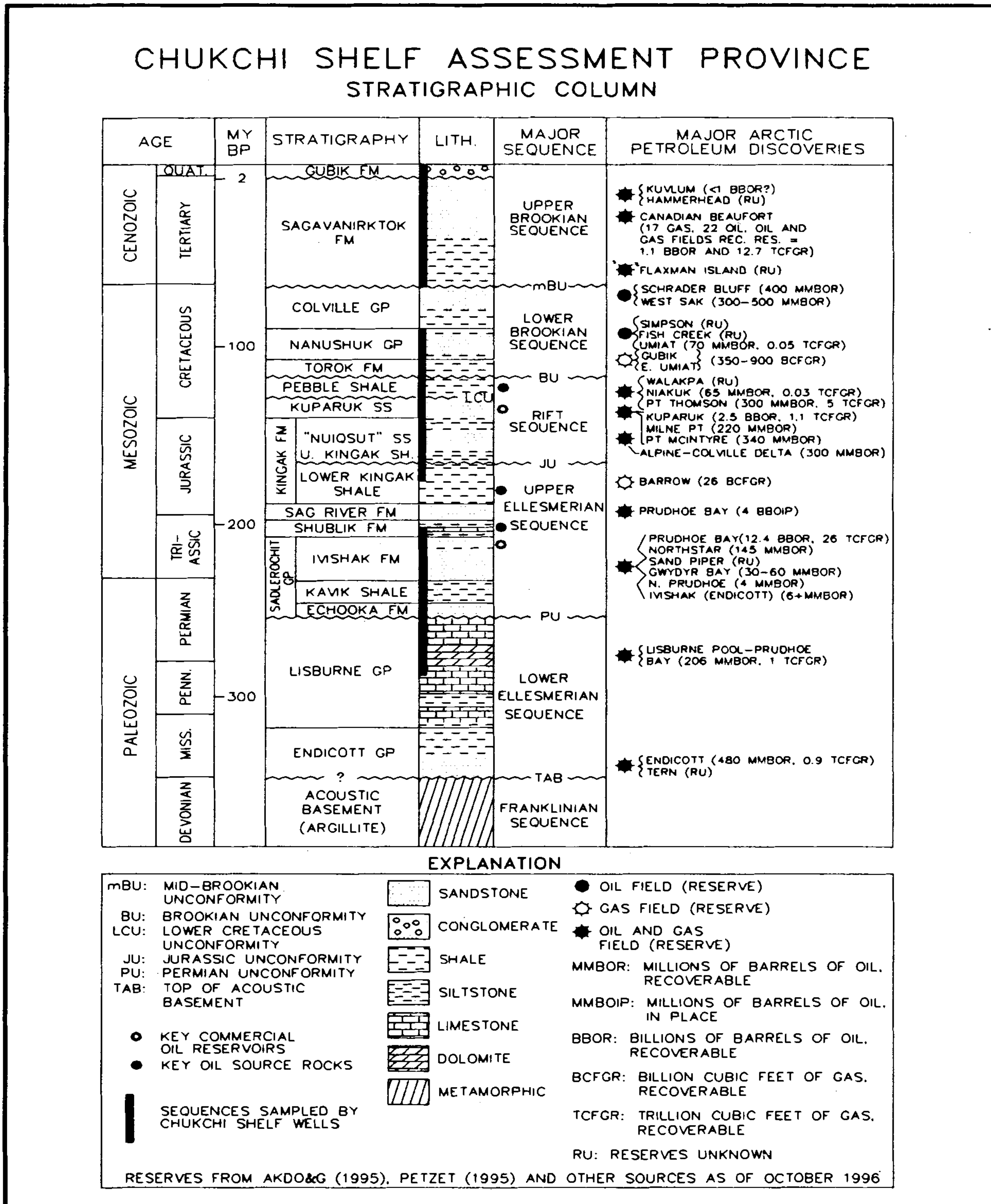

Figure 13.4: Stratigraphic column for northern Alaska and Chukchi shelf assessment province.

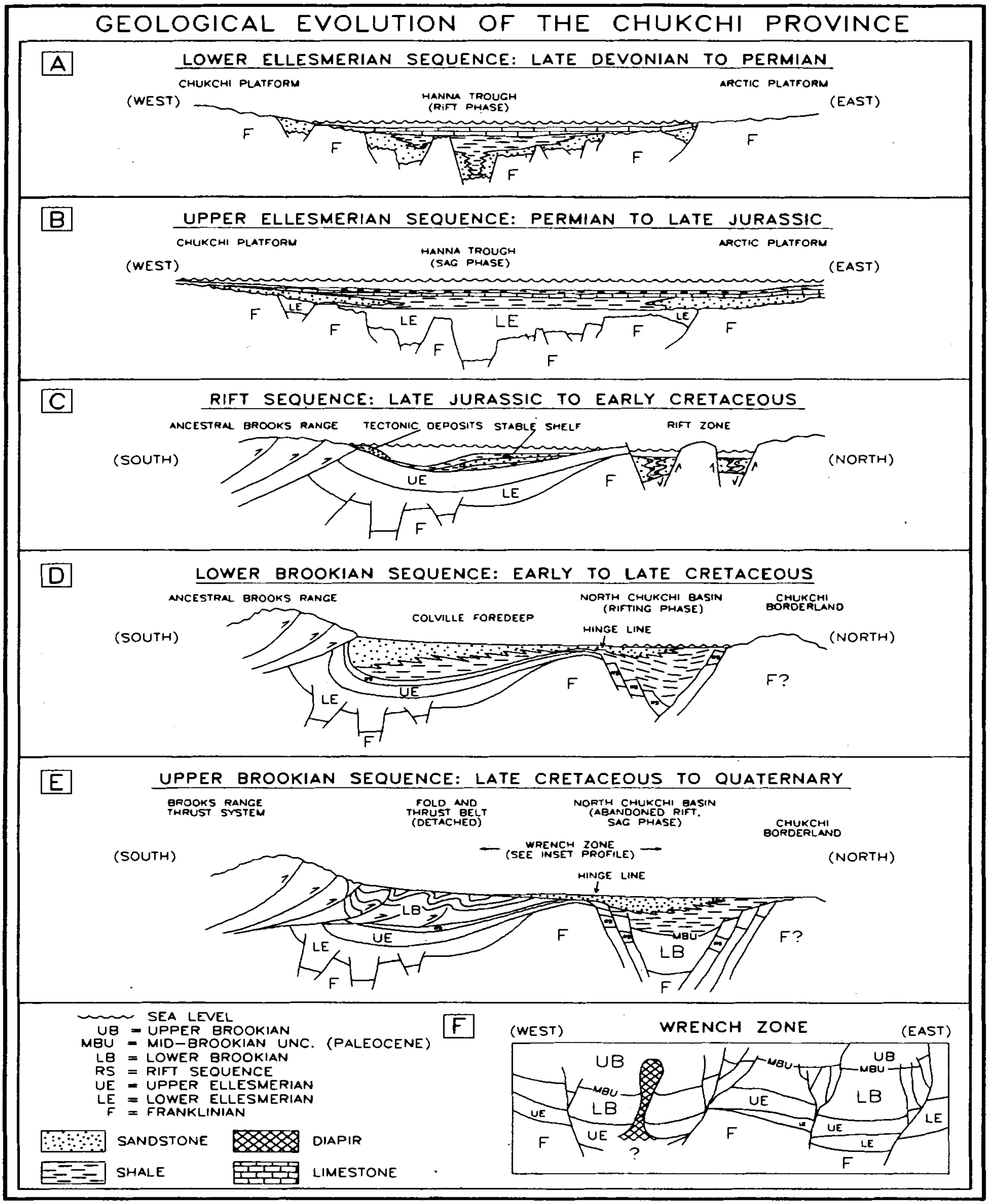

Figure 13.5: Schematic cross sections illustrating the five major basin-forming events that produced the five major play sequences beneath Chukchi shelf.

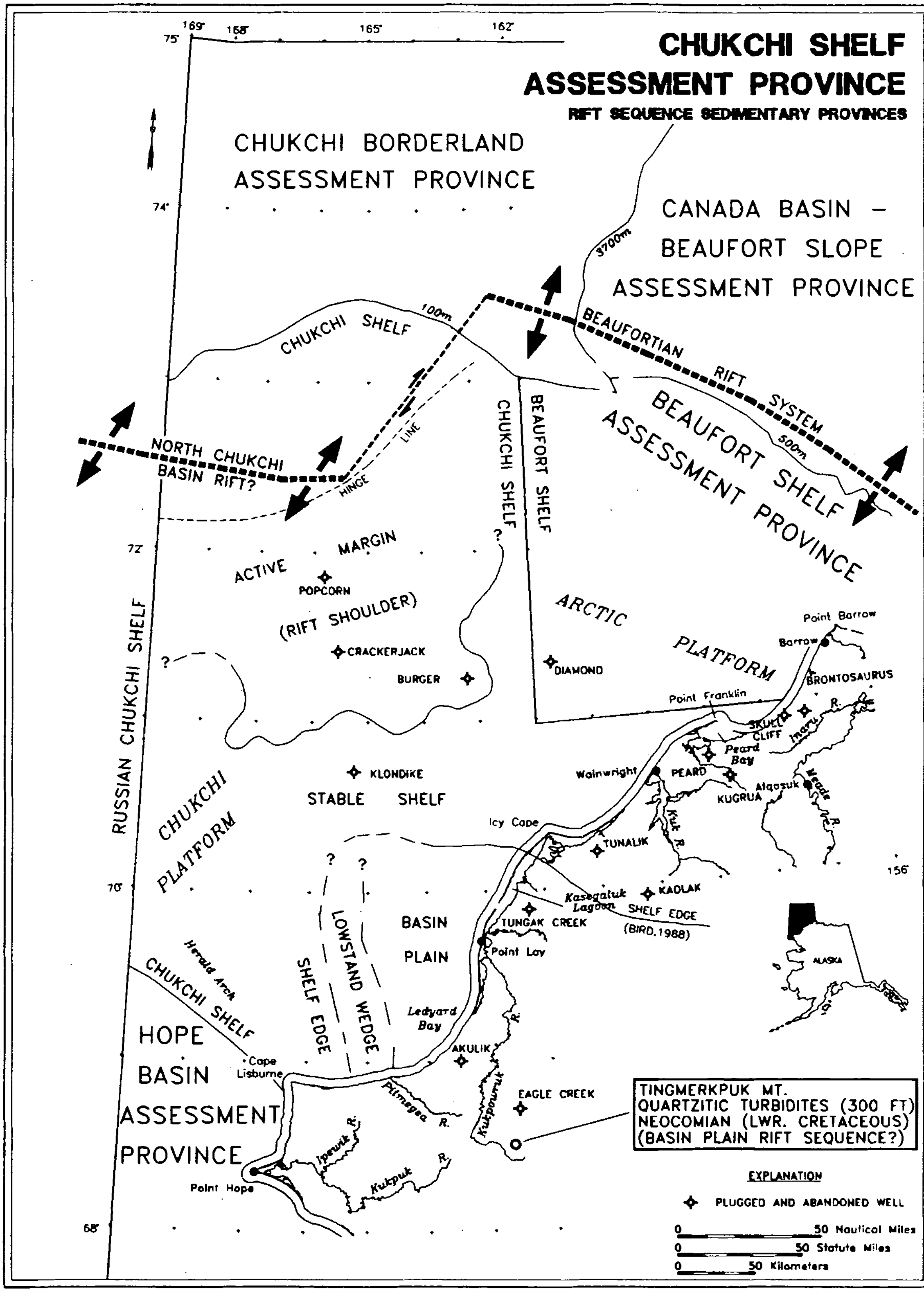

Figure 13.6: Tectonic and sedimentary provinces controlling Rift sequence sedimentation on Chukchi shelf from Jurassic to Early Cretaceous time.

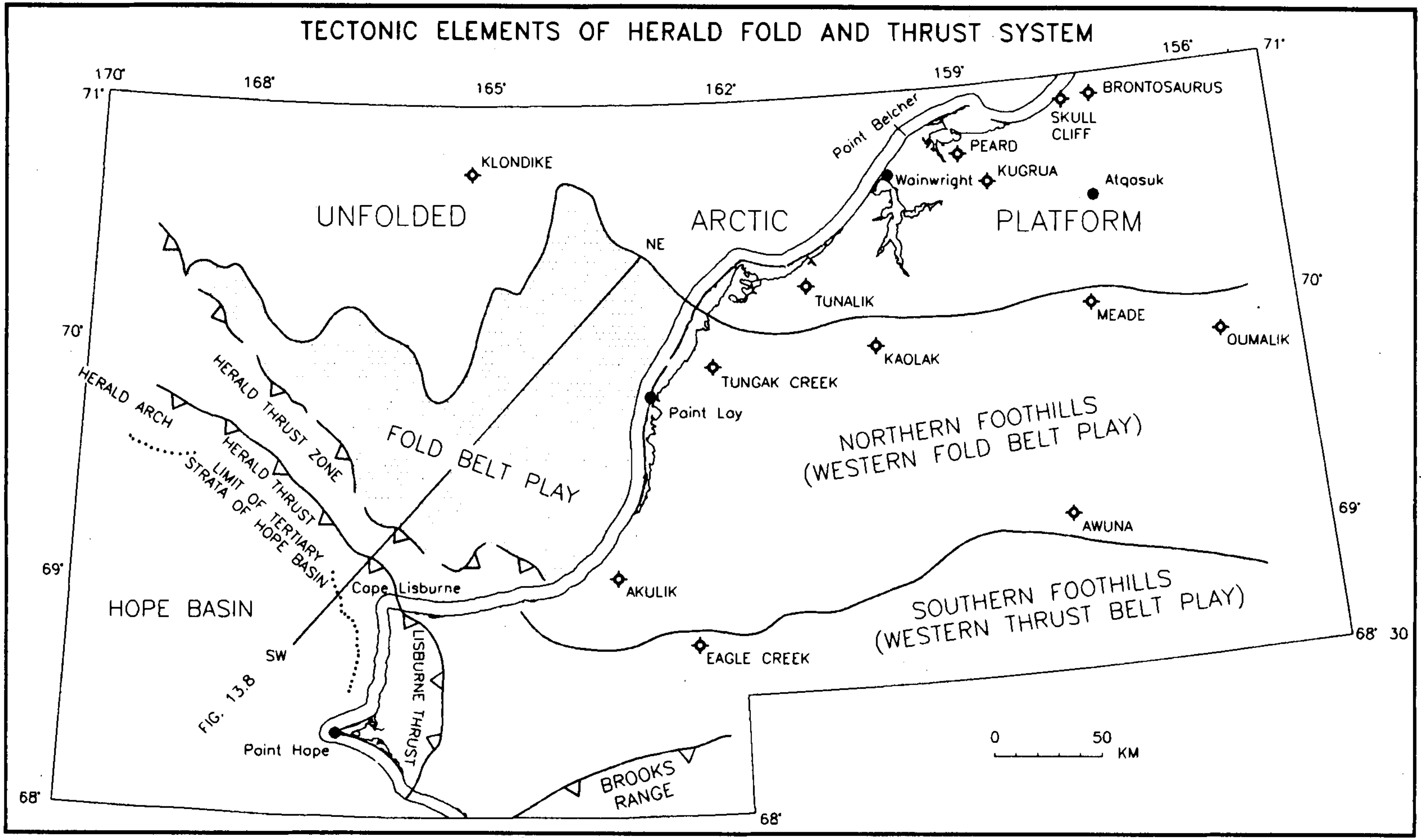

Figure 13.7: Tectonic elements of deformation belt in southern Colville basin. Onshore provinces are from Molenaar (1988).

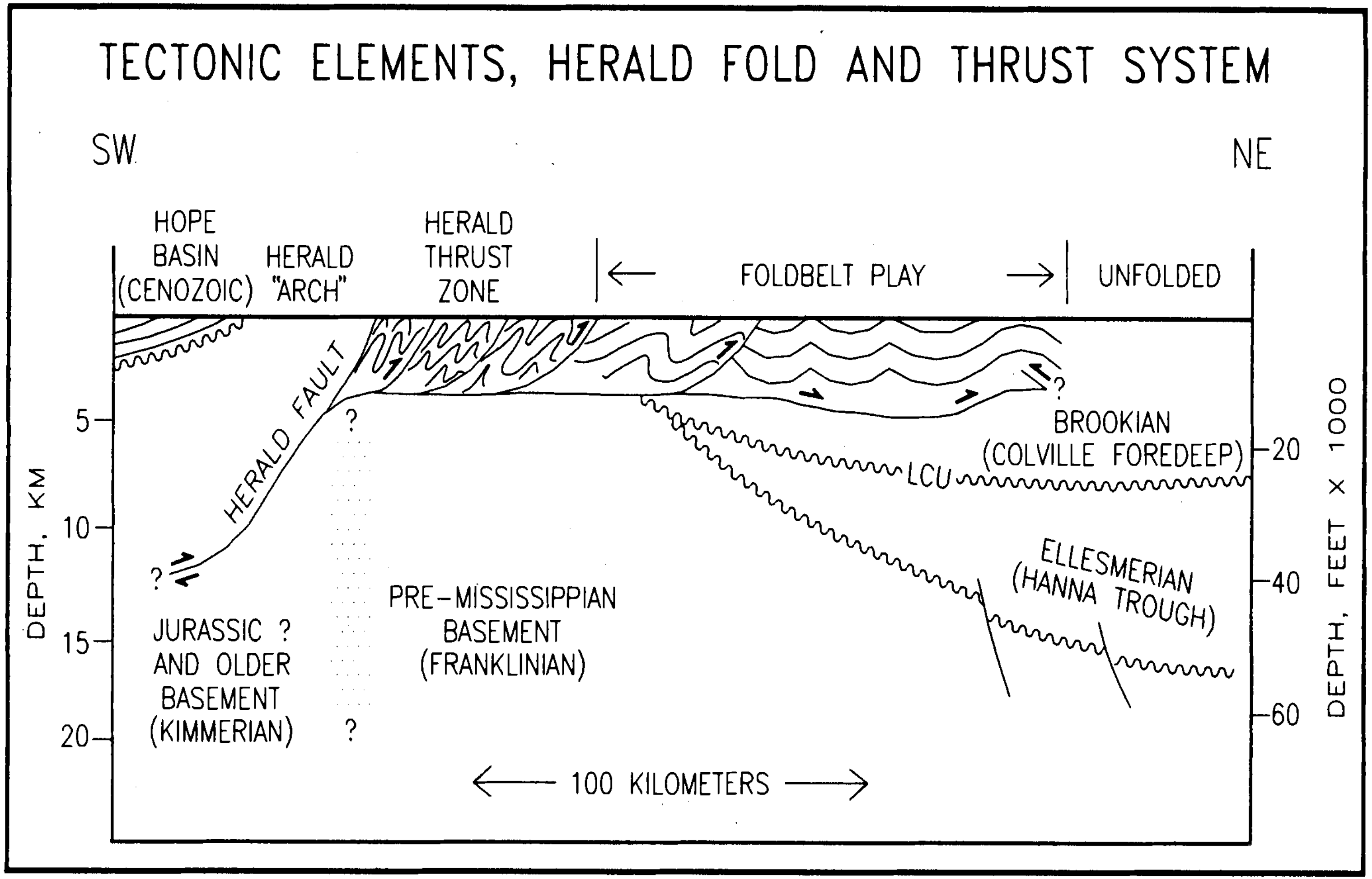

Figure 13.8: Cross section, Herald arch, Herald thrust zone, and foldbelt in southern Colville basin. See figure 13.7 for location of profile.

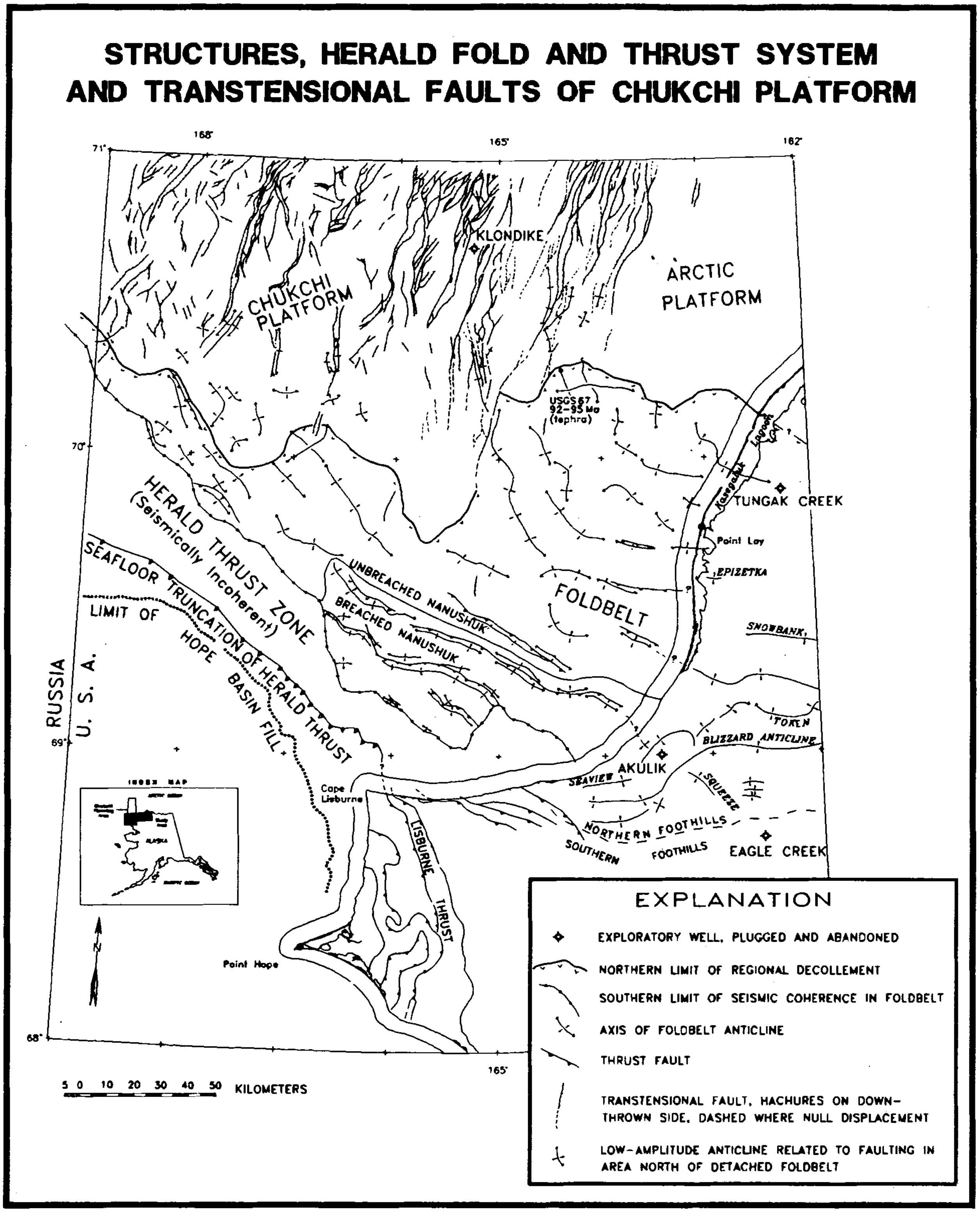

Figure 13.9: Structures of Herald thrust system, foldbelt, and transtensional fault swarms on Chukchi platform north of foldbelt. Most structures are probably of Paleocene age.

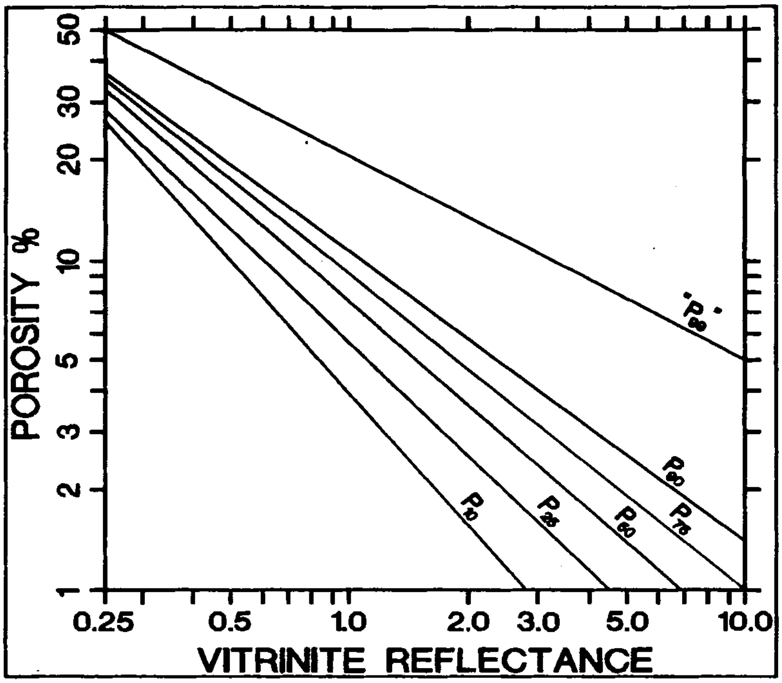

Figure 13.10: Porosity decline functions (P_{10}-P_{90}) from multi-basin model of Schmoker and Hester (1990). P_{99} is from Chukchi shelf data.

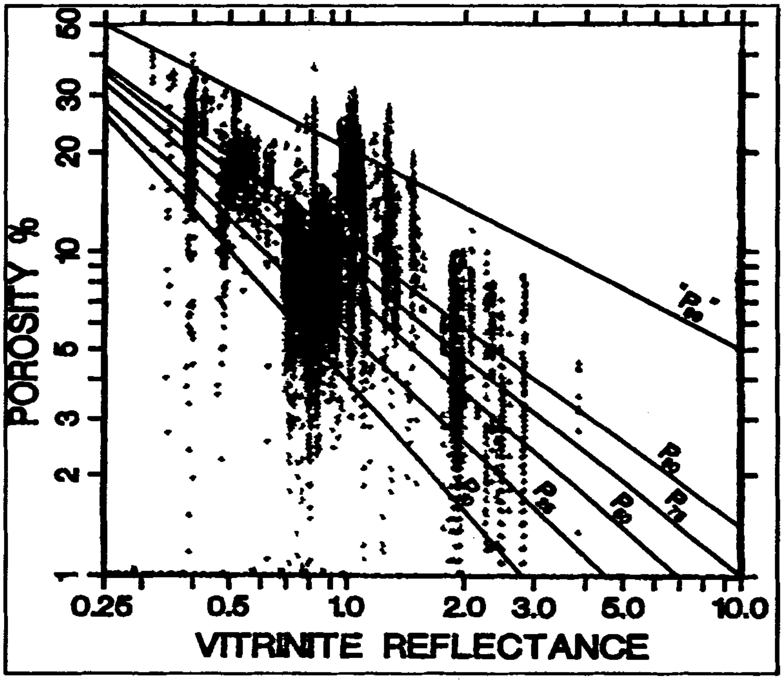

Figure 13.11: Chukchi shelf porosity data superposed on Schmoker and Hester (1990) multi-basin porosity model. Includes data from all sandstones in Diamond, Klondike, Akulik, Tunalik, and Popcorn wells.

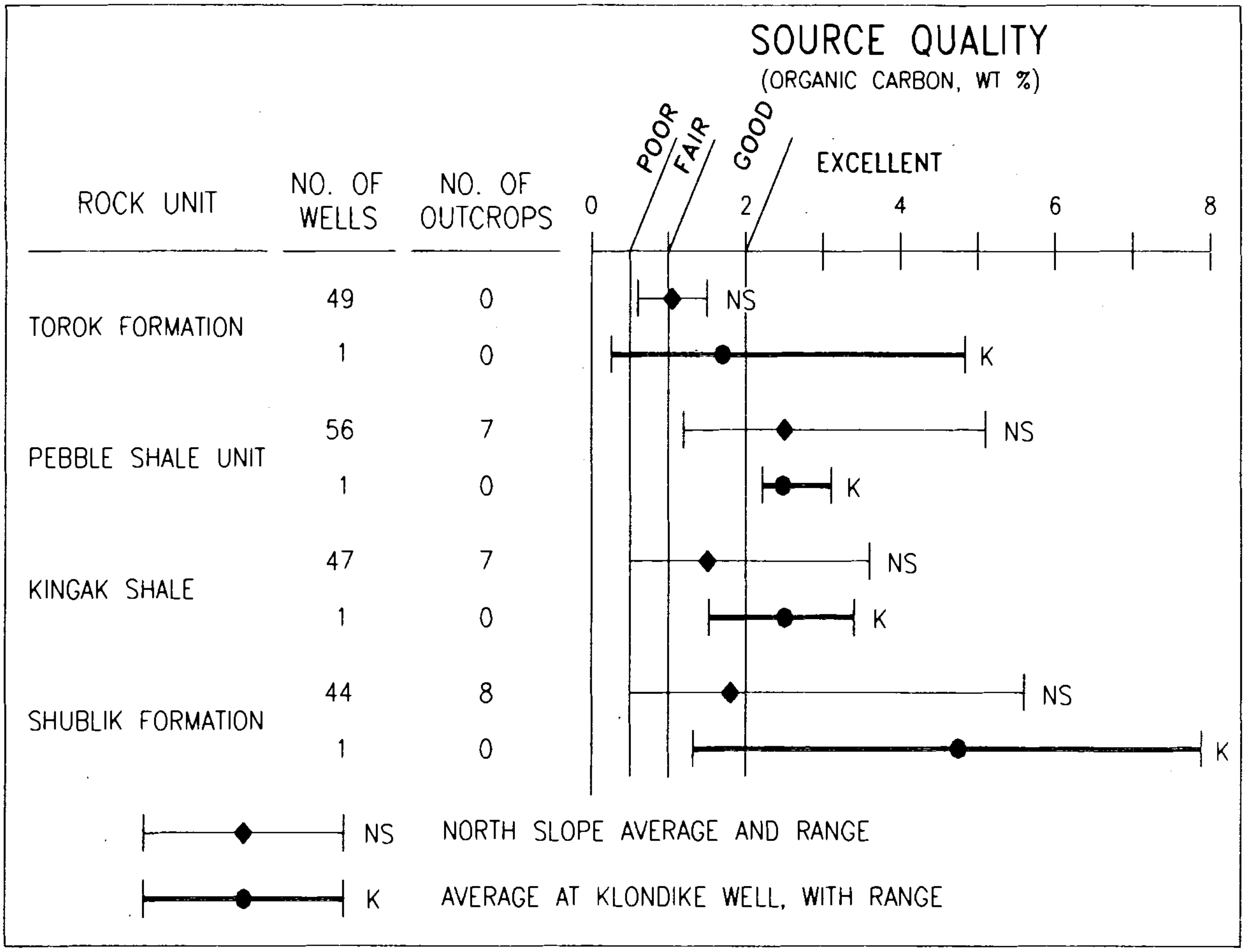

Figure 13.12: Organic carbon summary diagram of four northern Alaska rocks units, with data from correlative units sampled at Klondike well on Chukchi platform. Diagram modified after Magoon and Bird (1985, fig. 14).

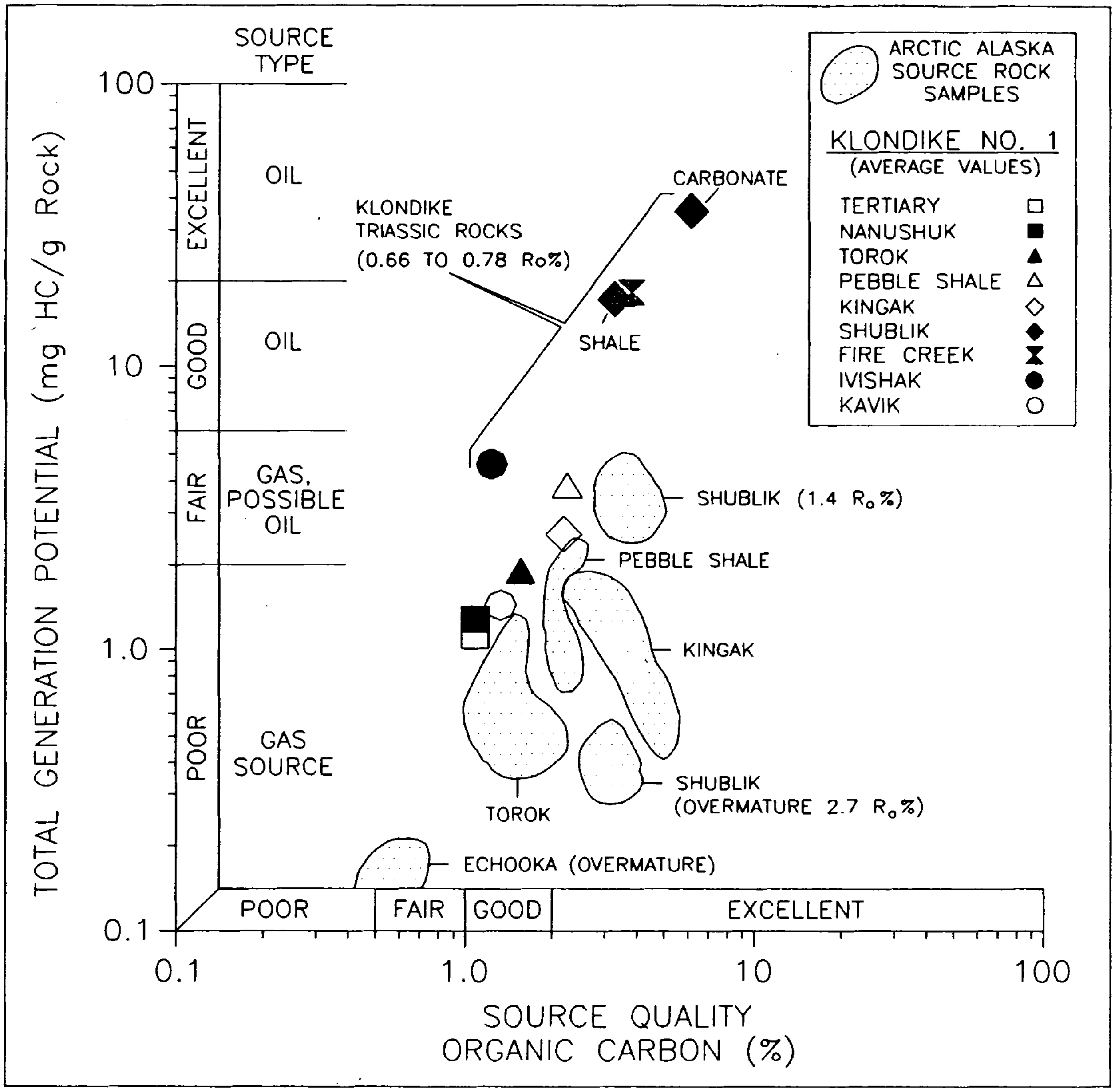

Figure 13.13: Plot of generation potential ($S_1 + S_2$) versus organic carbon for potential source sequences in Arctic Alaska and Chukchi shelf (Klondike well). Modified after Elrod and others (1985, fig. 8). Many Arctic Alaska samples are thermally mature and show generation potentials far below original values.

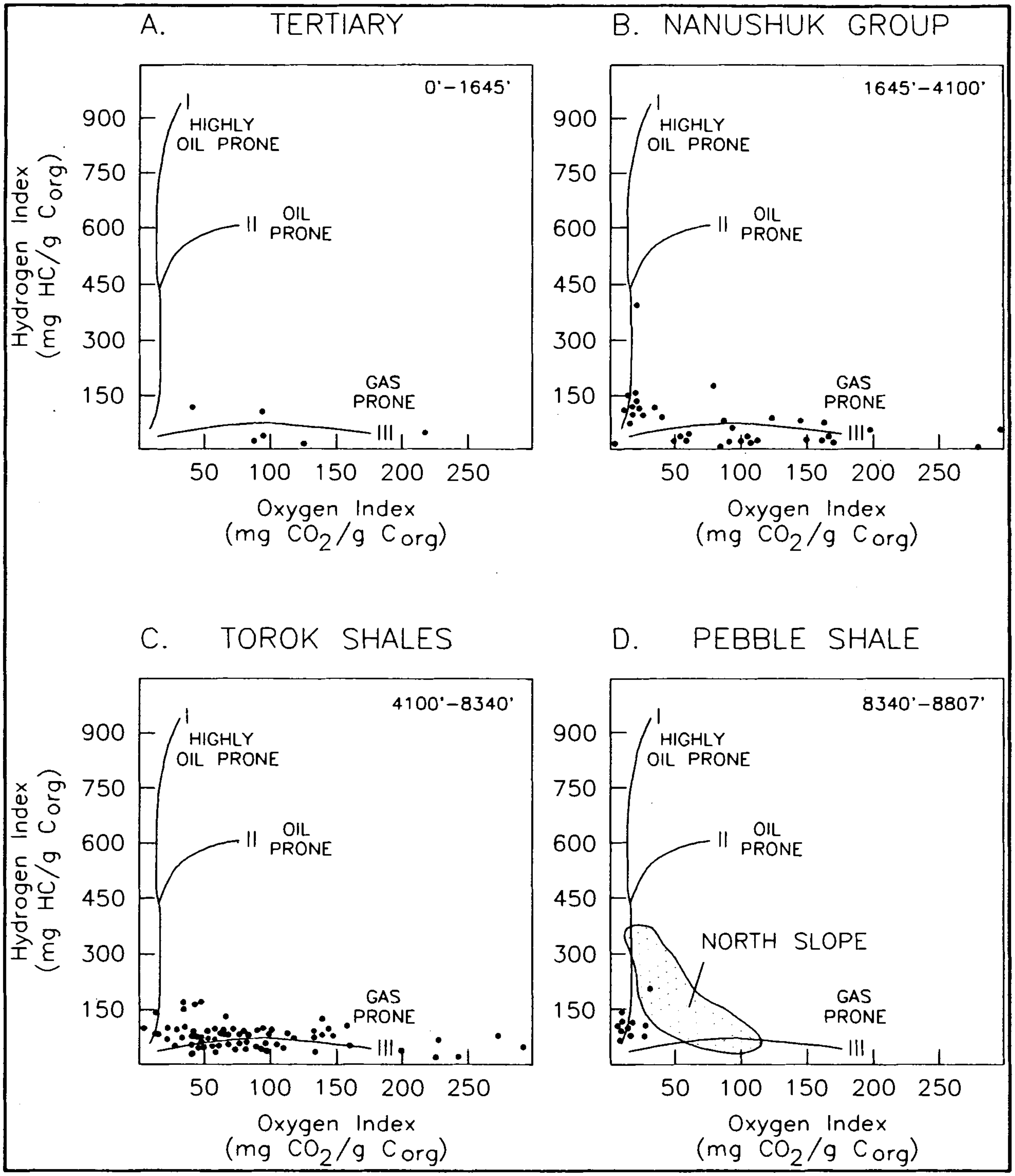

Figure 13.14: Modified Van Krevelen diagrams for kerogen types in Tertiary rocks (a), Nanushuk Group (b), Torok shales (c), and Pebble Shale (d) in Klondike well, Chukchi shelf. Diagram base from Peters (1986, fig. 5). Stippled area in diagram (d) shows samples of Pebble Shale from Arctic Alaska at comparable (to Klondike well) levels of thermal maturity (from Craig and others, 1985, fig. 14).

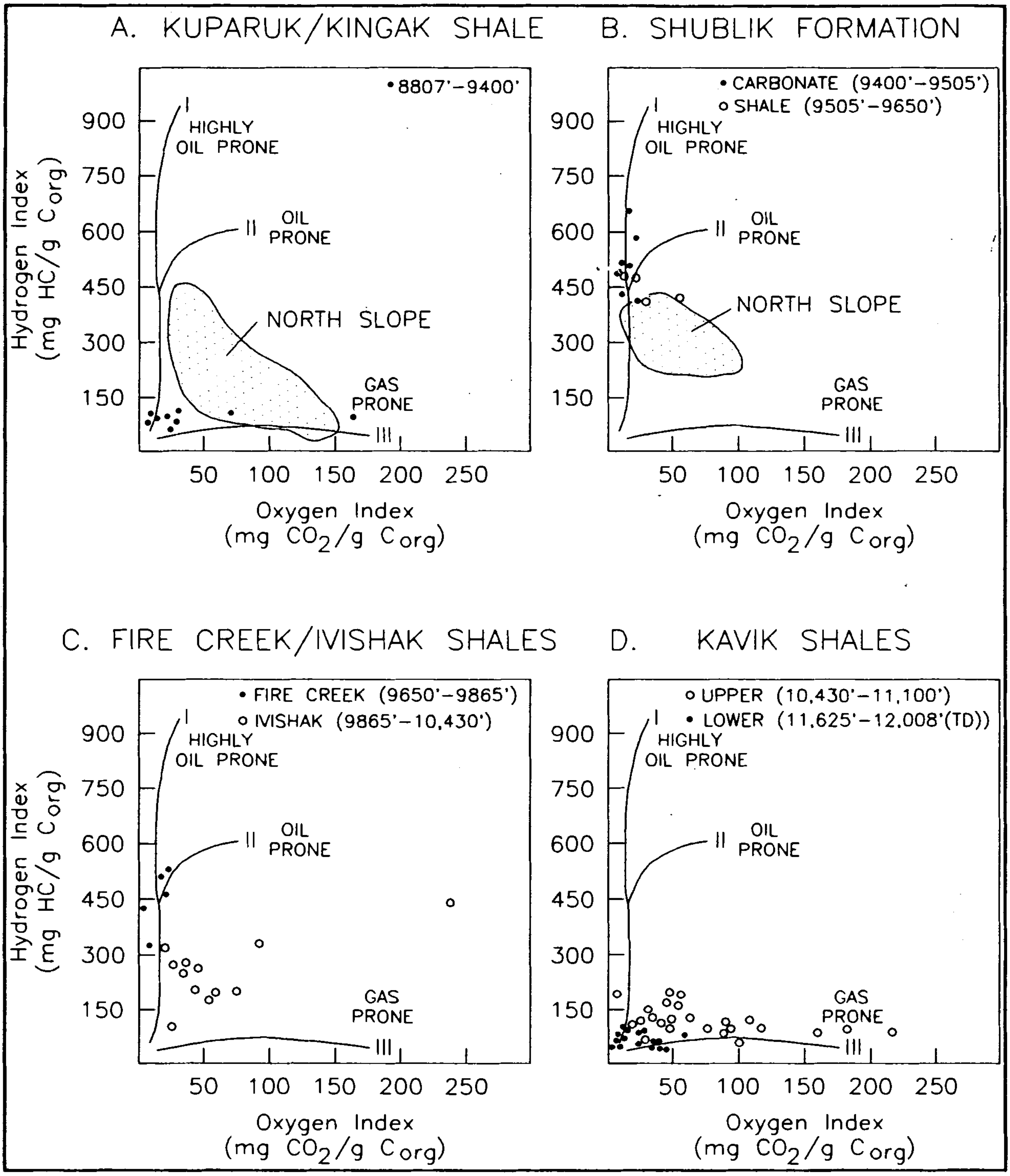

Figure 13.15: Modified Van Krevelen diagrams for kerogen types in Kuparuk/Kingak shales (a), Shublik Formation (b), Fire Creek- and Ivishak-equivalent shales (c), and Kavik-equivalent shales (d) at Klondike well, Chukchi shelf. Diagram base from Peters (1986, fig. 5). Stippled areas in diagrams (a) and (b) show equivalent formations in Arctic Alaska at comparable (to Klondike well) levels of thermal maturity (from Craig and others, 1985, fig. 14).

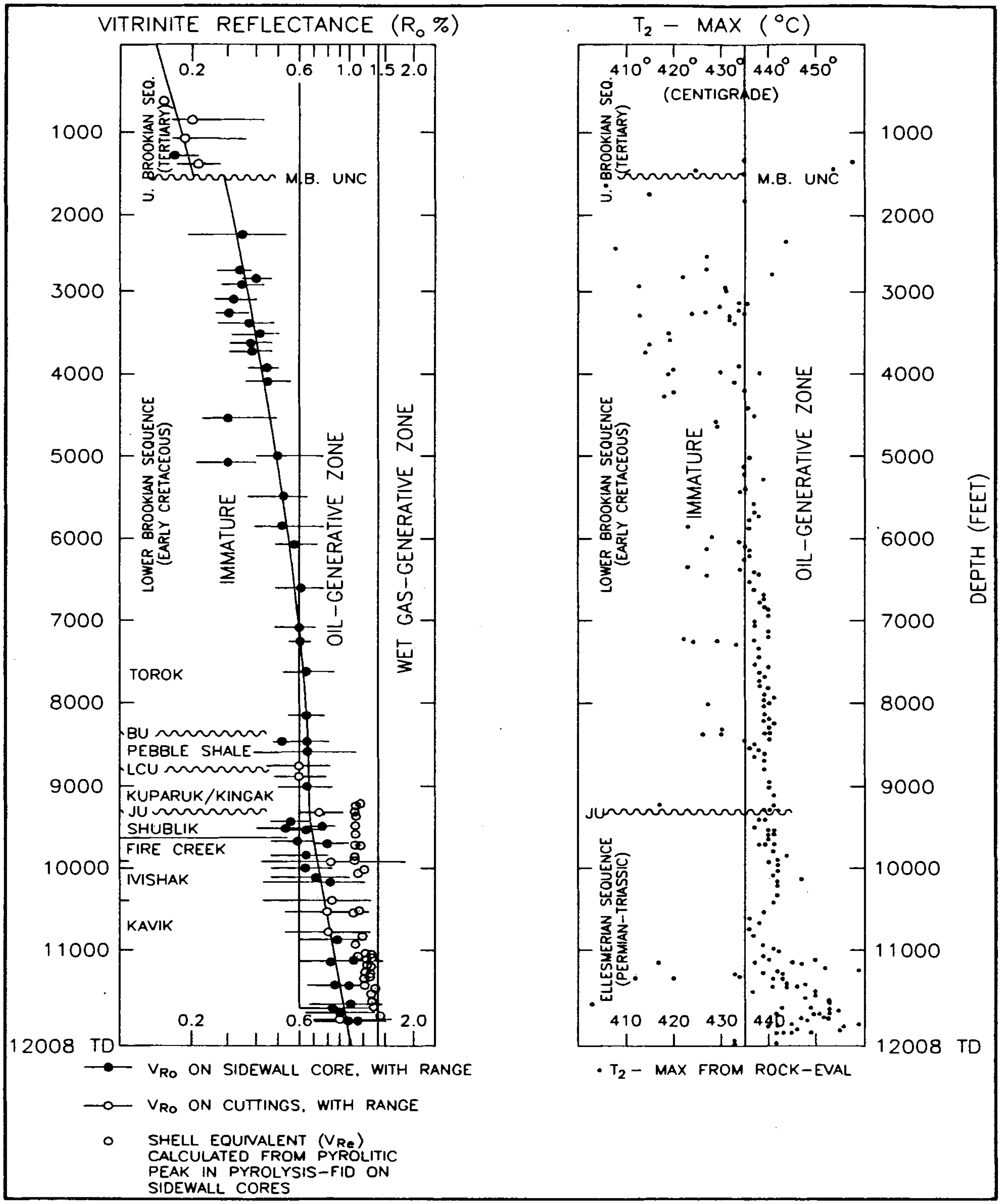

Figure 13.16: Thermal maturity data for Klondike well. The well reached total depth (12,008 ft) within the oil window. Oil-generative zone for T_2-MAX from Peters (1986, tbl. 3).

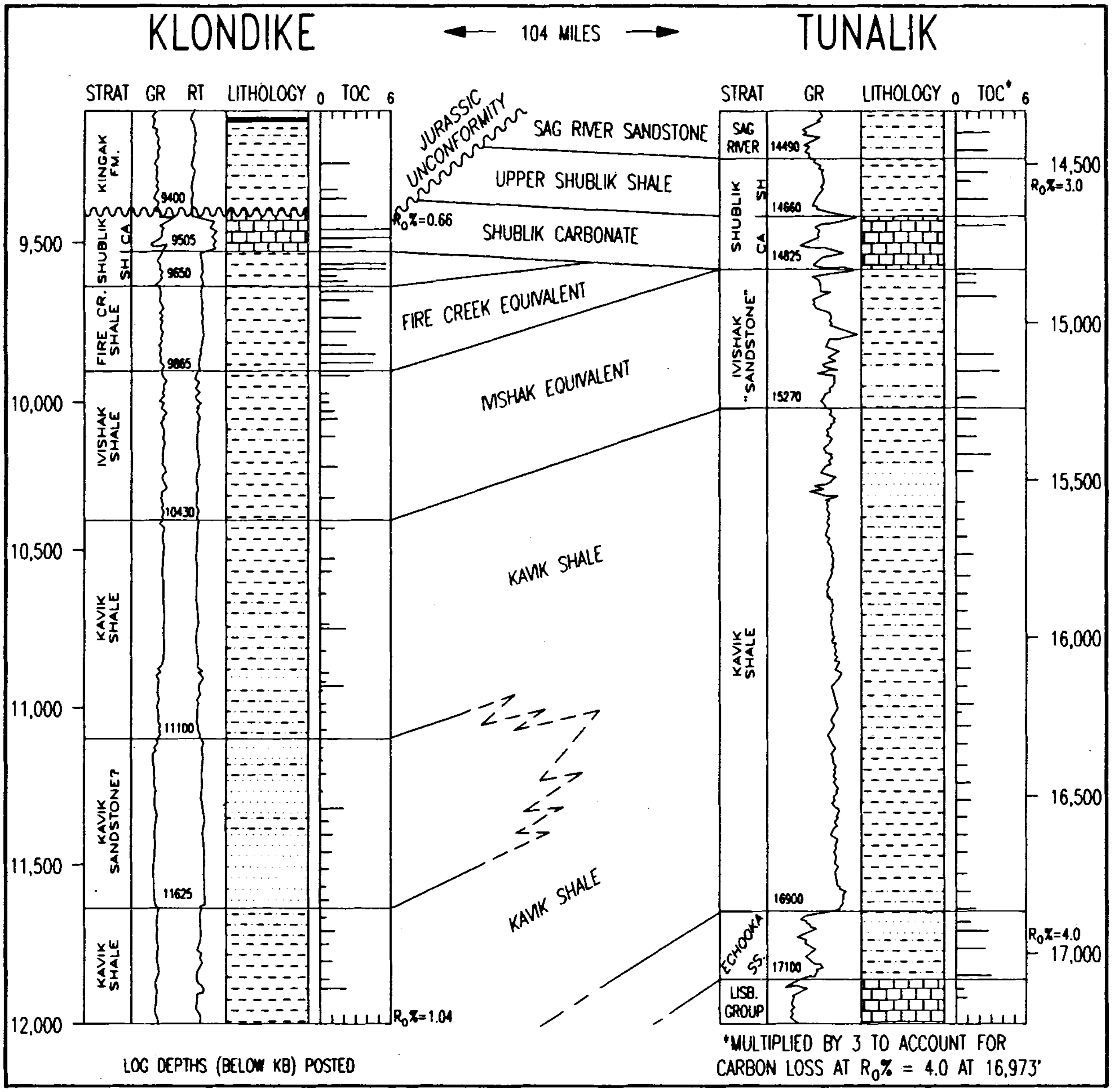

Figure 13.17: Stratigraphic cross section with organic carbon profiles showing proposed correlations in Ellesmerian rocks between Klondike and Tunalik wells. Tunalik data adapted from Magoon and others (1988, pl. 19.2). Paleontologic data supporting correlation of Klondike and Tunalik wells are from Micropaleo Consultants (1989a). The separation of units based on paleontologic data partly corresponds to natural subdivisions of the sequence into "organic units" based on organic carbon data. The organic carbon profile for Tunalik has been corrected for maturation effects. Thermal maturation to extreme levels ($R_o\%$ = 3.0 to 4.0) at Tunalik has certainly reduced by some amount the original organic carbon contents of the Triassic shales. For purposes of identification and correlation of organic units, the measurements of carbon contents of rocks at Tunalik were multiplied by a factor of three to restore them to pre-catagenic levels (method of White, 1989, p. 3-44).

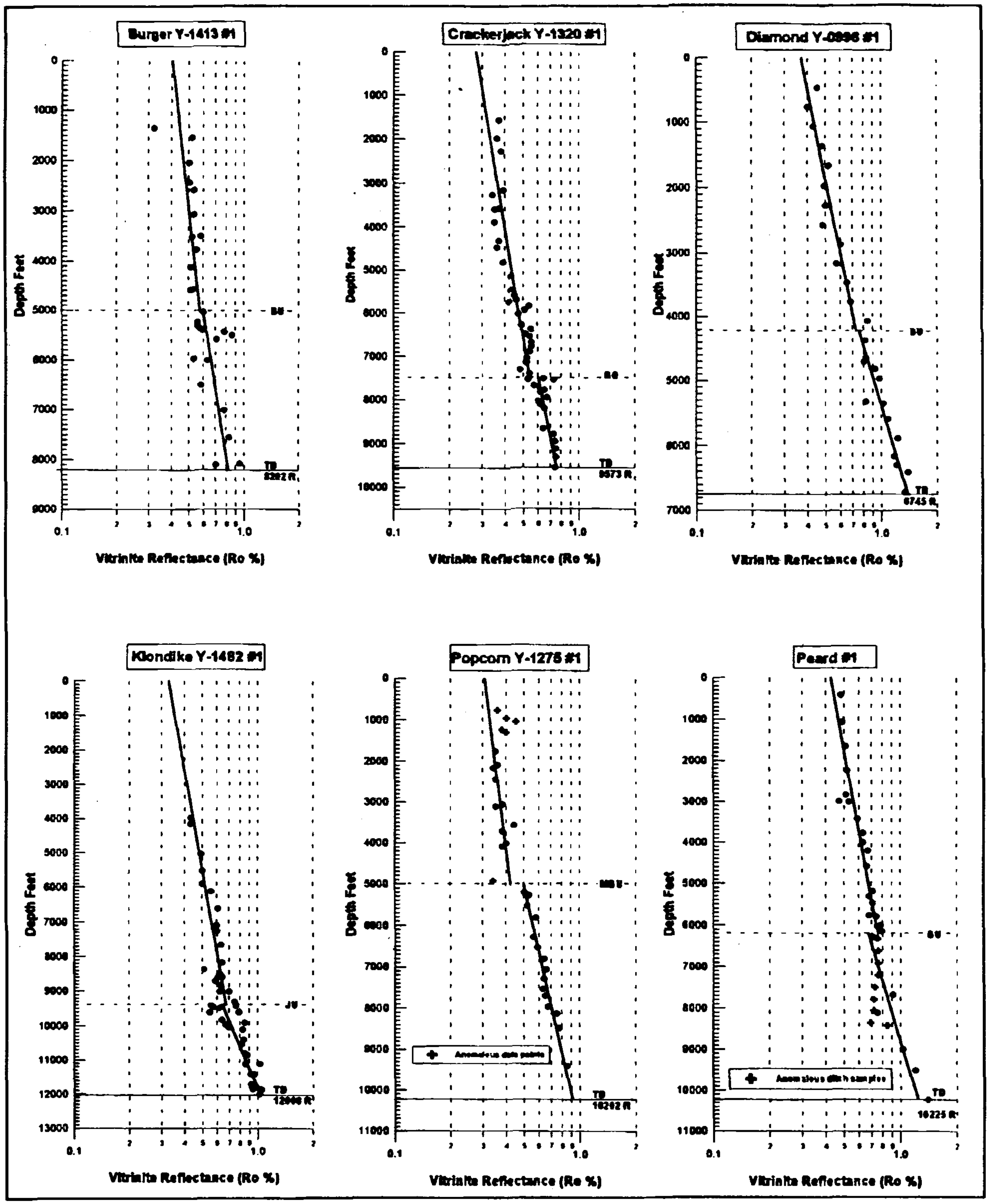

Figure 13.18: Vitrinite reflectance data, Chukchi shelf wells and Peard well (located in fig. 13.1). Data in Chukchi shelf wells is from sidewall cores. Data in Peard well is from drill cuttings. Samples annotated as "anomalous ditch samples" (drill cuttings) or "anomalous data points" (sidewall cores) were not included in statistical fitting used to develop functions for variation of vitrinite reflectance with depth.

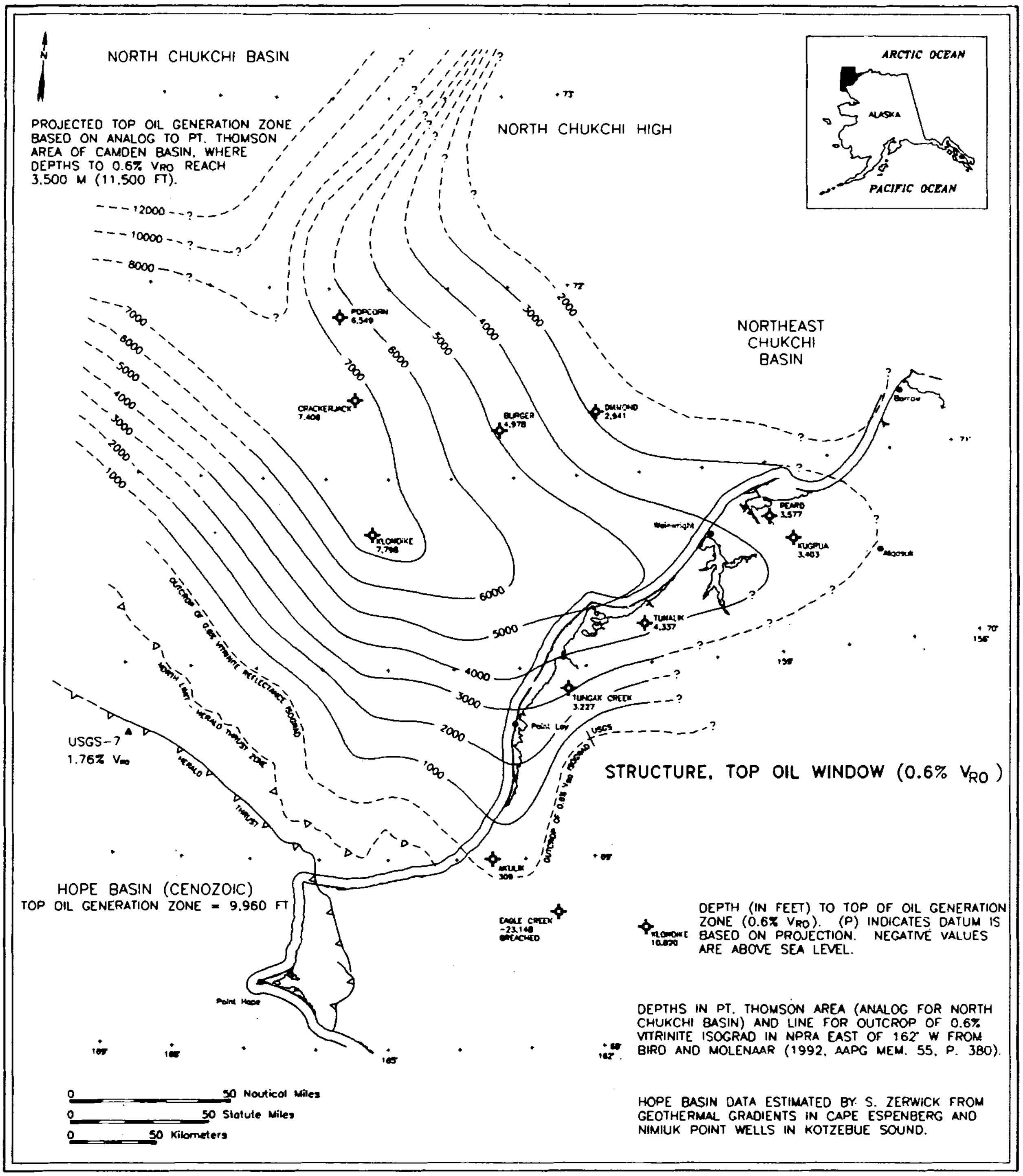

Figure 13.19: Structure on top of zone of oil generation (0.6 percent vitrinite reflectance isograd).

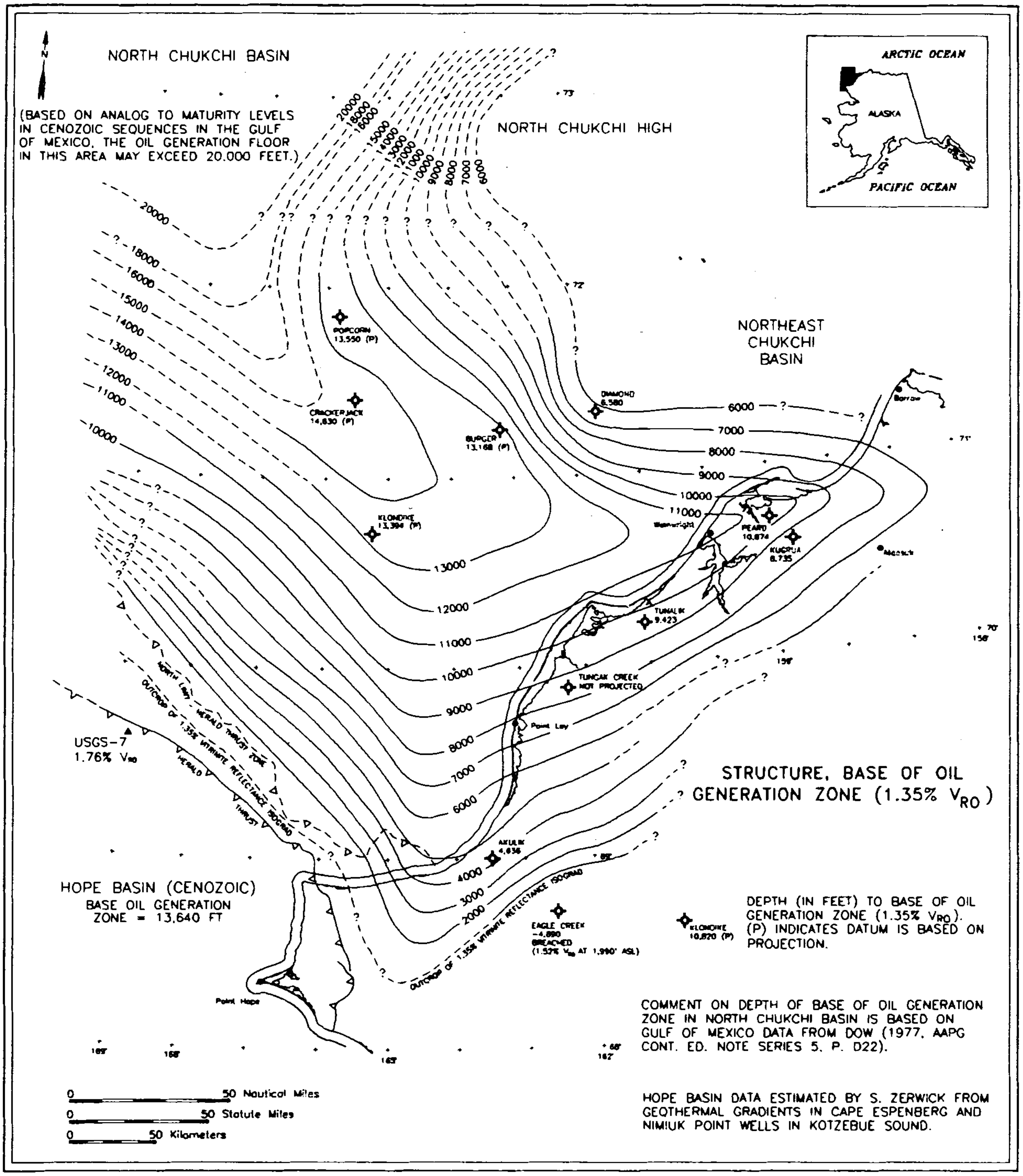

Figure 13.20: Structure on base of zone of oil generation (1.35 percent vitrinite reflectance isograd).

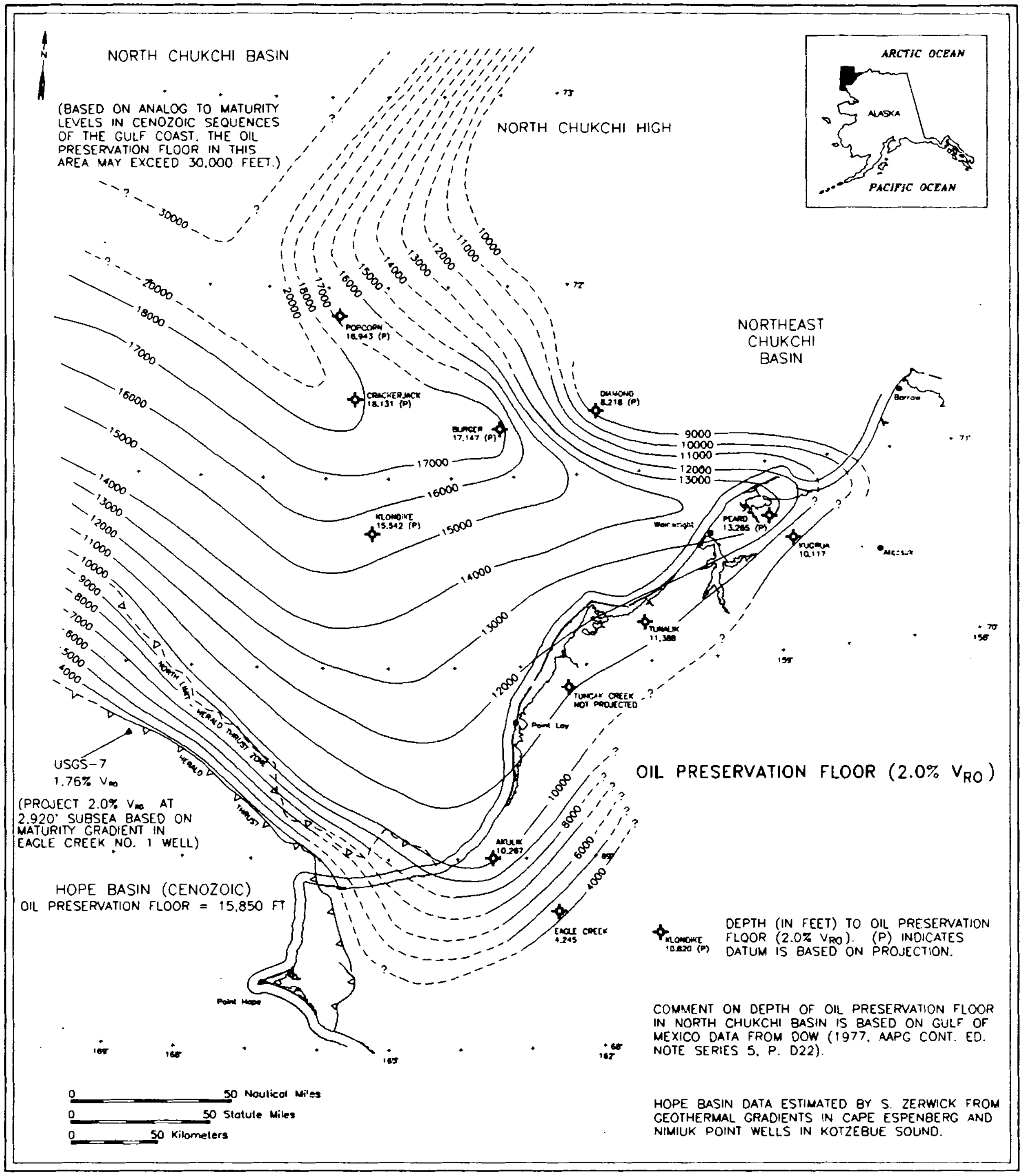

Figure 13.21: Structure on floor for oil preservation (2.0 percent vitrinite reflectance isograd).

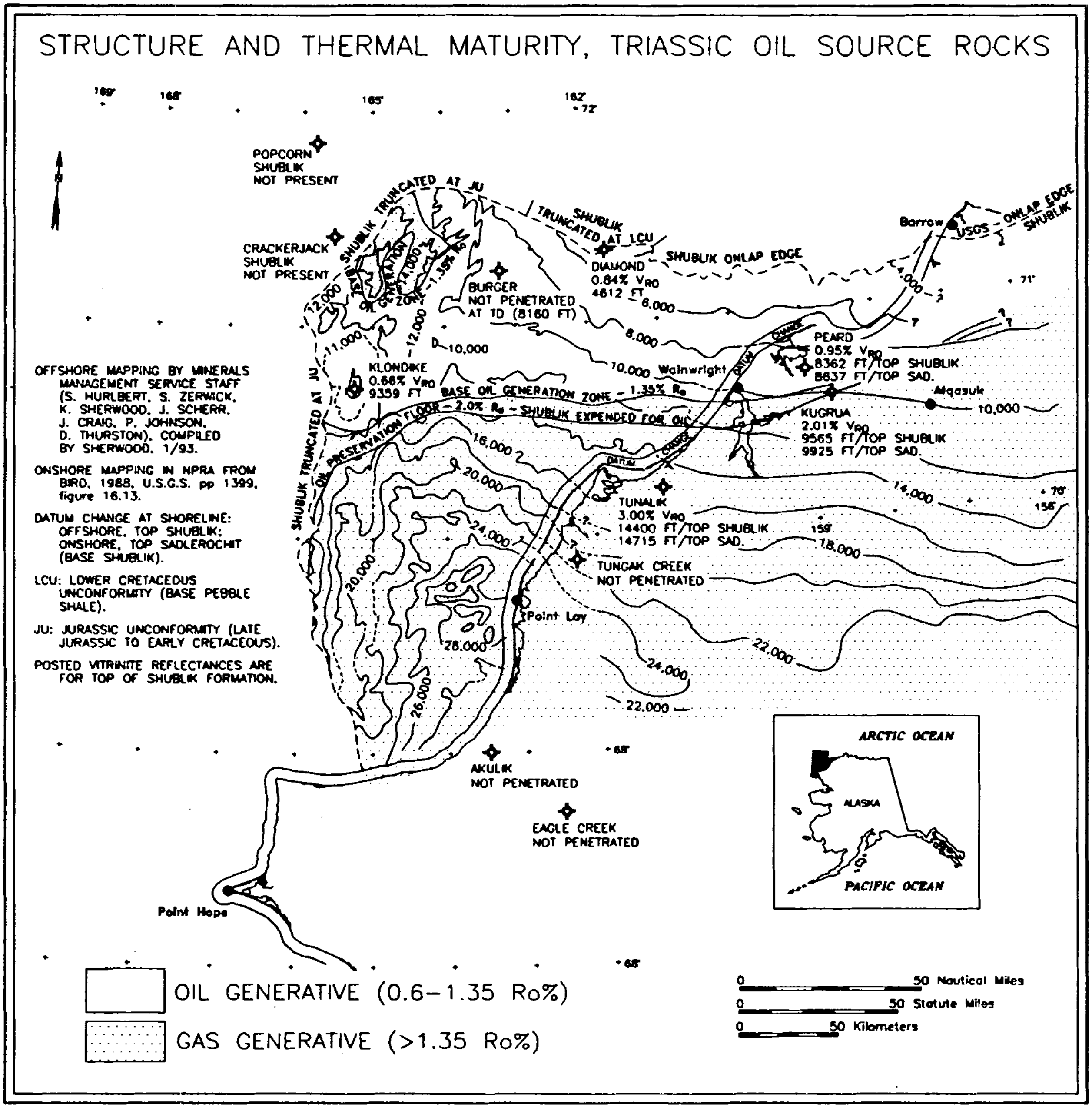

Figure 13.22: Structure map for top of Shublik Formation (top of oil source rock sequence), with lines of intersections with 1.35 $\%R_o$ and 2.00 $\%R_o$ isograd surfaces.

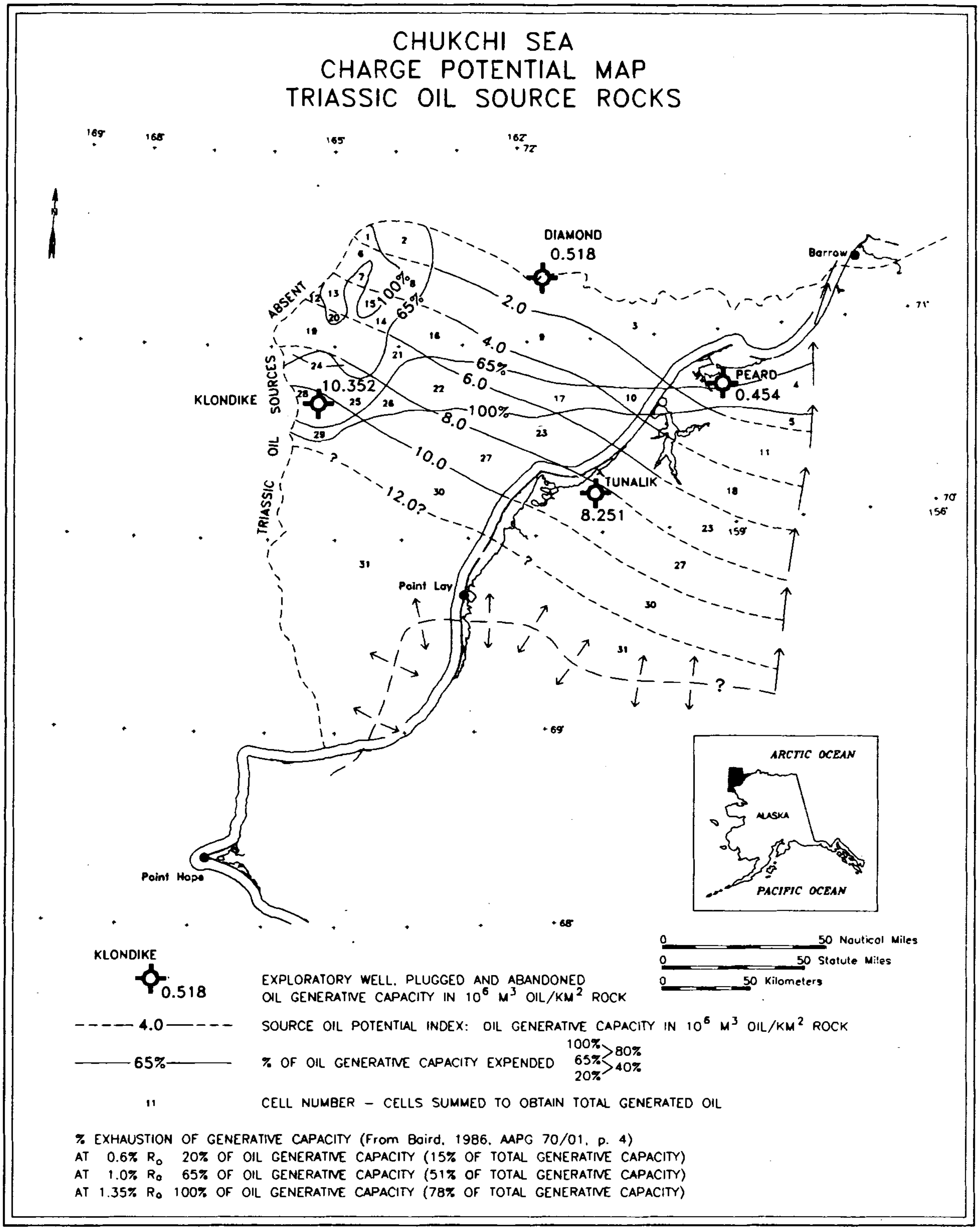

Figure 13.23: Contoured map for source oil potential indices in Hanna trough charge area with 31 cells integrated to estimate generation potential. Aggregate generation potential of all 31 cells is 2.97 trillion barrels of oil.

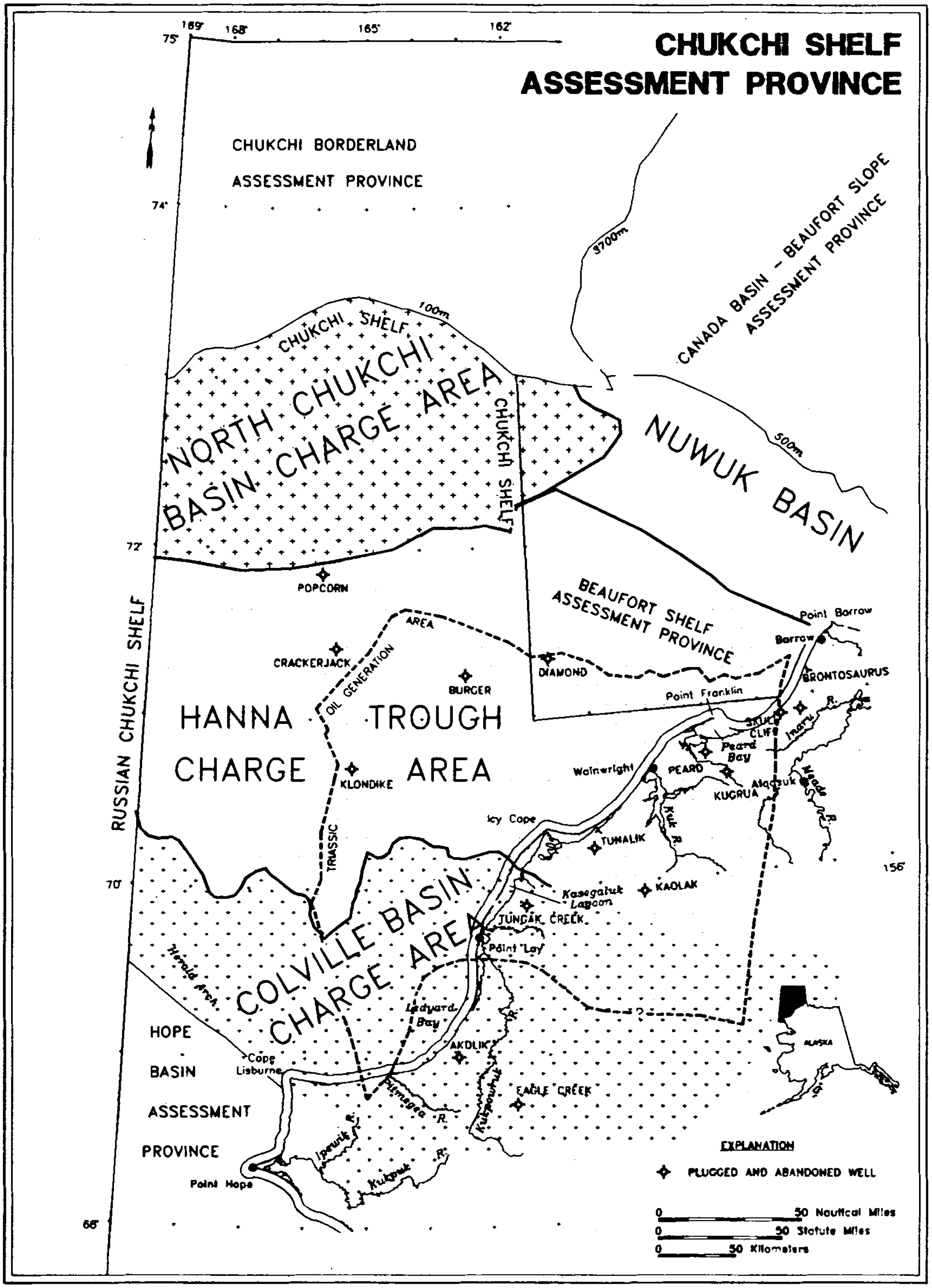

Figure 13.24: Map showing areas of three hypothetical Chukchi shelf play charging systems. Dashed line outlines charge area of Triassic oil source rocks in Hanna trough.

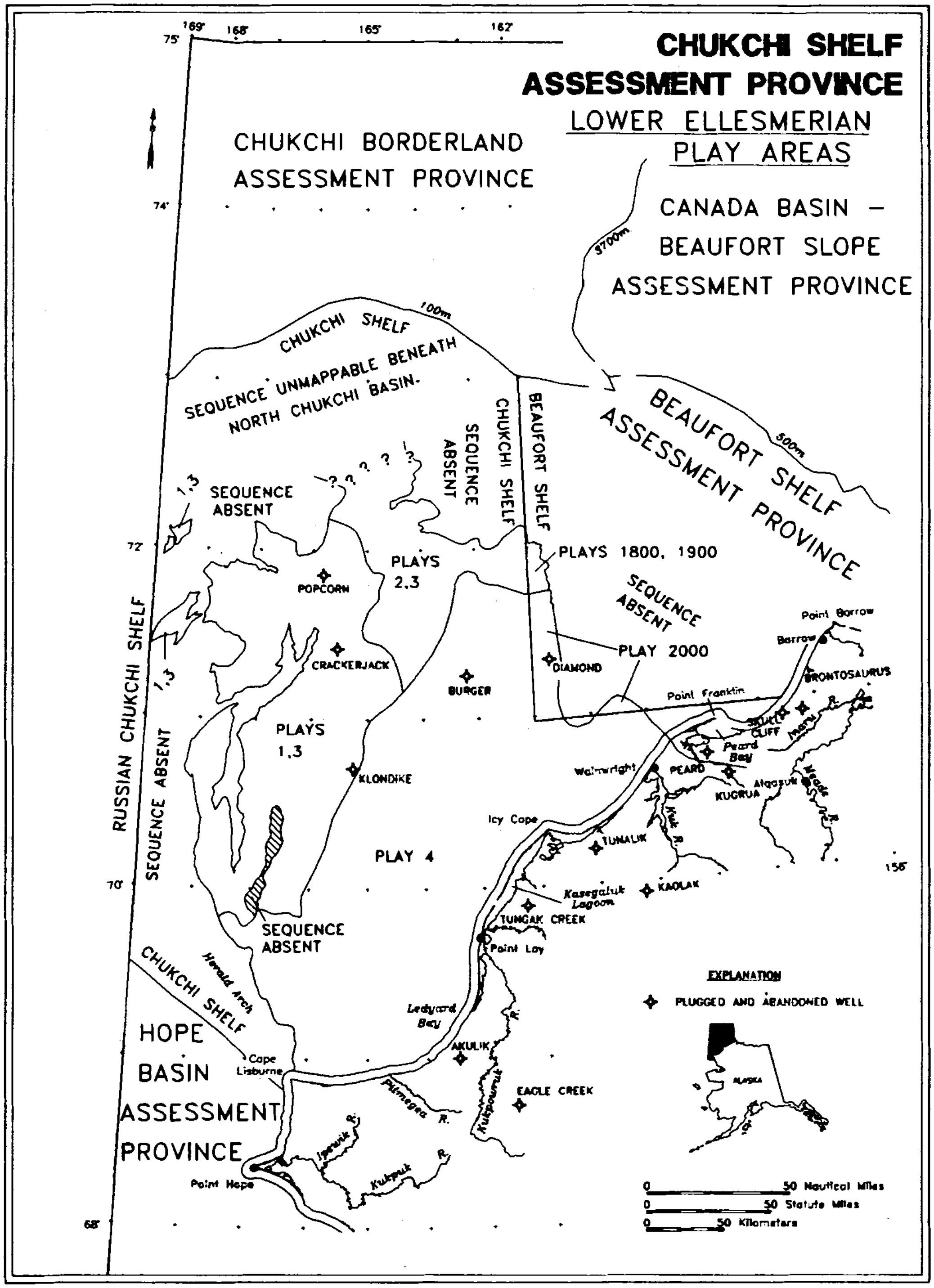

Figure 13.25: Play areas, Lower Ellesmerian sequence play group. Play 1, Endicott Clastics, Chukchi platform (UACS0100). Play 2, Endicott Clastics, Arctic platform (UACS0200). Play 3, Lisburne carbonates (UACS0300). Play 4, Overmature "Deep Gas" (thermally overmature reservoirs) (UACS0400).

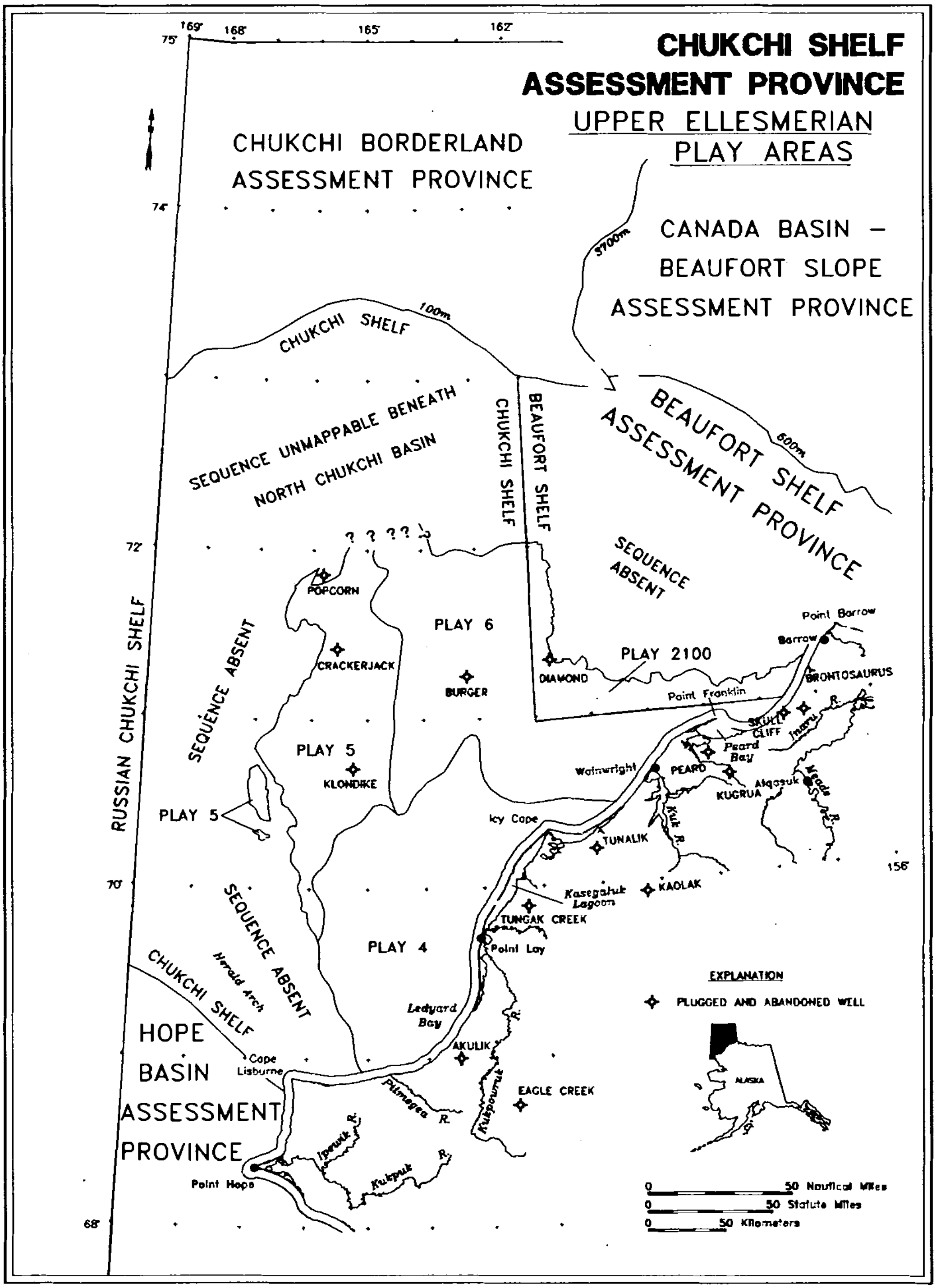

Figure 13.26: Play areas, Upper Ellesmerian sequence play group. Play 4, Overmature "Deep Gas" (thermally overmature reservoirs) (UACS0400). Play 5, Sadlerochit Group, Chukchi platform (UACS0500). Play 6, Sadlerochit Group, Arctic platform (UACS0600).

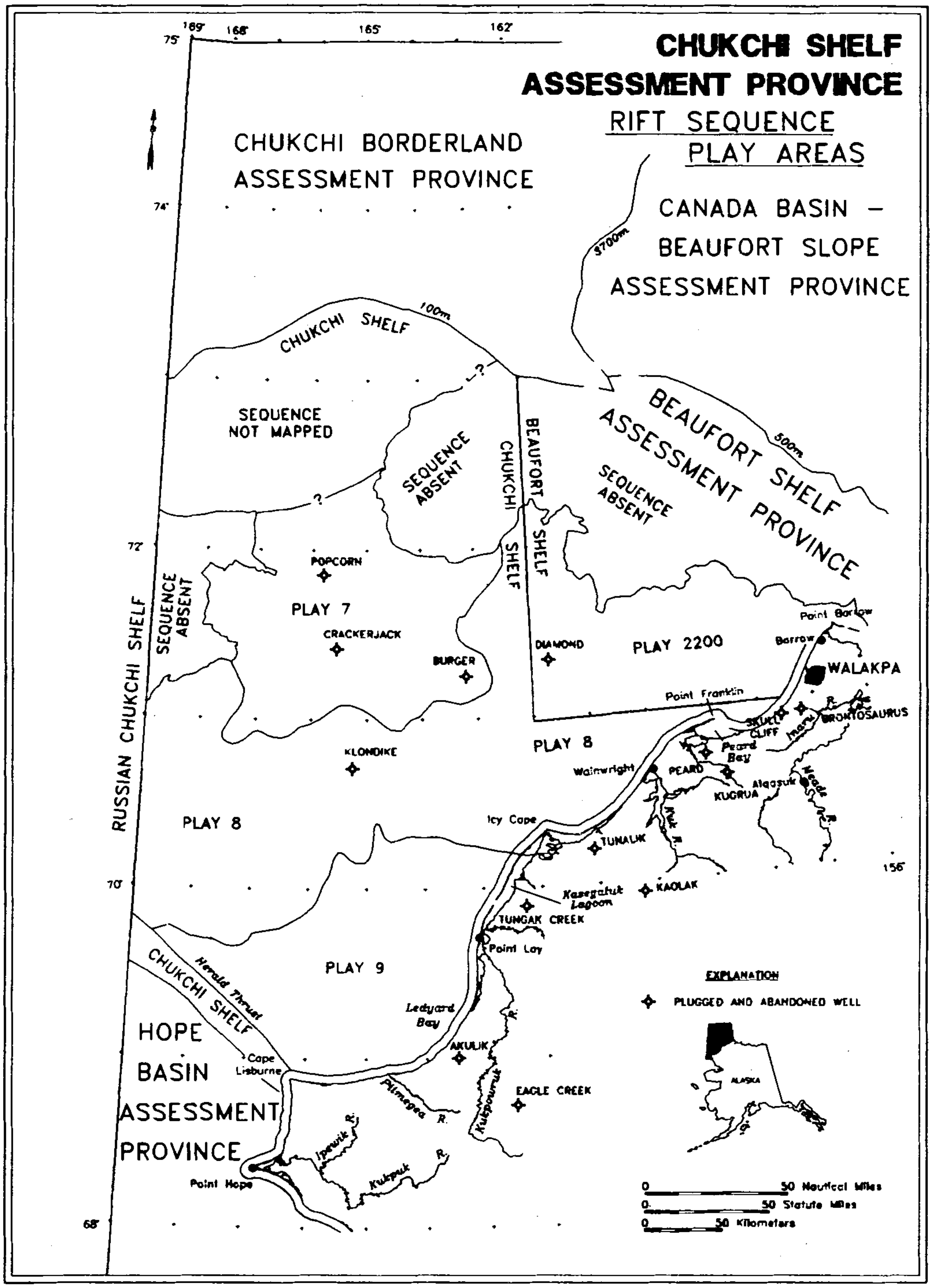

Figure 13.27: Play areas, Rift sequence play group. Play 7, Active margin clastics (UACS0700). Play 8, Stable marine shelf (UACS0800). Play 9, Overmature "Deep Gas" (thermally overmature reservoirs) (UACS0900).

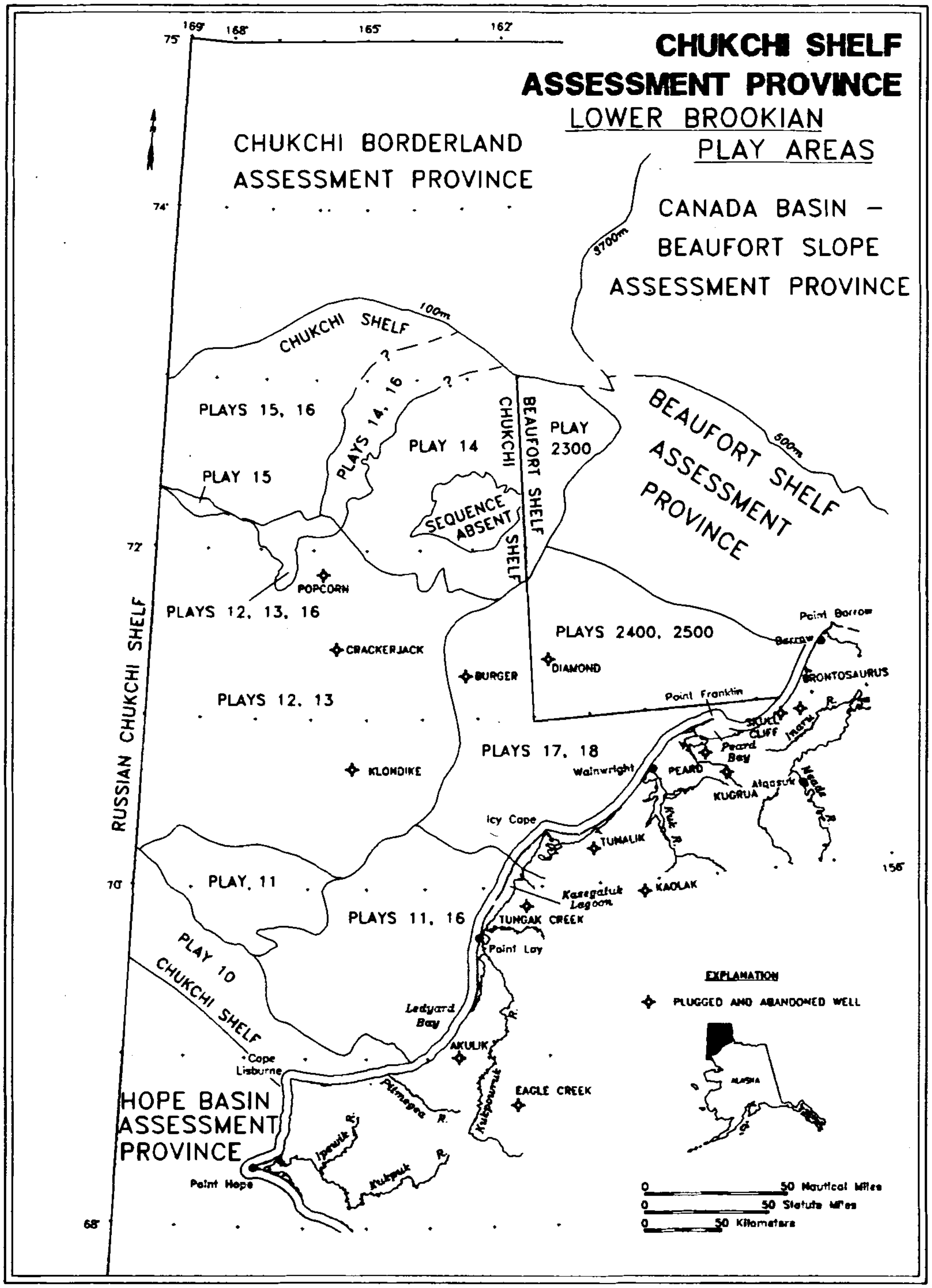

Figure 13.28: Play areas, Lower Brookian sequence play group. Play 10, Herald arch and thrust zone (UACS1000). Play 11, Foreland foldbelt (UACS1100). Play 12, Torok turbidites - Chukchi platform wrench zone (UACS1200). Play 13, Nanushuk topset - Chukchi platform wrench zone (UACS1300). Play 14, Brookian "sand apron", North Chukchi high (UACS1400). Play 15, Cretaceous topset - North Chukchi basin (UACS1500). Play 16, Overmature "Deep Gas" (thermally overmature reservoirs) (UACS1600). Play 17, Torok turbidites - Arctic platform (unstructured) (UACS1700). Play 18, Nanushuk topset - Arctic platform (unstructured) (UACS1800).

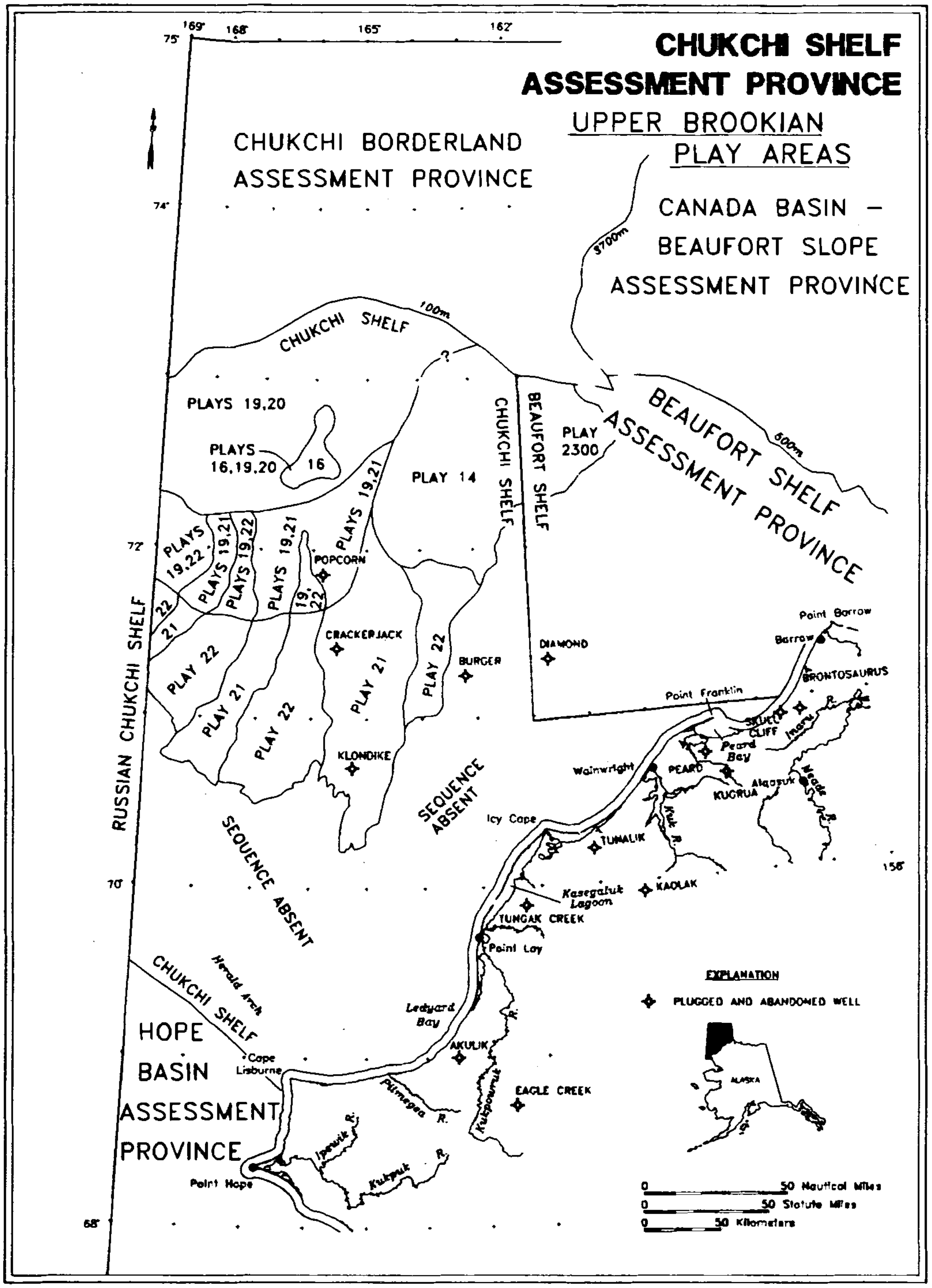

Figure 13.29: Play areas, Upper Brookian sequence play group. Play 16, Overmature "Deep Gas" (thermally overmature reservoirs) (UACS1600). Play 19, Upper Tertiary sag phase - North Chukchi basin (UACS1900). Play 20, Lower Tertiary turbidites - North Chukchi basin (UACS2000). Play 21, Lower Tertiary paleovalley fill (UACS2100). Play 22, Tertiary basal transgressive sands - intervalley uplifts (UACS2200).

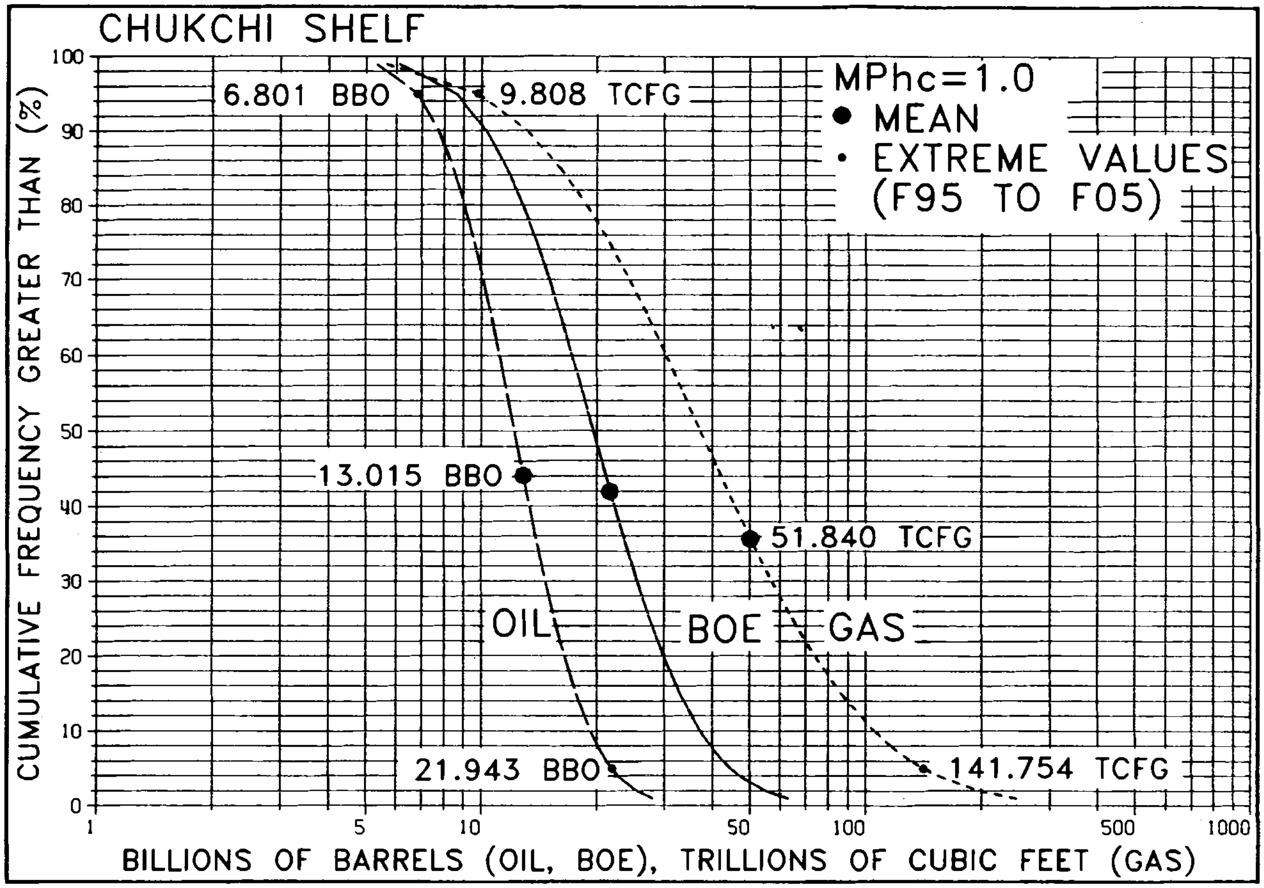

Figure 13.30: Cumulative probability curves for undiscovered, conventionally recoverable resources (oil, gas, and BOE) for Chukchi shelf assessment province. ***BOE**, total oil and gas in energy-equivalent barrels, obtained by converting gas to energy-equivalent barrels (5,620 cubic feet per barrel) and adding to oil; **MPhc**, marginal probability for occurrence of pooled hydrocarbons in province.*

GEOLOGIC ASSESSMENT
1995 National Resource Assessment
Alaska Federal Offshore
U.S. Minerals Management Service

14. BEAUFORT SHELF ASSESSMENT PROVINCE

by
James Scherr and Peter Johnson

INTRODUCTION

The Beaufort shelf assessment province includes the offshore Arctic platform from the Chukchi shelf to the Canadian maritime boundary. It is comprised of a series of basins and intervening highs formed during a complex history of rifting and continental break-up north of Alaska and folding and thrusting on the south and east.

EXPLORATION HISTORY

Petroleum exploration of Alaska's North Slope (that area between the Brooks Range and the Beaufort Sea coast) began with the establishment of the Naval Petroleum Reserve No. 4 (NPR-4) in 1923. As a result of drilling from 1944 to 1953, small oil fields were discovered at Umiat, Simpson, and Fish Creek. Gas fields were discovered at Gubik, South Barrow, Meade, Square Lake, Oumalik, and Wolf Creek. The South Barrow gas field supplied fuel to the Naval Arctic Research Lab for a number of years. The field still provides gas to the village of Barrow.

In 1975, federally-funded exploration resumed in NPR-4 and continued for 7 years. This drilling program found gas fields and some oil shows at East Barrow and Walakpa, both of which provide gas for the village of Barrow. NPR-4 became the National Petroleum Reserve in Alaska (NPRA) in 1977 when the Department of the Interior received responsibility for the area.

The State of Alaska held the first competitive lease sale on the North Slope in late 1964. The State held a second competitive lease sale in 1965 that included the Prudhoe Bay structure. Atlantic Richfield Company and Humble Oil announced the discovery of the Prudhoe Bay field in 1968 after drilling the Prudhoe Bay State #1 well. Other oil fields discovered during the flurry of exploration activity following the Prudhoe Bay discovery include Kuparuk (1969), West Sak (1969), Milne Point (1970), Flaxman Island (1975), Point Thomson (1977), and Sag Delta- Duck Island (1978), later called the Endicott field.

Petroleum exploration of the Beaufort shelf assessment province began with a joint State of Alaska— Federal offshore lease sale in December 1979. Four additional lease sales have been held since and a total of 28 OCS wells drilled. Wells drilled on these leases led to oil discoveries at Tern Island, Seal Island, Hammerhead, and Kuvlum fields. In addition, two wells at the Sandpiper prospect encountered significant quantities of gas and condensate. The Mukluk, Antares, and Phoenix wells encountered minor amounts of oil and the Galahad well encountered minor amounts of gas and an oil show.

PRODUCTION HISTORY

At present, there is no commercial hydrocarbon production from any of the discovered fields in the Beaufort shelf Federal offshore, although development work at Northstar field, 5 miles north of Prudhoe Bay field, may begin in 1998. Development of marginally-economic fields such as Northstar (or Seal Island), Hammerhead, Tern Island, and Kuvlum depends on real future growth in oil prices, future reductions in development costs, and environmental constraints. There are five large producing oil fields on State lands, the best known being the Prudhoe Bay field with over 12 billion barrels of recoverable oil (Petzet, 1995). Other producing fields are the Kuparuk field with 2.4 billion barrels of recoverable oil (Petzet, 1995), the Milne Point field with 220 million barrels of recoverable oil (Anchorage Daily News, 1995), the Endicott field with 480 million barrels of recoverable oil (Petzet, 1995) and the Point McIntyre field with 340 million barrels of recoverable oil (ARCO, 1993 and Petzet, 1995). Relatively small additional quantities of oil are produced from the Niakuk, North Prudhoe, West Beach, and Lisburne pools in Prudhoe Bay field, the West Sak pool in Kuparuk field, the Schrader Bluff pool in Milne Point field, and the Ivishak and Alapah pools of Endicott field. Three gas fields (South Barrow, East Barrow, and Walakpa) near the village of Barrow are producing gas for local community consumption.

RESERVOIR ROCKS

The reservoirs for the commercial fields are thick sandstones of the Ellesmerian and Beaufortian (here, Rift) sequences. The reservoirs at Prudhoe Bay (main and North Prudhoe pools) and Endicott (Ivishak pool) fields are in the quartz-rich sandstones of the Permian to Triassic Sadlerochit Group. These rocks are the primary focus for the Upper Ellesmerian plays (0601, 2100) in the Beaufort shelf assessment province. The reservoirs at the Kuparuk, Point McIntyre, Milne Point, and Prudhoe Bay (Niakuk and West Beach pools) fields are in marine sandstones of the Cretaceous Kuparuk Formation, part of the Beaufortian sequence. These rocks are the focus for the Rift plays (0701, 2200) offshore in the Beaufort shelf assessment province. The Endicott field's reservoir is in the fluvial sandstones of the Mississippian Endicott Group. These rocks are the focus of the Endicott plays (0401, 1800) on Beaufort shelf.

Carbonates of the Mississippian Lisburne Group (part of the Ellesmerian sequence) form the reservoirs for the Lisburne pool of Prudhoe Bay field. These carbonates are the focus for Lisburne plays (0501, 1900) in the Beaufort offshore. Pre-Mississippian carbonates near Point Thomson have yielded hydrocarbons to well tests and are the basis for the "Undeformed Pre-Mississippian" play (0101). The reservoir in the Pre-Devonian play (0200) is unsampled but is expected to be carbonate based on seismic velocity studies.

Brookian sequence reservoirs occur in delta and prodelta sandstones of the Nanushuk Group, Torok Formation, Canning Formation, and Sagavanirktok Formation. They are generally thinner than reservoir sandstones in the underlying Ellesmerian or Beaufortian (here, Rift) sequences. In the western part of the Beaufort shelf assessment province, the Nanushuk Group and Colville Group both have poor quality reservoirs (low porosity and permeability) due to the high clay content of the sandstones. Reservoir quality in the Torok Formation is poor nearly everywhere due to the fine-grained and mud-rich nature of the sediments supplied to the shelf break by the Nanushuk delta system.

Sandstones with excellent reservoir qualities occur within the Sagavanirktok Formation in the central North Slope and reservoir-quality sandstones probably extend offshore into Beaufort shelf. Sagavanirktok discoveries in this area (West Sak and Ugnu pools) contain heavy hydrocarbons which are difficult to extract. Reservoirs in the Canning Formation consist mostly of turbidite sands enclosed within thick shale sequences, all deposited in mostly submarine fan environments. In the eastern part of the Beaufort shelf assessment province, in the Brookian Foldbelt play (1602), offshore wells found only thin, scarce reservoir-quality sands. However, to the east in Canada, wells encountered excellent reservoir-quality sandstones in Brookian sequences of Tertiary age (Dixon and others, 1992).

SOURCE ROCKS

The Shublik Formation and Kingak shale in the Ellesmerian sequence are the primary source rocks for all of the commercial hydrocarbons (oil) on the North Slope (Bird, 1994). The Pebble Shale also has oil source potential. The only Brookian oil source rocks are the Hue Shale, and possibly, the shales of the Torok Formation and the Colville Group. While the Hue Shale contains oil-prone kerogen, the Torok Formation and Colville Group source rocks are primarily gas prone.

PLAY DEFINITION

Hydrocarbon resources are contained in 23 geologic plays in the Beaufort shelf assessment province. The locations of these plays are shown in figures 14.1 to 14.6. Eight plays overlap the Chukchi and Beaufort shelf assessment provinces in the area west of Point Barrow. These overlap plays are distinguished and separately described below. A more thorough description of the overlap plays is provided in chapter 13 (Chukchi shelf assessment province).

Plays in the Beaufort shelf assessment province are primarily defined by stratigraphic unit. The Undeformed Pre-Mississippian (0101) and Pre-Devonian (0200) plays are in the Franklinian sequence. The Ellesmerian sequence is split into the Endicott (0401, 1800), Lisburne (0501, 1900), and Upper Ellesmerian (0601, 2000, 2100) plays. The Rift plays (0701, 2200) are part of the Beaufortian sequence.

The Brookian sequence is divided into plays first on the basis of stratigraphy and then further subdivided on the basis of structural setting. The Brookian sequence is a system of overlapping, northeast-prograding deltas with sandstone reservoirs formed in both topset and prodelta facies within the delta system. Potential hydrocarbon traps within the Brookian sequence are therefore first grouped into either "topset" plays or "prodelta (turbidite)" plays. These two play groups are then further separated into "east" and "west" play groups that recognize important lateral stratigraphic changes[1] within the Brookian sequence. The Brookian play groups, topset versus prodelta, and east versus west, are further divided into "unstructured" plays which occur on the Arctic platform south of the hinge line fault zone and "faulted" plays which occur from the hinge line fault zone north to the province's northern border. In the eastern part of the Beaufort shelf assessment province, a regional foldbelt intersects the hinge line fault zone to produce numerous complex structures. Here, we do not distinguish "topset" versus "prodelta" facies within the Brookian sequence, and, the structured area is assessed as simply the Brookian Foldbelt play (1602).

PLAY DESCRIPTIONS

Undeformed Pre-Mississippian Basement Play (UABS0101[2]): The Undeformed

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[1] *In the western part of the province ("western" Brookian plays), the topset plays are in the Nanushuk and Colville Groups. and the turbidite plays are in the Torok Formation. In the central part of the province ("eastern" Brookian plays), the topset plays are in the Sagavanirktok Formation, and the turbidite plays are in the Canning Formation.*

[2] *The "UA" Code is the "Unique Assessment Identifier" for each play, and is the principal guide to GRASP data files.*

Pre-Mississippian Basement play (fig. 14.1) consists of stratigraphic traps in carbonate or sandstone reservoirs in the pre-Mississippian basement complex near Point Thomson (Dolton and others, 1987, p. 238). Leaching of carbonates or carbonate cements in the sandstones may have created some porosity and fractures may enhance permeability development. Potential source rocks are the overlying Hue Shale and Canning Formation, which also act as the seal. No OCS wells have tested this play. In State waters, the Alaska State F-1 well tested 2.975 MMcf/day and 152 bbl/ day of 35.3° API gravity condensate from rocks of play 0101. .

Pre-Devonian Play (UABS0200): The Pre-Devonian play (fig. 14.1) includes probable carbonates and overlying shales of lower Paleozoic to Precambrian age in the western part of the Beaufort shelf assessment province. The source rock is either the carbonates or overlying shales. A source rock analog may be the organic-rich Cape Phillips shales of Silurian age in possibly correlative sequences in the Canadian Arctic Islands (Stuart Smith and Wennekers, 1977). The hydrocarbon traps are formed by anticlines, faulted anticlines, or faults. This play has not been tested nor is it seen in outcrop. It is only seen in CDP seismic profiles.

Endicott Play (UABS0401): The Endicott play (fig. 14.1) includes the sandstone reservoirs of the Mississippian Endicott Group. The depositional environment is a pair of regressive and transgressive sequences consisting of swamp, braided stream, flood plain and shallow marine environments. Hydrocarbon traps are formed by anticlines, faulted anticlines, fault blocks, and unconformable truncations of Endicott reservoirs at younger unconformities. Two OCS wells, Y-0191 #1 and Y-0191 #2, unsuccessfully tested prospects in the play. Three OCS wells tested the Tern Island oil field that occurs in this play. Onshore, the Endicott field with 480 million barrels of recoverable oil (Petzet, 1995) produces from this play.

Lisburne Play (UABS0501): The Lisburne play (fig. 14.2) includes the platform carbonates (limestone and dolomite) of the Mississippian to Pennsylvanian Lisburne Group. Potential hydrocarbon traps of structural origins include anticlines, faulted anticlines, and fault- block traps. Potential stratigraphic traps may be associated with porosity pinchouts, unconformity truncations or paleokarst topography at the Lower Cretaceous or other unconformities. Six OCS wells, Y-0191 #1, Y-0191 #2, Mukluk, Mars, Y-0181 (Seal Island), and Phoenix, tested prospects in the play without commercial success. The onshore Lisburne field with 200 million barrels of recoverable oil (Petzet, 1995) produces from the play.

Upper Ellesmerian Play (UABS0601): The Upper Ellesmerian play (fig. 14.3) includes the sandstone reservoirs of the Triassic Sag River Formation and Triassic to Permian Sadlerochit Group. The depositional environment is marine shelf for the Sag River Formation while the Sadlerochit Group has shallow marine, fluvial, floodplain, alluvial fan delta, and point bar sediments. Carbonates within the Shublik Formation are sometimes porous. Potential hydrocarbon traps are formed by anticlines, faulted anticlines, unconformity truncations, faults, or stratigraphic pinchouts. This play was the primary objective of 13 OCS wells, including the well-known Mukluk well. Two OCS wells discovered and tested two oil fields, Sandpiper and Northstar (Seal Island). There are three producing fields onshore, including the main pool of the Prudhoe Bay field with 12 billion barrels recoverable oil (Petzet, 1995), the Ivishak pool of Endicott field with 17.7 million barrels in place oil (AOGCC, 1991b), and the North Prudhoe pool of Prudhoe Bay field with 12 million barrels in place oil (AOGCC, 1994, p. 2).

Rift Play (UABS0701): The Rift play (fig. 14.4) contains locally derived clastics of the Beaufortian sequence and Pebble Shale, mostly preserved in fault blocks (e.g., Dinkum graben) associated with an Early Jurassic to Early Cretaceous rifting event, but also including correlative strata deposited beyond the rift zone. The reservoirs are marine and fluvial sandstones. The traps are anticlines, faulted anticlines, fault blocks, unconformity truncations, or stratigraphic terminations of reservoir beds. Potential source rocks may occur in the underlying Shublik or Kingak Formations or the overlying Pebble Shale and HRZ ("Highly Radioactive Zone") sequences. The play was penetrated by six OCS tests (that targeted deeper formations), including Mars, Y-191, Fireweed, Antares, Mukluk, and Phoenix wells.

There are several onshore fields in the play, including Kuparuk field with 2.4 billion barrels of recoverable oil (Petzet, 1995), the Milne Point field with 220 million barrels of recoverable oil (Anchorage Daily News, 1995), the Point McIntyre field with 340 million barrels of recoverable oil (ARCO, 1993 and Petzet, 1995), and the Point Thomson field with 300 million barrels of condensate (Thomas and others, 1991). Three fields are in NPRA, the South Barrow gas field with 25 billion cubic feet of recoverable gas, East Barrow gas field with 12 billion cubic feet of recoverable gas, and Walakpa gas field with 30 billion cubic feet of recoverable gas (Thomas and others, 1991; AOGCC, 1991a, p. 54).

Brookian Faulted Western Topset Play (UABS0800): The Brookian Faulted Western Topset play (fig. 14.6) includes Cretaceous deltaic-topset facies of the Nanushuk and Colville Groups extending northward from the hinge line fault zone to the province boundary. Reservoir quality is likely to be poor due to the distance from the sediment source and the high clay content of sandstones associated with distal parts of this mud-rich delta system. Sandstones may thicken abruptly in downthrown fault blocks. Source rocks are primarily gas-prone shales of the underlying Torok Formation and Colville Group. Rotated blocks along listric growth faults are the chief trapping mechanisms. No prospects have been tested in the play area.

Brookian Unstructured Western Topset Play (UABS0902): The Brookian Unstructured Western Topset play (fig. 14.6) occurs in the deltaic-topset facies of the Brookian sequence, primarily the Nanushuk Group, in the area between Barrow arch and the hinge line fault zone offshore to the north. The Nanushuk Group in the play area is likely to be a poor reservoir due to the high clay content of the deltaic sandstones. Potential source beds include the underlying Torok Formation, the Pebble Shale, the Kingak shale and the Shublik Formation. These sources may generate oil and/or gas. The play area is sparsely faulted and the sequence dips homoclinally to the north. Prospects are primarily stratigraphic traps related to the pinchout of reservoir beds. Prospects in this play have not been tested in the offshore. Sub-commercial oil pools onshore include the Simpson (12 MMBO recoverable) and Fish Creek (no resource estimate) fields in the National Petroleum Reserve-Alaska (Thomas and others, 1991 Table 2.2).

Brookian Faulted Western Turbidite Play (UABS1000): The Brookian Faulted Western Turbidite play (fig. 14.5) includes the Cretaceous prodelta facies of the Brookian deltas—the Torok Formation and lower Colville Group. Expected reservoirs include lowstand wedge sandstones or submarine fan turbidite sandstones. Sandstone sequences may thicken abruptly in down-thrown blocks along the hinge line fault zone. Sandstones are likely to offer only poor reservoir quality due to the fine-grained and mud-rich nature of the sediments fed to the shelf break by the Nanushuk delta system. Shales in the Torok Formation and Colville Group are primarily gas sources due to kerogen content and because many thousands of feet of the shales have passed through the oil window and into the gas window. Traps in the play are expected to be primarily stratigraphically controlled. There is also potential for fault traps against hinge line listric growth faults. No prospects have been tested in the play area.

Brookian Unstructured Western Turbidite Play (UABS1102): The Brookian Unstructured Western Turbidite play (fig. 14.5) occurs within the Lower Cretaceous prodelta shales and turbidite sandstones of the Torok Formation (lower part of the Brookian sequence). It mostly underlies the Brookian Unstructured Western Topset play (0902). Expected reservoirs include turbidite sands deposited in submarine fan environments. Sandstones are likely to offer only poor reservoir quality due to the fine-grained and mud-rich nature of the sediments fed to the shelf break by the Nanushuk delta system. The Torok Formation, Pebble Shale, Kingak shale and Shublik Formation all form potential source rocks for charging reservoirs in this play. The Kingak shale in this area may be oil prone, but probably reaches sufficient thermal maturity only in rift grabens with expanded sedimentary thicknesses. Prospects are primarily stratigraphic traps formed by sand mounds within a shale sequence. The Phoenix well tested heavy oil in the Torok Formation and the Mukluk well had several Torok Formation oil shows.

Brookian Faulted Eastern Topset Play (UABS1201): The Brookian Faulted Eastern Topset play (fig. 14.6) includes deltaic-topset facies of the Tertiary Sagavanirktok Formation and the Upper Cretaceous Colville Group. It is located north of the hinge line fault zone across the central part of the province. Sagavanirktok Formation sandstones offer excellent reservoir characteristics. Potential source rocks are organic-rich marine shales within the Canning Formation that reach thermal maturity north of the hinge line fault zone in the Nuwuk and Kaktovik basins. There is also potential for oil generation from Beaufortian sequence source rocks deeply buried within the Dinkum graben. The latter source rocks have passed completely through the oil generation window. Prospects in the play are likely to be fault traps along down-to-the-north listric growth faults. Seal continuity may be a risk factor for many prospects due to the high sandstone content of the Sagavanirktok Formation. One offshore well, Galahad, was drilled in the play area and encountered a gas sand that yielded frothy brown oil.

Brookian Unstructured Eastern Topset Play (UABS1302): The Brookian Unstructured Eastern Topset play (fig. 14.6) includes the deltaic-topset facies of the Tertiary Sagavanirktok Formation and equivalent facies of the Upper Cretaceous Colville Group. It is located north of the Barrow arch and south of the hinge line fault zone east of the eastern stratigraphic limit of the Nanushuk Group (generally east of the Colville River delta). Excellent reservoir-quality sandstones occur within the Sagavanirktok Formation in most coastal wells and we expect similar reservoir sequences to also extend offshore. The Canning Formation, Pebble Shale, Hue Shale, lower Kingak shale, and the Shublik Formation are variable to rich oil source rocks that lie within the projected oil window and underlie the play sequence across most of the play area. The play sequence is sparsely faulted. Most of the prospects are expected to be stratigraphic traps or small-offset fault traps. Seals are likely to be a risk factor for many of the prospects because of the abundance of sandstones within the play sequence. Oil was discovered offshore at Hammerhead (reserves not published) and Kuvlum (reserves not published) and onshore at West Sak (15-25 BBO in place; Thomas and others, 1991 Table 2-5) and Ugnu (11-19 BBO in place reserves; Thomas and others, 1991 Table 2-5). In Harrison Bay, the Phoenix well tested oil from a sandstone in the Colville Group.

Brookian Faulted Eastern Turbidite Play (UABS1400): The Brookian Faulted Eastern Turbidite play (fig. 14.5) includes the Upper Cretaceous and Tertiary prodelta shales and turbidites of the Canning Formation where they lie north of the hinge line fault zone and east of the eastern stratigraphic limit of the Torok Formation. Reservoirs are primarily turbidite sandstones in a submarine fan environment. The primary source rocks are expected to be gas-prone shales of the Canning Formation. There is also a potential for hydrocarbon generation from Beaufortian (or "Rift") sequence source rocks that underlie the Brookian play sequence. These Beaufortian sources are likely to be buried to below the base of the oil window and are most likely fully expended with respect to oil. Prospects in the play are both stratigraphic traps related to sand mounds within the marine shale sequences, and fault traps against listric growth faults. No wells have tested the play.

Brookian Unstructured Eastern Turbidite Play (UABS1502): The Brookian Unstructured Eastern Turbidite play (fig. 14.5) includes Late Cretaceous and Tertiary prodelta shales and turbidites of the Canning Formation. It is located on the relatively unstructured part of the shelf between the Barrow arch and the hinge line fault zone. It lies east of the eastern stratigraphic limit of the Torok Formation (east of the Colville River delta). It underlies much of the Brookian Unstructured Eastern Topset play (1302). Reservoirs include turbidite sandstones, enclosed by shales, mostly deposited in submarine fan environments. Source rocks include relatively gas-prone shales of the Canning Formation, and rich oil-prone shales of the Hue Shale and Pebble Shale units. The base of the play sequence lies in direct contact with these source beds. Stratigraphic traps predominate, although small scale fault traps also occur. Marine shales that enclose turbidite sandstones provide good seals. The OCS Y-191 (Beechy Pt. #2) well in Steffanson Sound flowed oil and gas out of the Canning Formation. Onshore, oil has been tested in turbidite sands of the Canning Formation in the Badami field (estimated reserves, 100 MMbbl oil and 100 BCF gas; Alaska Report, 1994) and in the Flaxman Island area.

Brookian Foldbelt Play (UABS1602): The Brookian Foldbelt play (fig. 14.6) includes Tertiary Sagavanirktok Formation topset sequences and Cretaceous to Tertiary Canning Formation topset and prodelta sequences complexly structured by both Brooks Range folding and coeval faulting along the hinge line fault system. The hinge line fault zone obliquely intersects the foldbelt within the Brookian Foldbelt play. Major offshore structural features in the play include Herschel high, Demarcation subbasin, and Camden anticline. Onshore, the play includes Marsh Creek anticline and other shallow structures in the coastal plain of the northern Arctic National Wildlife Refuge (ANWR). Reservoir sandstones are very sparse in the three offshore wells (Belcher, Corona, and Aurora) that tested prospects in this play. However, in the Natsek well at the southeast end of the Herschel high in Canadian waters, reservoir-quality sandstones were encountered in Upper Cretaceous and Paleocene rocks. Potential oil sources include the Hue Shale and Canning Formation, which probably underlie many offshore structures in the Brookian Foldbelt play. However, wells testing the play penetrated only Tertiary shales with gas-prone kerogen. The dominant recognized trap types include anticlines, faulted anticlines and fault closures. Also likely are stratigraphic traps occurring in syn- and post-tectonic sediments that filled basins developed between folded uplifts. Late stage structuring may have disrupted some earlier-formed hydrocarbon pools. Three offshore wells tested the play but failed to find pooled hydrocarbons. Belcher well was drilled on an anticline on the Herschel high and encountered neither sandstones nor hydrocarbon shows. Corona was drilled on the crest of Camden anticline, and encountered only sparse thin sandstones with no hydrocarbon shows. Aurora was drilled on an anticlinal feature adjacent to ANWR. It primarily encountered shales and no hydrocarbon shows in the Brookian sequence.

Beaufort Shelf Plays That Overlap with Chukchi Shelf:

Endicott Portion Shared with Chukchi Shelf (UABS1800) *Chukchi Shelf Play 2 (UACS0200). Lower Ellesmerian—Endicott Clastics-Arctic Platform:* Reservoir objectives primarily include Late Devonian(?) to Mississippian sandstones deposited in marginal- to non-marine environments on the east side of Hanna trough during the early rift phase of subsidence. Early-formed horst and stratigraphic wedge traps have been buried to greater depths than their counterparts to the west on Chukchi platform and are associated with higher levels of thermal maturity and poorer reservoir properties. The play is charged by the Hanna trough play charging system (see chapter 13, this volume). Most identified prospects lie considerably deeper than the primary regional source rock (Shublik), and the high thermal maturity predicted for most traps suggests the hydrocarbon endowment of the play is largely dry gas. Beaufort shelf play 1800 is therefore modeled with a higher gas content than other Chukchi shelf plays also charged by the Hanna trough play charging system. Play 18 play was not tested by any wells. The area of play 1800 is shown in figures 14.1 and 13.25.

Lisburne Portion Shared with Chukchi Shelf (UABS1900) *Chukchi Play 3 (UACS0300). Lower Ellesmerian—Lisburne Carbonates:* Reservoir objectives include Mississippian to Permian carbonates that were deposited on a stable marine shelf, with deeper water facies in the southeast part of the province in axial parts of Hanna trough. Porosity in Lisburne carbonates is associated with sparse porous zones in limestones and thin dolomite beds. No reef facies have been documented within the Lisburne carbonate assemblage, which ranges in age from Mississippian to Permian beneath Chukchi shelf. The play is primarily charged by the Hanna trough play charging system (see chapter 13, this volume), with perhaps minor contributions from interbedded organically-lean and gas-prone shales. Incomplete penetrations of the Lisburne carbonates occurred at Popcorn, Crackerjack, and Diamond wells, which encountered mostly nonporous carbonates with sparse thin zones where porosities range up to 14 percent. No hydrocarbons were encountered in Lisburne carbonates in these wells. The area of play 1900 is shown in figures 14.2 and 13.25.

Ellesmerian Deep Gas Shared with Chukchi Shelf (UABS2000) *Chukchi Shelf Play 4 (UACS0400). Ellesmerian Sequence — Overmature "Deep Gas" (Lower and Upper Ellesmerian Sequences):* Reservoir objectives include all potential reservoirs in both Lower Ellesmerian and Upper Ellesmerian sequences (reservoir strata described in chapter 13 with Chukchi shelf plays 1,2,3,5, and 6). Prospects in the "Deep Gas" play occur at subsurface depths beneath the oil floor (2.0% vitrinite reflectance) and would contain only gas. High thermal maturities have had a detrimental effect on reservoir properties, as has the the multi-cycle tectonic history combined with extremely deep burial at present (to 38,000 ft). This aspects of play history result in high exploration risks for Beaufort shelf play 2000. This play was penetrated at Tunalik well in northwestern Alaska with no hydrocarbons present. At the level of Lower Ellesmerian rocks, Beaufort shelf play 2000 extends from the Beaufort shelf province into northeastern parts of the Chukchi shelf assessment province, where it was assessed as Chukchi shelf play 4. The area of play 2000 is shown in figures 14.1 and 13.25).

Upper Ellesmerian - Portion Shared with Chukchi Shelf (UABS2100) *Chukchi Shelf Play 6 (UACS0600). Upper Ellesmerian—Sadlerochit Group-Arctic Platform*: Reservoir objectives primarily include Late Permian to Triassic marginal to shallow marine sandstones of the Sadlerochit Group that were deposited on the south-facing shelf that then existed on the Arctic platform. Diamond well, offshore on the east flank of Hanna trough, encountered over 500 feet of potential reservoir strata that are correlative to the Permian Echooka Formation. Primary trap styles include stratigraphic wedges and fault traps, with hydrocarbons migrating northward into traps from the Hanna trough play charging system (described in chapter 13, this volume) on the south. A prospect in this play was penetrated at Diamond well where it is barren of hydrocarbons. Several wells also penetrated the play sequence (with no pooled hydrocarbons) in northwestern Alaska. The area of play 2100 is shown in figures 14.3 and 13.26.

Rift Portion Shared with Chukchi Shelf (UABS2200) *Chukchi Shelf Play 8 (UACS0800). Rift Sequence—Stable Marine Shelf:* Reservoirs are primarily Late Jurassic to Early Cretaceous sandstones equivalent to the Kuparuk Formation of Arctic Alaska. Unlike the sandstones in the tectonically active rift zone (Chukchi shelf play 7) to the west, these rocks were deposited at distance away from the rift zone on a tectonically stable shelf and slope that rimmed a deep water area in southernmost Hanna trough. Here, we anticipate fine-grained marine shelf sandstones that are probably thinner and less laterally continuous than their counterparts in Chukchi shelf play 7. This play is charged by the Hanna trough play charging system (described in chapter 13, this volume). A prospect within the play was tested by Klondike well, which encountered pooled oil in a sandstone 80 feet thick. Diamond well encountered no sandstones (only the Pebble Shale was present) and was barren of hydrocarbons. The area of play 2200 is shown in figures 14.4 and 13.27.

Sand Apron Shared with Chukchi Shelf (UABS2300) *Chukchi Shelf Play 14 (UACS1400). Sand Apron-North Chukchi High (Upper and Lower Brookian sequences)*: Potential reservoirs are inferred to consist primarily of shallow marine to fluvial sandstones of Early Cretaceous to Tertiary age that are hypothesized to have been deposited in littoral systems that fringed North Chukchi high, an area of recurrent uplift throughout Albian-Aptian and later times (Johnson, 1992). This play therefore includes both the Lower (Early Cretaceous) and Upper (Tertiary) Brookian sequences of Chukchi shelf. The play is probably charged primarily from the west by the North Chukchi basin play charging system (described in chapter 13). This play has not been tested by any well. The area of play 2300 is shown in figures 14.6, 13.28, and 13.29.

Turbidites (Torok) Shared with Chukchi Shelf (UABS2400) *Chukchi Shelf Play 17 (UACS1700). Lower Brookian Sequence—Torok Turbidites-Arctic Platform (Unstructured)*: This play addresses the unstructured area of the Arctic platform that lies south of Barrow arch, east of the wrench fault province of western Chukchi shelf, and north of the foldbelt. Potential reservoirs are turbidite sandstones within the Lower Cretaceous Torok Formation. Exploratory drilling has shown that sandstone is quite sparse within the Torok Formation in this play. Reservoir presence is therefore one important risk element for the play. Low-relief anticlines (possibly related to compaction), mounded fan complexes, and slope turbidites isolated within slope shales form the primary anticipated trap types, few of which are readily observable in seismic data. The play is modeled as predominately charged by the Hanna trough play charging system (described in chapter 13, this volume), although some contribution from the gas-rich Colville basin play charging system (also described in chapter 13) is also possible. The play was tested by Burger and Diamond wells offshore and several wells onshore. No pooled hydrocarbons were encountered in any well. The area of play 2400 is shown in figures 14.5 and 13.28.

Topset (Nanushuk) Shared with Chukchi Shelf (UABS2500) *Chukchi Shelf Play 18 (UACS1800). Lower Brookian Sequence — Nanushuk Topset-Arctic Platform (Unstructured)*: This play addresses the unstructured area of the Arctic platform that lies south of Barrow arch, east of the wrench fault province of western Chukchi shelf and north of the foldbelt. Reservoir objectives include delta-plain and nearshore sandstones of the Lower Cretaceous Nanushuk Group. Low-relief anticlines possibly related to differential compaction and stratigraphic terminations of homoclinally-dipping sandstones form the primary trap types. This play is modeled as predominately charged by the Hanna trough play charging system, although some contribution from the gas-rich Colville basin play charging system (described in chapter 13, this volume) is possible. The play was tested at Diamond and Burger wells. A gas-charged sandstone 36 feet thick was encountered at Burger well within several miles of a fault that passes downward into the Burger gas pool. This fault may have formed a migration conduit for gas escaping upward from Kuparuk-equivalent, gas-charged sandstones of the Burger gas pool. The area of play 2500 is shown in figures 14.6 and 13.28.

PLAY DEPENDENCY MODEL

The plays in Beaufort shelf assessment province were aggregated with dependencies using the ***FASPAG*** modeling program. This program allow for the accounting of dependencies between plays and groups of plays.

The play dependency is viewed as the frequency of physical coincidence between pools among two or more plays. For example, a dependency value of 100 percent between play A and B indicates that every pool in play A is located above, below or next to a pool in play B (a coincidence frequency rate of 100%) owing to some commonality in origin. A dependency value of 0 percent indicates complete independence of hydrocarbon occurrences between plays (generally caused by physical isolation of plays, such that hydrocarbons cannot migrate from one play to another). In the case of zero dependence, a hydrocarbon pool in play A is never accompanied by a hydrocarbon pool in play B. Because we have no meaningful discovery statistics offshore, the values for dependency used here essentially reflect the frequency of prospect sharing (fraction of structures or potential traps with two or more play sequences). Figure 7 is a tree of the dependencies among plays used in the ***FASPAG*** aggregation for Beaufort shelf assessment province. The plays are identified by their play numbers, as listed in table 14.1.

RESOURCE ENDOWMENT

Table 14.1 lists the mean undiscovered oil and gas resources for the 23 Beaufort shelf plays. Three plays, 1201-*Brookian Faulted Eastern Topset* (1.05 BBO), 1302-*Brookian Unstructured Eastern Topset* (1.65 BBO), and 1602-*Brookian Foldbelt* (2.04 BBO), each have over 1 billion barrels of risked, undiscovered, conventionally recoverable oil. The 1.05 BBO of liquid resources for play 1201-*Brookian Faulted Eastern Topset* are almost entirely condensate (natural gas liquids), while all other plays offer both crude oil and condensate. Five other plays have undiscovered resources of greater than 300 million barrels, including: 0601-*Upper Ellesmerian* (763 MMBO), 0701-*Rift* (910 MMBO), 2100-*Upper Ellesmerian portion shared with Chukchi* (497 MMBO), 2200-*Rift portion shared with Chukchi* (606 MMBO), and 2300-*Sand Apron shared with Chukchi* (291 MMBO).

The ranked pool sizes for the plays in the Beaufort shelf assessment province are shown in the play summaries in Appendix B1. The median size of the largest oil pool modeled in Beaufort shelf is estimated to be 580 million barrels (1602-*Brookian Foldbelt* play).

Three plays, 0401-*Endicott without portion shared with Chukchi shelf*, 1302-*Brookian Unstructured Eastern Topset*, and 0601-*Upper Ellesmerian*, have discovered fields in the offshore that have been removed from the ranked

Table 14.1
OIL AND GAS ENDOWMENTS OF BEAUFORT SHELF PLAYS
Risked, Undiscovered, Conventionally Recoverable Oil and Gas

PLAY NO.	PLAY NAME (UAI* CODE)	OIL (BBO)			GAS (TCFG)		
		F95	MEAN	F05	F95	MEAN	F05
0101	Undeformed Pre-Miss. Bsmt (UABS0101)	0.000	0.006	0.027	0.000	0.028	0.109
0200	Pre-Devonian (UABS0200)	0.000	0.173	0.505	0.000	3.534	9.958
0401	Endicott w/o Portion Shared/Chukchi (UABS0401)	0.000	0.037	0.120	0.000	0.109	0.303
0501	Lisburne Play (Beaufort Only: UABS0501)	0.006	0.208	0.805	0.009	0.452	2.117
0601	Upper Ellesmerian (Beaufort Only: UABS0601)	0.135	0.763	2.200	0.273	1.834	8.057
0701	Rift (Beaufort Only: UABS0701)	0.564	0.910	1.570	1.302	2.559	5.512
0800	Brookian Faulted Western Topset (UABS0800)	0.000	0.082	0.254	0.000	1.570	5.372
0902	Brookian Unstructured Western Topset (UABS0902)	0.000	0.146	0.631	0.000	0.211	0.748
1000	Brookian Faulted Western Turbidites (UABS1000)	0.000	0.029	0.095	0.000	0.601	1.923
1102	Brookian Unstructured Western Turbidite (UABS1102)	0.000	0.057	0.214	0.000	0.133	0.468
1201	Brookian Faulted Eastern Topset (UABS1201)	0.518	1.046	2.042	7.323	16.074	35.665
1302	Brookian Unstructured Eastern Topset (UABS1302)	0.907	1.648	3.497	0.539	0.813	1.258
1400	Brookian Faulted Eastern Turbidites (UABS1400)	0.000	0.183	0.355	0.000	3.585	7.252
1502	Brookian Unstructured Eastern Turbidites (UABS1502)	0.000	0.042	0.169	0.000	0.090	0.349
1602	Brookian Foldbelt (UABS1602)	1.205	2.038	3.680	1.662	3.188	6.108
1800	Endicott-Overlaps Chukchi (UABS1800)	0.000	0.0006	0.002	0.000	0.012	0.034
1900	Lisburne-Overlaps Chukchi (UABS1900)	0.000	0.018	0.083	0.000	0.065	0.273
2000	Ellesmerian Deep Gas-Overlaps Chukchi (UABS2000)	0.000	0.004	0.014	0.000	0.150	0.583
2100	Upper Ellesmerian-Overlaps Chukchi (UABS2100)	0.000	0.497	1.407	0.000	1.391	4.075
2200	Rift-Overlaps Chukchi (UABS2200)	0.248	0.606	1.300	0.855	2.166	4.404
2300	Sand Apron-Overlaps Chukchi (UABS2300)	0.000	0.291	1.173	0.000	4.895	17.000
2400	Turbidites (Torok)-Overlaps Chukchi (UABS2400)	0.000	0.003	0.021	0.000	0.008	0.057
2500	Topset (Nanushuk)-Overlaps Chukchi (UABS2500)	0.000	0.044	0.167	0.000	0.034	0.127
	FASPAG AGGREGATION	*6.278*	*8.835*	*11.965*	*20.101*	*43.502*	*79.148*

***Unique Assessment Identifier, code unique to play.**

pool plots in order to calculate the remaining **undiscovered** resources. The discovered fields, when removed mathematically, create gaps on the ranked pool size plots; these gaps and the discovered fields that once filled them are annotated on the ranked pool size plots for these plays (plays 0401, 1302, and 0601, Appendix B1).

Table 14.1 shows that there are four plays in Beaufort shelf assessment province that offer over 3 trillion cubic feet of risked, undiscovered gas resources. These include: Play 0200-*Pre-Devonian*, play 2300-*Sand Apron shared with Chukchi*, play 1602-*Brookian foldbelt*, and play 1201-*Brookian Faulted Eastern Topset*. Play 1201-*Brookian Faulted Eastern Topset* offers the largest gas endowment[3] —16 trillion cubic feet. Two of these plays, play 1201-*Brookian Faulted Eastern Topset* and play 2300-*Sand Apron shared with Chukchi,* have pools with median (conditional, or unrisked) sizes greater than 4 TCF. The largest gas pools in most other plays offer median (conditional) gas resources less then 1 TCF.

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[3]*mean, risked, undiscovered, conventionally recoverable gas*

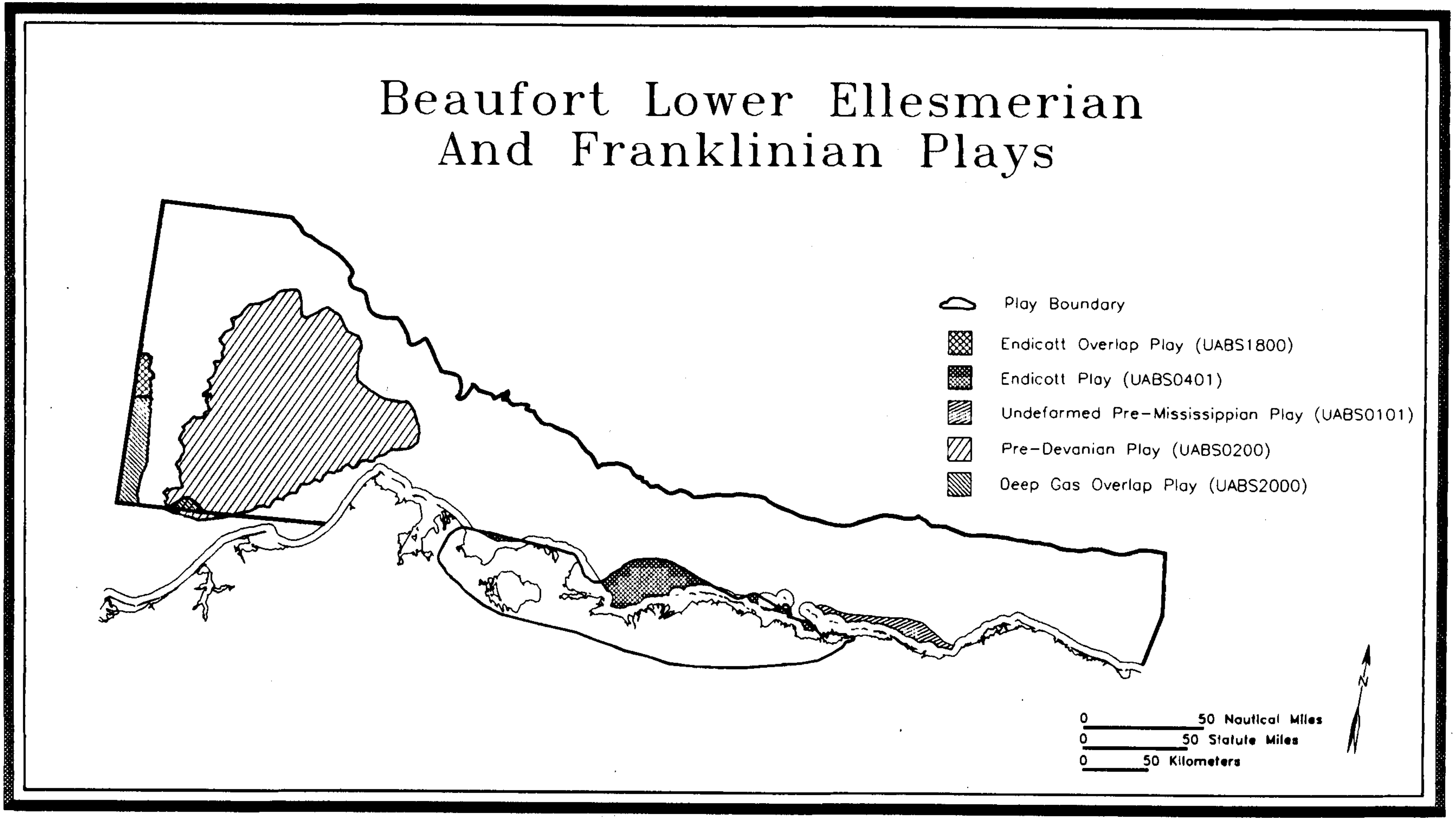

Figure 14.1: Map for areas of Lower Ellesmerian and Franklinian plays, Beaufort shelf assessment province.

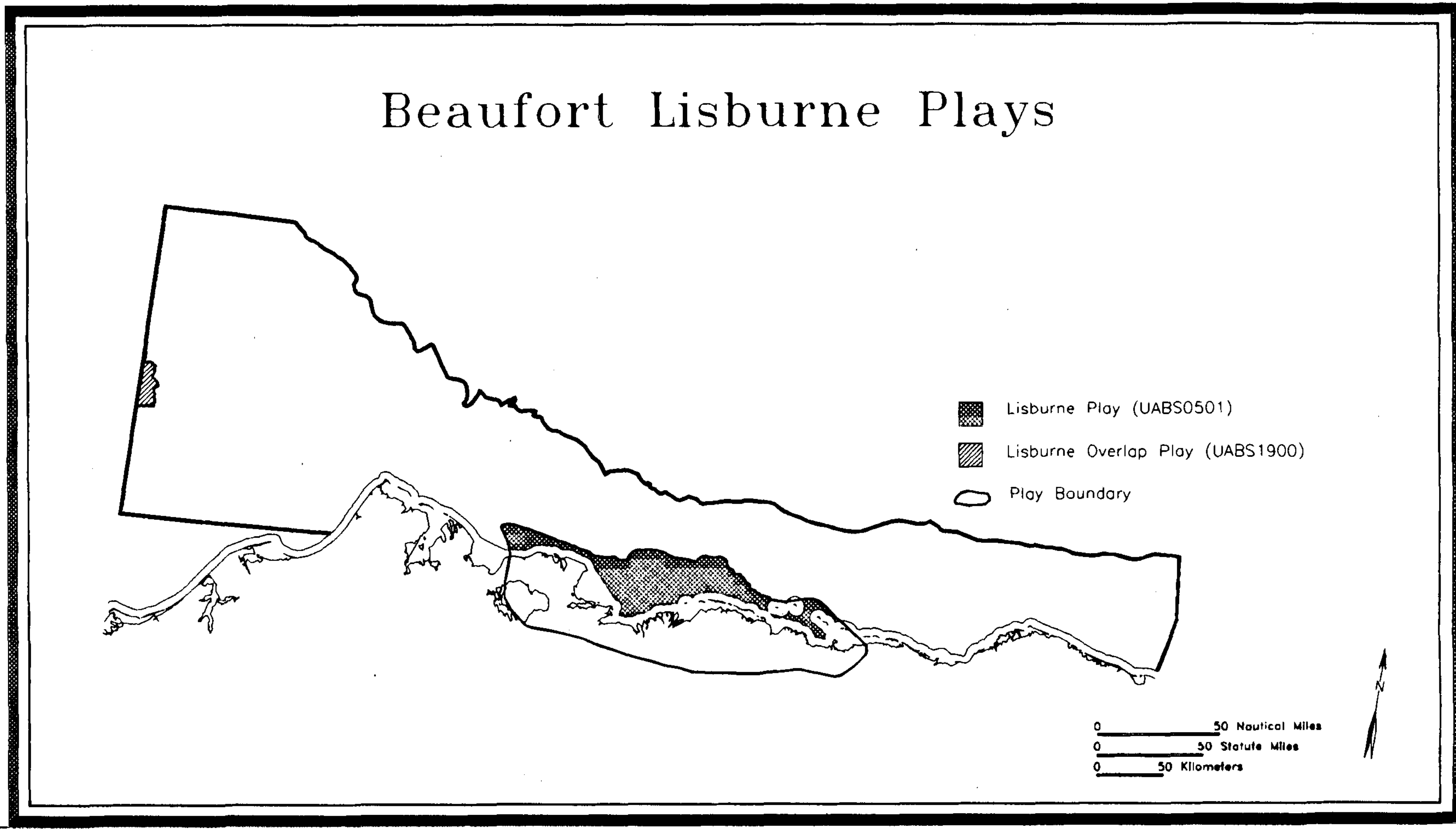

Figure 14.2: Map for areas of Lisburne plays, Beaufort shelf assessment province.

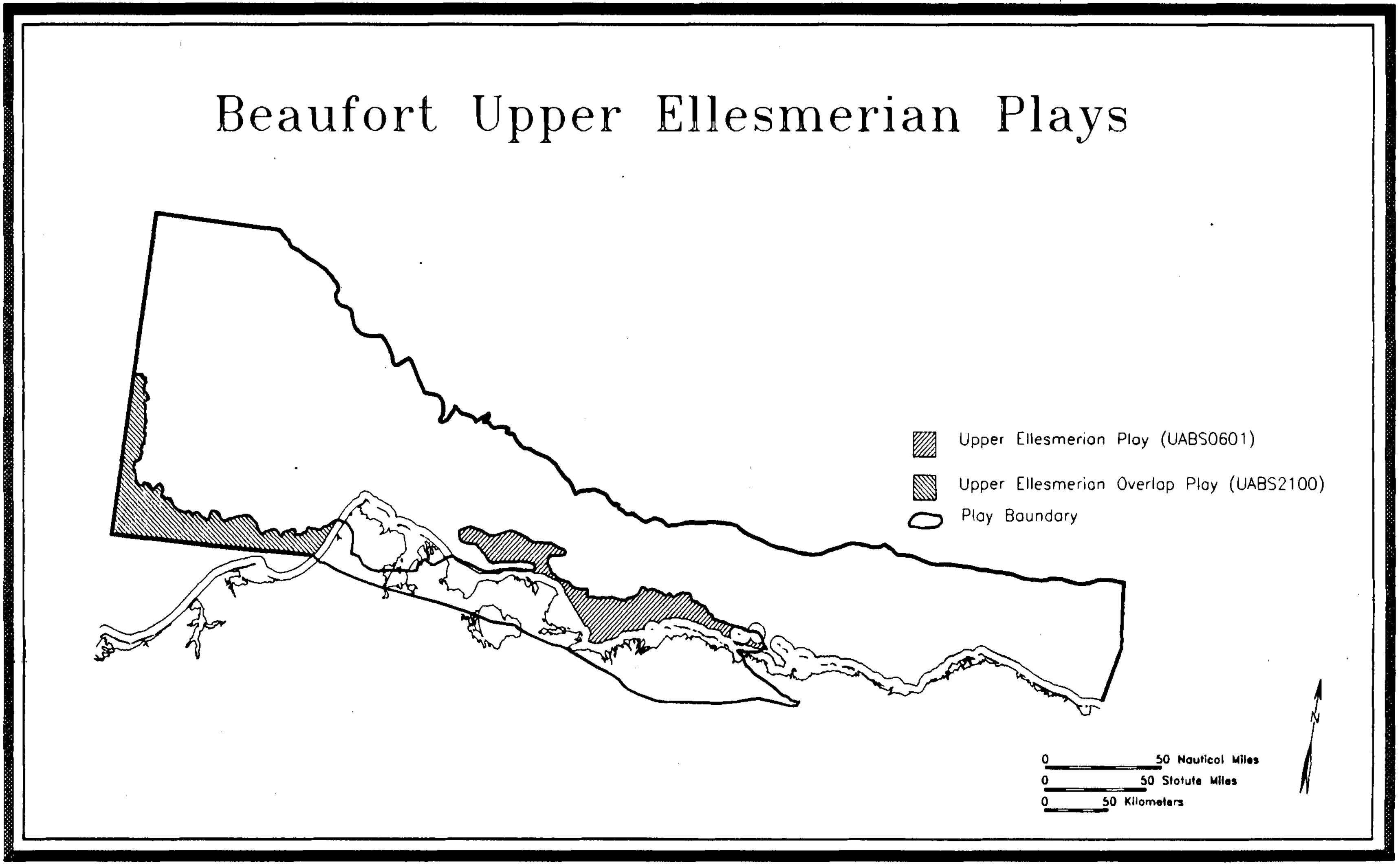

Figure 14.3: Map for areas of Upper Ellesmerian plays, Beaufort shelf assessment province.

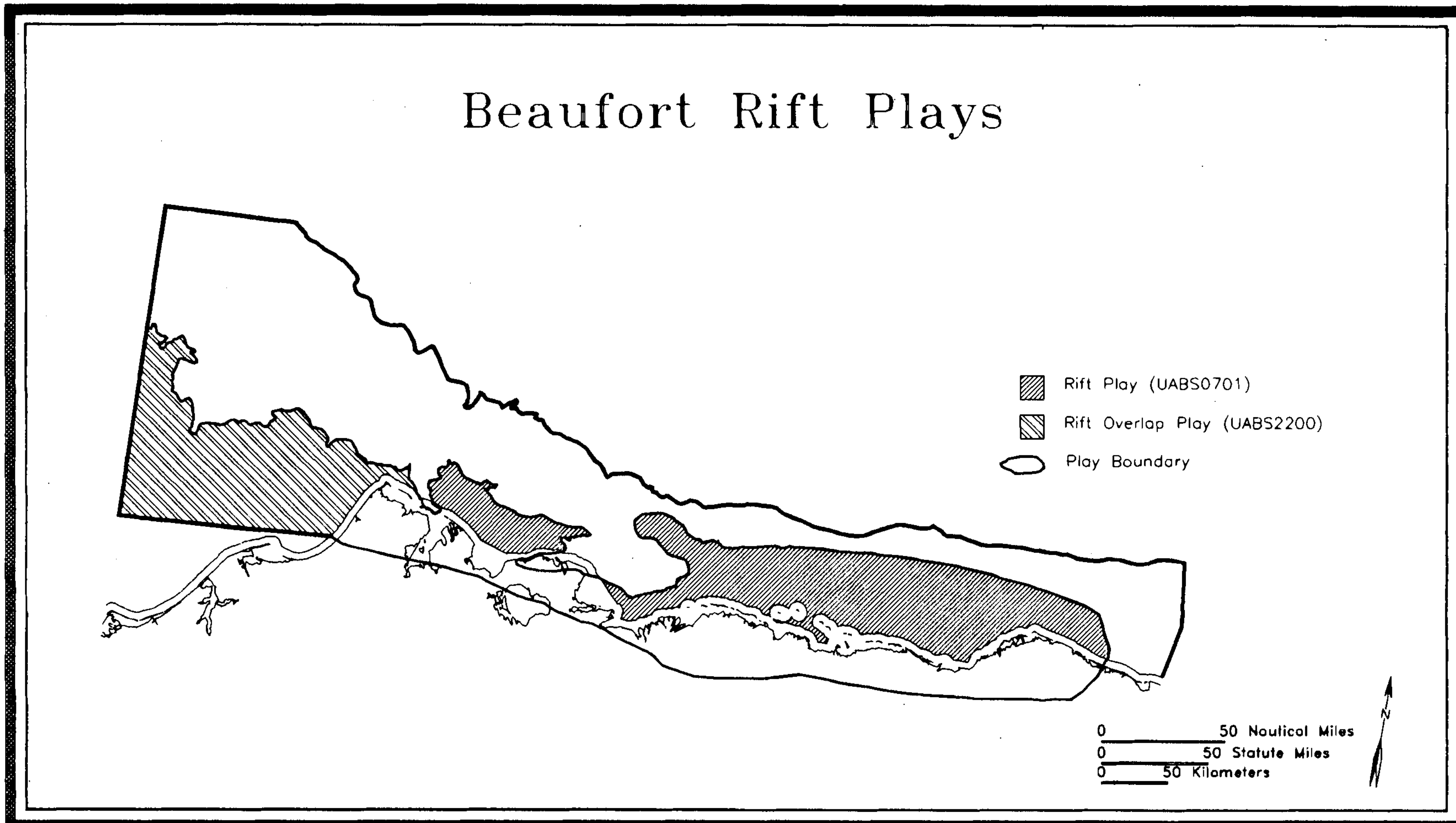

Figure 14.4: Map for areas of Rift (Beaufortian sequence) plays, Beaufort shelf assessment province.

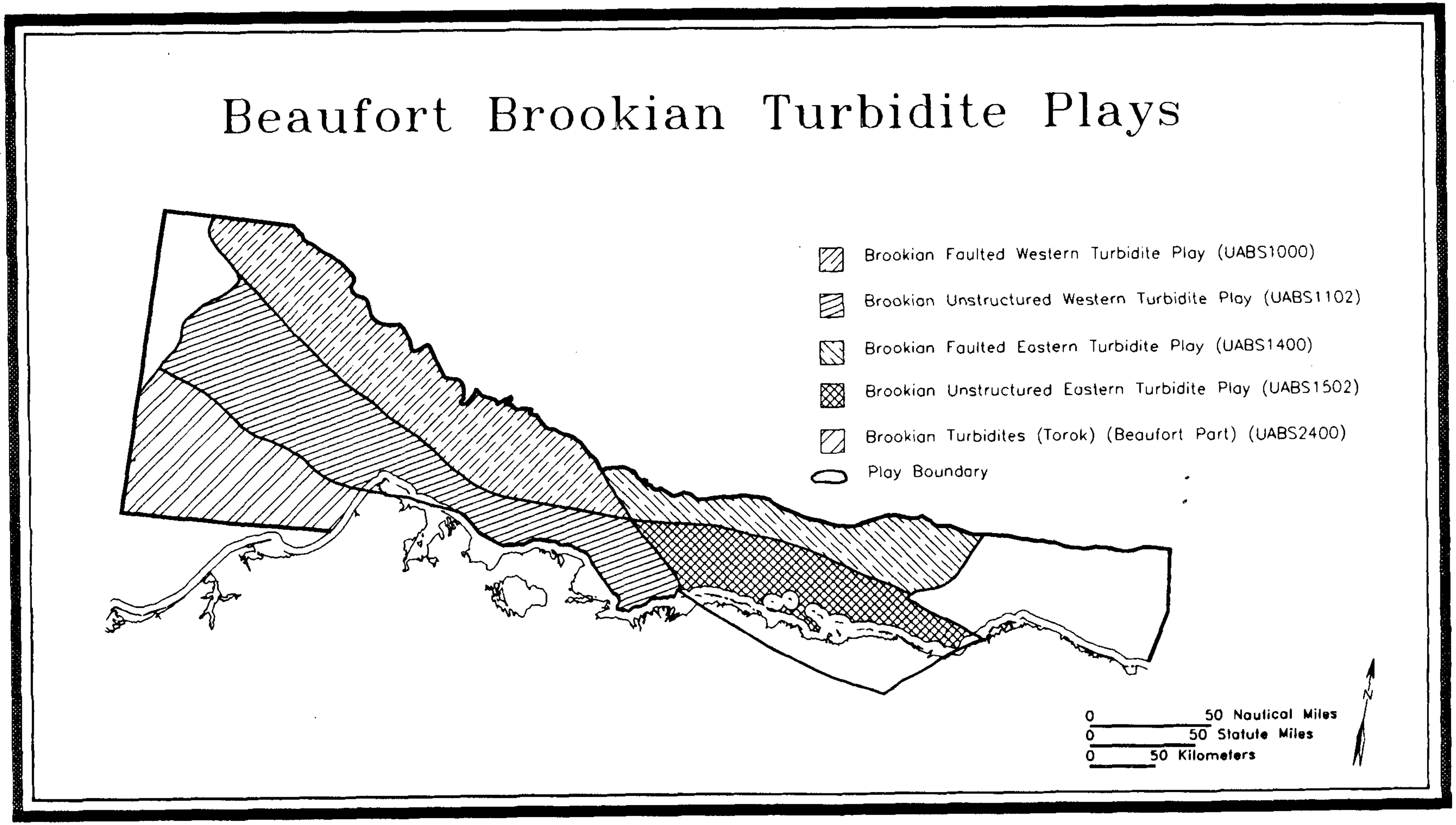

Figure 14.5: Map for areas of Brookian sequence turbidite plays, Beaufort shelf assessment province.

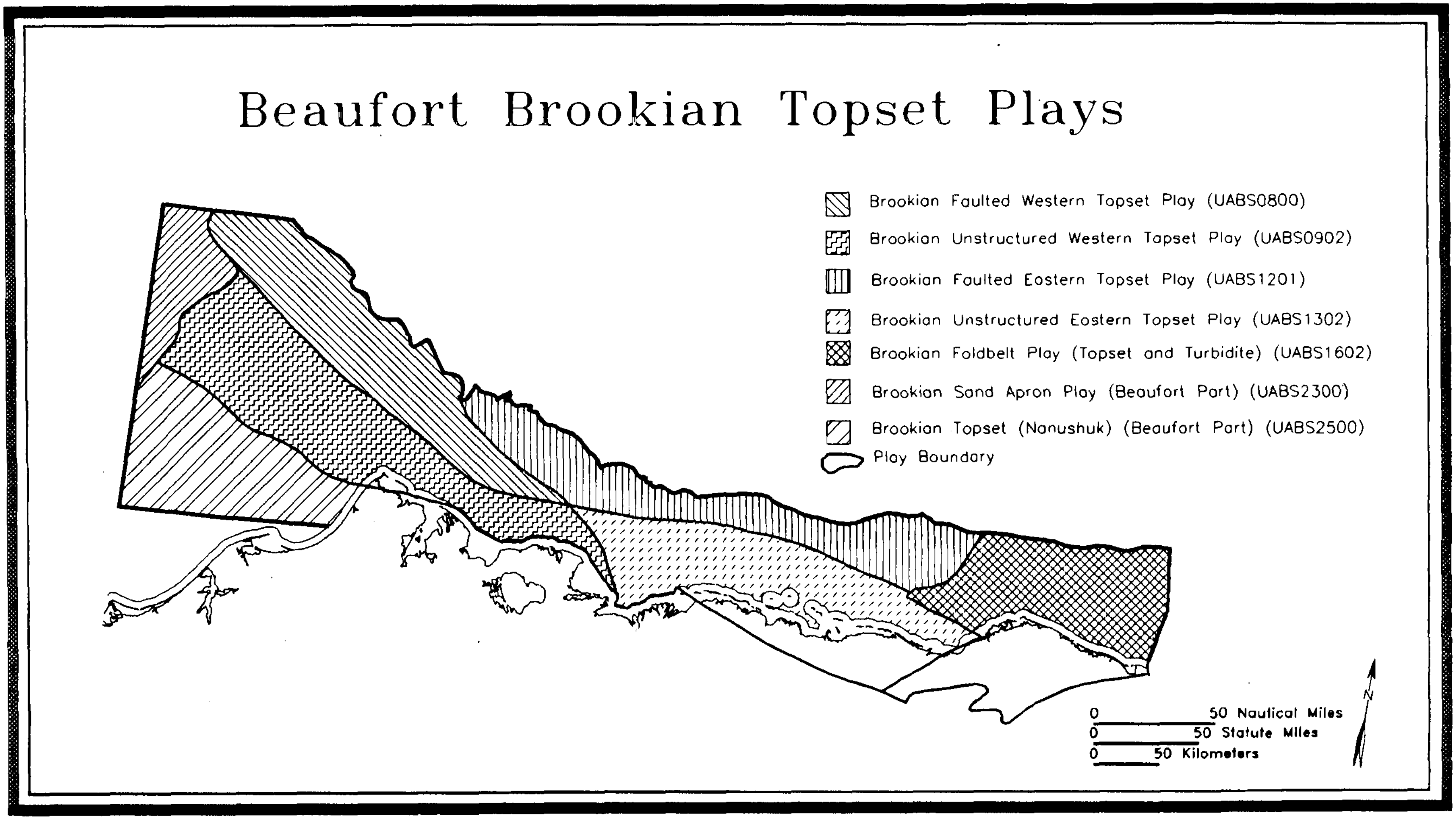

Figure 14.6: Map for areas of Brookian sequence topset-facies plays, Beaufort shelf assessment province.

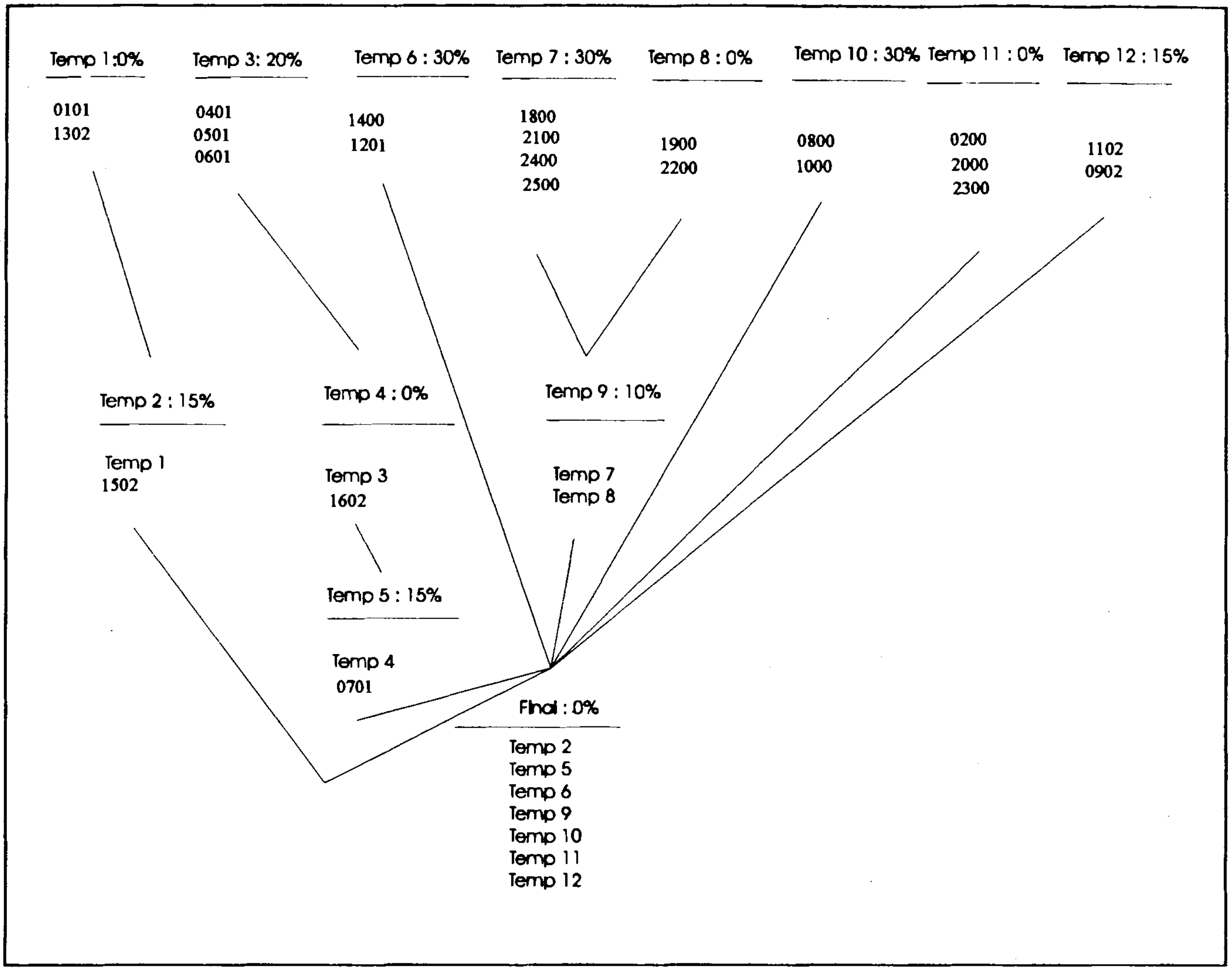

Figure 14.7: Tree of dependencies used for aggregation of plays in Beaufort shelf assessment province. **Numbers** correspond to **play numbers** and **UAI codes** for plays. The labels **Temp 1** through **Temp 12** are intermediate groupings of plays that share common dependency values. **Final** is the grouping of all the intermediate groupings. The number that follows the group name, for example as in **"Temp 1: 0%"**, is the dependency value for the plays and/or groups listed immediately below. A dependency value of 0 percent indicates a complete lack of dependence. A dependency value of 100 percent indicates complete dependence.

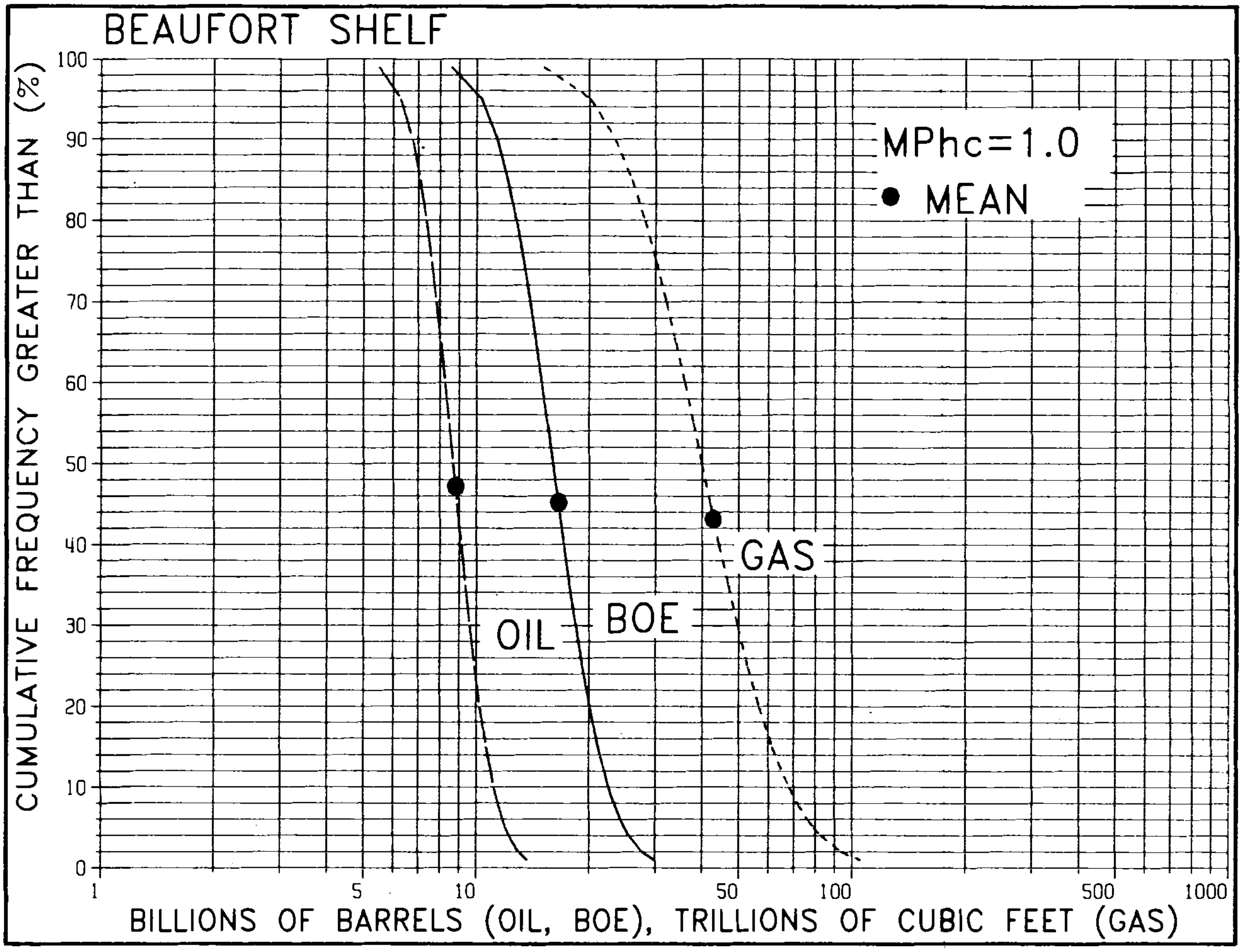

Figure 14.8: Cumulative probability curves for undiscovered, conventionally recoverable resources (oil, gas, and BOE) for Beaufort shelf assessment province. ***BOE**, total oil and gas in energy-equivalent barrels, obtained by converting gas to energy-equivalent barrels and adding to oil; **MPhc**, marginal probability for occurrence of pooled hydrocarbons in province.*

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15. HOPE BASIN ASSESSMENT PROVINCE

by

Susan A. Zerwick

INTRODUCTION

The Hope basin assessment province lies in the southern Chukchi Sea between the northwest coast of Alaska and the U.S. - Russia maritime boundary. It includes portions of both Hope and Kotzebue basins, separated within the assessment province by Kotzebue arch (fig. 15.1). The assessment province includes the easternmost part of the larger Hope basin system that extends 300 miles west into Russian waters. The assessment province includes offshore parts of Kotzebue basin, which extends eastward beneath State of Alaska lands. Only the Federal offshore parts of these basins were evaluated as part of Hope basin assessment province.

Hope basin ***assessment province*** also includes that part of Chukchi Sea ***Planning Area*** that lies north of Pt. Hope and south of Herald arch (fig. 15.1). To the south, Hope basin ***assessment province*** is separated from Norton basin ***assessment province*** at the northern boundary of Norton Basin ***Planning Area*** in Bering Strait. The location of Hope basin assessment province is shown in figure 15.1.

The Hope Basin ***Planning Area*** (areas of Kotzebue basin and Hope basin south of Pt. Hope) has never been offered in a Federal OCS lease sale. The part of Hope basin ***assessment province*** north of Pt. Hope was offered in Chukchi Sea ***Planning Area*** lease sales in 1988 and 1991, but attracted no bids.

Exploratory drilling within Hope and Kotzebue basins consists of two onshore wells, Cape Espenberg No. 1 and Nimiuk Point No. 1, drilled on the south and north flanks, respectively, of Kotzebue basin in 1975 (located in fig. 15.1). These drill holes penetrated Tertiary sediments with no oil or gas shows. Seismic data has been collected over most of the Hope basin assessment province, ranging from an approximate 3X5 mile grid north of Pt. Hope to an irregular web of lines 5 to 15 miles apart in Kotzebue basin. Seismic sequences analogous to the major stratigraphic sequences penetrated by the Kotzebue basin wells were correlated across Kotzebue arch and into Hope basin on the basis of seismic character and position. Our hypothetical model for the age, lithology and hydrocarbon potential of Hope basin is necessarily drawn from seismic data, speculative correlations to distant wells in the separate, but related Kotzebue basin, and regional stratigraphic information from drilling in the entirely separate but analogous Norton basin 200 miles to the south.

GEOLOGIC SETTING OF HOPE BASIN

Both Hope and Kotzebue basins are transtensional pull-apart basins that may be related to right-lateral movement along the Kobuk fault. Basin extension and subsidence probably began in the early Tertiary. Two stages of faulting, during the Eocene and Miocene, caused extensive structural deformation in Hope basin (Tolson, 1987a).

The northern parts of Hope basin apparently lie on deformed Mesozoic and Paleozoic rocks of the Brookian-Chukotkan orogenic belt exposed on Wrangel Island and in the western Brooks Range of Alaska. Eastern Kotzebue basin probably overlies sedimentary and igneous Cretaceous rocks like those exposed to the east in the northern Yukon-Koyukuk province of Alaska. Sediments in the Kotzebue basin wells overlie Paleozoic(?) schists and carbonates like those widely exposed on the Seward Peninsula. These latter rocks probably form basement beneath western Kotzebue basin, and the southernmost parts of Hope basin.

HOPE BASIN STRATIGRAPHY

The sedimentary fill reaches approximately 18,000 feet in maximum thickness in both Hope and Kotzebue basins. Outcrops surrounding Hope basin (summarized by Grantz and others, 1975, and Tolson, 1987a) and the Kotzebue basin wells indicate that basin fill consists of two main tectonostratigraphic sequences: 1) Eocene(?) volcanics, volcaniclastics, conglomerates and sandstones; overlain by 2) Oligocene(?) and younger shallow-marine to nonmarine sandstones, siltstones and conglomerates. In Kotzebue basin, the seismic sequence correlated to the Eocene(?) sequence reaches 10,500 feet in thickness and the seismic sequence correlated to the Oligocene(?) and younger sequence reaches 8,500 feet in thickness. In Hope basin, the correlative seismic sequences each reach 11,500 feet in maximum thickness. In figure 15.2, the Eocene(?) seismic sequence is recast as the "Early Sequence" and the Oligocene(?) and younger seismic sequence is shown as the "Late Sequence."

In Russian waters, Hope basin appears to be underlain by up to 2 km of seismically-stratified rocks inferred to be Cretaceous in age (Shipilov, 1989; Pol'kin, 1984). The petroleum source and reservoir potential of these inferred Cretaceous rocks are unknown. Whether these rocks extend eastward into the deepest parts of U.S. Hope basin is not known, although analysis of seismic reflection and refraction data has never identified such a layer flooring Hope basin in U.S. waters (Grantz and others, 1975; Tolson, 1987a).

BASINS ANALOGOUS TO HOPE BASIN

Analog basins formed a source for some input parameters provided to our model for the oil and gas potential of Hope and Kotzebue basins. The eastern subbasin of Norton basin is a reasonable analog to both basins because it is similar in age and structural setting and appears to have a similar history of basin subsidence. Drilling data indicate that eastern Norton basin is filled with continental to shallow marine sediments ranging from Paleocene to Pleistocene in age (Turner and others, 1986), similar to the strata penetrated by the Kotzebue basin wells. To help determine reasonable maximum pool areas for Hope basin province, we resorted to data for field areas in the heavily explored Reconcavo basin of Brazil. Like Hope basin, Reconcavo basin is a transtensional pull-apart basin highly deformed by faulting (Ghignone and de Andrade, 1970) and is therefore a reasonable structural analog.

PETROLEUM GEOLOGY OF HOPE BASIN

Density log porosities averaging 29 percent over approximately 700 net (aggregate over interval) feet of sandstone in each of the two Kotzebue basin wells indicate good reservoir potential for the Oligocene(?) and younger sequence. The underlying Eocene(?) sequence has a high proportion of volcaniclastics rich in chemically unstable grains that promoted cementation or collapse of internal pore spaces of sandstones. Density log porosities of the Eocene(?) sequence average 15 percent over 110 net feet of sandstone (Larson and Olson, 1984).

Although not observed in the Kotzebue basins wells, sandstones are inferred to have been deposited near the base of basin fill across broad areas of Hope and Kotzebue basins. The inference of the widespread existence of these basal sandstones is based upon analogy to eastern Norton basin, where sandstones are common within Paleocene(?) and Eocene rocks overlying basement and have conventional core porosities ranging up to 12.8 percent (Norton Basin COST No. 2 well; Turner and others, 1983).

Organic material in samples from Tertiary strata of both Kotzebue basin wells is predominately type III (gas prone) kerogen. Tertiary rocks in Hope basin in Russian waters are underlain by up to 2 km of rocks observed only in seismic data but inferred to be Cretaceous in age (Shipilov, 1989; Pol'kin, 1984). The petroleum source potential of these inferred Cretaceous rocks is unknown. Although thermally immature Cretaceous rocks are exposed north and west of Kotzebue basin (Tolson, 1987b), Cretaceous strata do not appear to floor Hope basin in U.S. waters. Paleozoic basement rocks are overmature in the Kotzebue basin wells and in most outcrops surrounding Hope and Kotzebue basins. There are, however, limited exposures of thermally mature Paleozoic rocks on the western Seward Peninsula and in the western Brooks Range (Harris and others, 1987). These rocks may extend beneath western parts of U.S. Hope basin. There is some very small possibility that these latter Paleozoic rocks might act as local sources for oil.

Because available data fail to identify any credible oil source rocks, we view Hope and Kotzebue basins as fundamentally gas prone. This view is reflected in the analytical model by the (0.9) data entry for "GPROB" that predicts that 90 percent of all hydrocarbon accumulations in Hope basin assessment province will consist entirely of gas. The gas-prone view of Hope basin is also reflected in the (0.0) data entry for "OPROB" that predicts that ***no*** hydrocarbon accumulations will consist entirely of oil. Our model predicts that 10 percent of all accumulations will contain both free gas and free oil. In such cases, we estimate that the fraction of pool volume filled with oil is 0.05. We introduce this small, oil-bearing fraction to hypothetical pool volumes in the model to acknowledge two highly speculative potential sources for liquid petroleum: 1) Cretaceous(?) or Paleozoic(?) rocks beneath western parts of U.S. Hope basin; or 2) resinite in coals in the shallower sequences in Hope basin. However, there are no data from outcrops or wells to support the presence of credible Cretaceous or Paleozoic oil sources or oil sources related to coal resinite.

Tertiary sediments in the Kotzebue sound wells are thermally immature (vitrinite reflectance values less than 0.5%), except where associated with igneous rocks. However, extrapolation of geothermal data from the Kotzebue basin wells projects the depth to the 100°C isotherm at roughly 10,000 feet. We take the 100°C isotherm to approximately predict the onset of oil generation, based on data published for Eocene Gulf coast sediments by Dow (1977). Assuming a 10,000 ft depth for the top of the oil generation zone across the entire Hope basin assessment province, we observe that only deepest parts of Hope and Kotzebue basins reach thermal maturities sufficient to have generated oil or gas (areas mapped in fig. 15.1).

Shale formations sufficiently thick and laterally continuous to form regional seals have not been identified at the Kotzebue basin wells or in surrounding outcrops. Extensive north- to northwest-trending faults in the assessment area offer many potential avenues for migration of hydrocarbons rising out of thermally mature rocks in the deepest parts of the basin. The lack of regional seals and the extensive faulting within the basin suggests that any hydrocarbons generated at depth probably migrated vertically along faults, rather than laterally along dip in porous carrier beds beneath regional seals. Vertical migration typically dominates petroleum movement patterns in highly-faulted rift or wrench basins (Demaison and Huizinga, 1991).

Hope and Kotzebue basins offer mostly low-side fault-seal traps, but faulted anticlines, simple anticlines, and stratigraphic traps are also observed and mapped in seismic data. Hope basin prospects are areally quite large; a few range up to 80,000 acres in size. Median values of prospect area distributions (for plays) range from 10,000 to 12,000 acres (tabulated in Appendix A1), nearly double those mapped in other Alaska basins outside the Arctic.

In Hope basin assessment province, the small volume of potential petroleum source, the lack of regional seals, the poor seal integrity anticipated for the complexly-faulted traps, and the large sizes of many prospects all suggest that Hope basin prospects, if ever reached by hydrocarbons, are probably not generously filled. This is reflected in the data for the analytical model by the low fill fraction values (0.15 at the median) modeled into probability distributions for ***trap fill***.

PLAY DEFINITION IN HOPE BASIN

We divided the sedimentary fill of Hope and Kotzebue basins into two regionally stacked geologic play sequences on the basis of the observed contrast in reservoir characteristics of the two principal stratigraphic sequences sampled by the Kotzebue basin wells. The Oligocene(?) and younger sequence, offering abundant high-quality reservoir sandstones, hosts play 1, the ***"Late Sequence" play***. The Eocene(?) sequence, offering relatively thin, modest-quality reservoir sandstones, hosts play 2, the ***"Early Sequence" play***.

Two additional plays are based upon the sandstones hypothesized to occur at the base of the sedimentary fill in Hope and Kotzebue basins, marking the onset of basin rifting and subsidence (analogy to known occurrences in Norton basin). The basal sandstone plays are referred to as play 3, the ***"Shallow Basal Sand" play***, and play 4, the ***"Deep Basal Sand" play***. Plays 3 and 4 are differentiated on the basis of burial depth and related issues of reservoir quality. Figure 15.1 maps the areas underlain by these four plays in Hope and Kotzebue basins. The stratigraphic and structural relationships of the 4 plays are illustrated in the cross section of figure 15.2. Data used to model the oil and gas resources of Hope basin plays are tabulated in Appendix A1.

PLAY DESCRIPTIONS

Play 1 (UAHB0101[1]), Late Sequence Play: This play includes all Oligocene(?) and younger strata in the assessment area. Shallow shelf or fluvio-deltaic sandstones form the most likely reservoir rocks. Two exploratory wells drilled in Kotzebue basin indicate that the sandstones in the Late Sequence play are highly porous. Organic material in well samples is cellulosic with hydrogen indices generally below 200 mgHC[2]/gTOC[3], indicating that any hydrocarbons generated upon burial and heating would probably be gas. Total organic carbon values average over 1.0 percent, but higher values are associated with coals[4] and confined to the upper, thermally immature part of the sequence (Mobil E&P, 1981). Only very small volumes of this sequence, in the very deepest parts of the basins, reach thermal maturity. Therefore, hydrocarbons would have to migrate into Late Sequence prospects from thermally mature sources in other, underlying sequences. Traps within the Late Sequence play were formed during a second stage of widespread basin faulting, probably in Miocene(?) time, well before the deepest sediments in the basins reached thermal maturity,

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[1] *The "UA" Code is the "Unique Assessment Identifier" for each play, and is the principal guide to **GRASP** data files*

[2] ***HC**, hydrocarbon matter evolved from samples during heating (pyrolysis) experiments.*

[3] ***TOC**, total organic carbon*

[4] *therefore not indicative of any significant petroleum source potential*

the latter probably occurring in Pliocene or Pleistocene time.

Play 2 (UAHB0201). Early Sequence Play: This play consists mostly of Eocene(?) rocks. The Kotzebue basin wells penetrated rocks of Eocene age that are highly volcaniclastic and that have suffered extensive porosity destruction by diagenetic processes and compaction in reaction to deep burial. Therefore, the reservoir potential of the Early Sequence play is modeled as considerably lower than that of the Late Sequence play. We speculate that reservoirs consist primarily of fluvio-deltaic sands and conglomerates deposited along the edges of rift grabens formed during the early fault-driven phase of Hope basin subsidence in Eocene time. Organic matter in samples of the Early Sequence from the Kotzebue basin wells is cellulosic, with hydrogen indices generally below 200 mgHC/gTOC and total organic carbon values averaging <0.5% (Mobil E&P, 1981). The source potential of these rocks is therefore gas prone and very poor overall. The Early Sequence reaches thermal maturity in the central areas of both Hope and Kotzebue basins (mapped in fig. 15.1). Most of the Early Sequence sediments reached thermal maturity late in the deposition of the overlying Late Sequence (Pliocene and later), after most fault traps in both plays 1 and 2 had formed.

Plays 3 (UAHB0301 - Shallow Basal Sand Play) and 4 (UAHB0401 - Deep Basal Sand Play): These plays were defined to acknowledge the possible existence of sandstones (presence inferred by analogy to Norton basin) creating potential traps at the base of the sedimentary fill of Hope and Kotzebue basins. The two plays are separated at a burial depth of 10,000 feet. Density log porosities of sandstones in the Kotzebue basin wells are projected[5] to fall below 10 percent at burial depths greater than 10,000 feet. Because many types of sandstones cannot reservoir extractable petroleum when porosities fall below 10 percent, the model reflects our view that it is improbable that viable (sufficiently porous and permeable) sandstone reservoirs were preserved in the Deep Basal Sand (4) play. Potential source rocks for prospects in plays 3 and 4 would include the gas-prone organic material detected in Early Sequence samples in the two Kotzebue basin wells. Other petroleum sources of a speculative nature might include older, unsampled rocks in the deeper parts of Hope basin, or basement rocks. The Shallow Basal Sand play (3), by definition shallower than 10,000 feet, lies laterally apart from the zone of thermally mature strata. Lateral migration, unlikely because of the abundant faulting and apparent lack of regional seals, would be required to charge prospects in this play. Play 3 is therefore unlikely to be charged by thermogenic hydrocarbons from Tertiary sources. The Deep Basal Sand play (4) lies entirely within the thermally mature area, and, given viable sources within the Early Sequence play (2), would be best positioned to capture hydrocarbons expelled from such sources.

RISK ASSESSMENT OF HOPE BASIN PLAYS

The greatest risk to the possible existence of petroleum deposits anywhere in Hope basin is the probable absence of petroleum sources within the basin. No credible source rock has been identified and only small volumes of basin fill have been sufficiently heated to generate petroleum. Risk related to absence of petroleum source rocks increases with depth, because petroleum migration is dominantly vertical and with increasing depth there is less chance that a directly-underlying viable source rock exists. The Late Sequence play (1) has access to any petroleum migrating vertically along faults upward from deeper parts of the basin. Although

[5] *extrapolated below well data using a Norton basin porosity decline rate (based on data presented by Turner and others, 1986, fig. 24)*

at considerable risk for failure due to absence of source, play 1 has the greatest chance of all Hope basin plays to have been charged by petroleum.

Within individual plays, some fraction of prospects are variously at risk (of failing to become pools) because of prospect seal integrity (all plays), difficulties in petroleum migration (plays 1, 2, and 3), destruction of porosity (plays 2 and 4), or stratigraphic absence of reservoir (plays 3 and 4).

We assume that shales that might act as sealing horizons are more likely to have been deposited in the central (distal) parts of Hope and Kotzebue basins; risk related to absence of seal was therefore assessed as higher for parts of play areas near basin edges. Some plays have many low-side fault traps of doubtful seal integrity owing to abundance of sandstones within the faulted sequences and young ages and complexity of prospect-bounding faults. Migration of petroleum is assumed to be a risk element for prospects lying away from the central part of the basins, because the dense faulting makes it very improbable that hydrocarbons could have migrated any significant distance laterally from away the thermally mature central areas. Some prospects are at risk for porosity destruction from diagenesis of volcaniclastics (play 2) or compaction (play 4). The Deep Basal Sands play (4) may fail altogether, even if petroleum is available to prospects, because of the loss of all effective porosity in all sandstones. Even if there is sufficient porosity in some prospect somewhere in play 4 (therefore successful at the play level), we estimate that no more than half of the sandstone-bearing prospects in play 4 will have retained a pore system sufficient to become petroleum reservoirs. Porosity therefore forms a risk factor at both the play and prospect levels in play 4. Table 15.1 shows the risk structure provided to the analytical model for Hope basin plays.

PLAY DEPENDENCY MODEL

Play resources were aggregated to calculate total assessment province resources using the ***FASPAG*** aggregation software. The ***FASPAG*** software allows the user to model dependencies among plays in the course of aggregating probability distributions for the resources of plays into a probability distribution for the resources of the assessment province. The dependency model for Hope basin assessment province is shown in table 15.2.

Play dependency was viewed in this assessment as the frequency of coincidence, or coexistence of hydrocarbon accumulations between plays. Geographic clustering of petroleum pools in multiple plays, particularly stacked plays, implies a common geologic origin, especially sharing of petroleum source and local migration systems.

No specific hydrocarbon source has been identified in Hope basin, and the migration paths from any postulated source are expected to be vertical. For example, the Late Sequence (1) and Early Sequence (2) plays are stacked plays that would share the same hypothetical hydrocarbon source over thermally mature parts of the basin. Both plays are cut by many faults that could provide common migration routes for charging prospects in both plays. Therefore, play dependency values were devised primarily on the basis of physical overlap of play areas. On this basis, plays 1 and 2 were assigned a high dependency, DEP=0.65, when aggregated into "Group 1."

The Shallow Basal Sand (3) and Deep Basal Sand (4) plays are adjacent to one another and their areas do not overlap. If migration paths are primarily vertical, each play would have independent sources providing petroleum to prospects via independent migration paths. Plays 3 and 4 were therefore aggregated into a "Group 2" using a relatively low dependency value,DEP=0.20.

TABLE 15.1
PLAY AND PROSPECT LEVEL RISK FACTORS
Hope Basin Assessment Province

PLAY		PLAY RISK FACTORS		PROSPECT RISK FACTORS	
NO.	**NAME**	**CHANCE OF SUCCESS**	**RISK FACTOR**	**CHANCE OF SUCCESS**	**RISK FACTOR**
1	LATE SEQUENCE	0.5	SOURCE	0.6	SEAL PRESENCE
				0.4	MIGRATION
2	EARLY SEQUENCE	0.4	SOURCE	0.6	SEAL PRESENCE
				0.8	POROSITY
				0.4	MIGRATION
3	SHALLOW BASAL SANDS	0.3	SOURCE	0.6	SEAL PRESENCE
				0.8	RESERVOIR PRESENCE
				0.3	MIGRATION
4	DEEP BASAL SANDS	0.3	SOURCE	0.2	SEAL PRESENCE
				0.5	RESERVOIR PRESENCE
		0.9	POROSITY	0.5	POROSITY

TABLE 15.2
DEPENDENCY MODEL FOR HOPE BASIN PLAYS
Hope Basin Assessment Province

TIER 1		DEP	TIER 2	DEP
GROUP 1	LATE SEQUENCE PLAY (1)	0.65	**FINAL GROUP** (GROUP 1 + GROUP 2)	0.75
	EARLY SEQUENCE PLAY (2)			
GROUP 2	SHALLOW BASAL SANDS PLAY (3)	0.20		
	DEEP BASAL SANDS PLAY (4)			
DEP, dependency, or frequency of coexistence of pools among plays or aggregation groups				

The dependency (DEP=0.75) modeled in the aggregation of of Groups 1 and 2 is based primarily on the amount of composite overlap of "Group" areas.

TABLE 15.3
OIL AND GAS ENDOWMENTS OF HOPE BASIN PLAYS
Risked, Undiscovered, Conventionally Recoverable Oil and Gas

PLAY NO.	PLAY NAME (UAI* CODE)	OIL (BBO)			GAS (TCFG)		
		F95	MEAN	F05	F95	MEAN	F05
1.	Late Sequence (UAHB0101)	0.000	0.090	0.262	0.000	3.341	9.368
2.	Early Sequence (UAHB0201)	0.000	0.011	0.039	0.000	0.387	1.331
3.	Shallow Basal Sands (UAHB0301)	0.000	0.009	0.037	0.000	0.333	1.387
4.	Deep Basal Sands (UAHB0401)	0.000	0.00009	0.0006	0.000	0.004	0.026
	FASPAG AGGREGATION	*0.000*	*0.110*	*0.343*	*0.000*	*4.064*	*12.673*

*** *Unique Assessment Identifier, code unique to play.***

RESOURCE ENDOWMENTS OF HOPE BASIN PLAYS

The oil and gas resources[6] for the Hope basin assessment province are 0.110 billion barrels of oil and 4.064 trillion cubic feet of gas. Petroleum liquids (crude oil and natural gas liquids) form only 13 percent of the 0.830 billion-barrel BOE endowment, reflecting the gas prone character of the Hope basin assessment model. Most of the hydrocarbon resource occurs in the Late Sequence play (1). Play 1 contains most of the resources because it was modeled with reservoir potential (storage volume) far superior to other Hope basin plays, based on the high porosities and greater sand thicknesses observed in the Late Sequence in the Kotzebue basin wells. Part of the play 1 area overlies the central part of the basin where any viable source rocks within the oil generation zone below 10,000 feet would have expelled hydrocarbons that migrated upward to charge prospects in the Late Sequence play (1). The assessed endowments of oil and gas for the four Hope basin plays are listed in table 15.3 and illustrated graphically in figure 15.3. Ranked pool and cumulative probability plots for each play are shown in the play summaries of Appendix B1.

[6]*mean, risked, undiscovered, conventionally recoverable oil and gas*

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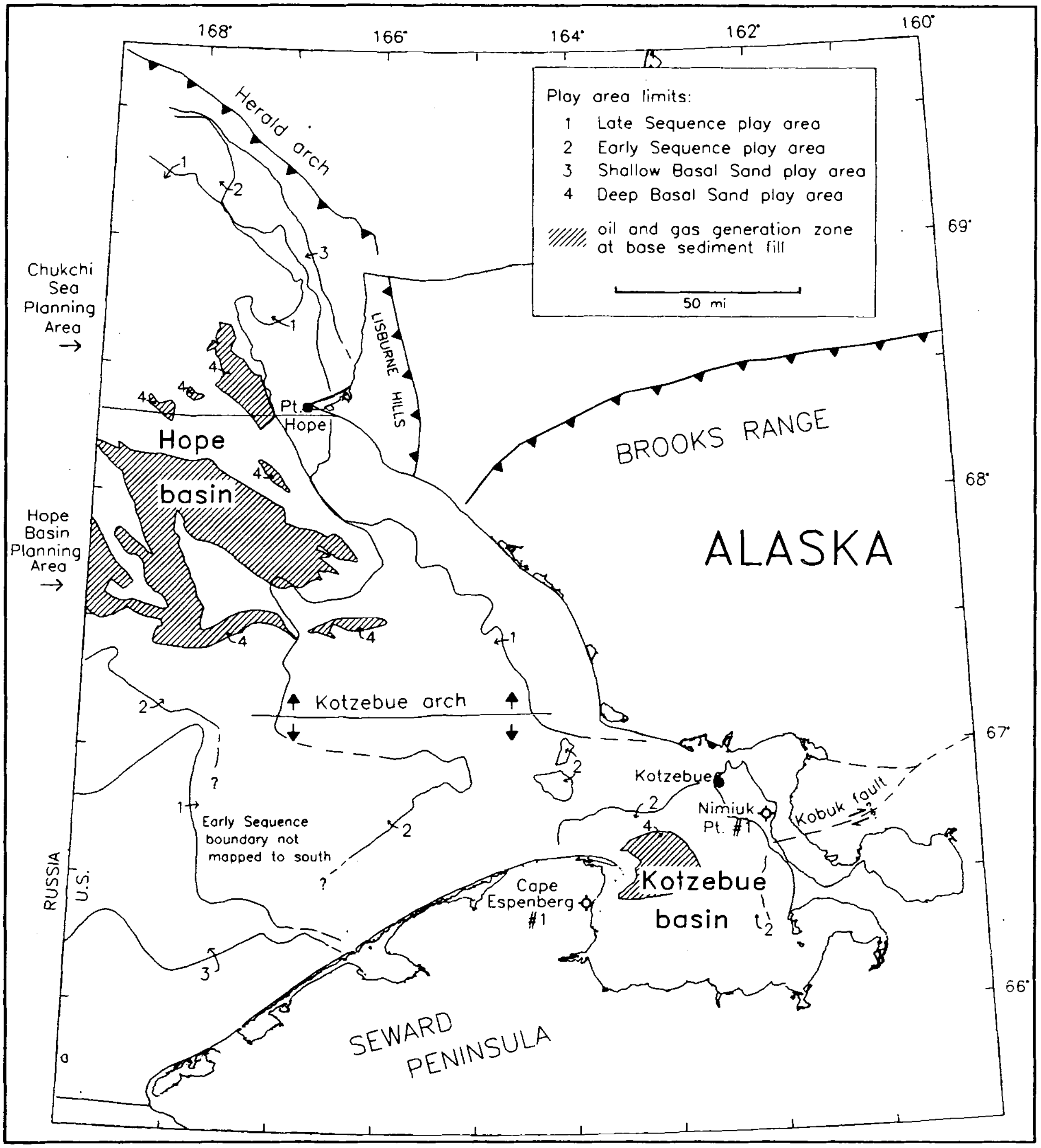

Figure 15.1: Major structural elements and geologic play area limits of the Hope basin assessment province. All plays extend into the center of the basin except for the Shallow Basal Sand play (3), which extends to the limits of the Deep Basal Sand play (4). The oil and gas generation zone shown is for the base of sediment fill, and therefore is the maximum area of thermal maturity. Play area boundaries are from U.S. Minerals Management Service mapping.

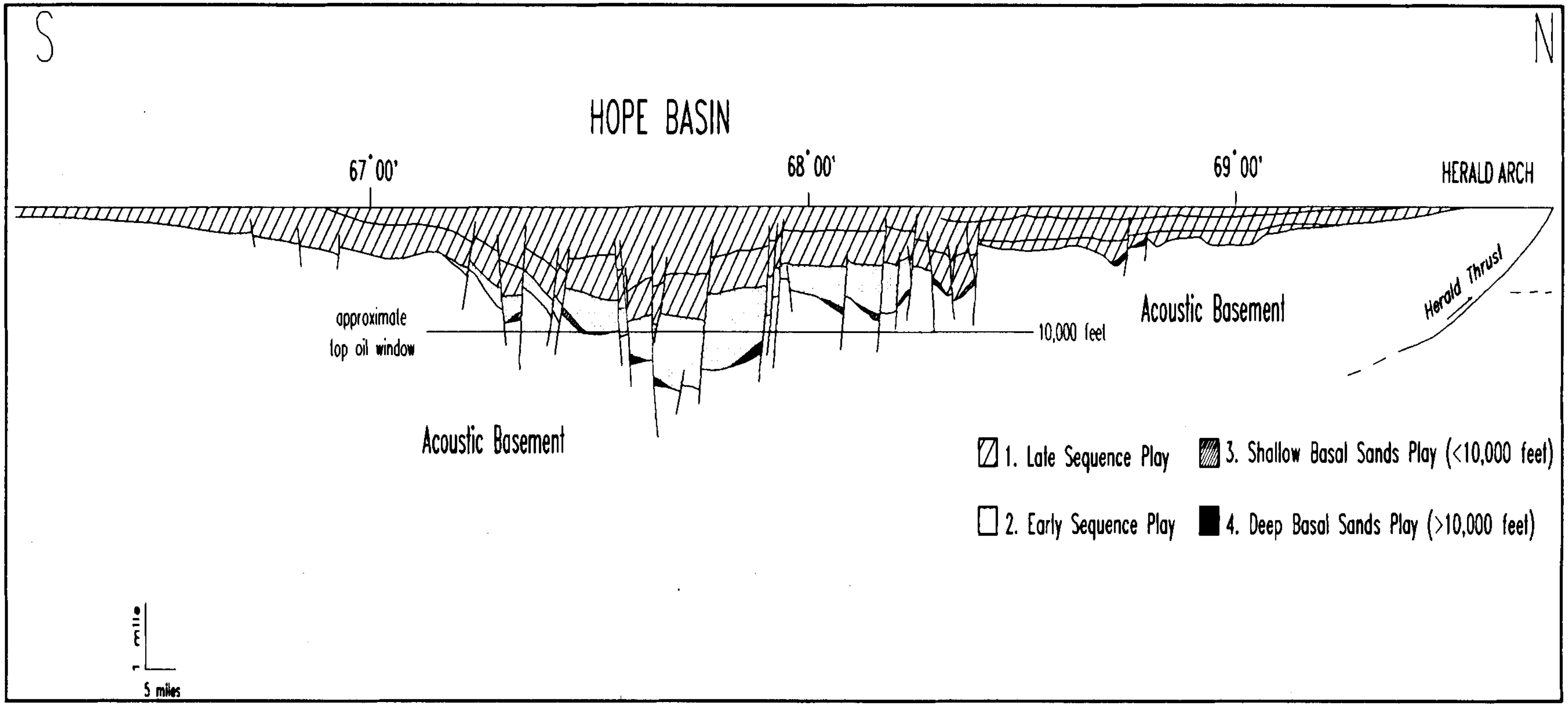

Figure 15.2: Generalized north-south cross section across the western part of the Hope basin assessment province. Depiction of Shallow Basal Sand (3) and Deep Basal Sand (4) plays is schematic.

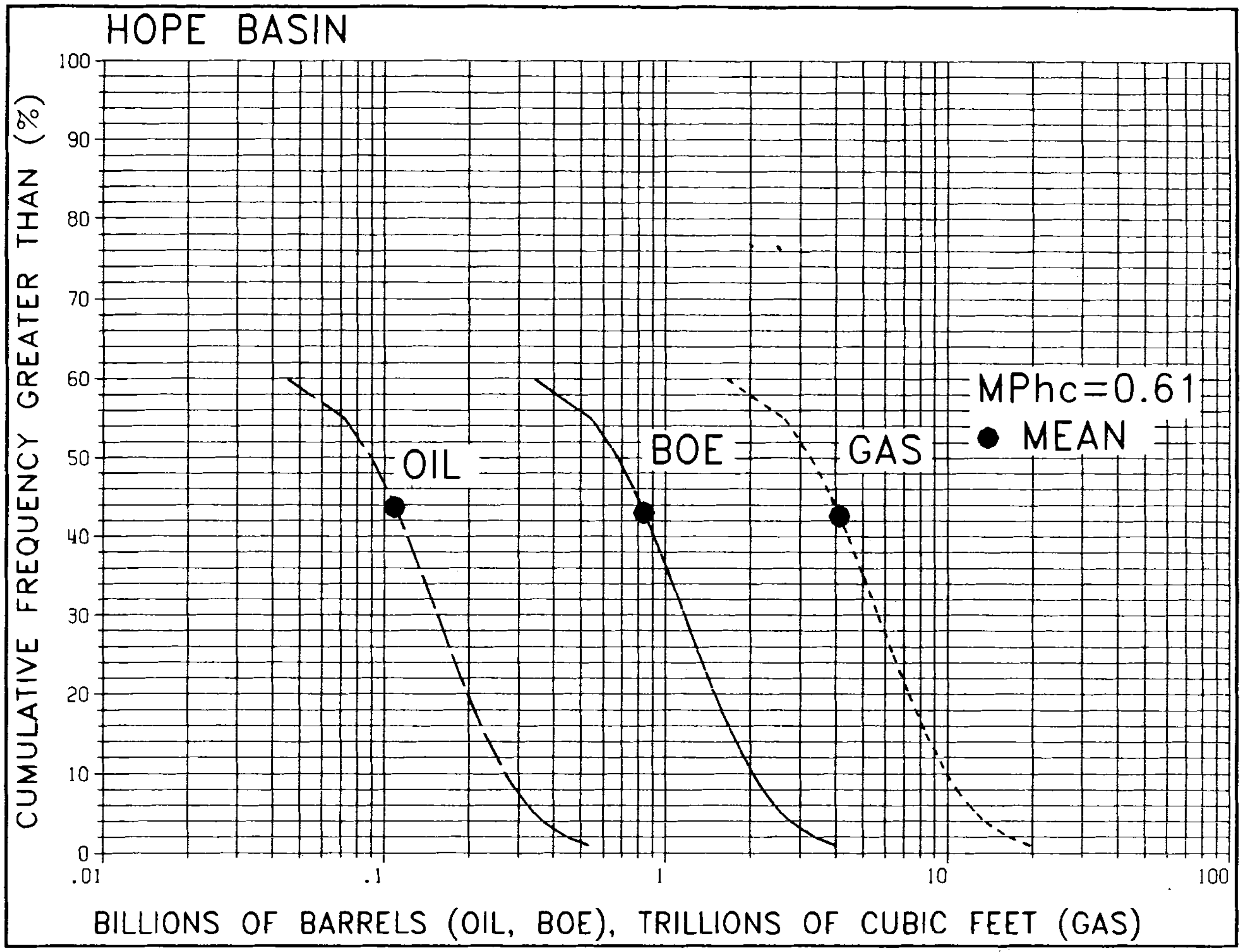

Figure 15.3: Cumulative probability curves for undiscovered, conventionally recoverable resources (oil, gas, and BOE) for Hope basin assessment province. ***BOE**, total oil and gas in energy-equivalent barrels, obtained by converting gas to energy-equivalent barrels and adding to oil;* ***MPhc**, marginal probability for occurrence of pooled hydrocarbons in province.*

GEOLOGIC ASSESSMENT
1995 National Resource Assessment
Alaska Federal Offshore
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BERING SHELF ASSESSMENT PROVINCES

16. INTRODUCTION

by
Bruce M. Herman

SUMMARY OF REGIONAL GEOLOGY OF BERING SHELF

The crust beneath the Bering Sea continental shelf is thought to comprise terranes of various ages that were accreted during the Late Jurassic to Late Cretaceous time. Subsequent Paleogene tectonic deformation was driven predominantly by oblique subduction or possibly strike-slip motion between the Kula plate and North America at the Beringian margin and to a lesser extent by strike-slip motion along the Kaltag fault. The depocenters associated with this wrench faulting were filled by middle Eocene and younger sediments and are the primary focus of petroleum exploration interest on the Bering Sea continental shelf.

BASEMENT GEOLOGY

The oldest rocks on the northern Bering Sea continental shelf are Precambrian, Paleozoic, and lower Mesozoic miogeoclinal strata which outcrop on the Seward Peninsula and St. Lawrence Island (Fisher and others, 1982). The rocks on the Seward Peninsular have been metamorphosed to greenschist and amphibolite facies (Sainsbury, 1975; Hudson, 1977), whereas those on St. Lawrence are unmetamorphosed (Patton and Csejtey, 1971, 1980). Metasedimentary rocks comparable to those on the Seward Peninsular have been drilled in the Norton Basin (Turner and others, 1983a, 1983b), where they form the acoustic basement beneath much of the basin. These rocks are thought to be correlative with rocks of the same age in the Brooks Range. Ophiolites with paleontologic ages ranging from Mississippian to Jurassic are found thrust over the southern Brooks Range from the south and over the eastern Seward Peninsular (Tailleur, 1973; Roeder and Mull, 1978). Similar ophiolites are found to the south in the Ruby Range (Patton, 1973; Mull, 1982). Jones and others (1981) proposed that both groups of ophiolites were part of the same obducted oceanic crust, which they called the Angayuchum terrane. Between the two areas of exposed Angayuchum terrane lies the Yukon-Koyukuk province. This is an area of Cretaceous volcanic and sedimentary rocks (Patton, 1973) that may overlie the Angayuchum terrane at depth (Worrall, 1991). Extending the trends of the rock exposures from the Seward Peninsula into the Norton Sound suggests that the Yukon-Koyukuk province is within the acoustic basement in the eastern-most

Norton basement (Miller, 1972; Patton, 1973; Fisher and others, 1982).

One explanation for the pre-latest Cretaceous geology described above is that the Yukon- Koyukuk terrane and the underlying Angayuchum terrane are the remanents of an oceanic island arc, or an arc on a continental fragment, which was active during the Late Jurassic and Early Cretaceous. South-directed subduction ended when the Precambrian, Paleozoic, and lower Mesozoic rocks of the Brooks Range and Seward Peninsula were partially subducted beneath the arc in the mid-Cretaceous (Fisher and others, 1982; Wallace and others, 1989). It is not clear whether the Seward Peninsula subsequently rotated counterclockwise due to oroclinal bending (Patton and Tailleur, 1977), or whether the arc collision occurred in an existing embayment in the continental margin and then was followed by compression due to convergence between North America and Eurasia (Wallace and others, 1989). In either case, the compression occurred during the Late Cretaceous.

No exposures of pre-Mesozoic rocks have been found on islands on the southern Bering Sea continental shelf, nor have any been encountered in petroleum exploration wells drilled there. Onshore, however, high-grade metamorphic Precambrian rocks with a continental affinity trend southwest toward Kuskokwim Bay (Turner and others, 1983, cited in Wallace and others, 1989). These rocks form the Kilbuck terrane (Jones and others, 1987). The Goodnews terrane, which borders the Kilbuck on the south, also trends southwest at the coast. As described by Jones and others (1987) and Box (1985) the Goodnews terrane contains a dismembered ophiolite suite with Permian and Middle Jurassic mafic and ultramafic rocks, Ordovician to Permian limestones and Late Paleozoic and Mesozoic chert. The Togiak terrane lies immediately southeast of the Goodnews terrane. It contains complexly deformed Triassic, Jurassic and Lower Cretaceous volcanic and volcaniclastic rocks (Box, 1985). Each of these terranes is exposed on the coast, but their offshore extents are not known.

The Southern Kahiltna terrane is immediately east of the Togiak terrane (Jones and others, 1987) and trends toward the Bering Sea. Because the terrane disappears beneath Cenozoic cover to the west, it is not known whether it extends beneath the Bering Sea continental shelf. Rocks of the Southern Kahiltna terrane include metamorphosed volcanic and volcaniclastic rocks with chert and Upper Triassic limestones and structurally complex Upper Jurassic to Lower Cretaceous volcaniclastic turbidites.

The Peninsular terrane extends from the Alaska Peninsula to the northeast, south of the Southern Kahiltna terrane, and from there to the southeast (Jones and others, 1987). Wilson and others (1985) proposed that the terrane be divided into two subterranes. The Illiamna subterrane consists of Permian through Jurassic marine sedimentary and volcanic rocks, which are moderately deformed, and gneiss, marble and schist. The Illiamna subterrane includes the Middle to Late Jurassic Alaska-Aleutian Range batholith, which intrudes the aforementioned rocks. The Chignik subterrane is characterized by a Permian through Upper Cretaceous sequence of continental clastic rocks that have suffered little deformation.

The oldest rocks outcropping on the north side of the Alaska Peninsula are from the Upper Jurassic Naknek Formation, an arkosic sandstone and siltstone from the Chignik subterrane. Naknek-equivalent rocks were dredged from the seafloor near the Pribilof Islands (Vallier and others, 1980) and were also encountered in acoustic basement at the COST No. 2 well in St. George basin (Comer and others, 1987). The Peninsular terrane is thought to extend north beneath the Bering continental shelf from the Alaska Peninsula at the Black Hills uplift and then northwestward along the modern shelf edge some (unknown) distance northwest of the Pribilof Islands (Marlow and Cooper, 1983).

Like the northern Bering Sea continental shelf, the basement rock of the southern Bering Sea continental shelf consists of terranes that were accreted prior to Late Cretaceous time. The oldest terrane is the Peninsular terrane, with a basement consisting of metamorphosed Paleozoic oceanic crust and sediments. It appears to have been an intra-oceanic island arc during Late Triassic and Early Jurassic time (Plafker and others, 1989). The Togiak terrane is believed to have been an intra-oceanic island arc during Middle to Late Jurassic time (Box, 1985; Wallace and others, 1989). The Goodnews terrane is thought to have been the subduction complex for the Togiak (arc) terrane with the Kilbuck terrane part of the North American continent with which the arc collided, probably in the Late Jurassic to Early Cretaceous (Box, 1985) or mid-Cretaceous time (Wallace and others, 1989). Wallace and others (1989) do not identify a subduction complex for the arc represented by the Peninsular terrane, nor do they believe that the arc collided with North America. Instead, subduction on the continentward side of the arc ceased in the Late Jurassic to Early Cretaceous, leaving a small intervening ocean basin. The oceanic crust and the sediment that accumulated on it became the Southern Kahiltna terrane.

The rate and angle of subduction of the Kula plate beneath North America changed as a consequence of a major spreading center reorganization in the Pacific during the Late Cretaceous. Wallace and others (1989) explain the deformation in the Southern Kahiltna terrane by proposing right-lateral motion between the Peninsular terrane and North America during the Late Cretaceous. The southwest end of the Togiak (arc) terrane may have been truncated by faulting at this time. In latest Cretaceous and Paleogene time, further changes in the relative motion between the Kula and North American plates were accompanied by extensive Andean-style arc volcanism that extended along the south facing coast of Alaska and then along the Beringian margin to connect with the Okhotsk-Chukotsk volcanic belt (Scholl, and others, 1975; Marlow and others, 1976; Marlow and Cooper, 1983; Wallace and others, 1989). Marlow and Cooper (1980) suggested that oblique subduction along the Beringian margin during Tertiary time may have initiated the ***wrench-fault basins*** that contain most of the undiscovered resources of the Bering shelf.

BERING SHELF WRENCH-FAULT BASINS

The crustal extension that created the Norton basin is most likely related to strike-slip motion along the Kaltag fault in early Paleogene time (Fisher and others, 1982; Turner and others, 1986). Initially, continental sediments with numerous coals accumulated in the grabens. Two subbasins developed before the end of the Eocene. The western subbasin contains Eocene and Oligocene sedimentary rocks deposited in deep-water marine settings, whereas correlative strata in the eastern subbasin were deposited in nearshore to continental shelf settings. Faulting had nearly ceased by late Oligocene time in both subbasins. Regional subsidence and the accumulation of continental shelf sediments has characterized both subbasins since the cessation of faulting in late Oligocene time (Turner and others, 1983a, 1983b; Turner and others, 1986).

The St. Matthew-Hall basin is also thought to have opened as a result of strike-slip motion on the Kaltag fault. The timing of structural deformation is postulated to be the same as that in the Norton basin, but the nature of the sedimentary rocks that fill St. Matthew-Hall basin is unknown.

The major sedimentary basins along the modern day Bering Sea continental shelf edge are the Navarin, St. George, and Pribilof basins (pl. 1.1). The remaining major basin on the shelf, the North Aleutian basin, lies adjacent to and north of the Alaska Peninsula. All of these basins are thought to have formed in a fore-arc environment. They are believed to be a result of oblique, right-lateral motion between the Kula and North American plates during the Late Cretaceous and Paleogene (Scholl and others, 1975, Marlow and Cooper, 1980; Marlow and others, 1983). The timing is based on paleontologic ages from sedimentary rocks recovered during drilling in the basins. The COST No. 1 well in the North Aleutian basin (Turner and others, 1988) and exploratory wells in the Navarin and St. George basins encountered Paleocene and lower Eocene sedimentary rocks below a ***lower Eocene unconformity***. Early to middle Eocene age strata overlie the unconformity.

Some wells encountered continental sedimentary rocks beneath the unconformity, and others encountered marine sedimentary rocks. Broad folds and faulting of these strata in the Navarin basin (Worrall, 1991), and wrench faults mapped in early Paleogene age rocks (Haley, personal comm., 1994), are evidence for oblique compression in the forearc during this time, possibly due to oblique subduction (Worrall, 1991). Faulting in the St. George and North Aleutian basins is over a broader area and is not diagnostic.

The ***lower Eocene unconformity*** is recognized extends across much of the Bering Sea continental shelf. It is the surface upon which sediments accumulated in the Navarin basin, St. George graben and Pribilof basin (Scholl and others, 1975; Marlow and others, 1976). The lower Eocene unconformity is believed to be a result of uplift during the initiation of a major wrench-fault system that can be mapped from the Black Hills ridge in the North Aleutian basin, through the St. George graben, and into the Navarin basin (Whitney and Wallace, 1984; Herman and others, 1987). The Pribilof basin lies along a splay of the major wrench-fault system, between the shelf edge and the St. George graben. Subsidence along normal or oblique slip faults occurred over a broad area north of the major wrench-fault system (Worrall, 1991). Active faulting in all of these basins continued through the early Oligocene, when it was superseded by regional subsidence. The Paleogene wrench faulting described here may indicate that oblique subduction along the Beringian margin had been replaced by strike-slip motion (Herman and others, 1987; Comer and others, 1987). Unlike the Navarin, St. George, and Pribilof basins, subsidence in the North Aleutian basin was directly associated with one or perhaps two master faults.

Seismic reflection and paleontologic data from the COST wells in the North Aleutian, St. George, and Navarin basins all indicate rapid subsidence following the uplift that created the regional unconformity. This subsidence lasted into Oligocene time. The North Aleutian basin experienced the shortest and least subsidence, ending in the early Oligocene with the depositional environment never being deeper than middle neritic (Turner and others, 1988). Subsidence in the St. George basin also ceased by the end of the early Oligocene, but with the seafloor at outer neritic to upper bathyal depths. Seafloor depths remained stable until the earliest Pliocene when water depths began to decrease (Turner and others, 1984a). The Navarin basin, like the previous two basins, subsided rapidly following the uplift, but to upper bathyal depths. Indicated depths began to decrease in mid to late Oligocene time (Turner and others, 1984b).

The depositional environments in the major basins on the southern Bering Sea continental shelf are reflected in the lithologies of their sedimentary rocks. The North Aleutian basin has the most sandstone, and consequently the best reservoir rocks. Sedimentary rocks in the St. George basin are generally siltstones and fine grained sandstones, although there are good volcaniclastic sandstones from the Oligocene, when water depths were outer shelf to upper slope. Shales and silts were the primary sediments deposited in the Navarin basin, which was the deepest of the three basins. Some sandstones may be derived from local highs, but sandstones fringing uplifts have not been found to have either significant thicknesses or lateral extents.

The Aleutian arc is believed to have formed in the Paleogene when subduction beneath the Beringian margin ceased. Scholl and others (1983) cite the age of sedimentary rocks on the Kormandorsky Islands in the western Aleutians as evidence that volcanism began at 55 Ma (million years ago). Wallace and Engebretson (1984) prefer 43 Ma for the initiation of subduction based on the age of the oldest Aleutian volcanic rocks associated with the current pulse of magmatism. The remnant Kula plate behind the Aleutian arc in the Aleutian Basin is speculated to be Mesozoic in age, but the sea floor magnetic anomalies have not been successfully correlated with the Mesozoic magnetic time scale (Cooper and others, 1992). Cooper and others (1992) propose a model in which the Bowers Ridge and Bowers basin were an active volcanic arc and back-arc basin, respectively, in early and middle Tertiary time. Previously, they had been assumed to be active only in Mesozoic time (Scholl and others, 1975).

Cenozoic volcanism has not been limited to the Aleutian arc. Comer and others (1987) observed probable volcanic sills in Miocene strata in the St. George graben, and Patton and Csejtey (1971) report Neogene and Quaternary basalts from St. Lawrence Island. The origin of these basalts is problematical, but they indicate that the Bering Sea continental shelf remains tectonically active.

OIL AND GAS ENDOWMENTS OF BERING SHELF PROVINCES

All of the undiscovered, conventionally recoverable oil and gas resources of the Bering shelf subregion are associated with strata within the wrench-fault basins of Tertiary age that lie in shallow waters of the modern Bering Sea continental shelf. The complexes of amalgamated terranes that compose basement beneath the Tertiary basins on the shelf are assessed as offering negligible oil and gas potential. Deep-water areas of the Bering Sea were divided into the "Bering Sea Deep-Water Basins" province and the "Bering Shelf-Margin Basins" province (pl. 1.1; fig. 1.1). These remote areas are thought to offer negligible potential for undiscovered, conventionally recoverable oil or gas resources. However, Scholl and others (1995) predict that the deep water basins of Bering Sea could offer from 900 to 1100 trillion cubic feet of natural gas if liberated from methane gas-hydrates (a non-conventional resource not assessed here) lodged in the sedimentary column. An eighth province, the Aleutian Arc assessment province, consists of a modern intra-oceanic volcanic arc and is considered to have negligible potential for undiscovered oil or gas resources of any kind.

The undiscovered oil and gas potential of the eight provinces of the Bering shelf subregion are listed in table 16.1. Navarin basin assessment province offers the greatest resources, mostly owing to the great size of the basin and the numerous large prospects that occur within the basin, the sheer size of the basin offsetting many negative attributes. Norton basin and St. Matthew-Hall basin assessment provinces were assessed as offering potential ***only for gas***. The petroleum liquids reported as "oil" for these provinces are entirely natural gas liquids, or condensates that would be recovered only as a by-product of gas production. Navarin, North Aleutian, and St. George basins were assessed as highly (but not entirely) gas-prone, and most of the "oil" reported in table 16.1 is actually natural gas liquids. Cumulative probability distributions for the undiscovered oil and gas potential of the Bering shelf subregion are shown in figure 16.2.

TABLE 16.1
RESOURCES OF THE BERING SHELF SUBREGION
RISKED, UNDISCOVERED, CONVENTIONALLY RECOVERABLE OIL AND GAS

AREA	OIL (BBO)*			GAS (TCFG)			BOE (BBO)			MPhc
	F95	MEAN	F05	F95	MEAN	F05	F95	MEAN	F05	
NAVARIN BASIN	0.00	0.50	1.21	0.00	6.15	18.18	0.00	1.59	4.41	0.88
N. ALEUTIAN BASIN	0.00	0.23	0.57	0.00	6.79	17.33	0.00	1.44	3.63	0.72
ST. GEORGE BASIN	0.00	0.13	0.41	0.00	3.00	9.72	0.00	0.67	2.14	0.94
NORTON BASIN	0.00	0.05	0.15	0.00	2.71	8.74	0.00	0.53	1.70	0.72
ST. MATTHEW-HALL	0.00	<0.01	<0.01	0.00	0.16	0.69	0.00	0.03	0.13	0.44
DEEP BERING BASINS	neg	neg	neg	neg	neg	neg	neg	neg	neg	neg
SHELF-MARGIN BASINS	neg	neg	neg	neg	neg	neg	neg	neg	neg	neg
ALEUTIAN ARC	neg	neg	neg	neg	neg	neg	neg	neg	neg	neg
TOTAL	*0.36*	*0.91*	*1.81*	*6.98*	*18.80*	*38.64*	*1.65*	*4.26*	*8.57*	*0.9997*

* *for Norton basin and St. Matthew-Hall assessment provinces, "oil" quantities are entirely natural gas liquids obtained from gas extraction; no pooled oil is present*

***BBO**, billions of barrels (oil values include both crude oil and natural gas liquids); **TCFG**, trillions of cubic feet; **BOE**, total oil and gas in billions of energy-equivalent barrels (5,620 cubic feet of gas=1 energy-equivalent barrel of oil); reported **MEAN**, resource quantities at the mean in cumulative probability distributions; **F95**, the resource quantity having a 95-percent probability of being met or exceeded; **F05**, the resource quantity having a 5-percent probability of being met or exceeded; **MPhc**, marginal probability for hydrocarbons for basin, i.e., chance for the existence of at least one pool of undiscovered, conventionally recoverable hydrocarbons somewhere in the basin; **neg**, negligible resources. Resource quantities shown are risked, that is, they are the product of multiplication of conditional resources and MPhc. Mean values for provinces may not sum to values shown for subregion because of rounding.*

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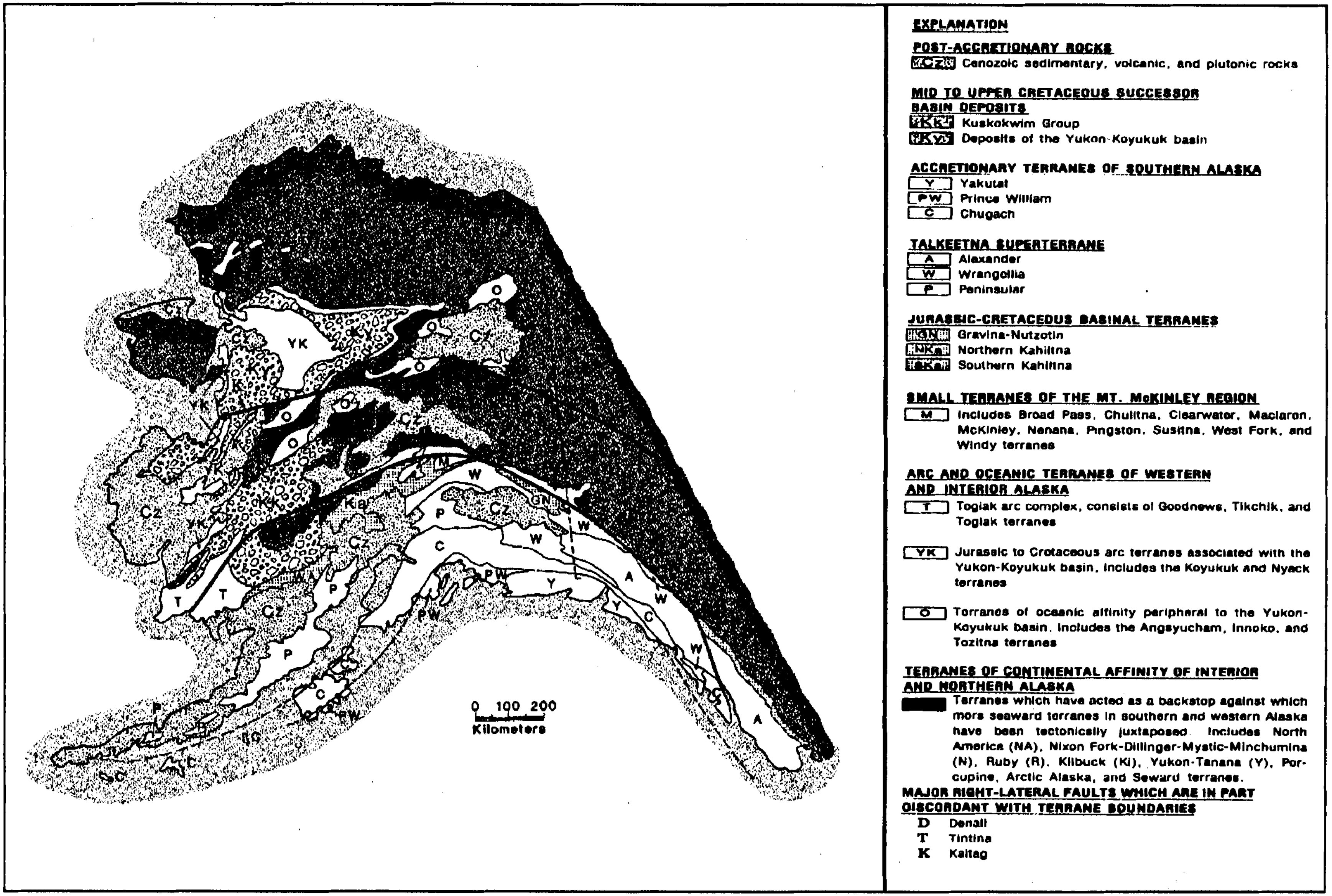

Figure 16.1: Terrane map of Alaska (used with permission of W. Wallace).

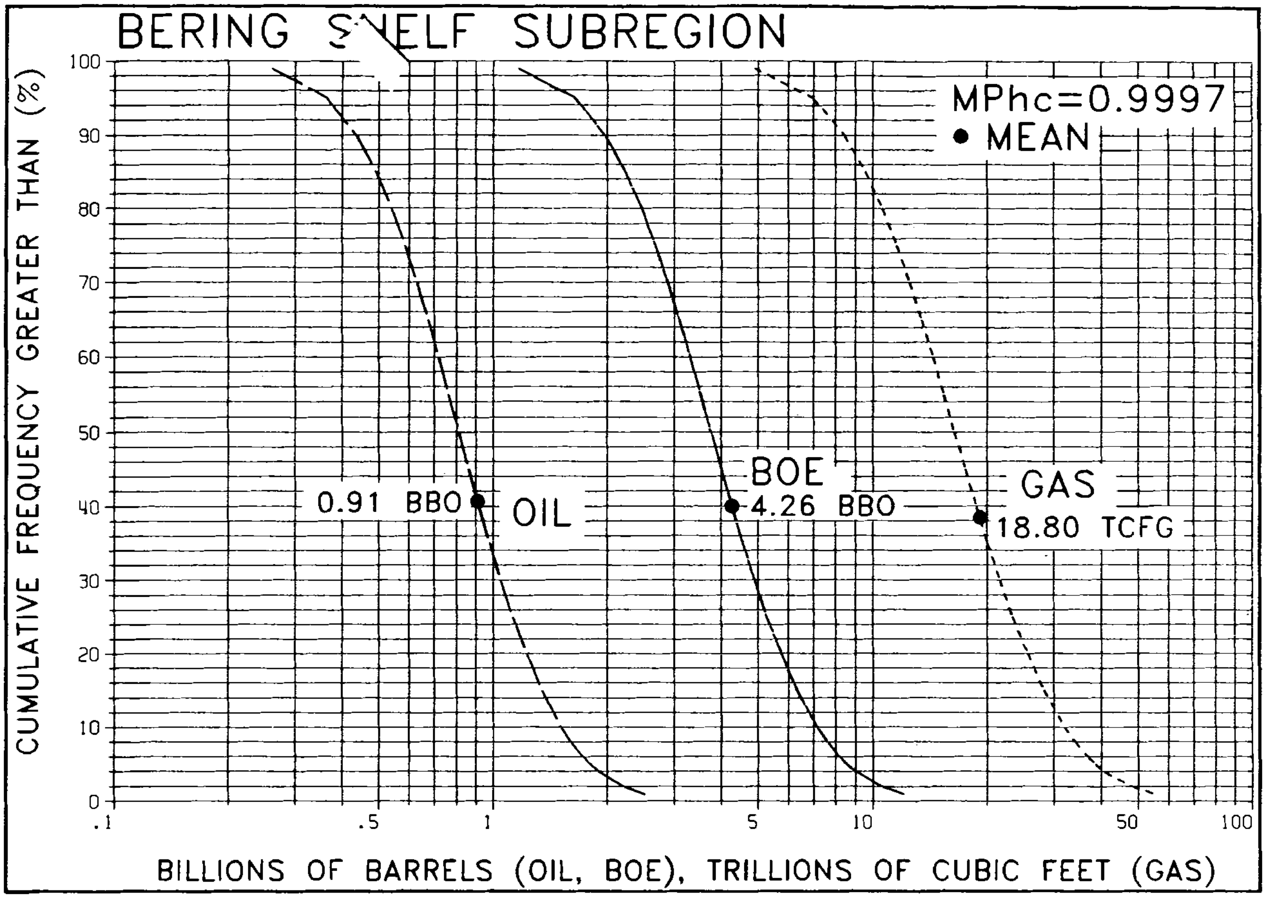

Figure 16.2 : Cumulative probability curves for undiscovered, conventionally recoverable resources (oil, gas, and BOE) for Bering shelf subregion. ***BOE**, total oil and gas in energy-equivalent barrels, obtained by converting gas to energy-equivalent barrels (5,620 cubic feet per barrel) and adding to oil; **MPhc**, marginal probability for occurrence of pooled hydrocarbons in subregion.*

GEOLOGIC ASSESSMENT
1995 National Resource Assessment
Alaska Federal Offshore
U.S. Minerals Management Service

17. NAVARIN BASIN ASSESSMENT PROVINCE

by
Dorothy McLean, Steve Haley, and John Larson

LOCATION

The Navarin basin, at least that part in which sediment thickness exceeds 7,000 feet, covers an area of approximately 32,000 square miles of the Bering Sea Outer Continental Shelf (OCS). It is bounded by the continental shelf break to the southwest, an elevated basement platform to the east and southeast, and the Anadyr Ridge to the northwest. Navarin basin is filled with up to 36,000 feet of sedimentary rocks of Tertiary age.

GEOLOGIC SETTING

Navarin basin formed as a result of wrench faulting that began in middle to late Eocene time. It consists of three subbasins, which have been informally named the Navarinsky, Pervenets, and Pinnacle Island subbasins (Turner and others, 1985).

EXPLORATION HISTORY

A Continental Offshore Stratigraphic Test (COST) well, Navarin Basin COST No.1, was drilled on the edge of the Pervenets subbasin in 1983. This was followed by eight exploratory wells drilled on large basement highs in 1986 and 1987. All wells failed to discover any significant quantities of oil or gas. A possible oil show was encountered in the OCS Y-0673 (Misha) well. Sidewall core samples from the OCS Y-0719 (Nancy) well contain migrated oil. Trace shows of oil were found in the OCS Y-0560 (George), OCS Y-0707 (Nicole), OCS Y-0639 (Danielle), and OCS Y-0719 wells. A gas show was reported in the OCS Y-0639 well, and minor shows of gas were reported for the OCS Y-0560, OCS Y-0707, OCS Y-0719, OCS Y-0673 and OCS Y-0586 (Packard) wells.

SOURCE ROCKS

Data from the nine Navarin basin wells indicate that the best potential sources for generation of hydrocarbons are Eocene mudstones, shales, and argillites. In four wells [the COST No.1, OCS Y-0639, OCS Y-0599 (Redwood No. 1), and OCS Y-0583 (Redwood No. 2) wells], Eocene strata contain 1 percent to 2 percent (by weight) total organic carbon, indicating fair to good overall source potential. In three of the four wells, the average hydrogen index (HI) of these Eocene rocks is 200 or more; in the fourth well (OCS Y-0583) the average HI for Eocene rocks is 195. All of these HI values indicate some potential for generation of both gas and oil (Peters, 1986). The kerogen is probably a mixture of type II and type III. Eocene coals encountered in the OCS Y-0673 and OCS Y-0707 wells form a potential source for gas, and highly resinous Paleocene coals found in the OCS

Y-0719 well could generate both oil and gas. Although these potential source rocks are immature in the wells, they probably become more mature as they deepen and thicken towards the centers of the subbasins. They form the potential source rock for all of the plays that were evaluated. The Paleocene resinous coals are included as part of the source rock sequence.

In most of the wells vitrinite reflectance and T-MAX data (the latter from pyrolysis) indicate that sediments reach thermal maturity (onset of oil generation, at about 0.6% vitrinite reflectance) at a depth of about 10,000 feet. The exceptions are the OCS Y-0673 well, where the top of the oil generation zone occurs at about 6,000 feet, and the OCS Y-0586 well, where the top of the oil generation zone occurs at about 12,000 feet. However, basin-wide Lopatin modeling reported by Turner and others (1985, p.89) indicates a regional zone of oil generation mostly extending from about 10,000 feet (onset of generation) to about 15,000 feet (oil generation potential exhausted, vitrinite reflectance>1.3%).

Well data and modeling indicate that Eocene and (?) Paleocene strata in deeper parts of Navarin basin are probably capable of generating oil (Turner and others, 1985, figs. 23 and 24). However, because the identified source rocks are comparatively lean and form marginal oil sources, and, because no definite oil shows were found in the wells, the basin is modeled as gas-prone in this assessment.

PLAY IDENTIFICATION

Seven plays based on the facies-cycle wedge model of White (1980) have been identified in the Navarin basin assessment province. In this facies-cycle wedge model, the base of a wedge is made up of a succession of facies deposited during a marine transgression. The middle of the wedge represents the peak of the transgression, and the top of the wedge represents a subsequent marine regression. Stratigraphic relationships among wedge components and Navarin basin plays are illustrated in figure 17.1.

The plays proposed for Navarin basin include: 1) Miocene transgressive shelf sands (wedge base); 2) regressive shelf sands (wedge top); 3) Oligocene tectonic sands (wedge middle); 4) turbidite and submarine fan sands (wedge middle); 5) Eocene transgressive shelf sands (wedge base); 6) subunconformity nonmarine and marginal marine sands (subunconformity); and 7) Paleocene marine sands (apparent wedge top).

Data used to characterize and model the oil and gas resources of Navarin basin plays are tabulated in Appendix A2.

PLAY DESCRIPTIONS

Play 1 (UANA0100[1]). Miocene Transgressive Shelf Sands (Wedge Base): Data from the COST No.1 well indicate that during early Miocene time a basin-wide regression concluded and was superseded by a basin-wide transgression that continued through late Miocene time. Intrabasinal highs exposed to wave-base erosion during the previously regression were transgressed and onlapped by Miocene sediments. The postulated regional sediment source terrane consisted of a low-lying borderland (i.e., surrounding parts of Bering shelf and Alaska) drained by sluggish streams. The reservoir formation proposed for play 1 is sandstone derived from recycled older sediments and volcaniclastic basement rocks transported into littoral to neritic settings in Navarin basin. The depositional system in Navarin basin was probably mud-rich near the west (distal) margin. The transgression set the stage for deposition of a discontinuous series of beach sands that impinged on the unconformity and wedged out toward basin interiors. These hypothetical sandstones form the chief anticipated reservoir formations for play 1. Play 1 includes strata ranging in age from

[1]*The "UA" Code is the "Unique Assessment Identifier" for each play, and is the principal guide to GRASP data files.*

lower to upper Miocene (fig. 17.1), and is located along the outer margins of Navarin basin. The area of play 1 is located in figure 17.2.

Play 2 (UANA0200). Regressive Shelf Sands (Wedge Top): Data from the Navarin COST No. 1 well indicate that a basin-wide regression began during late Oligocene time and culminated during the early Miocene.

During the regression, older sand deposits were exposed, eroded, and redeposited seaward. This process continued throughout the regression, leaving the remaining accumulation of sand at the lowest stand of the sea. The regressive marginal marine beach or bar sand bodies that are hypothesized to have formed in this manner probably had a very limited width but may have extended many miles along depositional strike. These conditions, along with structural controls (faults and folds) that shaped depositional surfaces, probably precluded sand deposition in some areas while concentrating sand deposition in other areas. The largest sand bodies in the play probably flank the larger structures in Navarin basin.

Play 2 includes the best reservoir sands found in the nine wells drilled in the basin. Over 200 feet of sandstones with porosities of 15 to 20 percent were found in the COST No. 1 well. These occur in five beds ranging in thickness from 21 to 100 feet (Turner and others, 1984). Play 2 includes rocks ranging from late Oligocene to early Miocene in age and is located around the edge of Navarin basin. The area of play 2 is shown in figure 17.3.

Play 3 (UANA0300). Oligocene Tectonic Sands (Wedge Middle): Uplifts of prominent structural highs within Navarin basin occurred from late Eocene through earliest Oligocene time and during middle Oligocene time. Older sediments on the structural uplifts were exposed, reworked, and redeposited around the flanks of uplifts. Tectonic sands formed in this manner may have been exposed, cannibalized, and redeposited seaward, leaving the largest accumulations of sand in play 3 at the line of maximum lowstand encircling uplifts. Play 3 includes rocks of late Eocene to Oligocene and middle Oligocene ages (fig. 17.1). The areas of play 3 are shown in figure 17.4.

Play 4 (UANA0400). Turbidite and Submarine Fan Sands (Wedge Middle): The centers of the subbasins of Navarin basin remained submerged during most or all of Tertiary time, and we hypothesize that turbidity currents carried sand to basin centers from basin flanks. Evidence for such turbidites is observed on seismic profiles. In addition, coarse-grained materials, including conglomerates, were dredged from Eocene to early Oligocene rocks on the continental slope. Other, and perhaps analogous, strike-slip basins (Hornelen basin, Norway; Little Sulphur Creek and Ridge basins, California) feature prominent basin-axis turbidite and submarine fan sequences. Play 4 includes sequences ranging in age from late Eocene to early Miocene (fig. 17.1). The areas of play 4 are shown in figure 17.5.

Play 5 (UANA0500). Eocene Transgressive Shelf Sands: The reservoir sands for this play were deposited as a result of a basin-wide transgression lasting from the middle Eocene to the late Eocene or early Oligocene. This transgression is hypothesized to have deposited a series of beach sands that impinged on the unconformity and wedged out basinward. Sand supply may have been insufficient to form a continuous blanket over the middle Eocene unconformity. Play 5 may include rocks ranging in age from middle or late Eocene possibly to early Oligocene. Most of the Navarin basin is included in the area of play 5, shown in figure 17.6.

Play 6 (Not Quantified). Nonmarine and Marginal Marine Sands (Subunconformity): A regression during Late Cretaceous time led to the deposition of nonmarine and marginal marine sands. At the OCS Y-0599 well, these sands were deposited beginning in the Maastrichtian and possibly continuously into Eocene time. At other well locations the nonmarine sands appear to be confined to the Paleocene to early Eocene. The distribution of the Cretaceous to early Eocene strata is unknown. Further, no source rocks have been identified within the Cretaceous to early Eocene nonmarine sequence. This play was not evaluated because it was viewed as offering an extremely low probability for the occurrence of pooled, conventionally recoverable hydrocarbons.

Play 7 (Not Quantified). Paleocene Marine Sands (Apparent Wedge Top): Data from the OCS Y-0673 well indicate that marine sands were deposited in parts of the basin during the Paleocene (fig. 17.1). However, the distribution of this facies is unknown, and no source rock was identified. This play was not evaluated because it is believed to offer an extremely low probability for the occurrence of pooled, conventionally recoverable hydrocarbons.

RESOURCE ENDOWMENTS OF NAVARIN BASIN PLAYS

The mean total resources for the Navarin basin assessment province are 0.496 billion barrels of oil and 6.147 trillion cubic feet of gas. "Oil", mostly natural gas liquids, forms 31 percent of the total BOE for the basin. Cumulative probability distributions for oil, gas, and BOE are shown in figure 17.7.

Navarin basin was modeled as gas-prone. This is reflected in the entries for OPROB (0% chance that any accumulation will consist entirely of oil), GPROB (40% to 75% chance that any accumulation will be entirely gas), and OFRAC (only 10% to 40% of the volume of any mixed pools filled by oil). The values used to model the gas-oil mix in each play are listed in Appendix A2.

Most of the undiscovered hydrocarbon resources occur in play 2, where the best quality reservoir sands occur (fig. 17.3), and in play 4, where thick basin-center turbidite sands overlie deeply buried Eocene source rocks with the highest potential to generate oil (figs. 17.1, 17.5). The assessed endowments of oil and gas for each of the five Navarin basin plays are shown in table 17.1. Cumulative probability

TABLE 17.1
OIL AND GAS ENDOWMENTS OF NAVARIN BASIN PLAYS
Risked, Undiscovered, Conventionally Recoverable Oil and Gas

PLAY NO.	PLAY NAME (UAI* CODE)	OIL (BBO)			GAS (TCFG)		
		F95	MEAN	F05	F95	MEAN	F05
1.	Miocene Transgressive Shelf Sands (UANA0100)	0.000	0.078	0.206	0.000	0.666	1.951
2.	Regressive Shelf Sands (UANA0200)	0.000	0.272	0.605	0.000	2.432	5.655
3.	Oligocene Tectonic Sands (UANA0300)	0.000	0.020	0.054	0.000	0.196	0.599
4.	Turbidite and Submarine Fan Sands (UANA0400)	0.000	0.116	0.275	0.000	2.518	6.236
5.	Eocene Transgressive Shelf Sands (UANA0500)	0.000	0.011	0.036	0.000	0.335	1.024
6.	Nonmarine and Marginal Marine Sands (Subunc.)	na	na	na	na	na	na
7.	Paleocene Marine Sands (App. Wedge Top)	na	na	na	na	na	na
	FASPAG AGGREGATION	*0.000*	*0.496*	*1.214*	*0.000*	*6.147*	*18.176*

* *Unique Assessment Identifier, code unique to play.*
na *not assessed*

distributions and ranked pool size plots for each of the plays are shown in Appendix B2.

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Turner, R.F., ed., McCarthy, C.M., Steffy, D.A., Lynch, M.B., Martin, G.C., Sherwood, K.W., Flett, T.O., and Adams, A.J., 1984, Geological and operational summary, Navarin Basin COST No. 1 well, Bering Sea, Alaska: U.S. Minerals Management Service, Alaska OCS Region, OCS Report MMS 84-0031, 245 p.

Turner, R.F., Martin, G.C., Flett, T.O., and Steffy, D.A., 1985, Geologic report for the Navarin Basin planning area, Bering Sea, Alaska: U.S. Minerals Management Service, Alaska OCS Region, OCS Report MMS 85-0045, 156 p.

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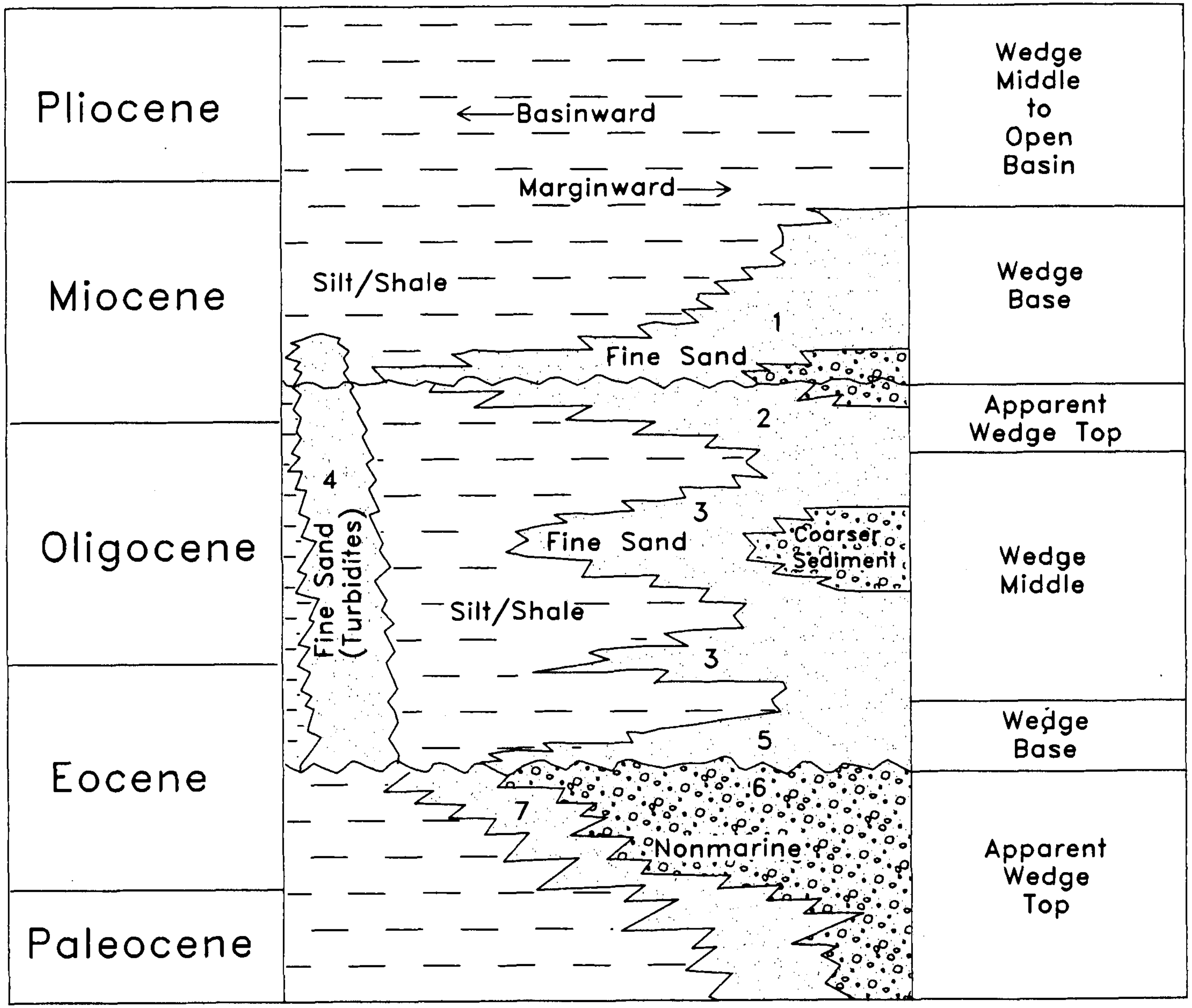

Figure 17.1: Facies-cycle wedge model. Numbers correspond to plays identified in Navarin basin assessment province. Modified from White (1980). Plays 1 to 5 were assessed for oil and gas potential. Plays 6 and 7 were not quantified because they offer extremely low probabilities for the occurrence of pooled, conventionally recoverable hydrocarbons.

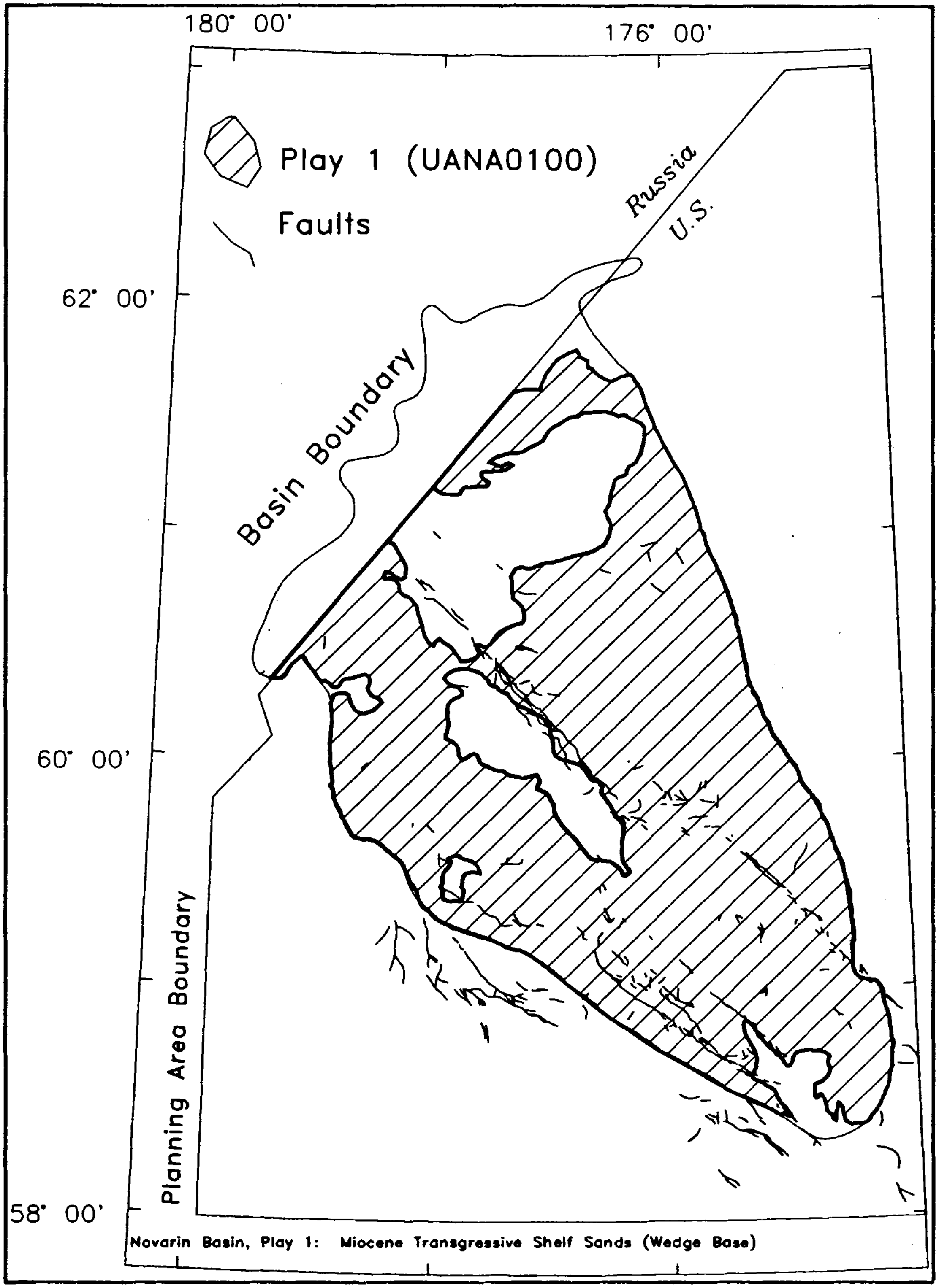

Figure 17.2: Map showing area of Navarin basin play 1 (Miocene Transgressive Shelf Sands-Wedge Base; UANA0100).

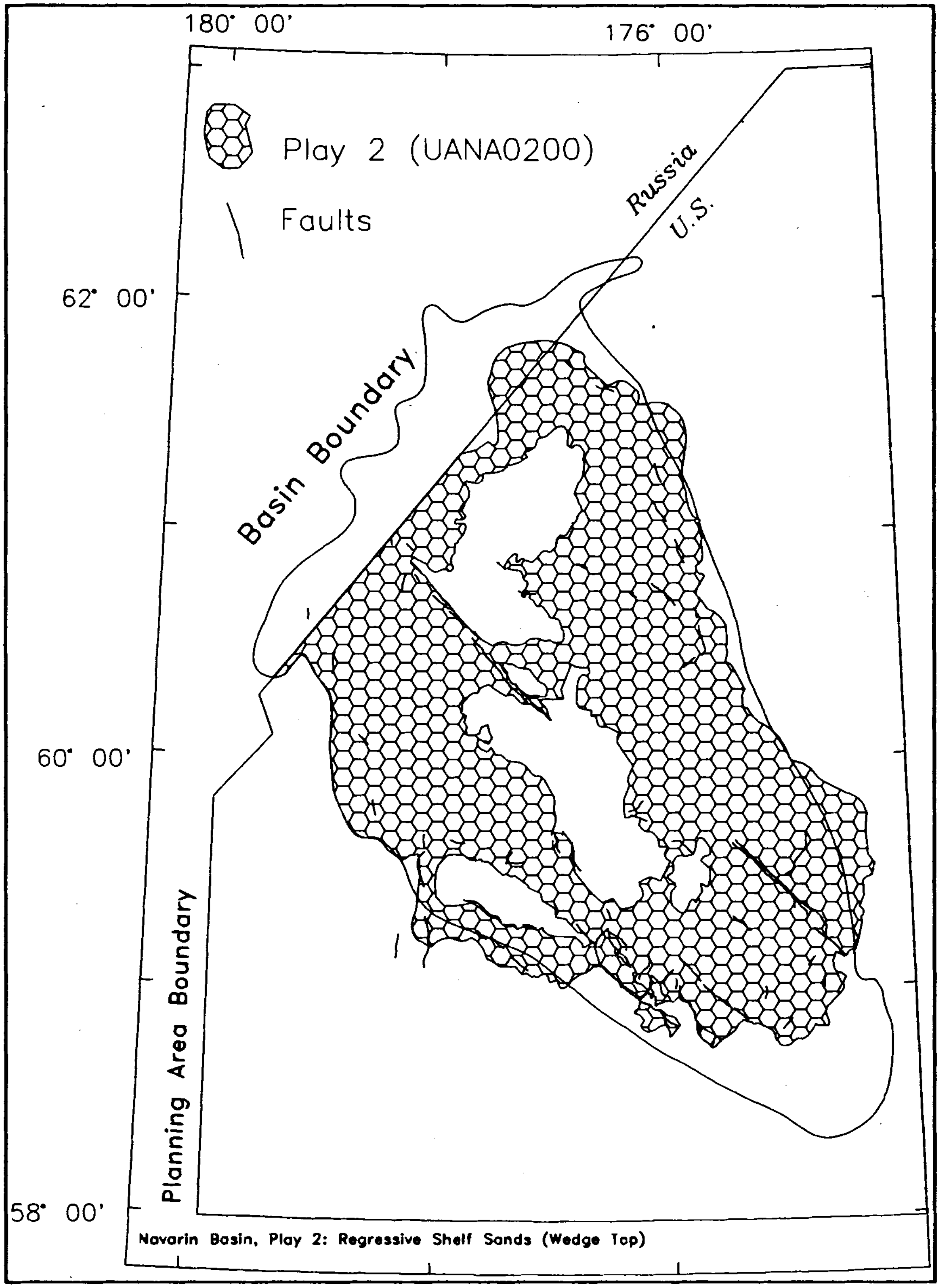

Figure 17.3: Map showing area of Navarin basin play 2 (Regressive Shelf Sands - Wedge Top; UANA0200).

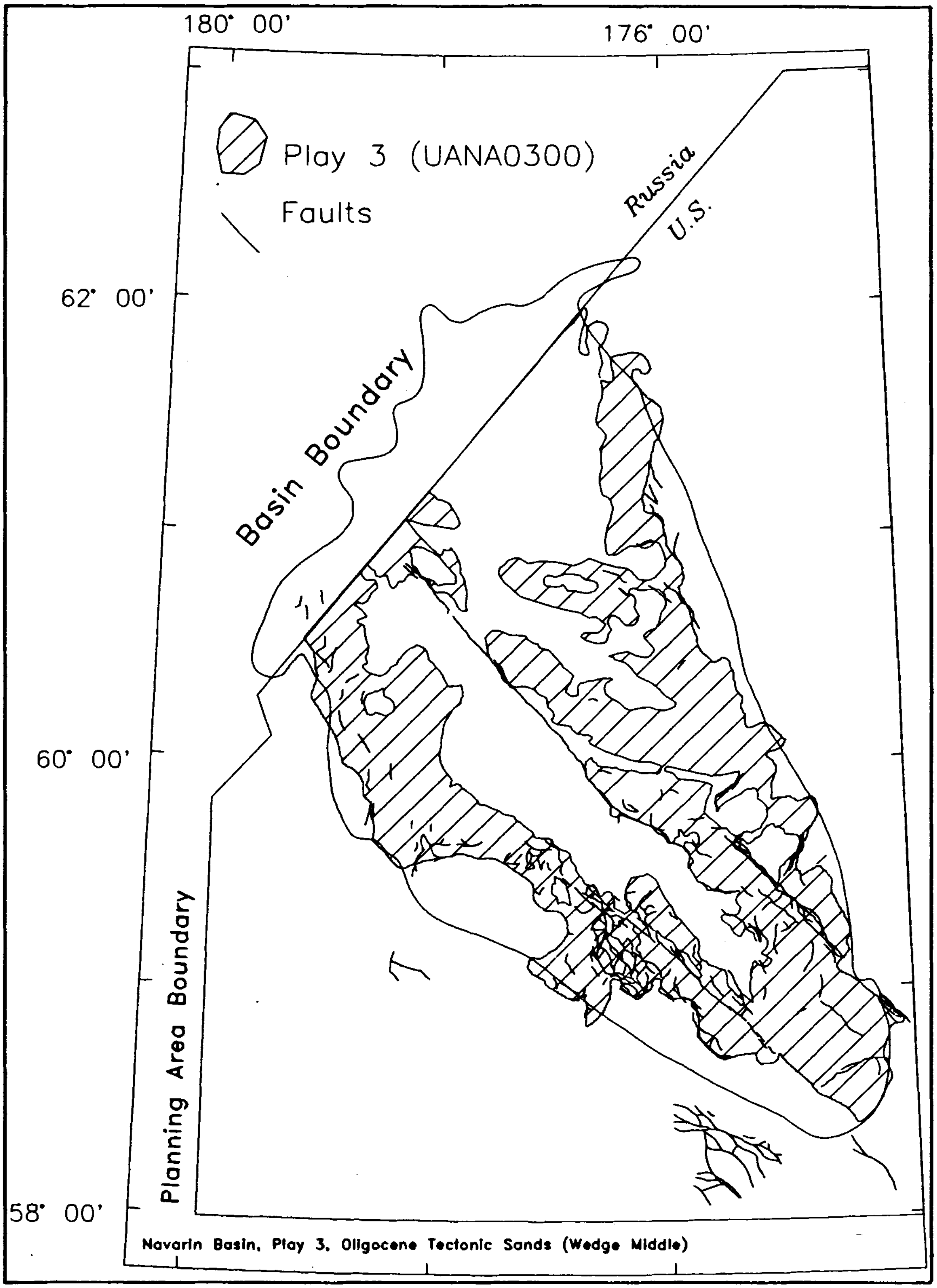

Figure 17.4: Map showing area of Navarin basin play 3 (Oligocene Tectonic Sands - Wedge Base; UANA0300).

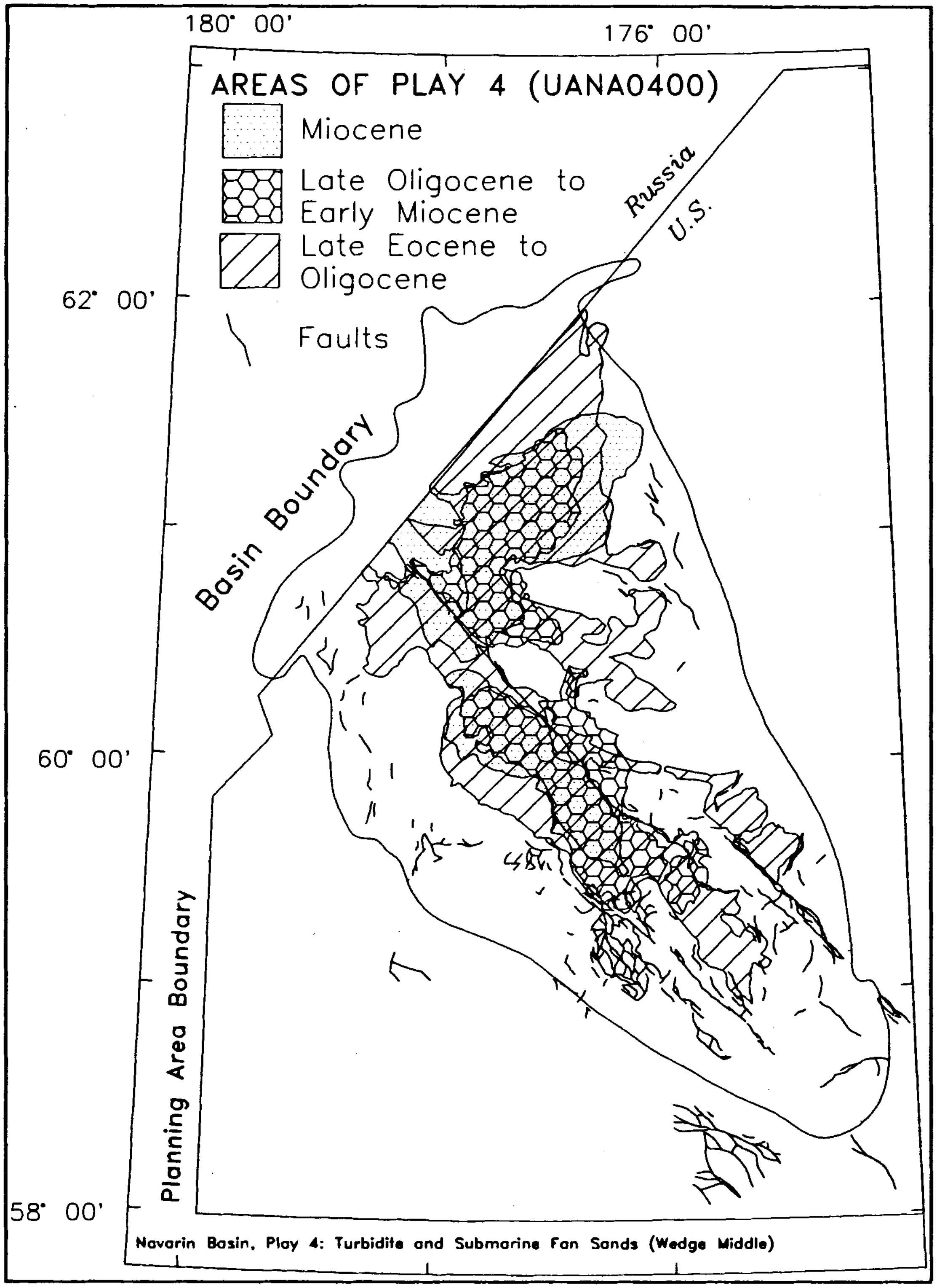

Figure 17.5: Map showing area of Navarin basin play 4 (Turbidite and Submarine Fan Sands-Wedge Middle; UANA0400).

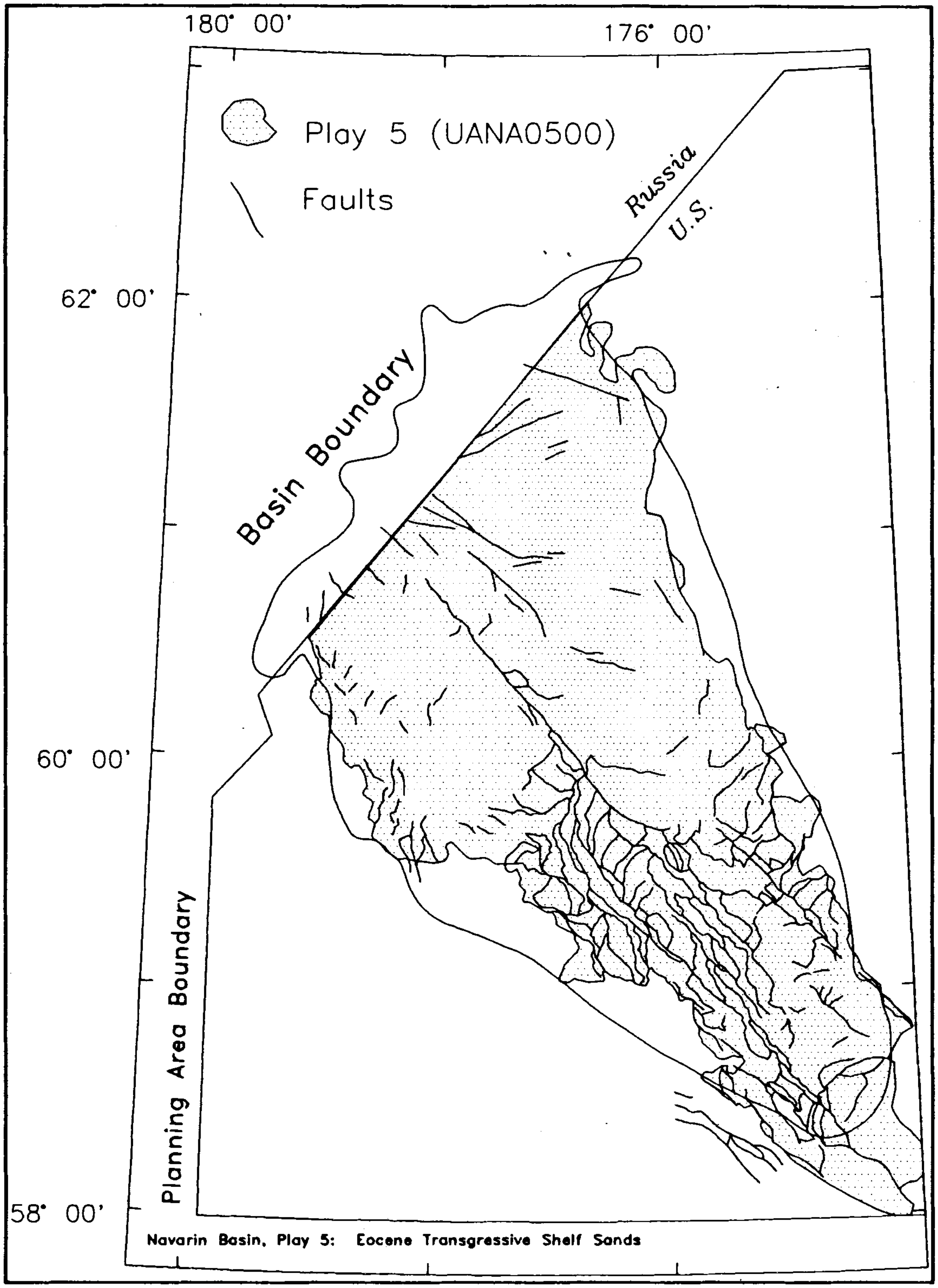

Figure 17.6: Map showing area of Navarin basin play 5 (Eocene Transgressive Shelf Sands; UANA0500).

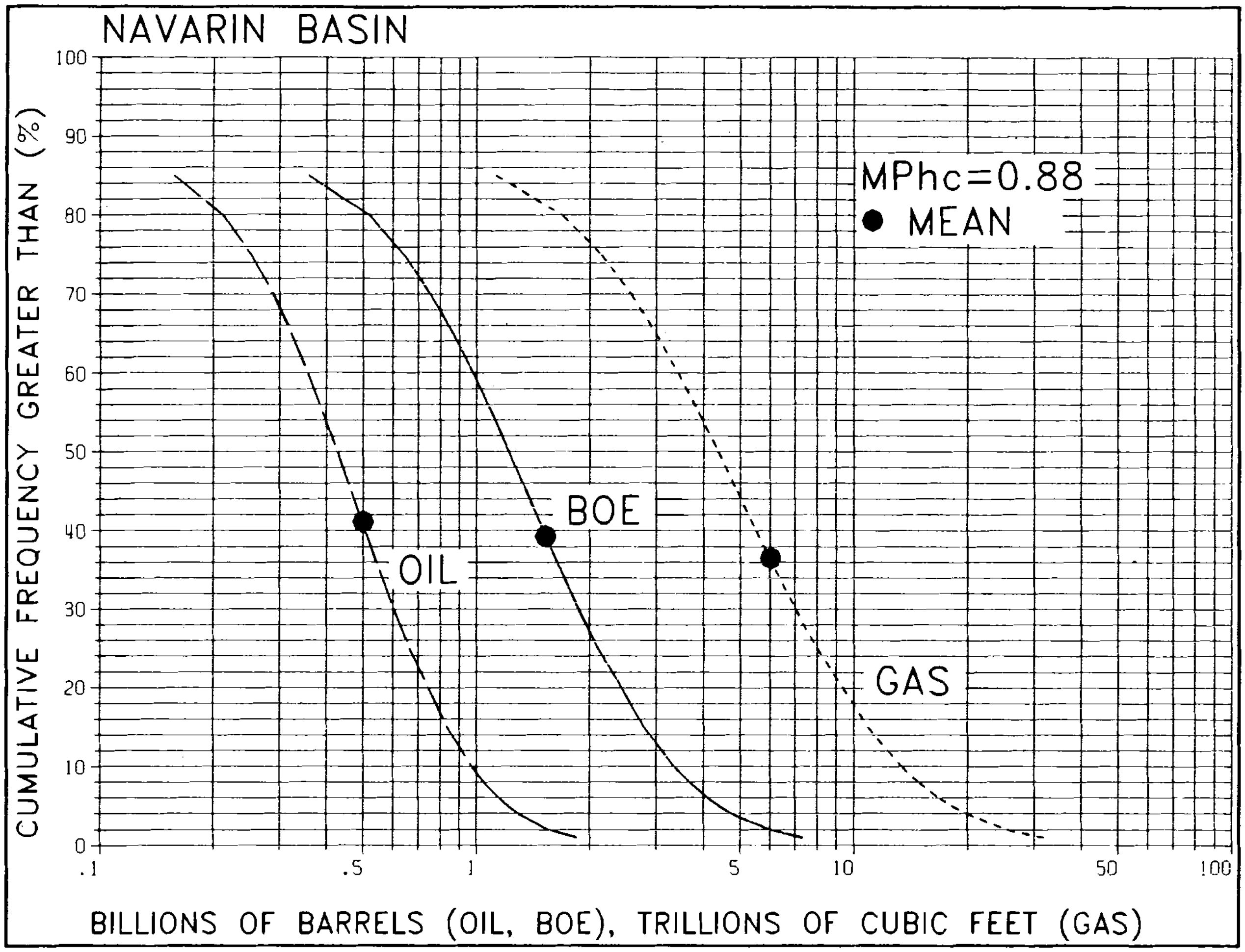

Figure 17.7: Cumulative probability curves for undiscovered, conventionally recoverable resources (oil, gas, and BOE) for Navarin basin assessment province. ***BOE**, total oil and gas in energy-equivalent barrels, obtained by converting gas to energy-equivalent barrels (5,620 cubic feet per barrel) and adding to oil; **MPhc**, marginal probability for occurrence of pooled hydrocarbons in province.*

18. NORTH ALEUTIAN BASIN ASSESSMENT PROVINCE

by
John Parker and Richard Newman

LOCATION

The North Aleutian basin assessment province contains several structural elements. The most important of these, from an oil and gas perspective, is the area of very thick Tertiary strata and numerous anticlines in western North Aleutian basin (figure 18.1). All five of the structures leased in 1988 are within this area, and the North Aleutian COST No. 1 well is at the center of it. In Federal waters, the basin thins to the southwest onto the Black Hills uplift and to the northeast into upper Bristol Bay. South of the Black Hills uplift is a small portion of the Amak basin, and the southeast end of the St. George graben attenuates into the Black Hills uplift on the western border of the province.

GEOLOGIC SETTING

The most dramatic event in the Cenozoic geologic history of the area was the relocation of the Kula plate subduction zone from the Beringian margin to its present location at the Aleutian arc. This occurred in the Eocene and resulted in the creation of a block-faulted horst-and-graben terrane which accumulated nonmarine, volcaniclastic sediments in the grabens. The North Aleutian COST No. 1 well and seismic data show a significant change in the late Eocene, when the sedimentary environments changed from nonmarine to transitional, and the content of volcanic clasts in sandstones decreased. Within upper Eocene rocks at 10,400 feet in the COST No. 1 well, the seismic data show a regional paraconformity with discontinuous, semi-chaotic reflections below and continuous reflections above. In the well, the seismic paraconformity corresponds to a marked change from older nonmarine rocks to a younger "transitional" to nertic marine rocks. From the paraconformity, the Tertiary sequence becomes progressively more marine and the volcaniclastic content of the sediments progressively diminishes.

EXPLORATION HISTORY

Since 1959, 17 wells have been drilled in the North Aleutian basin or in nearby areas. Fifteen wells were drilled onshore on the Alaska Peninsula, from the Cathedral River No. 1 well on the Black Hills uplift in the south, to the Great Basin wells in the north, which reached total depth in the Naknek Lake batholith. Three wells on the north side of the Alaska Peninsula encountered hydrocarbon shows. The Hoodoo Lake No. 2 and the Sandy River No. 1 wells had oil shows in the Tertiary section, and the Becharof No. 1 well tested gas. In addition to the subsurface data, considerable geologic information has been collected from Mesozoic and Cenozoic rocks on north side of the Alaska Peninsula.

The wells on the south side of the Alaska Peninsula have less relevance to the North Aleutian basin assessment province. The Tertiary section is thin or missing, and the major structural deformation occurred in the Pliocene, versus Eocene in the North Aleutian basin. The only noticeable Pliocene structural event in the North Aleutian basin was an increase in the rate of subsidence at the COST well location.

The North Aleutian COST No. 1 well was completed in 1983 at the center of an area of exceptionally thick Tertiary rocks in the basin. This is the only offshore well to penetrate North Aleutian basin. Another well was drilled in the nearby offshore: the Mobil Bertha well (OCS-Y-0466 No. 1), an exploratory hole drilled in 1984 in St. George Basin Planning Area, just west of 165° west longitude (well located in fig. 19.1).

The North Aleutian COST No. 1 well was a 17,000 foot stratigraphic test well exhaustively evaluated with logs, extensive sidewall cores, and 19 conventional cores, which bottomed in the Eocene Tolstoi Formation.

PLAY DESCRIPTION

The potential for undiscovered oil and gas resources in the North Aleutian basin assessment province are limited to Tertiary rocks. A Mesozoic play was identified, but not assessed. Data used to characterize and model the oil and gas potential of the one play assessed in North Aleutian basin are tabulated in Appendix A2.

Play 1 (UANB0100[1]). Oligocene-Miocene Play: The main significant play involves high-quality reservoir sandstones of Oligocene and Miocene age in anticlines draped over fault-bounded basement highs. Reservoir potential is good to excellent in Oligocene and Miocene sandstones in the COST No. 1 well above 9,500 feet. Porosity and permeability increase and consolidation decreases as burial depth decreases. Onshore, reservoir quality is generally poor, but the Miocene Bear Lake Formation is promising.

The organic material tested in the COST well was predominantly type III, humic, gas-prone kerogen. The top of the window for hydrocarbon generation is at 12,700 feet; the base is projected to be 20,000 feet. The traps are mainly simple anticlines and lightly faulted anticlines.

Play 2 (Not Assessed). Mesozoic Play: Good oil-prone Mesozoic source rocks are known in onshore areas of the Alaska Peninsula, but the extension of these rocks offshore is problematic. In the northerneastern part of the Alaska Peninsula, Mesozoic sedimentary rocks on the east are separated from a Mesozoic magmatic arc complex on the west by the Bruin Bay fault. There is a belt of high-amplitude magnetic and gravity anomalies in North Aleutian basin that trends northeast toward the Mesozoic magmatic arc complex exposed onshore. It is therefore reasonable to speculate that a magmatic arc terrane underlies much of the North Aleutian basin assessment province. The inferred magmatic character of the Mesozoic substrate and the uncertainty about the nature and structural configuration of Mesozoic strata precluded quantitative assessment of the Mesozoic play.

RESOURCE ASSESSMENT

The undiscovered, conventionally recoverable oil and gas resources for the North Aleutian basin assessment province average 0.232 billion barrels of oil and 6.791 trillion cubic feet of gas. Table 18.1 shows that there is potential for up to 0.575 billion barrels of oil and 17.328 trillion cubic feet of gas.

Oil forms 16.2 percent of the BOE, reflecting the view that the basin is gas-prone. (For example, the basin model used GPROB=0.80, implying that 80% of all accumulations would

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[1] *The "UA" Code is the "Unique Assessment Identifier" for each play, and is the principal guide to GRASP data files.*

consist entirely of gas; see Appendix A2). The "oil" reported in table 18.1 consists mostly of natural gas liquids that would be recovered only as a by-product of gas production. All of the hydrocarbon resources occur in the Oligocene-Miocene play. Cumulative probability distributions for oil, gas, and BOE resources for the North Aleutian basin assessment province are shown in figure 18.2. A ranked pool size plot for the play is shown in Appendix B2.

TABLE 18.1
OIL AND GAS ENDOWMENTS OF NORTH ALEUTIAN BASIN ASSESSMENT PROVINCE
Risked, Undiscovered, Conventionally Recoverable Oil and Gas

PLAY NO.	PLAY NAME (UAI* CODE)	OIL (BBO)			GAS (TCFG)		
		F95	MEAN	F05**	F95	MEAN	F05**
1.	Oligocene-Miocene (UANB0100)	0.000	0.233	0.555	0.000	6.791	16.031
	FASPAG AGGREGATION	***0.000***	***0.233***	***0.575***	***0.000***	***6.791***	***17.328***

* *Unique Assessment Identifier, code unique to play.*
** *Differences in F05 values at play and basin levels reflect different mathematic methods for construction of probability distributions.*

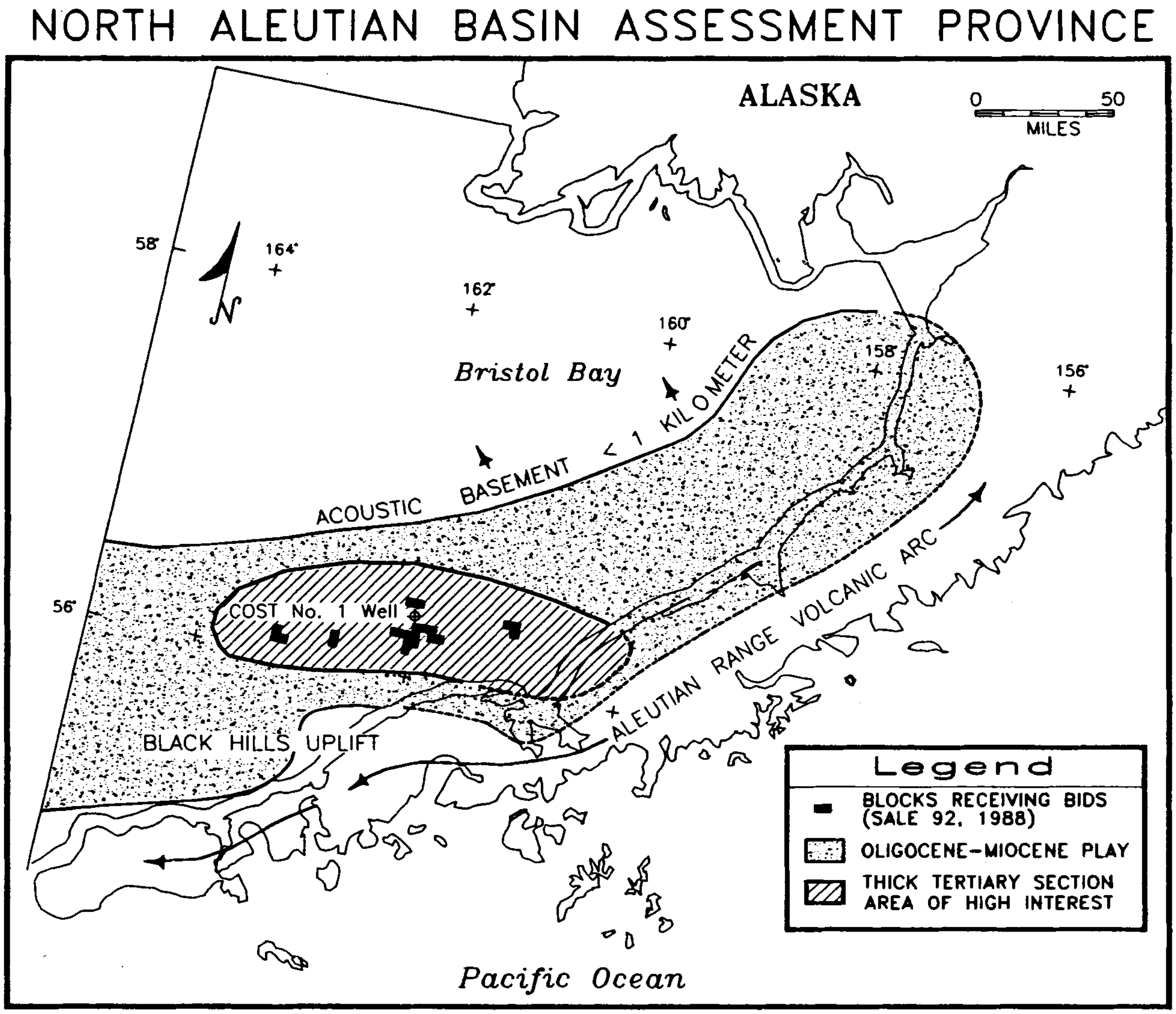

Figure 18.1: Area of play 1 or "Oligocene-Miocene" play (UANB0100), North Aleutian basin, with blocks receiving total high bids of $95.4 million in OCS Sale 92 in 1988. Aside from the COST No. 1 stratigraphic test well, no exploratory wells were drilled in offshore North Aleutian basin.

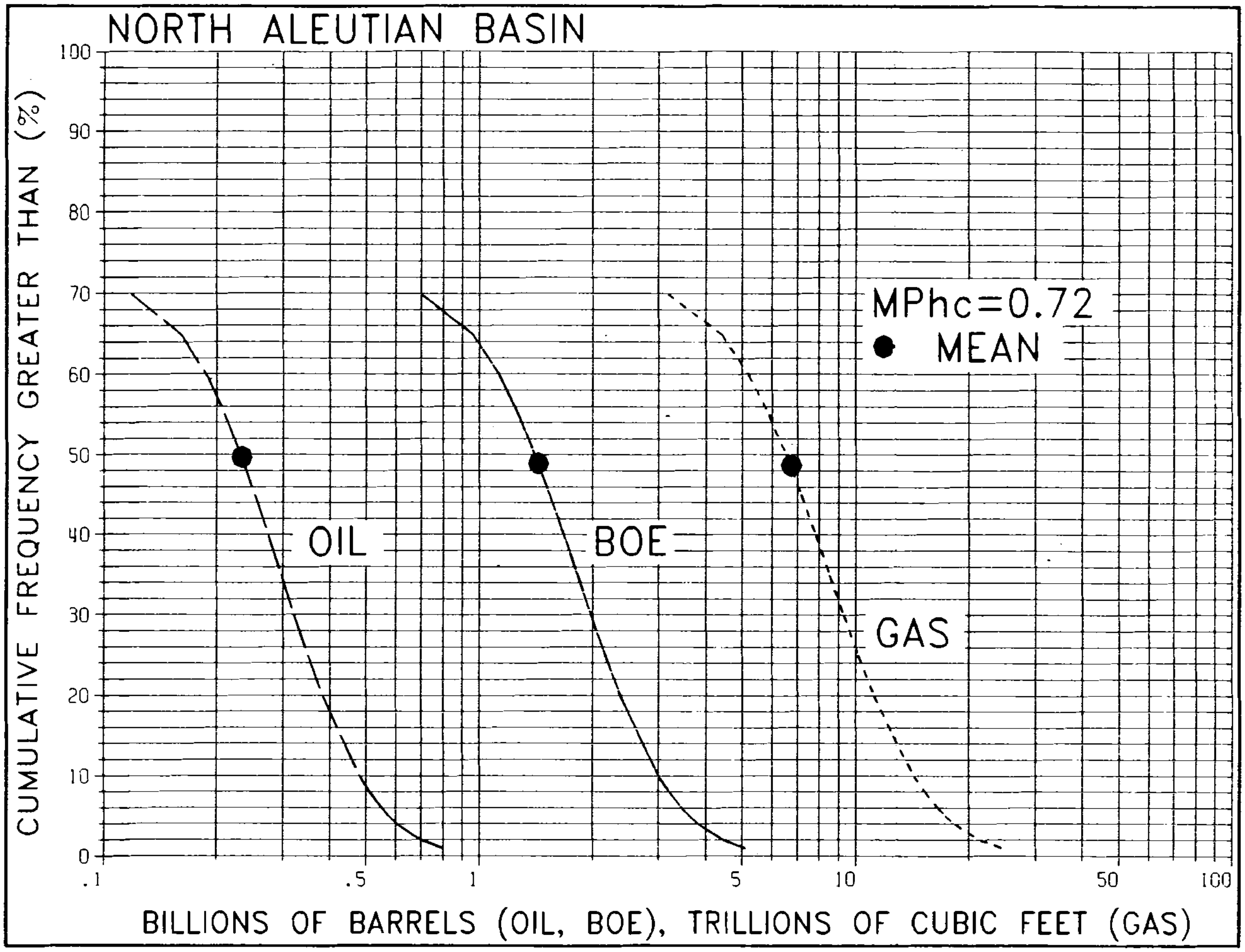

Figure 18.2: Cumulative probability curves for undiscovered, conventionally recoverable resources (oil, gas, and BOE) for North Aleutian basin assessment province. ***BOE**, total oil and gas in energy-equivalent barrels, obtained by converting gas to energy-equivalent barrels (5,620 cubic feet per barrel) and adding to oil; **MPhc**, marginal probability for occurrence of pooled hydrocarbons in province.*

GEOLOGIC ASSESSMENT
1995 National Resource Assessment
Alaska Federal Offshore
U.S. Minerals Management Service

19. ST. GEORGE BASIN ASSESSMENT PROVINCE

by
C. Drew Comer and Bruce M. Herman

LOCATION

The St. George basin assessment province contains two main Cenozoic depocenters, the St. George graben and the Pribilof basin (fig. 19.1). The assessment area is on the outer Bering Sea shelf between the 100-meter isobath and the continental slope, at approximately the 200-meter isobath. The eastern boundary is the North Aleutian basin assessment province and the western boundary adjoins the Navarin basin assessment province (pl. 1.1).

GEOLOGIC SETTING

The outer Bering Sea shelf was a Mesozoic forearc margin prior to the formation of the Aleutian volcanic arc (Marlow and Cooper, 1980). Plate reorganization in the north Pacific region resulted in strike-slip tectonics in early Tertiary time. The St. George graben and the Pribilof basin opened as a result of transform motion along the outer Bering Sea shelf, overprinting the Mesozoic forearc margin with deep, rift-related depocenters. The Aleutian volcanic arc probably formed in the early Eocene, at about 55 Ma (Scholl and others, 1983; 1986). Major faulting in the St. George basin continued through at least early Oligocene time, but the margin was ultimately isolated from further tectonic plate motion. The rift-related basins, and the surrounding stable platforms, were subsequently covered by middle to late Cenozoic strata that are little deformed.

EXPLORATION HISTORY

Two Continental Offshore Stratigraphic Test (COST) wells were drilled in the basin in 1976 and 1982 (Turner and others, 1984a and 1984b). Ten exploratory wells, including one sidetrack, were drilled from 1984 to 1985 with no discoveries reported.

PLAY DESCRIPTIONS

Four plays with geophysically-mapped prospects have been identified in the assessment province: (1) the St. George graben, (2) the south platform, (3) the north platform, and (4) the Pribilof basin (fig. 19.1). Data used to model the oil and gas potential of these plays is tabulated in Appendix A2.

Play 1 (UASG0101[1]). St. George Graben: The St. George graben trends northwest-southeast for over 200 miles, is 10- to 25-miles

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[1] *The "UA" Code is the "Unique Assessment Identifier" for each play, and is the principal guide to GRASP data files.*

wide, and contains as much as 40,000 feet of Cenozoic strata (Marlow and others, 1976). Potential hydrocarbon traps include faulted anticlines, upthrown fault traps along the border faults of the graben, drape of Tertiary strata over basement fault blocks, stratigraphic onlap onto the basement, and possible pinchout of sands. Five exploratory wells, including one sidetrack hole, were drilled in the graben. All wells were plugged and abandoned with only minor gas shows encountered. The exploratory and stratigraphic test wells are located in figure 19.1.

The best reservoir rocks encountered in the graben are Oligocene sandstones. The Arco Y-0511 well encountered fine-grained Oligocene sandstones in beds ranging from 10- to 40-feet thick for a gross total of 460 feet. Porosities ranged from 20 to 30 percent and permeabilities ranged from 20 to 130 millidarcies. The Exxon Y-0527 well had Oligocene sandstones in beds ranging from 5- to 20-feet thick for a gross total of 185 feet. The Exxon Y-0530 and the Chevron Y-0519 wells, also located in the graben, had no sandstones of reservoir quality. Porosity loss with depth tends to be very high in the St. George basin province because the rocks have a high content of volcanic rock fragments which are diagenetically altered to zeolite and clay minerals with burial.

The source-rock potential is poorly known for the graben, but the COST No. 2 well, located along its southeastern margin, had relatively low TOC values in the Cenozoic and Mesozoic sections (Turner and others, 1984b). The kerogen types identified were gas-prone and the top of the oil window occurs at approximately 12,000 feet. Other unexplored areas of the graben are much deeper and may have better source-rock potential. The Arco Y-0511 well penetrated the northern boundary fault of the graben and recovered samples of Jurassic shales that had TOC values of 0.5 to 2.0 percent. The visual kerogen examination reported a high percentage of amorphous material. If oil-prone source rocks are present in the St. George basin assessment province, they probably occur in Jurassic strata. The province is underlain by the Mesozoic Peninsular terrane which extends from the Cook Inlet area, where Middle Jurassic strata are known to have generated oil (Magoon and Claypool, 1981; Magoon and Anders, 1992).

Play 2 (UASG0201). South Platform Play: The south platform includes the area south of the St. George graben to the continental slope and east of Pribilof Canyon (fig. 19.1). This stable platform area generally contains less than 10,000 feet of nearly flat-lying strata, separated from acoustic basement by an angular unconformity. The overlying strata range in age from middle Eocene to Pleistocene and were mostly deposited in a marine-shelf environment. The basement at the COST No. 1 well consists of basaltic igneous rocks, but Mesozoic and lower Tertiary sedimentary rocks occur below the acoustic basement unconformity elsewhere. Potential traps include anticlinal structures within the acoustic basement, drape of Tertiary sands over basement highs, fault-bounded traps, and stratigraphic onlap onto basement highs. Five exploratory wells and one COST well were drilled in the south platform play area, all of which were plugged and abandoned with only minor gas shows encountered.

The best reservoir-rock potential is in the Oligocene section. The COST No. 1 well contained individual sandstone beds greater than 150 feet thick, with an aggregate total of 1,200 feet. Porosities were as high as 25 percent and permeabilities were as high as 37 millidarcies (Turner and others, 1984a). Permeabilities were as high as 300 to 400 millidarcies in Oligocene sandstones in the Shell Y-0454 well.

Source-rock potential in the south platform area appears to be poor. The sediments were deposited under oxidizing conditions and are low in TOC. Only gas-prone kerogen types were present in samples from the COST No. 1 well, and the rocks were thermally immature. The oil window occurs at approximately 12,000 feet, so any hypothesized thermally mature hydrocarbon source must involve rocks that lie below the acoustic basement unconformity, the latter generally shallower than 10,000 feet in this play area.

Play 3 (UASG0301). North Platform Play: The north platform extends north of the St. George graben for about 10 to 25 miles. This area contains 3,000 to 10,000 feet of Cenozoic sedimentary rocks over the acoustic basement unconformity. The basement just north of the graben is probably composed of Mesozoic and lower Tertiary sedimentary rocks. Farther north, less than 3,000 feet of Cenozoic strata occur over igneous basement. Potential traps include stratigraphic onlap onto basement highs, anticlinal structures within the basement, drape of Tertiary strata over basement highs, and fault-bounded traps. No exploratory wells have tested prospects in the north platform play.

Oligocene sandstones probably have the best reservoir-rock potential, based on seismic correlation from well control in the graben to the south. The oil window occurs at approximately 12,000 feet, so thermally mature source rocks would have to be present in basement strata for the north platform play to be viable. The best source-rock potential is probably in Jurassic strata, based on data from the Arco Y-0511 well, which was drilled in the graben but penetrated the north-bounding fault, passing below the fault into basement rocks of the north platform.

Play 4 (UASG0401). Pribilof Basin Play: The Pribilof basin is a half graben that is about 30-miles wide, trends northwest-southeast for about 70 miles, and contains as much as 20,000 feet of Cenozoic sedimentary rocks (Scholl and Hopkins, 1969). It lies between St. George Island and the continental slope west of Pribilof Canyon. The area has never been offered for leasing and no wells have been drilled there. Potential traps include anticlines in the acoustic basement with drape in overlying strata, upthrown fault traps over tilted basement blocks, and stratigraphic onlap.

There are no reservoir-rock or source-rock data for the Pribilof basin. However, seismic data suggest that the basal strata were deposited when the surrounding area was emergent (Comer and others, 1987). Therefore, restricted circulation in the early Tertiary may have been conducive to organic preservation, and strata with good source-rock potential may have been deposited. The oil window probably occurs at about 12,000 feet, so the basal strata should be thermally mature.

RESOURCE ASSESSMENT

The undiscovered, conventionally recoverable oil and gas resources for the St. George basin assessment province are estimated to average 0.135 billion barrels of oil and 2.995 trillion cubic feet of gas. Cumulative probability distributions for oil, gas, and BOE resources are shown in figure 19.4. BOE results are listed in table 16.1. "Oil" forms 20 percent of the total BOE, but most of it is actually natural gas liquids. Table 19.1 gives the undiscovered oil and gas endowments for each of the plays. Results for plays are reported in detail in Appendix B2.

All of the plays were modeled as predominately gas-prone (e.g., OPROB=0.0, corresponding to a 0% chance for the occurrence of accumulations consisting entirely of oil; see Appendix A2). The graben play (1) has the most resource potential, reflecting the thick sequence of thermally-mature Tertiary strata and the numerous prospects there. Plays 1 and 4 were modeled as the least gas-prone (but still given GPROB=0.8, or an 80% chance for the occurrence of accumulations consisting entirely of gas). The south platform play has the next highest endowment, mostly because of its vast areal extent and the large size of some of its prospects. That play was modeled as the most gas-prone, with a 0.95 GPROB input value, but it still had the second highest "oil" endowment because of the natural gas liquids associated with gas resources. The smaller endowments for both the north platform and Pribilof basin plays reflects

TABLE 19.1
OIL AND GAS ENDOWMENTS OF ST. GEORGE BASIN PLAYS
Risked, Undiscovered, Conventionally Recoverable Oil and Gas*

PLAY NO.	PLAY NAME (UAI* CODE)	OIL (BBO)			GAS (TCFG)		
		F95	MEAN	F05	F95	MEAN	F05
1.	St. George Graben (UASG0101)	0.000	0.059	0.155	0.000	1.007	2.743
2.	South Platform (UASG0201)	0.000	0.034	0.152	0.000	0.898	4.325
3.	North Platform (UASG0301)	0.000	0.025	0.101	0.000	0.676	2.674
4.	Pribilof Basin (UASG0401)	0.000	0.017	0.070	0.000	0.414	1.502
	FASPAG AGGREGATION	*0.000*	*0.135*	*0.414*	*0.000*	*2.995*	*9.716*

* *Unique Assessment Identifier, code unique to play.*

the relatively small areal extent and the limited number of prospects for those plays. Less is known about those two plays because of the lack of well control. The GPROB input values were 0.9 and 0.8, respectively, for the north platform and Pribilof basin plays. The Pribilof basin was modeled as less gas-prone because it contains a thicker sequence of Tertiary strata within an enclosed basin, leaving open the possibility for oil-prone source rocks occurring within the thermal-maturity zone for oil generation. Cumulative probability distributions and ranked pool size plots for the four plays in St. George basin assessment province are shown in Appendix B2.

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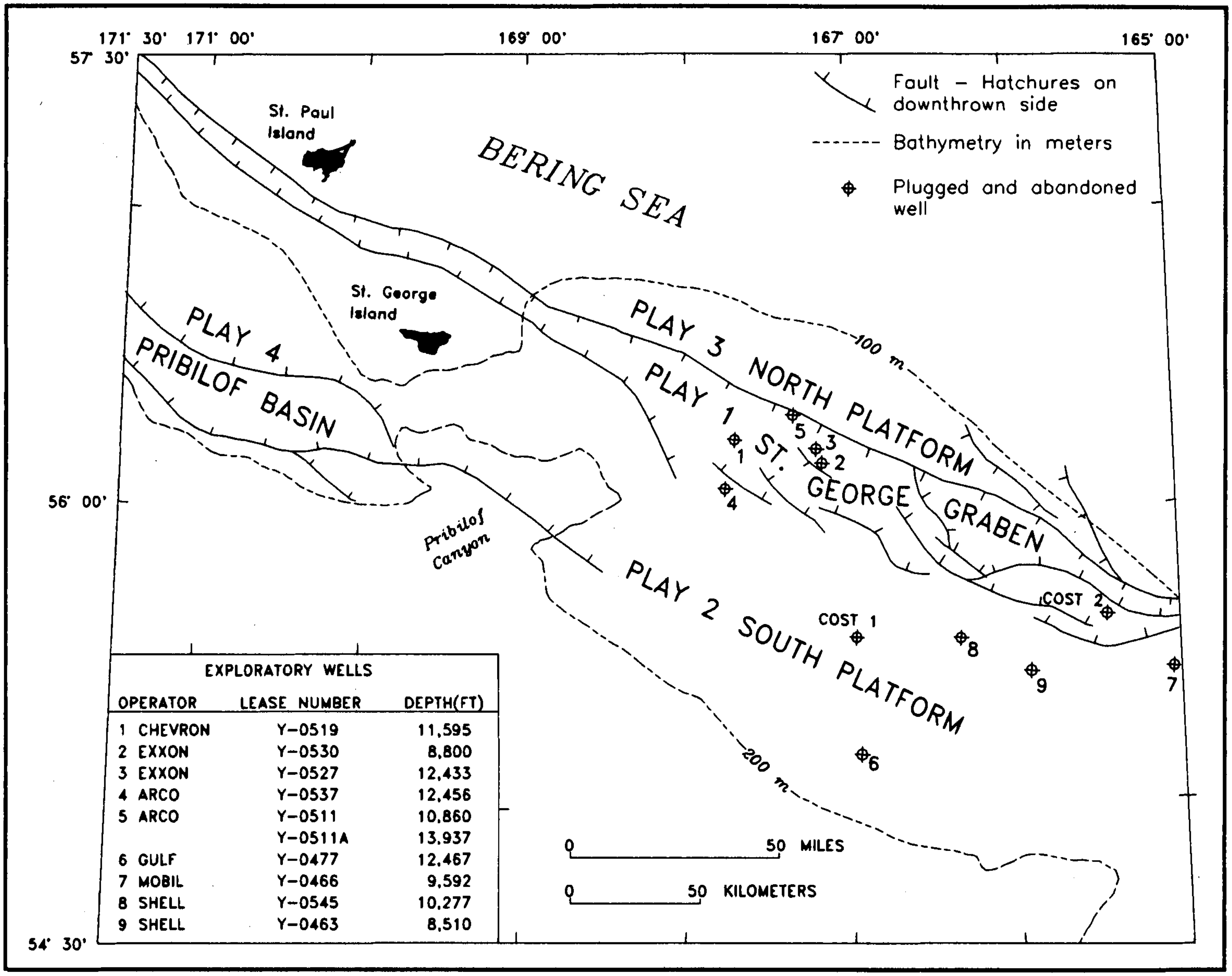

EXPLORATORY WELLS

OPERATOR	LEASE NUMBER	DEPTH(FT)
1 CHEVRON	Y-0519	11,595
2 EXXON	Y-0530	8,800
3 EXXON	Y-0527	12,433
4 ARCO	Y-0537	12,456
5 ARCO	Y-0511	10,860
	Y-0511A	13,937
6 GULF	Y-0477	12,467
7 MOBIL	Y-0466	9,592
8 SHELL	Y-0545	10,277
9 SHELL	Y-0463	8,510

Figure 19.1: Map showing locations of petroleum plays, major faults, COST wells, and exploratory wells in the St. George basin assessment province.

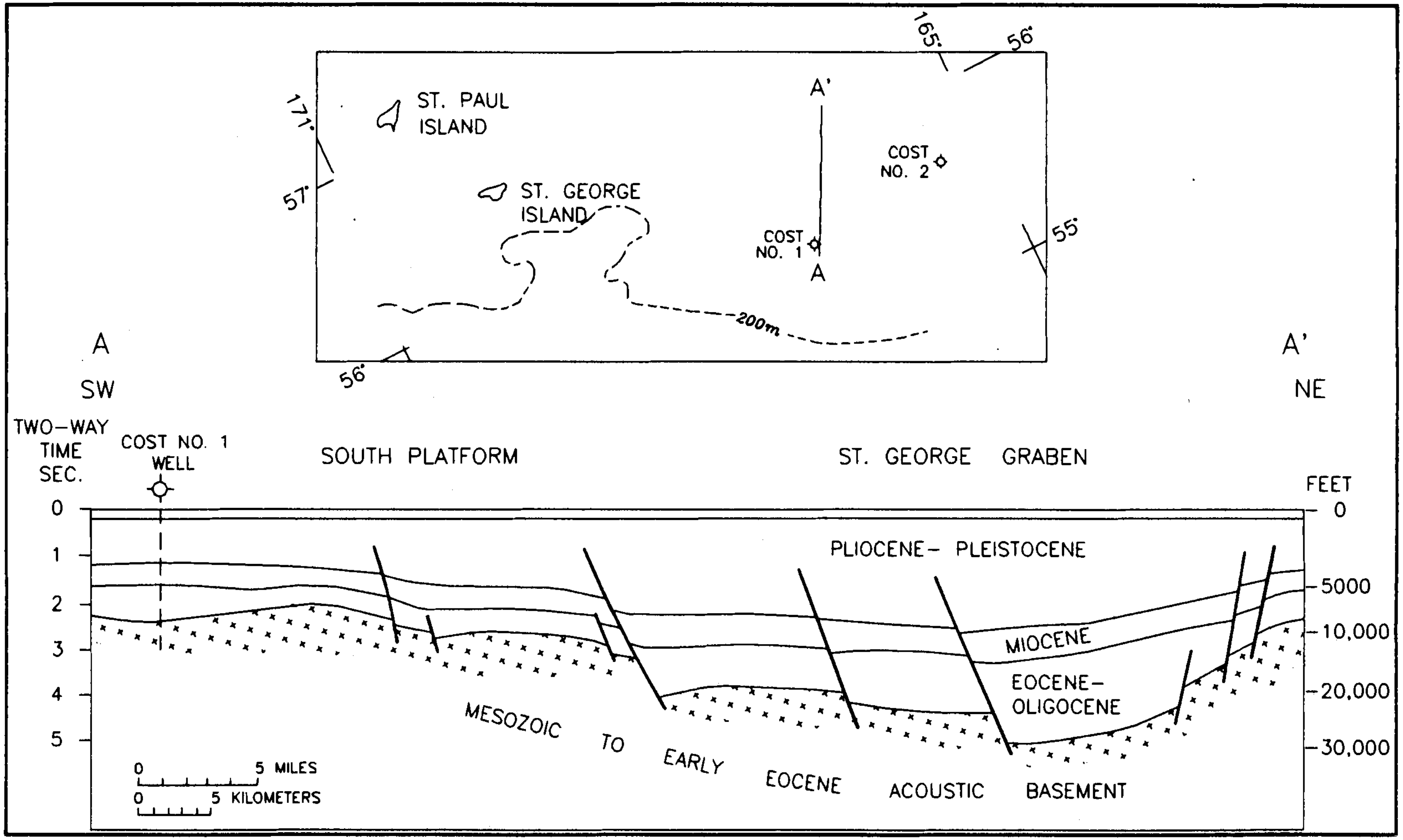

Figure 19.2: Generalized cross-section of St. George basin.

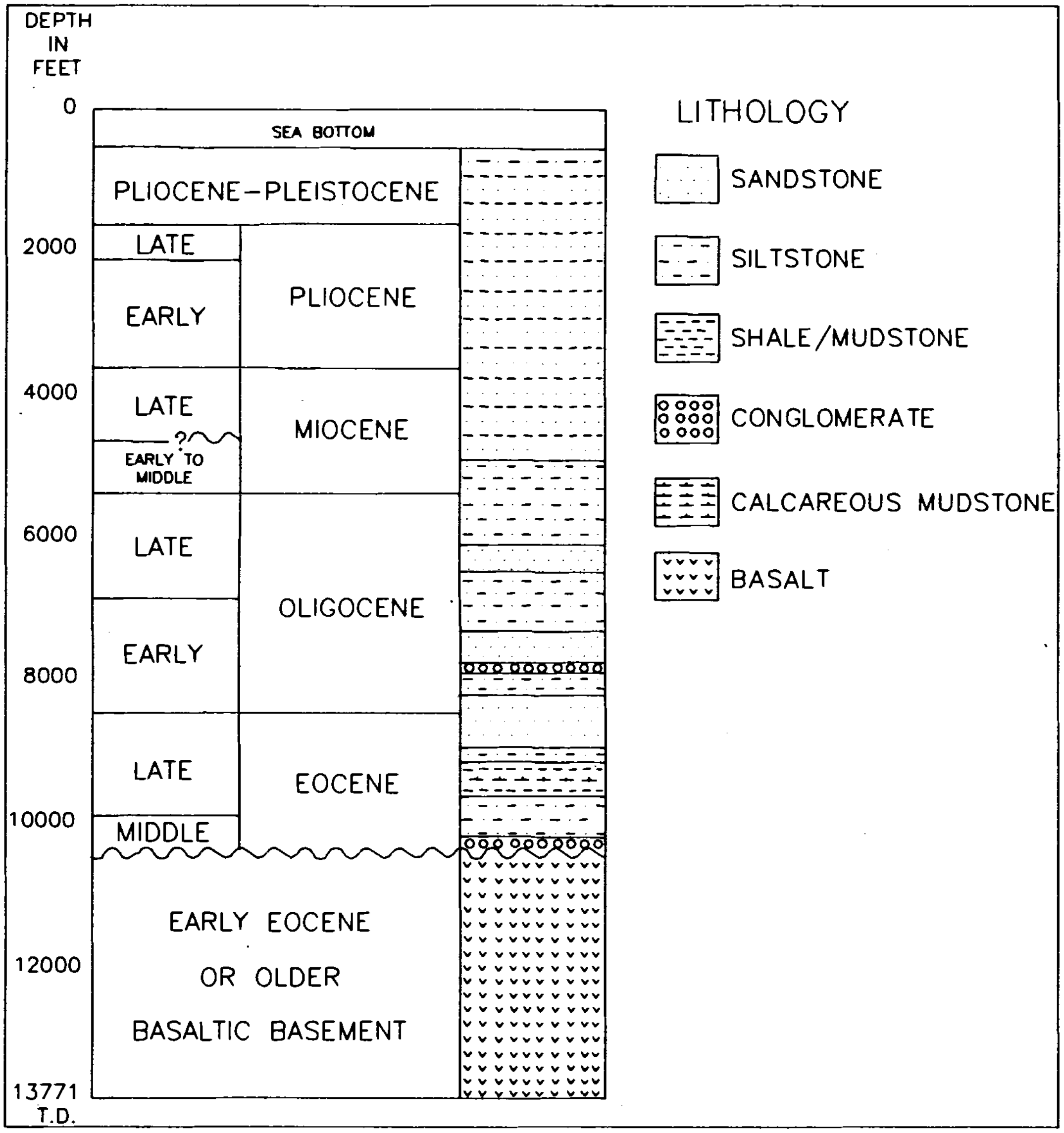

Figure 19.3: Generalized stratigraphic summary, St. George Basin COST No. 1 well.

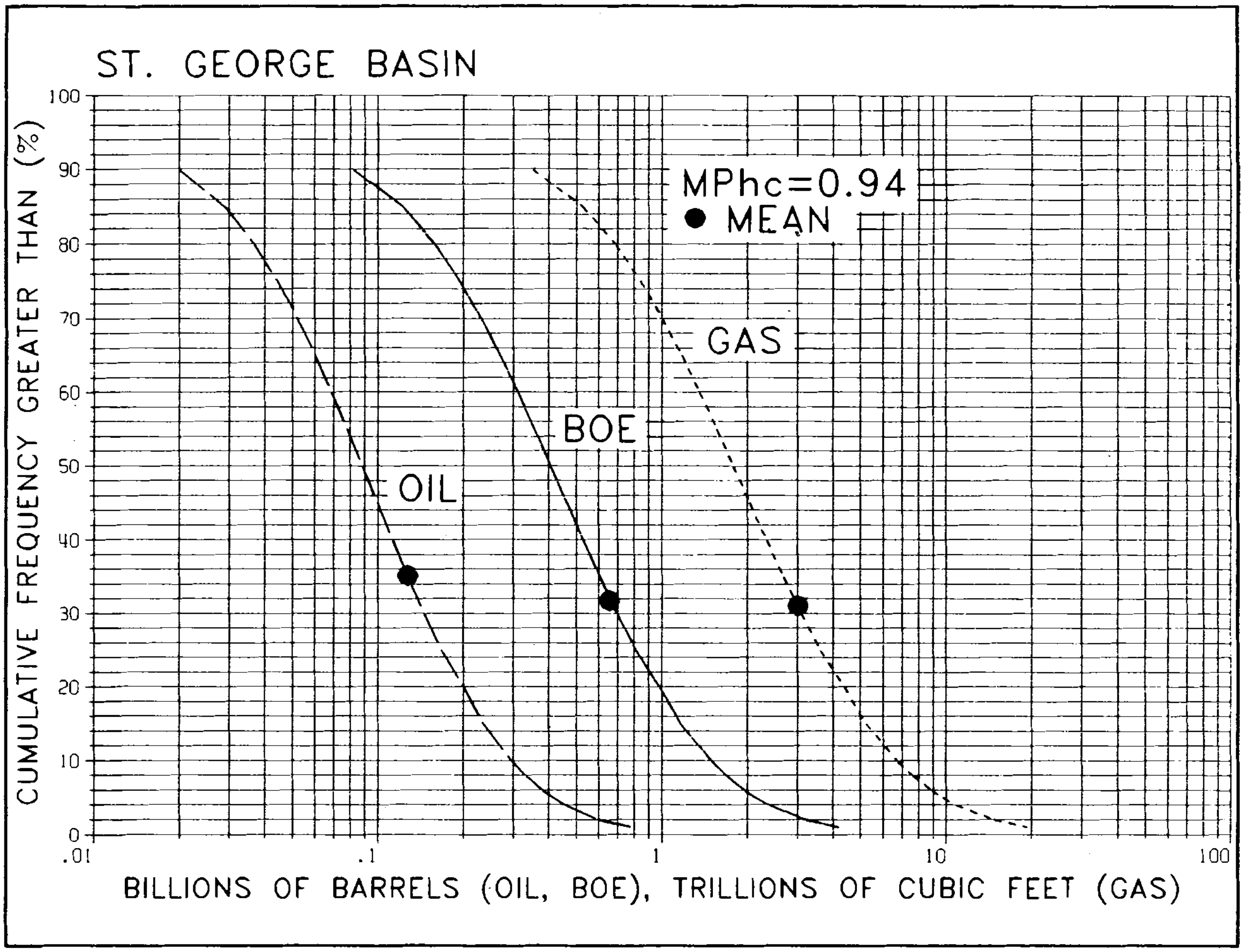

Figure 19.4: Cumulative probability curves for undiscovered, conventionally recoverable resources (oil, gas, and BOE) for St. George basin assessment province. ***BOE**, total oil and gas in energy-equivalent barrels, obtained by converting gas to energy-equivalent barrels (5,620 cubic feet per barrel) and adding to oil; **MPhc**, marginal probability for occurrence of pooled hydrocarbons in province.*

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20. NORTON BASIN ASSESSMENT PROVINCE

by
Susan M. Banet

GEOLOGIC SETTING

Norton basin is an extensional basin of Tertiary age associated with strike-slip movement along the Kaltag fault. The Tertiary clastic fill overlies metamorphosed sediments and igneous rocks of Paleozoic and Mesozoic ages. The basin is divided into two subbasins, the St. Lawrence (or western) subbasin and the Stuart (or eastern) subbasin. The two subbasins are separated by a narrow structural ridge termed the Yukon horst.

At the beginning of Tertiary time, these two subbasins began filling with nonmarine clastics, mainly alluvial fan and delta plain deposits. The two subbasins existed as discrete depocenters from Paleocene to middle Oligocene time, with the western basin dominated by marine depositional environments. Paleobathymetric indicators show that depositional environments ranged from continental to transitional in the eastern (Stuart) subbasin, while environments in the western (St. Lawrence) subbasin ranged from continental to upper bathyal. The Yukon horst evidently controlled shoreline positions or blocked marine invasions into the eastern subbasin during this time. Fault-controlled subsidence ceased by mid-Oligocene time, and subsequent subsidence of a "sag" nature extended across the entire Norton basin. From the late Oligocene to the present, Norton basin has been characterized by a shelf environment much like that of the present-day, with paleobathymetry ranging from transitional to middle neritic.

Two stratigraphic test wells (COST wells) and six exploration wells encountered good quality reservoir rock in both marine and non-marine sediments. A stratigraphic column for Norton basin is shown in figure 20.2. The COST wells encountered possible source rocks in both of the subbasins. The thermally mature strata (mainly Eocene and lower Oligocene) in the eastern subbasin contain type III, humic, gas-prone kerogen and abundant coal (fig. 20.2). In the western subbasin, the thermally mature strata (mainly Eocene) contains humic, type III kerogen with low total organic carbon content. A speculative and improbable third source for hydrocarbons might lie within Paleozoic carbonates and shales within acoustic basement. Basement rocks yielded minor amounts of high-sulfur oil in one of the exploratory wells. However, virtually no data exist for assessment of the petroleum-generation potential of the basement rocks. Based on the low amounts of type III kerogen found in well samples and the lack of any significant hydrocarbon shows in any of the wells, Norton basin is here assessed as offering potential only for gas.

Four plays were assessed in Norton basin assessment province: 1, the Upper Tertiary basin fill; 2, the Mid-Tertiary east subbasin fill; 3, the Mid-Tertiary west subbasin fill; and 4, the Lower Tertiary subbasin fill. A fifth play in rocks of acoustic basement was identified but not assessed owing to the low probability for the occurrence of pooled, conventionally recoverable hydrocarbons. Figure 20.1 shows the locations of these plays. The stratigraphic relationships among plays are shown in figure 20.2. Data used to model Norton basin plays are tabulated in Appendix A2.

PLAY DESCRIPTIONS

Play 1 (UANO0101[1]). Upper Tertiary Basin Fill Play: This play includes all of the upper Oligocene and younger clastic sediments that overlap both subbasins of Norton basin. During this time, transitional to outer neritic environments prevailed, with deeper water occurring to the west. All sediments in this play are thermally immature. Potential gas sources occur in older strata in the underlying Stuart and St. Lawrence subbasins. The potential traps are anticlines, faults, and stratigraphic traps.

Play 2 (UANO0201). Mid-Tertiary East Subbasin Fill Play: This play includes Eocene through early Oligocene clastic sediments deposited in the Stuart subbasin (east part of Norton basin). Delta plain to marginal marine sands are the most likely reservoir rocks. The Eocene and lower Oligocene rocks are thermally mature. The most likely hydrocarbon traps are faulted anticlines and onlap against basement.

Play 3 (UANO0301). Mid-Tertiary West Subbasin Fill Play: This play encompasses the Eocene to middle Oligocene clastic sediments deposited in the St. Lawrence subbasin (west part of Norton basin). The most likely reservoir rocks are shelf sands and turbidites, except along the Yukon horst and the basin margin, where alluvial fan and deltaic deposits may occur. The potential traps are primarily faulted anticlines and stratigraphic onlap against basement. The Eocene rocks are thermally mature but contain low amounts of type III kerogen.

Play 4 (UANO0401). Lower Tertiary Subbasin Fill Play: This play includes all the deep clastic sediments in both St. Lawrence and Stuart subbasins and ranging in age from possibly Paleocene to early Eocene (fig. 20.2). These deep rocks, which range in depth from approximately 12,000 to 23,000 feet, are predominately alluvial fan and delta plain deposits. Great burial depths adversely affect reservoir porosities, permeabilities, and reservoir yield factors. The thermal maturity of these rocks ranges from the middle of the oil-generation window to overmature.

Play 5 (Not Quantified). Basement Play: This play encompasses all of the Paleozoic and Mesozoic metamorphosed sedimentary and igneous rocks that make up acoustic basement beneath the Tertiary basin fill. The potential for reservoir is dependent upon fracture porosity and permeability developing along faults or folds in the basement and/or upon the presence of secondary porosity. Postulated source rocks are Paleozoic carbonates and shales and overlying thermally mature Eocene sediments. Because of the highly speculative and risky nature of this play, it was not assessed. A carbon dioxide gas seep occurs on the northeastern edge of the western subbasin. The CO_2 may be produced by the decarbonization of carbonates in the basement.

RESULTS OF RESOURCE ASSESSMENT

The undiscovered, conventionally recoverable resources for the Norton Basin assessment province average 0.047 billion barrels of oil and 2.708 trillion cubic feet of gas, as reported along with play results in table 20.1. The quantities reported as "oil" in table 20.1 are entirely natural gas liquids that would be recovered only as a by-product of gas production. (The Norton basin

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[1] *The "UA" Code is the "Unique Assessment Identifier" for each play, and is the principal guide to GRASP data files.*

model evaluated all potential accumulations as consisting entirely of gas.)

Cumulative probability distributions for oil, gas, and BOE resources for Norton basin are given in figure 20.3. BOE resources are also listed in table 16.1.

Over half of the hydrocarbon resource occurs in play 3 (Mid-Tertiary west subbasin fill). Play 3 covers a large area and is associated with most of the potential hydrocarbon source area in the basin. Only one prospect in play 3 was tested by the exploration wells; many prospects remain untested. Cumulative probability distributions and ranked pool-size plots for oil and gas resources of all Norton basin plays are given in Appendix B2.

TABLE 20.1
OIL AND GAS ENDOWMENTS OF NORTON BASIN PLAYS
Risked, Undiscovered, Conventionally Recoverable Oil and Gas

PLAY NO.	PLAY NAME (UAI* CODE)	OIL (BBO)**			GAS (TCFG)		
		F95	MEAN	F05	F95	MEAN	F05
1.	Upper Tertiary Basin Fill (UANO0101)	0.000	0.014	0.056	0.000	0.745	2.848
2.	Mid-Tertiary East Subbasin Fill (UANO0201)	0.000	0.005	0.026	0.000	0.306	1.533
3.	Mid-Tertiary West Subbasin Fill (UANO0301)	0.000	0.028	0.105	0.000	1.617	5.680
4.	Lower Tertiary Subbasin Fill (UANO0401)	0.000	0.0007	0.004	0.000	0.040	0.231
	FASPAG AGGREGATION	***0.000***	***0.047***	***0.150***	***0.000***	***2.708***	***8.742***

* *Unique Assessment Identifier, code unique to play.*
** *entirely natural gas liquids derived from gas extraction; no pooled oil present*

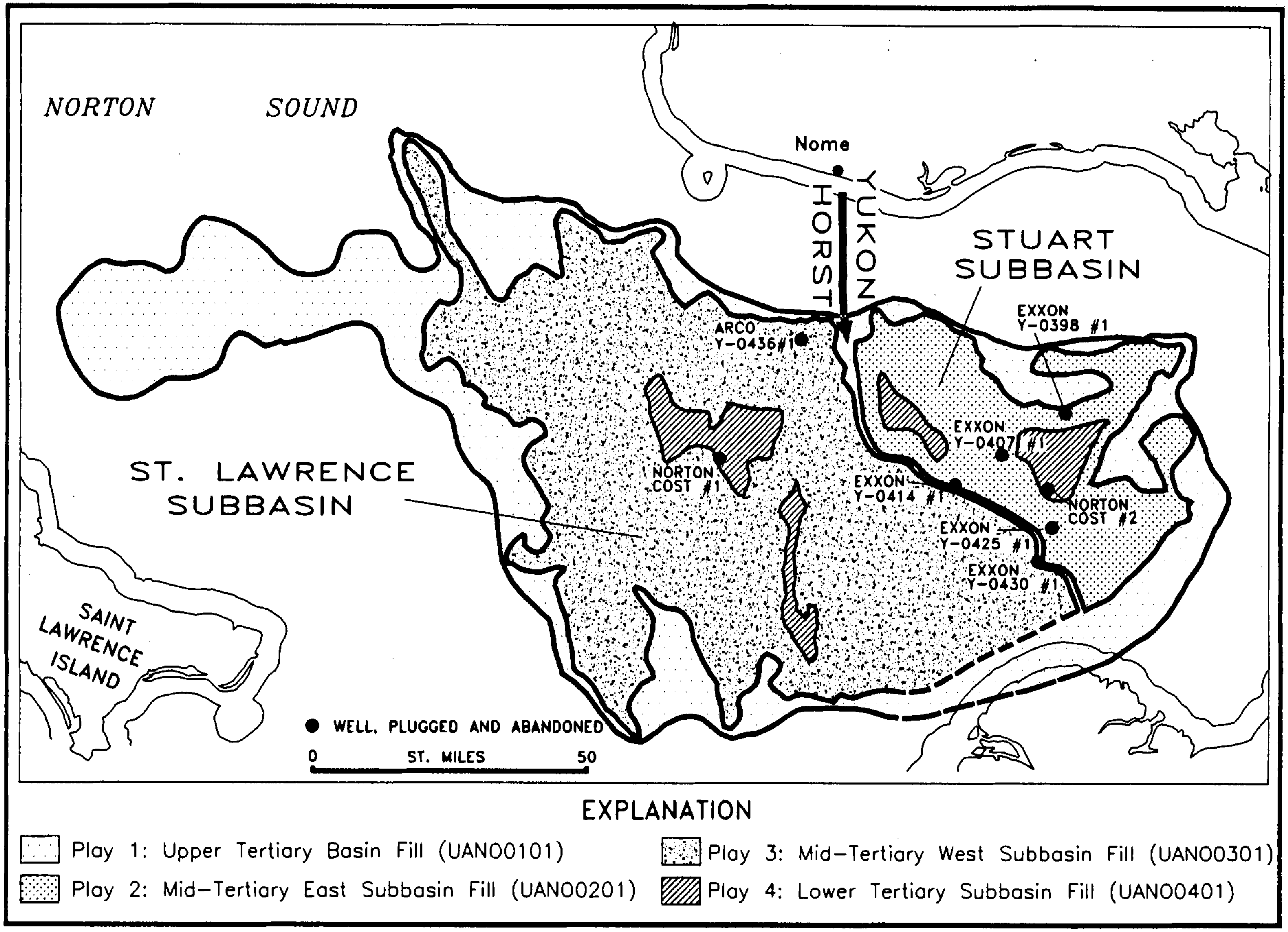

Figure 20.1: Map showing areas of four plays assessed in Norton basin assessment province.

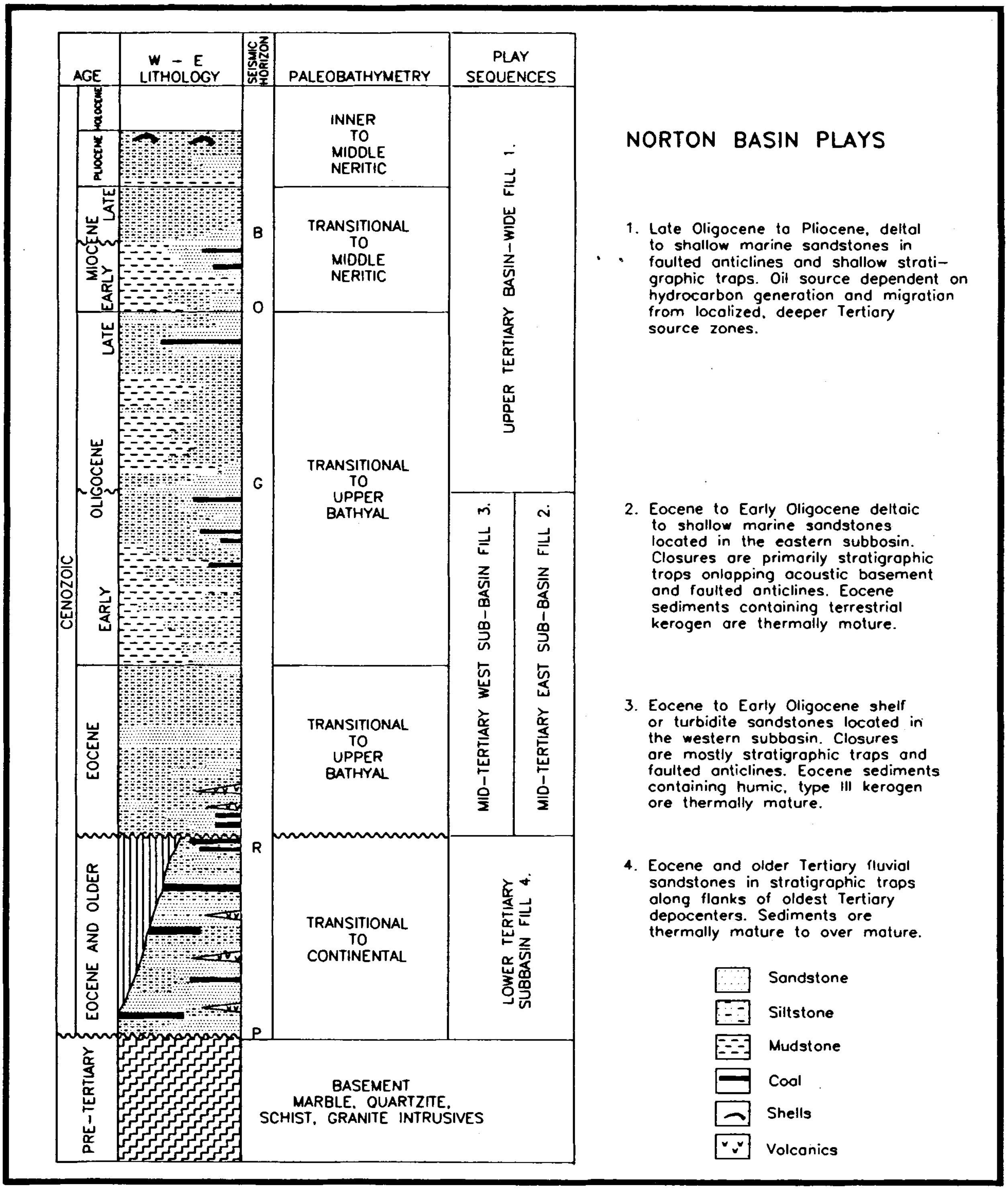

Figure 20.2: Generalized stratigraphic column for Norton basin assessment province.

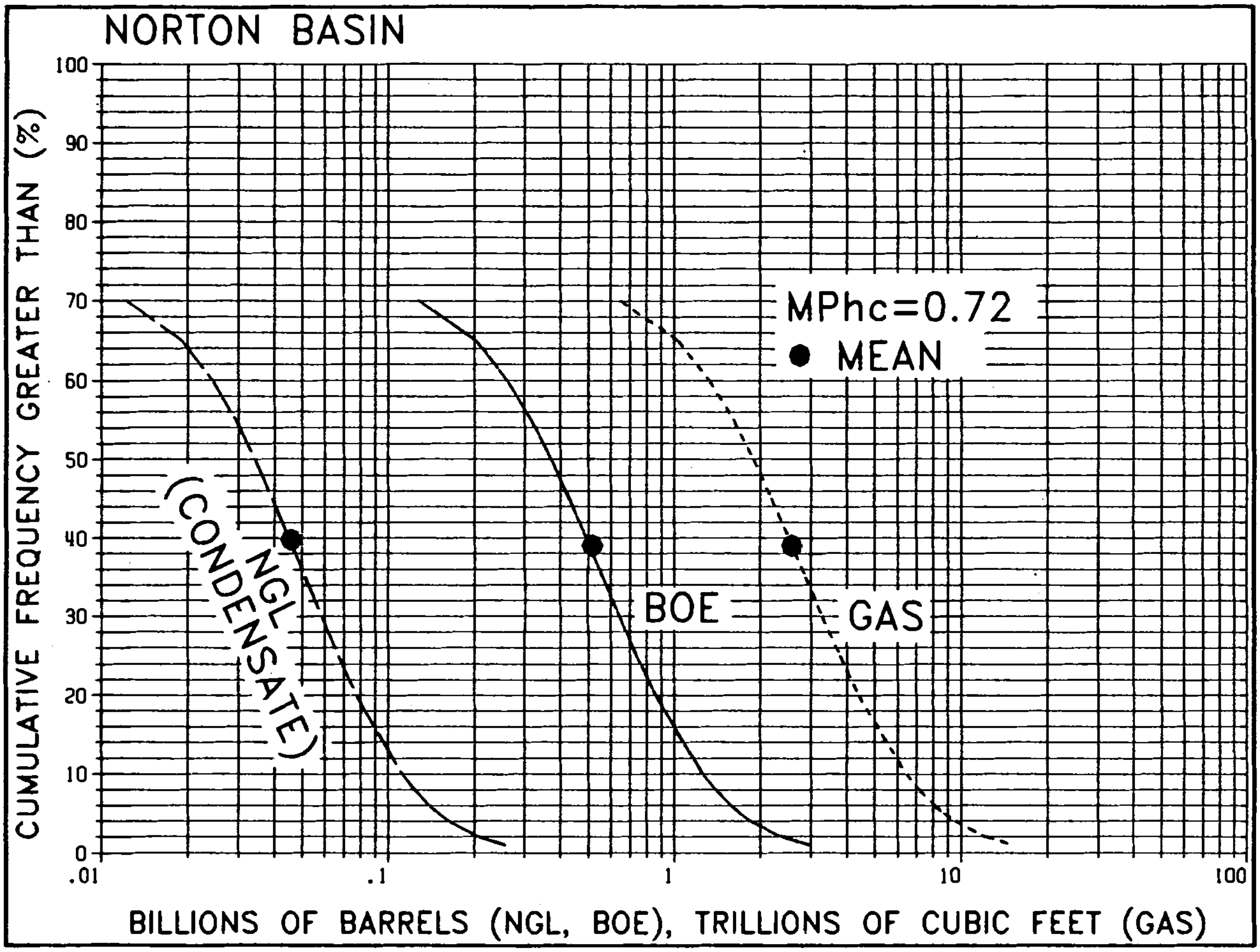

Figure 20.3: Cumulative probability curves for undiscovered, conventionally recoverable resources (oil, gas, and BOE) for Norton basin assessment province. *BOE, total oil and gas in energy-equivalent barrels, obtained by converting gas to energy-equivalent barrels (5,620 cubic feet per barrel) and adding to oil; MPhc, marginal probability for occurrence of pooled hydrocarbons in province. NGL, natural gas liquids, obtained only as a by-product of gas production (Norton basin was assessed as offering potential only for gas). NGL corresponds to "oil" quantities as reported in table 16.1, table 20.1, Appendix A2, and Appendix B2.*

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21. ST. MATTHEW-HALL BASIN ASSESSMENT PROVINCE

by

Sally B. Hurlbert, Kirk W. Sherwood, and Susan A. Zerwick

INTRODUCTION

The St. Matthew-Hall assessment province lies in the Bering Sea offshore west of Alaska and south of St. Lawrence Island, extending from 59° to 63° north latitude and from 162° to 174° west longitude. It includes St. Matthew, Hall and Nunivak Islands. The province encompasses all of the St. Matthew-Hall Outer Continental Shelf Planning Area and extends into a small part of the southwest part of Norton Basin Planning Area (fig. 21.1).

The only industry-sponsored exploration in the St. Matthew-Hall assessment province consists of seismic reflection data acquired on a grid ranging from 3 X 6 mi to 10 X 20 mi in spacing. No wells have tested the basin, nor have geologic or geochemical sampling programs been conducted.

St. Matthew-Hall "basin" refers to a little-known group of basins first illustrated and named in a 1976 paper by Marlow and others (1976, fig. 7) of the U.S. Geological Survey. In that paper it was shown as a series of northeast-trending basins with sediment thicknesses less than 3,000 feet.

Mapping by the U.S. Minerals Management Service using industry data has refined the outline of the basin earlier identified by Marlow and colleagues and has discovered a previously unrecognized northwest-trending arm of the basin south of St. Lawrence Island in which stratified rocks reach at least 13,000 feet in thickness (figs. 21.2, 21.3). This arm, as well as the separate basin mapped earlier by Marlow and others (1976), are here grouped as subbasins of the greater St. Matthew-Hall basin.

REGIONAL GEOLOGY

St. Matthew-Hall basin is separated from Norton basin by a shallow basement arch passing east from St. Lawrence Island to the Yukon delta area of western Alaska. On the south, it is isolated from St. George basin by the Nunivak arch, which passes east from St. Matthew Island to Nunivak Island (figs. 21.1, 21.2).

St. Matthew-Hall basin comprises two sub-basins separated by a shallow basement ridge (figs. 21.2, 21.3). The northern sub-basin is a highly faulted graben that trends southeast roughly parallel to the south coast of St. Lawrence Island, but abruptly bends northeasterly east of 170° west longitude. The northern subbasin is filled with up to 13,000 feet (3.0 s two-way travel time) of stratified rocks. The southern sub-basin trends east-northeast and is relatively sparsely faulted. Most of the subbasin contains 3,000 feet or less of fill, although there is up to 9,000 feet (2.2 s) of stratified rocks in small, narrow grabens.

Both sub-basins of St. Matthew-Hall basin probably originated as pull-aparts that form a right step in the right-lateral strike-slip Kaltag fault system as it passes west from Alaska into Russian parts(?) of Bering Sea (fig. 21.1). The much more pervasively faulted and larger graben system in the northern sub-basin of St. Matthew-Hall basin may be the principal site of right-lateral transtension across the right step inferred for the Kaltag system. The northern sub-basin is bounded by northwest-trending faults. En echelon normal faults within the graben in this area trend northerly, consistent with a right-lateral pull-apart mechanism.

The platform north and south of the northern subbasin features broad northeast-trending folds, mostly in the area where the sub-basin bends to the northwest. These folds deform both the basement and the overlying Tertiary strata. On the north, a north-trending reverse or thrust fault separates the folded terrane on the west from undisturbed rocks on the east. No comparable reverse fault has been identified south of the graben.

The folds on the north are postulated to accomodate a local left step in a northern strand of the fault system that caused local compression between opposing blocks (fig. 21.2). This northern strand, as yet unidentified, is speculated to lie just south of St. Lawrence Island. The northern strand is required to link the northern tip of the reverse fault at the leading (east) edge of the fold terrane to the main strike-slip system somewhere to the east. The fold terrane on the south may be the product of a shear couple across a lenticular block between two active fault strands (figs. 21.2). The folding in both areas occurred in waning phases of active strike-slip deformation, possibly as the fault system locked.

Strike-slip deformation was most active in early Tertiary time when the majority of structures (faults, folds and sub-basins) were developed. Strike-slip activity apparently finally ceased with the folding of the lower part of the Sag sequence in mid-Tertiary (late Oligocene?) time. The timing of cessation of strike-slip deformation suggested by offshore data is consistent with the observation that western reaches of the Kaltag fault onshore are overlapped by upper Cenozoic volcanic rocks (Grantz, 1966, p. 32).

PLAY STRATIGRAPHY

No wells have been drilled in the St. Matthew-Hall basin assessment province. Therefore, our conjectural stratigraphic model is entirely speculative, based upon seismic signature and analogy to sequences of similar seismic character and tectonic setting penetrated by wells in Norton basin.

A lower Tertiary (Paleocene?) unconformity floors St. Matthew-Hall basin, and overlies Mesozoic-age basement rocks, mostly part of the Okhotsk-Chukotsk volcanic belt. However, Paleozoic rocks related to the continental terranes of Seward Peninsula and Chukotka (Russia) are exposed on St. Lawrence Island, and these may underlie parts of St. Matthew-Hall basin as well.

Two seismic sequences are recognized. The lowermost, termed the Rift sequence, is much affected by coeval faults within and bounding the pull-apart grabens in each subbasin. The Rift sequence reaches maximum thicknesses of approximately 10,000 feet in the northern subbasin and 5,000 feet in the southern subbasin. We speculate that the Rift sequence consists mostly of non-marine sediments shed into fault-bounded basins from intrabasinal and extrabasinal uplifts raised during early phases of transtensional faulting. The Rift sequence is capped by a sparsely faulted sequence deposited during regional, thermally-driven "sagging" after fault-driven extension had mostly ceased. We assign these rocks to a "Sag" sequence that reaches a maximum thickness of 5,000 feet. The stratigraphic and structural relationships of these two sequences are illustrated in figure 21.3.

Our basic stratigraphic model and age assignments for the Rift and Sag sequences are based on the identification of analog sequences in Norton basin. The strength of the analog is drawn from the fact that both basins appear to be tectonically related, in that subsidence of both during the "rift" phase was driven by strike slip movements along Kaltag fault, as first speculated by Marlow and others (1976, p. 180). The two basins are similar in overall orientation and appear to terminate eastward at or near the main trace of the Kaltag fault (fig. 21.2). In Norton basin, the Rift sequence penetrated by the Norton Basin COST No. 2 well ranges from Paleocene(?) or Eocene to early Oligocene in age. The Sag Sequence ranges in age from late Oligocene to Pleistocene (Turner and others, 1986, fig. 11). The two sequences in Norton basin are separated by a regional unconformity corresponding to the rift-to-sag transition, here termed the ***mid-Oligocene unconformity***. An analogous regional unconformity of perhaps the same age is recognized in seismic records in St. Matthew-Hall basin (fig. 21.3).

RESERVOIR ROCKS

The largely volcanogenic rocks of the Okhotsk-Chukotsk volcanic belt basement complex were the probable sources for detritus shed from uplifts into eastern Norton basin (Turner and others, 1986, fig. 22, COST No. 2), and probably most of St. Matthew-Hall basin. This material is chemically unstable and mechanically soft, especially once altered *in situ* to clays, and upon compaction is extruded or chemically redistributed into pores. Sandstones rich in such clasts typically exhibit accelerated rates of porosity loss with burial depth. The presence of such material readily accounts for the extremely high rate of porosity loss, 5 porosity units per 1,000 feet, documented in Norton Basin COST No. 2 well (Turner and others, 1986, fig. 24).

Two potential reservoirs are postulated to occur within the Rift sequence in St. Matthew-Hall basin. The first includes sandstones in Paleocene to Eocene fluvial sandstones in fan-deltas at the base of the sequence or along the margins of grabens (fig. 21.3). These represent deposits formed during the initial rapid infilling of structural depressions at the onset of rifting. Unfortunately, most of these postulated reservoir sandstones now lie at depths below 10,000 feet in St. Matthew-Hall basin. In Norton basin, Rift sequence sandstones have very low porosities and permeabilities below 10,000 feet owing to porosity reduction processes as described above. The second potential reservoir is associated with sandstones postulated to occur within the Oligocene basin fill. In the Norton basin Rift sequence, potential reservoirs occur as lower Oligocene fluvio-deltaic sandstones found below the rift-to-sag transition marked by the mid-Oligocene unconformity. In Norton Basin Cost No. 2 well, these sandstones attain an aggregate thickness of 230 feet and have an average porosity of 16 percent (ranging from 12 to 21 percent). Analogous sandstones are speculatively drawn into the upper part of the St. Matthew-Hall basin Rift sequence just below the "mid-Oligocene" unconformity in figure 21.3.

Two potential reservoir sandstone sequences are postulated to occur in the Sag sequence in St. Matthew-Hall basin, again based on analogy to Norton basin. First, in Norton basin, late Oligocene sandstones that overlie the mid-Oligocene unconformity represent facies ranging from the shelf to submarine fan, to basin plain (in basin centers). In the Norton Basin Cost No. 2 well, these sandstones attain an aggregate thickness of 400 feet and have an average porosity of 18 percent (ranging from 10 to 25 percent). Correlative rocks are postulated to occur above the "mid-Oligocene" unconformity in St. Matthew-Hall basin (fig. 21.3). Secondly, in Norton basin, additional porous sandstones are found high within the Sag sequence at the top of the Oligocene sequence. We speculate that correlative sandstones are also present near the middle of the Sag sequence of St. Matthew-Hall basin (fig. 21.3). In the Norton COST No. 2 well, these sandstones attain an aggregate thickness of 285 feet and have an average porosity of 26 percent (ranging from 13 to 36 percent).

PETROLEUM SYSTEM

Our model for potential source rock sequences in St. Matthew-Hall basin is extrapolated from data obtained from well penetrations in Norton basin. The Norton Basin COST wells encountered shales dominated by type III, humic, gas-prone kerogens and thin coal seams, some with high resinite contents (Turner and others, 1986, p.121). The top of the oil window in Norton basin lies at approximately 10,000 feet in well penetrations (using the conventional top at 0.6% vitrinite reflectance). Thermally mature parts of the stratified column in Norton basin include mostly marine to non-marine shales of Eocene and Paleocene(?) ages.

In St. Matthew-Hall basin, the volume of sediments lying below 10,000 feet is extremely small because they are confined to the deepest parts of narrow rift-phase grabens. Depths greater than 10,000 feet are achieved only in the northern subbasin, although depths up to 9,000 feet are reached in very small parts of the southern subbasin. Only the oldest parts of the Rift sequence in St. Matthew-Hall basin, probably dominated by fluvial rocks and terrestrially-derived, gas-prone organic matter, lie within the oil window postulated below 10,000 feet. None of these rocks are projected to enter the gas window, so the quantity of fractional conversion (kerogens to gas hydrocarbons) is undoubtedly modest (Tissot and Welte, 1984, p. 215). The small volume of thermally-mature potential source rock must be a limiting factor for prospect charging, even for Rift sequence traps deep within grabens. This limitation is reflected in the very conservative fill fraction distributions postulated for plays in the data tables in Appendix A2. It is unlikely that thermogenic hydrocarbons from deep graben generative centers were created in quantities sufficient to reach and charge Sag sequence prospects at any significant distances from the grabens.

TIMING OF HYDROCARBON GENERATION AND TRAP FORMATION

Potential traps in St. Matthew-Hall basin are simple anticlines, faulted anticlines, fault traps, sub-unconformity traps and stratigraphic pinchouts. Most of the traps were likely formed in the Early Tertiary (Paleocene to early Oligocene) rift phase of the basin history when strike-slip deformation was most pronounced. Faulting and folding continued into Late Tertiary (late Oligocene to Miocene) time, producing some low-amplitude, but areally large, anticlines in the Sag sequence. Primary routes for secondary migrations of any thermogenic hydrocarbons would include graben-bounding fault systems, porous carrier beds, and regional unconformities. Vertical migration would dominate in the faulted areas near the pull-apart grabens, but lateral migration along stratigraphic carriers would be the primary style in the sparsely faulted Sag sequence away from grabens. Hydrocarbons were probably not generated until at least Miocene(?) or more recent time when the rocks in the floors of grabens entered the oil window. Trap formation, mostly completed in early Miocene(?) or earlier time, probably preceded any thermogenic hydrocarbon generation in St. Matthew-Hall basin.

ASSESSED PLAYS

In St. Matthew-Hall basin we distinguish two petroleum plays on the basis of tectonic setting, reservoir stratigraphy, dominant trap type, and access to thermogenic gas. Data used to model these plays are tabulated in Appendix A2.

Play 1 (UASM0100[1]), Rift Sequence Play: The Rift sequence play (play 1) is inferred, on the basis of analogy to Norton basin, to consist of

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[1]*The "UA" Code is the "Unique Assessment Identifier" for each play, and is the principal guide to GRASP data files.*

Paleocene to lower Oligocene fluvio-deltaic sandstones deposited in fan-deltas along the margins of fault-bounded pull-apart grabens during active wrench faulting in early phases of basin subsidence. Prospects are mostly fault traps, but also include anticlines, faulted anticlines, and sub-unconformity traps. Unmapped stratigraphic traps are anticipated in deep, graben-floor fan systems, but porosity at those depths (>10,000 feet) is expected to be quite low, consistent with the low porosities of sandstones below 10,000 feet in Norton basin. However, the deeper traps lie within the oil window and are best positioned to capture thermogenic gas. Potential traps in play 1 range in depth from 4,000 to 13,000 feet. Postulated source rocks are interbedded within the play sequence and are speculated, on the basis of analogy to Norton Basin, to include marine to non-marine shales and coal seams of Eocene and Paleocene age. Early Oligocene coals and shales are speculated to occur in the upper part of the sequence. These latter rocks are probably thermally immature, but may provide feedstock for microbial generation of biogenic gas.

Play 2 (UASM0200). Sag Sequence Play: The Sag sequence play (play 2) consists of inferred late Oligocene shallow shelf sandstones to submarine fan turbidite and basin plain deposits above a prominent (seismic data) unconformity, speculated from analogy to Norton basin to be mid-Oligocene in age. Possible trap types are mostly low-amplitude anticlines, many of drape origin, but also include faulted anticlines and fault traps. Additional unmapped traps may occur in stratigraphically isolated shelf sandstones in the upper part of the sequence. Sag sequence traps range in depth from 1,400 to 5,000 feet. Thermogenic gas from thermally mature rocks deep within grabens may charge traps near the grabens. Potential traps at shallow depths or at great distances (some up to 100 miles) from the deep pull-apart grabens are likely to contain only biogenic gas.

PLAY DEPENDENCY MODEL

The two plays in St. Matthew-Hall basin assessment province were aggregated with dependencies using ***FASPAG***, an aggregation software provided for that purpose by the project leadership.

Play dependencies were developed with the view that they formed a measure of the frequency of geological coincidence of accumulations. Geological coincidence is taken to mean that accumulations are within sufficient proximity to imply linked geological origin, mostly sharing a petroleum migration and delivery system. A dependency between two plays therefore implies that there exists a certain frequency with which accumulations in one play are paired with accumulations in other plays.

The group dependency value used in aggregation represents the degree of mutual dependence, or the frequency of geological coincidence, among petroleum pools in plays forming the dependency groups. A value of 1.0 indicates complete dependency. In a group consisting of two plays, a dependency value of 1.0 would imply that every petroleum pool in one play would be accompanied, within geologic proximity, by a second petroleum pool in the other play in the group. A dependency of 0.0 indicates complete independence, or no correlation, among petroleum pools in different plays within the play group. Independence typically implies geographic isolation or absence of hydraulic communication (migrating hydrocarbons) between plays (for example, stacked plays separated by an unbreached regional seal).

In constructing play dependencies, we considered the fractional overlap of areas of stacked (overlying stratigraphic sequences) plays, the frequency of coincidence of multiple play sequences in shared structures (e.g., separate zones in an anticline), and the potential for migrating hydrocarbons to pass from one play sequence into another. For example, in a highly faulted area, continuous faults passing through

TABLE 21.1
OIL AND GAS ENDOWMENTS OF ST. MATTHEW-HALL BASIN PLAYS
Risked, Undiscovered, Conventionally Recoverable Oil and Gas

PLAY NO.	PLAY NAME (UAI* CODE)	OIL (BBO)**			GAS (TCFG)		
		F95	MEAN	F05	F95	MEAN	F05
1.	Rift Sequence (UASM0100)	0.000	0.00008	0.0004	0.000	0.008	0.041
2.	Sag Sequence (UASM0200)	0.000	0.001	0.006	0.000	0.147	0.606
	FASPAG AGGREGATION	*0.000*	*0.002*	*0.007*	*0.000*	*0.155*	*0.689*

* *Unique Assessment Identifier, code unique to play.*

multiple play sequences might have formed common conductors for hydrocarbons migrating into fault-contact traps in all play sequences. This is probably the case in the areas of the highly faulted pull-apart grabens in St. Matthew-Hall basin. Outside the pull-apart grabens, the Rift sequence is generally absent and the Sag sequence rests directly upon basement (fig. 21.3). Here, the Sag sequence is completely independent of the Rift sequence. Because the Rift sequence play (1) underlies about 20 percent of the larger play area for the Sag sequence (play 2), we used a group dependency value of 0.2 in the ***FASPAG*** aggregation of the two plays.

RESOURCE ENDOWMENT

Both plays in St. Matthew-Hall basin were modeled as purely gas plays, although some liquid resource is inevitable as condensate from gas, at least for prospects charged by thermogenic sources. The mean endowments for the basin as a whole are 155 billion cubic feet of gas and 1.55 million (or 0.00155 billion) barrels of natural gas liquids, reported as "oil" in table 21.1. The Sag sequence play (play 2) contains the greater share of resources (147 BCFG, 1.47 MMBO) because it offers comparatively larger prospects, more abundant prospects, and reservoirs that are generally more shallow and therefore more porous. The Rift sequence play (play 1) has a very modest resource endowment of 8 BCFG and 0.08 MMBO. Undiscovered oil and gas resources are reported in table 21.1 and are shown as cumulative probability distributions (for the province) in figure 21.4. Cumulative probability distributions and ranked pool-size plots are presented in Appendix B2.

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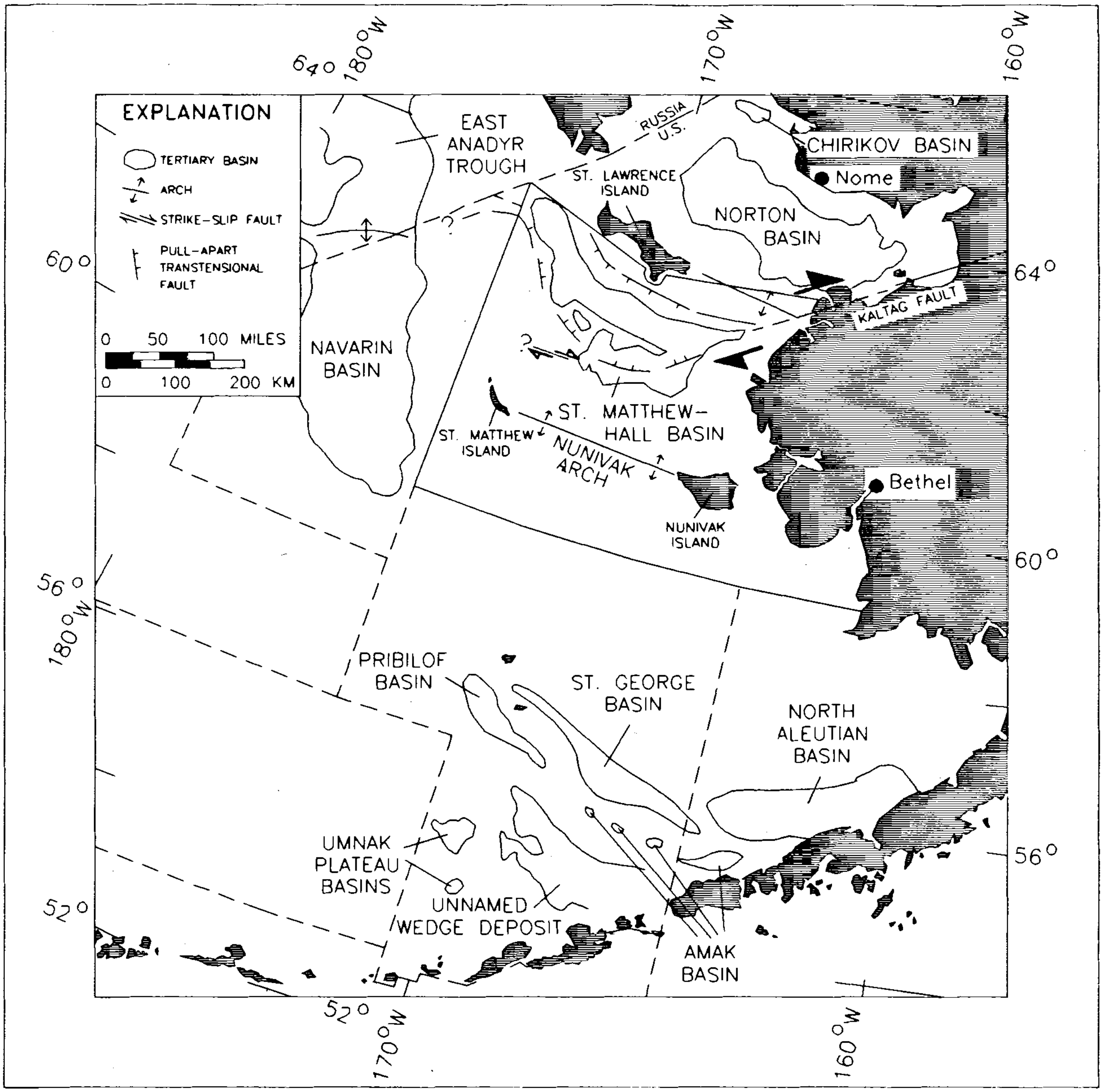

Figure 21.1: Regional tectonic setting for St. Matthew-Hall basin assessment province, speculating that showing St. Matthew-Hall basin formed as a pull-apart basin at a right step in the Kaltag (right-lateral, strike-slip) fault system.

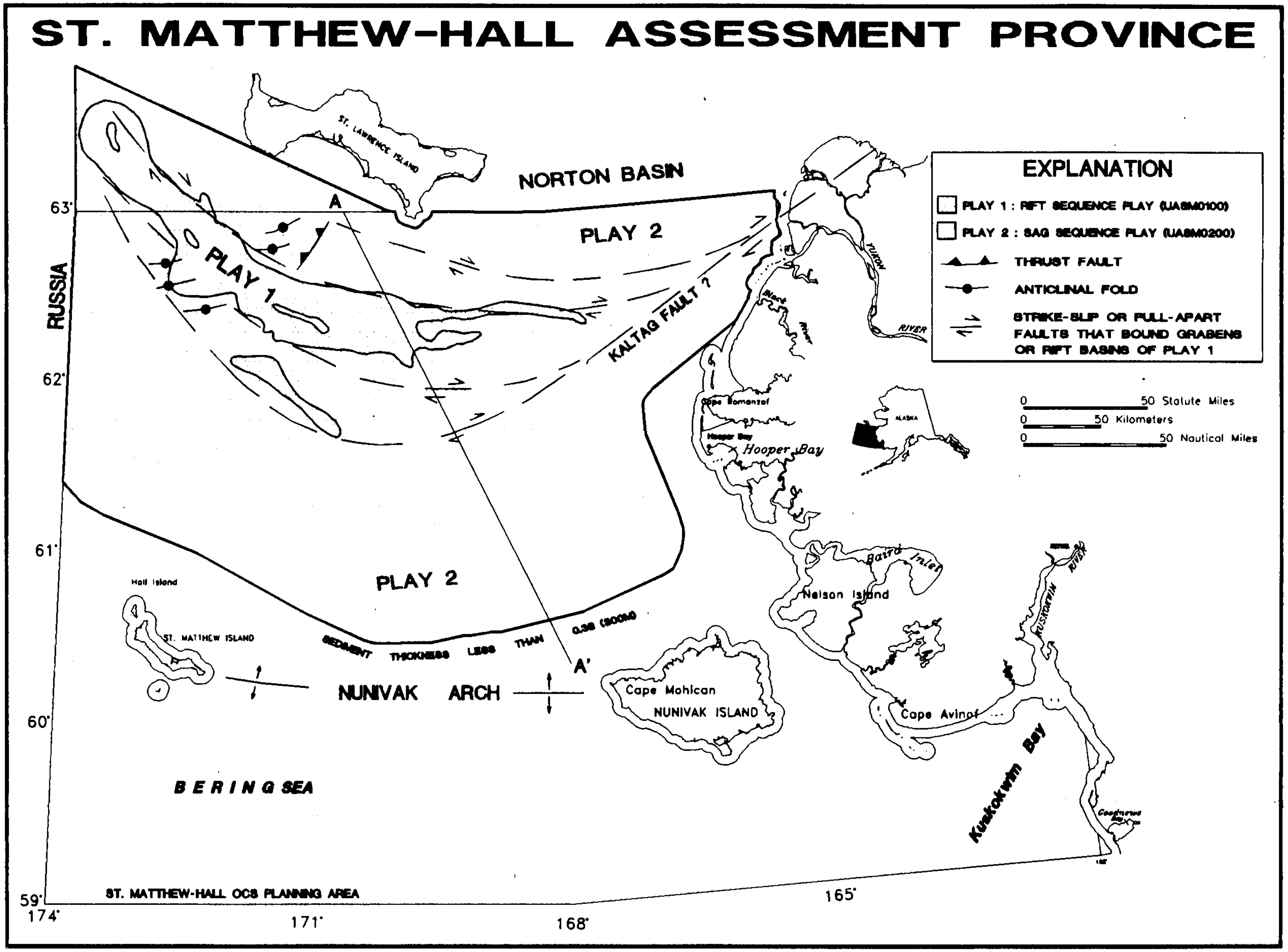

Figure 21.2: Areas of Rift sequence (1) and Sag sequence (2) plays and major structural elements, St. Matthew-Hall basin assessment province. Cross section A-A' shown in figure 21.3. Dashed faults are schematically drawn.

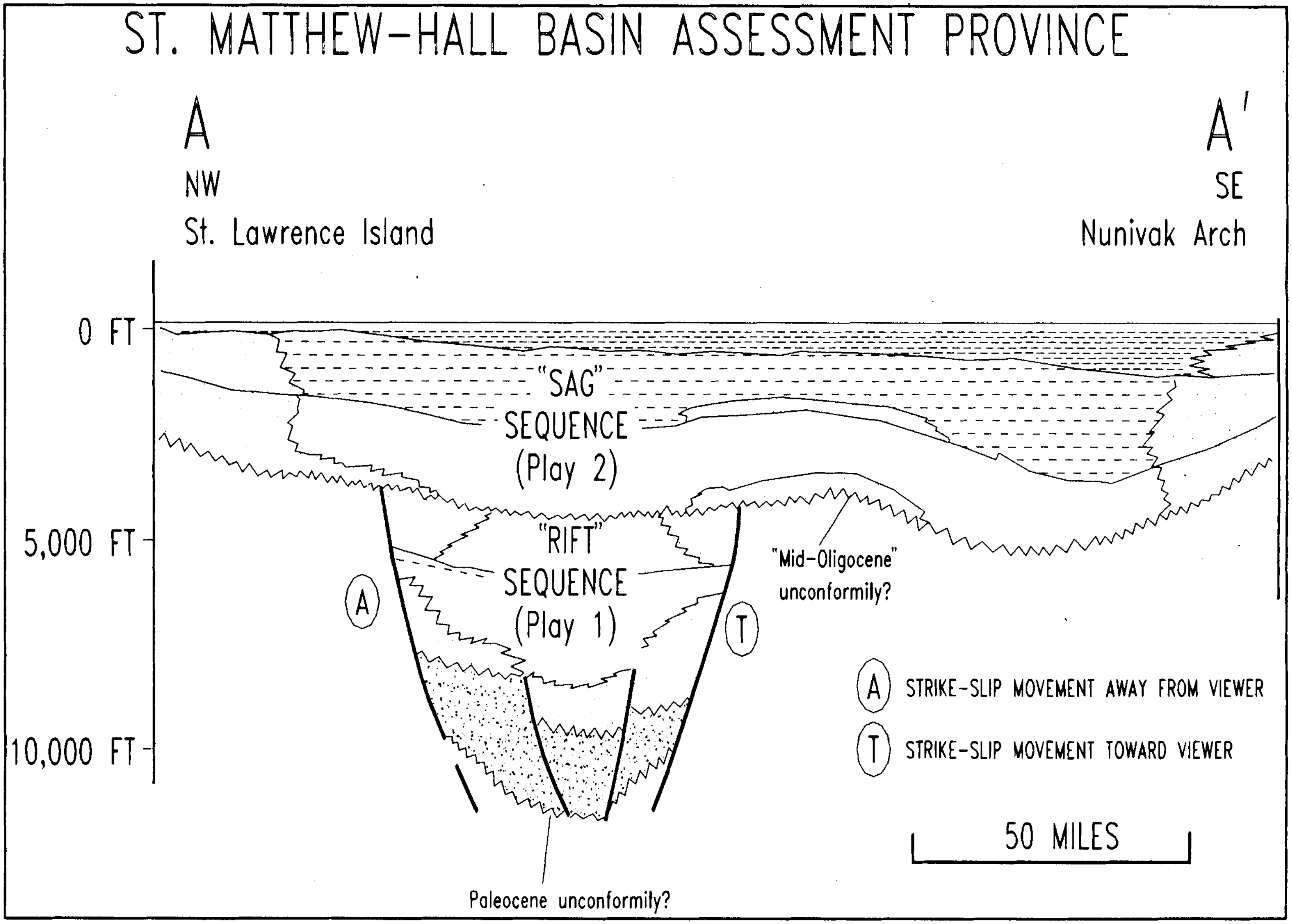

Figure 21.3: Schematic cross section A-A' showing stratigraphy of play sequences in St. Matthew-Hall basin assessment province. See figure 21.1 for location of section.

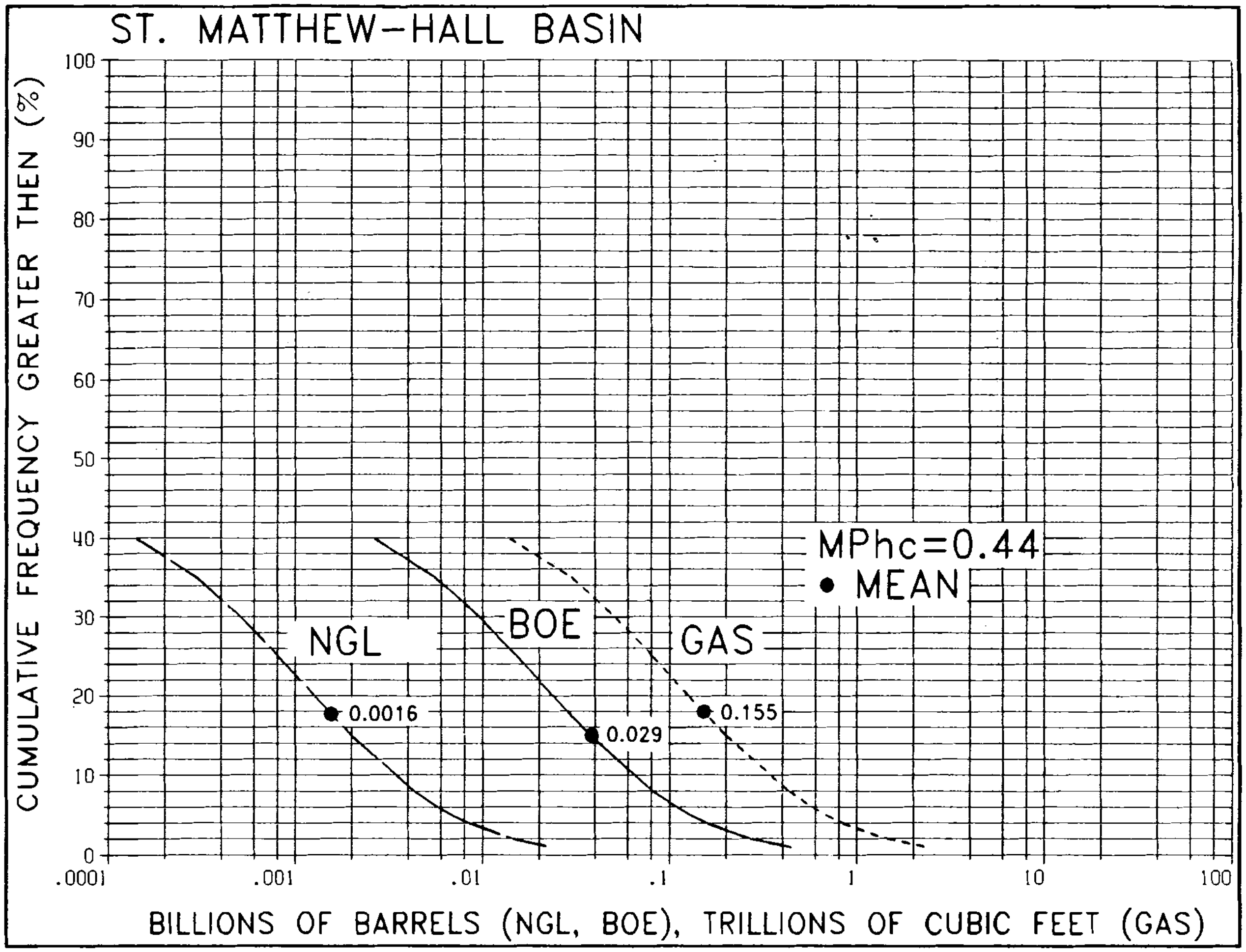

Figure 21.4: Cumulative probability curves for undiscovered, conventionally recoverable resources (oil, gas, and BOE) for St. Matthew-Hall basin assessment province. ***BOE**, total oil and gas in energy-equivalent barrels, obtained by converting gas to energy-equivalent barrels (5,620 cubic feet per barrel) and adding to oil; **MPhc**, marginal probability for occurrence of pooled hydrocarbons in province; **NGL**, natural gas liquids, obtained only as a by-product of gas production—St. Matthew-Hall basin was assessed as offering potential only for gas. NGL corresponds to "oil" quantities as reported in tables 16.1, 21.1, Appendix A2, and Appendix B2.*

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PACIFIC MARGIN ASSESSMENT PROVINCES

22. INTRODUCTION

by

C. Drew Comer

GEOLOGIC PROVINCES OF THE PACIFIC MARGIN OF ALASKA

The Outer Continental Shelf (OCS) of the Pacific margin of Alaska includes the following three geologic provinces for resource assessment purposes: (1) the Gulf of Alaska, (2) the Shumagin-Kodiak shelf, and (3) Cook Inlet (fig. 22.1; pl. 1.1). The Gulf of Alaska province extends from the Canadian border at Dixon Entrance for approximately 850 miles along the continental margin of southern Alaska. The northwestern boundary of the Gulf of Alaska province adjoins the Shumagin-Kodiak province at the Amatuli trough southeast of the Kenai Peninsula. From there the Shumagin-Kodiak province extends southwestward for approximately 750 miles along the continental shelf seaward of the Kodiak Archipelago and the Shumagin Islands. The Cook Inlet province is bounded on the east by the Kenai Peninsula and the Kodiak Islands, and on the west by the mainland and the Alaska Peninsula. This province includes both lower Cook Inlet and Shelikof Strait; upper Cook Inlet (shown in pl. 1.1) lies within State of Alaska waters and is not included in this assessment.

The geologic basins of the Pacific (continental) margin of Alaska are the result of tectonic interaction between the interior of Alaska (as part of the North American continental plate) and several converging oceanic plates. The Farallon, the Kula, and the Pacific oceanic plates have collided with southern Alaska during the last 100 million years (Engebretson and others, 1985). The present-day plate motion of the Pacific plate relative to the North American plate is 6 to 7 centimeters per year (Minster and Jordan, 1978). The Pacific plate is directly underthrusting the North American plate at the Aleutian trench beneath the Shumagin-Kodiak shelf and slope. That area is underlain by a broad accretionary complex that was formed by offscraping of sediment in the trench or underplating of material beneath the accretionary prism. Cook Inlet and Shelikof Strait compose a forearc basin formed between the accretionary complex and the Aleutian volcanic arc on the Alaska Peninsula.

The plate motion in southeast Alaska is accommodated by strike-slip movement along the Fairweather-Queen Charlotte fault zone. A transitional area occurs in the central Gulf of Alaska between the southeast Alaska transform margin and the Aleutian subduction zone. In this area, the Yakutat terrane is moving with the Pacific plate and obliquely underthrusting southern Alaska (Bruns, 1983). Subduction of the Yakutat terrane is responsible for the Wrangell volcanic belt north of the Gulf of Alaska.

TECTONOSTRATIGRAPHIC TERRANES

The Pacific margin of Alaska has formed a backstop to oceanic plate convergence since at least Mesozoic time. Numerous tectonostratigraphic terranes, also called lithotectonic terranes, travelled great distances with the oceanic plates and were accreted to southern Alaska (Coney and others, 1980; Jones and others, 1987; Nokleberg and others, 1994). These exotic terranes include island arcs, continental fragments translated northward along strike-slip faults, oceanic plateaus and seamounts rafted on oceanic plates, and accretionary prisms formed near the proto-Aleutian trench. The terranes of the Pacific margin of Alaska can be grouped as follows: (1) an amalgamated superterrane of Paleozoic to Mesozoic oceanic and island-arc rocks, (2) a late Mesozoic to Cenozoic accretionary complex, and (3) the most recent arrival, the Yakutat terrane. The terranes composing these groups are located in figure 16.1.

Amalgamated Superterrane: This composite terrane includes the Peninsular, the Wrangellia, and the Alexander terranes. The Cook Inlet province is underlain by the Peninsular terrane, which was a Mesozoic island-arc complex. The Peninsular terrane adjoins the Wrangellia terrane to the northeast. Those two terranes, along with the Alexander terrane of southeast Alaska, make up an amalgamated superterrane, which Nokleberg and others (1994) referred to as the Wrangellia superterrane. The individual terranes, which originated to the south, became amalgamated in transit and moved northward as a coherent unit until docking with the continental backstop. According to Plafker and others (1989), the terranes were assembled into their approximate present configuration in the Wrangellia superterrane by Late Triassic time. Accretion of the superterrane to southern Alaska was completed by middle to Late Cretaceous time. The seaward boundary of the amalgamated superterrane is the Border Ranges fault system, which separates the superterrane from the terranes of the accretionary complex.

Accretionary Complex: The accretionary complex lies outboard of the amalgamated superterrane and includes the Chugach and the Prince William terranes. The Chugach terrane consists of Lower Jurassic or older blueschist- to greenschist-facies metamorphic rocks sparsely exposed along the Border Ranges fault system, Upper Jurassic to Lower Cretaceous mélange, and Upper Cretaceous flysch, in three parallel belts successively exposed from northwest to southeast (seaward). The Prince William terrane lies outboard of the Chugach terrane and is separated from it by the Contact fault. The Prince William terrane includes a Paleocene to middle Eocene submarine-fan complex interbedded with oceanic volcanic rocks and minor pelagic sediments (Plafker, 1987). The accretionary complex was intruded by Paleogene granitic plutons in an arcuate belt that extends from Sanak Island in the west to Baranof Island in southeast Alaska (Hudson, 1986). Marine volcanic rocks, such as pillow basalt and andesitic tuff, are also present. Neogene depocenters in the Shumagin-Kodiak province and the northwestern part of the Gulf of Alaska province are underlain by rocks of the accretionary complex. The Yakutat terrane is presently underthrusting the accretionary complex in the central Gulf of Alaska.

Yakutat Terrane: This terrane lies seaward of the Chugach-St. Elias and Fairweather fault systems. It is bounded on the west by the Kayak zone and on the south by the Transition fault system (Plafker, 1987). Basement rocks consist of upper Mesozoic flysch and mélange east of the Dangerous River zone and lower Tertiary oceanic crust west of the Dangerous River zone. The basement is overlain by lower Eocene through Quaternary clastic rocks. The Yakutat terrane is presently moving northward with the Pacific plate and obliquely underthrusting the southern Alaska continental margin. This subduction has resulted in andesitic volcanism in the Wrangell Mountains, which has been ongoing since 26 Ma to the present (Richter and others, 1990). The collision of the terrane with the continental margin has uplifted the coastal Chugach and St. Elias Mountains (Plafker and others, 1978; Bruns, 1983). The petroleum plays in the central Gulf of Alaska province are underlain by rocks of the Yakutat terrane.

OIL AND GAS ENDOWMENTS OF PACIFIC MARGIN ASSESSMENT PROVINCES

Nearly all of the undiscovered, conventionally recoverable oil and gas resources of the Pacific margin subregion are associated with strata of Tertiary age in the Cook Inlet forearc basin or in sedimentary wedges beneath the Shumagin-Kodiak or Gulf of Alaska continental shelves. Except in Cook Inlet, Tertiary rocks overlap the older "acoustic basement" of amalgamated tectonostratigraphic terranes, the latter assessed as offering negligible potential for undiscovered, conventionally recoverable oil and gas.

Deep water areas of the north Pacific Ocean were grouped into the "Aleutian Trench and North Pacific Abyssal Plain" assessment province (fig. 1.1; pl. 1.1). Water depths in this province everywhere exceed 1,000 meters. These areas are generally floored by a thin mantle of pelagic oozes and mud-rich silts of Tertiary age that rest upon oceanic crust. Because these deposits are unpromising for the occurrence of pooled hydrocarbons, this remote province is considered to offer negligible potential for undiscovered, conventionally recoverable oil or gas resources.

The undiscovered oil and gas potentials of the four provinces of the Pacific margin subregion are listed in table 22.1. Cook Inlet offers the greatest potential for undiscovered oil, whereas the Gulf of Alaska offers the greatest overall (mostly gas) resource base. Cook Inlet is partly an extension of the commercially successful petroleum-producing region in upper Cook Inlet, which has yielded over a billion barrels of oil and nearly 5 trillion cubic feet of gas (AKDO&G, 1995).

The Shumagin-Kodiak shelf assessment province was assessed as offering potential ***only for gas***. The petroleum liquids reported as "oil" in Shumagin-Kodiak province in table 22.1 are

TABLE 22.1
RESOURCES OF THE PACIFIC MARGIN SUBREGION
RISKED, UNDISCOVERED, CONVENTIONALLY RECOVERABLE OIL AND GAS

AREA	OIL (BBO)*			GAS (TCFG)			BOE (BBO)			MPhc
	F95	MEAN	F05	F95	MEAN	F05	F95	MEAN	F05	
COOK INLET	0.32	0.74	1.39	0.40	0.89	1.65	0.39	0.90	1.68	1.00
GULF OF ALASKA	0.18	0.63	1.43	0.94	4.18	10.59	0.36	1.37	3.27	0.99
SHUMAGIN-KODIAK	0.00	0.07	0.29	0.00	2.65	11.35	0.00	0.54	2.30	0.40
ALEUTIAN TRENCH-ABYSSAL PLAIN	neg	neg	neg	neg	neg	neg	neg	neg	neg	neg
TOTAL	*0.72*	*1.44*	*2.49*	*2.12*	*7.72*	*18.34*	*1.15*	*2.81*	*5.50*	*1.00*

* *for Shumagin-Kodiak assessment province, "oil" quantities are entirely natural gas liquids obtained from gas extraction; no pooled oil is present*

***BBO**, billions of barrels (oil values include both crude oil and natural gas liquids); **TCFG**, trillions of cubic feet; **BOE**, total oil and gas in billions of energy-equivalent barrels (5,620 cubic feet of gas=1 energy-equivalent barrel of oil); reported **MEAN**, resource quantities at the mean in cumulative probability distributions; **F95**, the resource quantity having a 95-percent probability of being met or exceeded; **F05**, the resource quantity having a 5-percent probability of being met or exceeded; **MPhc**, marginal probability for hydrocarbons for basin, i.e., chance for the existence of at least one pool of undiscovered, conventionally recoverable hydrocarbons somewhere in the basin; **neg**, negligible resources. Resource quantities shown are risked, that is, they are the product of multiplication of conditional resources and MPhc. Mean values for provinces may not sum to values shown for subregion because of rounding.*

entirely natural gas liquids that would be recovered only as a by-product of gas production. The Gulf of Alaska assessment province was assessed as relatively (but not exclusively) gas prone, and, about one third of the "oil" endowment is actually in the form of natural gas liquids. Cumulative probability distributions for the undiscovered oil and gas potentials of the Pacific margin subregion are shown in figure 22.2.

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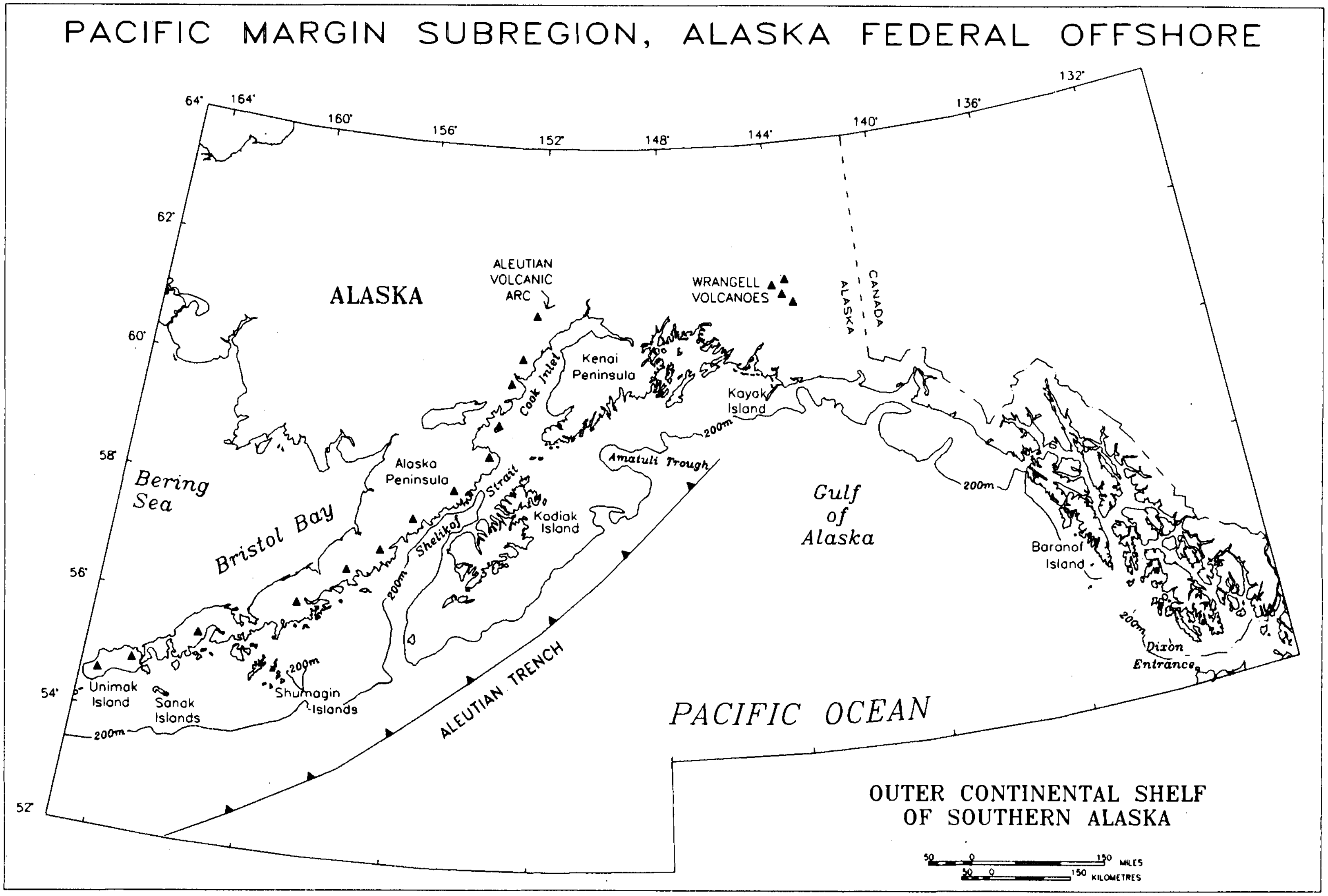

Figure 22.1: Geologic provinces of the Pacific margin subregion, Alaska Federal offshore.

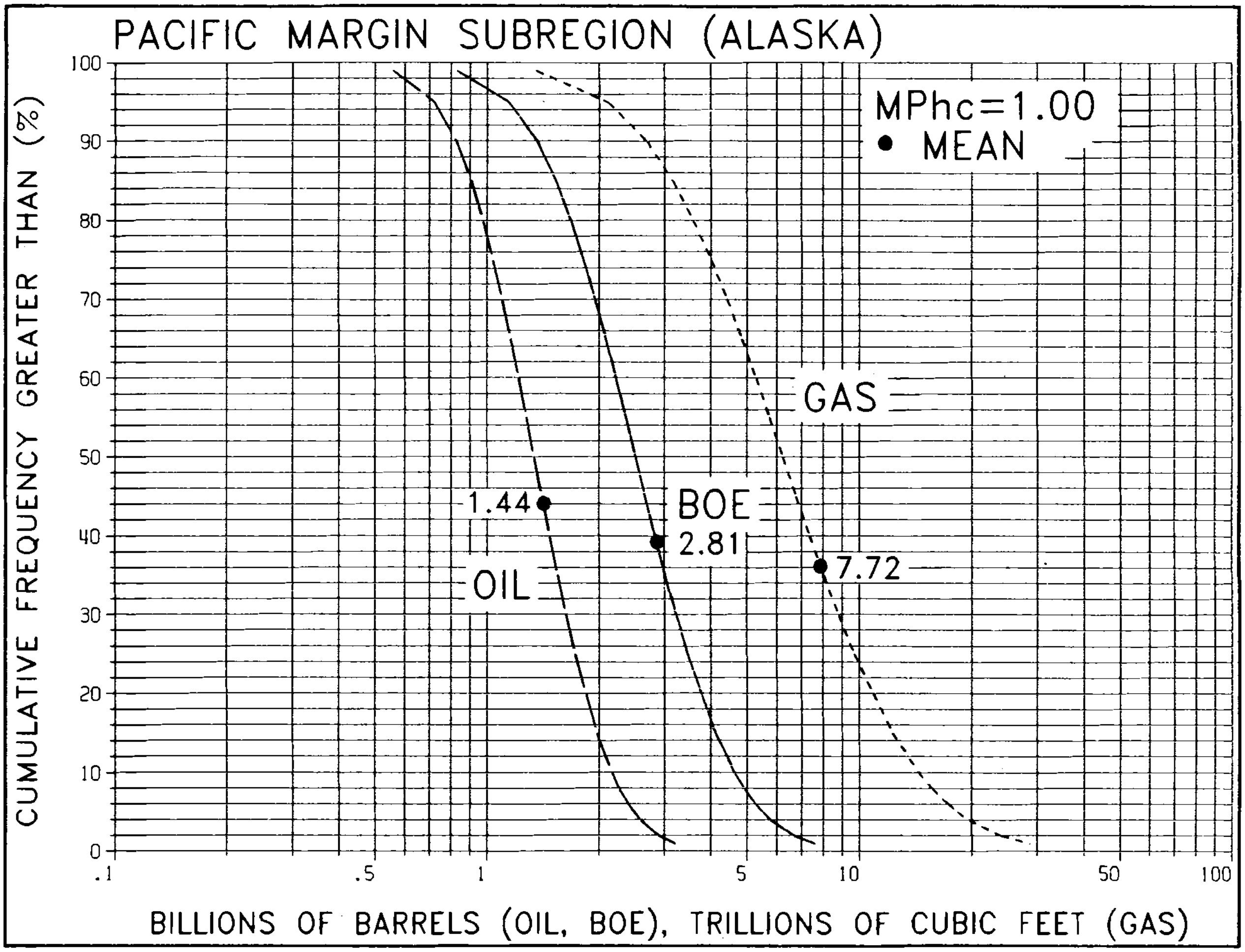

Figure 22.2: Cumulative probability curves for undiscovered, conventionally recoverable resources (oil, gas, and BOE) for the Pacific margin subregion of the Alaska Federal offshore. ***BOE**, total oil and gas in energy-equivalent barrels, obtained by converting gas to energy-equivalent barrels (5,620 cubic feet per barrel) and adding to oil; **MPhc**, marginal probability for occurrence of pooled hydrocarbons in province.*

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23. COOK INLET ASSESSMENT PROVINCE

by

C. Drew Comer, Pete Sloan, and Susan M. Banet

LOCATION

The waters of Cook Inlet and Shelikof Strait overlie a large forearc basin situated between the Aleutian trench and the active volcanic arc on the Alaska Peninsula (fig. 23.1). The Border Ranges fault system separates the forearc basin from a broad accretionary complex on the southeast that extends to the Aleutian trench (fig. 23.2). The northwestern boundary of the forearc basin is the Bruin Bay fault, which separates the basin from the Alaska-Aleutian Range batholith (fig. 23.2; Detterman and Reed, 1980). The Cook Inlet assessment province largely overlies the forearc basin and extends from the vicinity of Redoubt volcano and Kalgin Island on the north to the southern reaches of Kodiak Island on the south. The area of the Cook Inlet assessment province is shown in figure 23.3.

GEOLOGIC SETTING

The forearc basin and the plutonic rocks of the Alaska-Aleutian Range batholith both lie within the Peninsular tectonostratigraphic terrane of southern Alaska (Jones and others, 1987; Nokleberg and others, 1994). The Peninsular terrane, named for the Alaska Peninsula by Jones and Silberling (1979), was a Mesozoic island-arc complex that became amalgamated with the Wrangellia and Alexander terranes to form a composite superterrane by the Late Triassic (Plafker and others, 1989). This superterrane, referred to as the Wrangellia superterrane by Nokleberg and others (1994), collided with continental North America in the Middle to Late Jurassic and was translated northward along strike-slip faults (Wallace and others, 1989). The amalgamated superterrane was finally accreted to the southern Alaska continental margin by the Late Cretaceous (Plafker and others, 1989).

The Augustine-Seldovia arch, which is oriented east-west, transverse to the main structural trend of the basin, separates the forearc basin into two depocenters (fig. 23.2). The northern depocenter, in upper Cook Inlet, contains as much as 25,000 feet of Cenozoic strata. The southern depocenter, in lower Cook Inlet and Shelikof Strait, contains a thin Cenozoic section over as much as 36,000 feet of Mesozoic strata. The assessment area for this report, outlined in figure 23.3, is mostly confined to the Federal Outer Continental Shelf (OCS) of lower Cook Inlet and Shelikof Strait. The assessment province also includes a small part of the upper Cook Inlet Cenozoic depocenter north of the Augustine-Seldovia arch.

Mesozoic rocks in the Cook Inlet province are mostly marine and range in age from Late Triassic through Late Cretaceous (Magoon and others, 1976; Fisher and others, 1987). A stratigraphic column for the Mesozoic rocks of the Cook Inlet province is shown in figure 23.4.

Upper Triassic limestone and chert beds exposed on the Alaska Peninsula near Puale Bay appear to have excellent source-rock potential (Wang and others, 1988). Those rocks are high in TOC and they contain oil-prone kerogen types. Correlative Upper Triassic rocks probably underlie Cook Inlet assessment province, but are there so deeply buried that they were not penetrated by any of the OCS exploratory wells (located in fig. 23.3).

The Early Jurassic Talkeetna Formation consists of andesitic volcanic and reworked volcanogenic sedimentary rocks (Detterman and Hartsock, 1966). The Middle Jurassic strata contain petroleum source-beds in marine siltstones, particularly in the lower Tuxedni Group (Magoon and Claypool, 1981). The Late Jurassic Naknek Formation contains very thick sandstone and conglomerate beds which were encountered in all but two of the OCS wells. However, Naknek Formation sandstones and conglomerates uniformly preserve very low porosities and permeabilities because of cementation and the presence of zeolite minerals, particularly laumontite and heulandite (Franks and Hite, 1980; Bolm and McCulloh, 1986).

Early Cretaceous rocks include marine siltstones, bioclastic limestones or calcarenites, and sandstones. The sandstones have a higher quartz content and the pore spaces are less occluded by zeolite minerals than the underlying Jurassic sandstones. Because of this, the Early Cretaceous section may have good reservoir-rock potential offshore.

The Late Cretaceous Kaguyak Formation may have the best reservoir-rock potential in the Mesozoic section. This formation is 3,000- to 5,000-feet thick and contains mostly marine siltstones and fine-grained sandstones. However, coarse-grained sandstone beds are exposed on the Alaska Peninsula in an ancient submarine fan complex. Fan-delta deposits with relatively porous and permeable sandstone beds also occur in the upper Kaguyak Formation in an isolated outcrop and in several of the offshore wells. Both submarine fan and fan-delta deposits may contain good reservoir beds in both stratigraphic and structural traps in the assessment area.

EXPLORATION HISTORY

All of the oil and gas fields discovered in the forearc basin to date are in the upper Cook Inlet Tertiary depocenter in either State of Alaska waters or adjacent onshore areas. The traps are in Tertiary rocks deformed by northeast-trending, faulted compressional anticlines. Structural growth of the upper Cook Inlet anticlines occurred mainly in Plio-Pleistocene time (Boss and others, 1976). Approximately 1.2 billion barrels of oil (BBO) and 7.44 trillion cubic feet of gas (TCFG) were produced in the basin from 1958 through 1994 (AOGCC, 1995). Most of the petroleum reservoirs are nonmarine sandstones and conglomerates of Tertiary age, although a small amount of oil is produced from fractured Jurassic rocks in the McArthur River field. The oil source is thought to be marine siltstone of the Middle Jurassic Tuxedni Group (Magoon and Claypool, 1981). Oil generation was initiated during the Tertiary and migration has continued into the Holocene (Magoon and Anders, 1992; Magoon, 1994). The oil fields have associated gas (gas caps or dissolved gases) which accounts for approximately 2.96 TCF of the total gas production. Biogenic methane accumulations with no associated oil are also present in late Miocene to Pliocene sandstones (Claypool and others, 1980). This biogenic gas accounts for approximately 4.48 TCF of the total gas production in the basin through 1994 (AOGCC, 1995).

One stratigraphic test (COST[1]) well was drilled in lower Cook Inlet in 1977 (Magoon, 1986). Thirteen exploratory wells, one of which was in Shelikof Strait, were subsequently drilled between 1978 and 1985 in Federal waters (fig. 23.3). Three of the exploratory wells were abandoned at shallow depth and redrilled at

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[1]*Continental Offshore Stratigraphic Test well*

approximately the same location. All wells were plugged and abandoned. Drill stem tests in two of the wells recovered small amounts of oil from Cretaceous strata, but no commercial discoveries were made.

PLAY DESCRIPTIONS

Federal waters of Cook Inlet basin include three plays: (1) the Tertiary stratigraphic play, (2) the Mesozoic stratigraphic play, and (3) the Mesozoic structural play. Data used to model these plays are tabulated in Appendix A3.

Play 1 (UACI0101[2]). Tertiary Stratigraphic Play: This play is restricted to the northernmost part of the assessment area north of the Augustine-Seldovia arch. It occurs in the southernmost part pf the upper Cook Inlet Tertiary depocenter. Tertiary rocks in this area are not folded and only sparsely faulted. Therefore, most anticipated traps are of a purely stratigraphic nature. Potential source rocks are Upper Triassic carbonates and Middle Jurassic marine siltstones. Nonmarine sandstones and conglomerates of Eocene and Oligocene age are the reservoir targets. Those rocks include braided stream deposits of alluvial fans shed from the margins of the basin, and fluvial deposits that developed in the axis of the basin. Reservoir properties are assumed to be analogous to those of the upper Cook Inlet oil fields as reported by the Alaska Oil and Gas Conservation Commission (AOGCC, 1995). The area of play 1 is shown in figure 23.5.

Play 2 (UACI0201). Mesozoic Stratigraphic Play: This play is probably best developed in the central and southern parts of lower Cook Inlet and Shelikof Strait. This play involves stratigraphic traps in turbidite sandstones within marine siltstone sections. The turbidites may have developed in submarine fan complexes in the Upper Cretaceous Kaguyak Formation. Potential source rocks are Upper Triassic carbonates or Middle Jurassic marine siltstones. According to Magoon and Anders (1992), oil in the lower Cook Inlet-Alaska Peninsula area migrated from both Upper Triassic and Middle Jurassic sources during Late Cretaceous to early Tertiary time. The area of play 2 is shown in figure 23.5.

Play 3 (UACI0301). Mesozoic Structural Play: This play covers most of the assessment area and involves anticlines and fault traps in Mesozoic rocks. Many of the mapped anticlines were tested by exploratory wells and found to be barren of significant quantities of pooled hydrocarbons. Oil shows were present in Upper Cretaceous strata in the Arco Y-0097 well and the Marathon Y-0086 well. Potential source rocks are Upper Triassic carbonates or Middle Jurassic marine siltstones. The best reservoir rocks are probably nonmarine sandstones in fan-delta deposits in the Upper Cretaceous Kaguyak Formation. Marine sandstones in both Lower and Upper Cretaceous strata are also potential reservoirs. The area of play 3 is shown in figure 23.6.

OIL AND GAS RESOURCES OF COOK INLET ASSESSMENT PROVINCE

The undiscovered, conventionally recoverable oil and gas resources for the Cook Inlet assessment province are estimated to average 0.738 BBO and 0.893 TCFG, possibly ranging over 1.386 BBO and 1.649 TCFG. Cumulative probability distributions that show the full range in undiscovered potential for the Cook Inlet assessment province are shown in figure 23.7.

The resource potentials for all three plays are quite similar, as shown in table 23.1, with that of the Mesozoic stratigraphic play (2) being somewhat smaller than either play 1 or play 3. All of the plays were modeled as being oil with associated gas, analagous to the upper Cook Inlet

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[2] *The "UA" Code is the "Unique Assessment Identifier" for each play, and is the principal guide to GRASP data files.*

TABLE 23.1
OIL AND GAS ENDOWMENTS OF COOK INLET PLAYS
Risked, Undiscovered, Conventionally Recoverable Oil and Gas

PLAY NO.	PLAY NAME (UAI* CODE)	OIL (BBO)			GAS (TCFG)		
		F95	MEAN	F05	F95	MEAN	F05
1.	Tertiary Stratigraphic (UACI0101)	0.000	0.276	0.723	0.000	0.291	0.776
2.	Mesozoic Stratigraphic (UACI0201)	0.000	0.195	0.515	0.000	0.242	0.642
3.	Mesozoic Structural (UACI0301)	0.088	0.266	0.508	0.116	0.360	0.727
	FASPAG AGGREGATION	*0.323*	*0.738*	*1.386*	*0.402*	*0.893*	*1.649*

* *Unique Assessment Identifier, code unique to play.*

oil fields. The late Miocene to Pliocene biogenic gas play of upper Cook Inlet was not considered viable in this assessment province, because those strata are too shallow in lower Cook Inlet to be prospective. Cumulative probability distributions and ranked pool-size plots for each of the three Cook Inlet plays are shown in Appendix B3.

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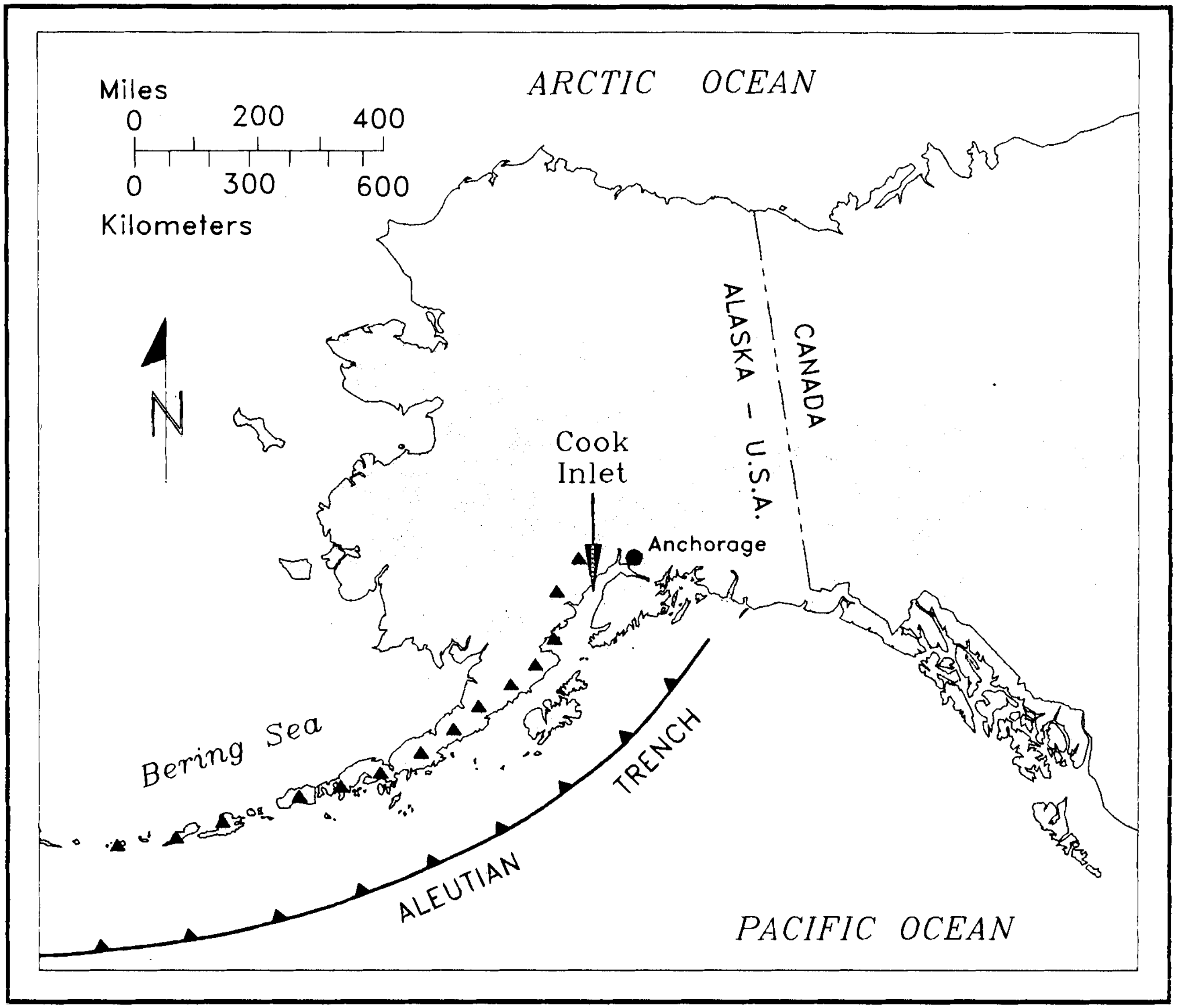

Figure 23.1: Map showing location of Cook Inlet forearc basin between the Aleutian trench and the Aleutian volcanic arc (volcanoes located as triangles).

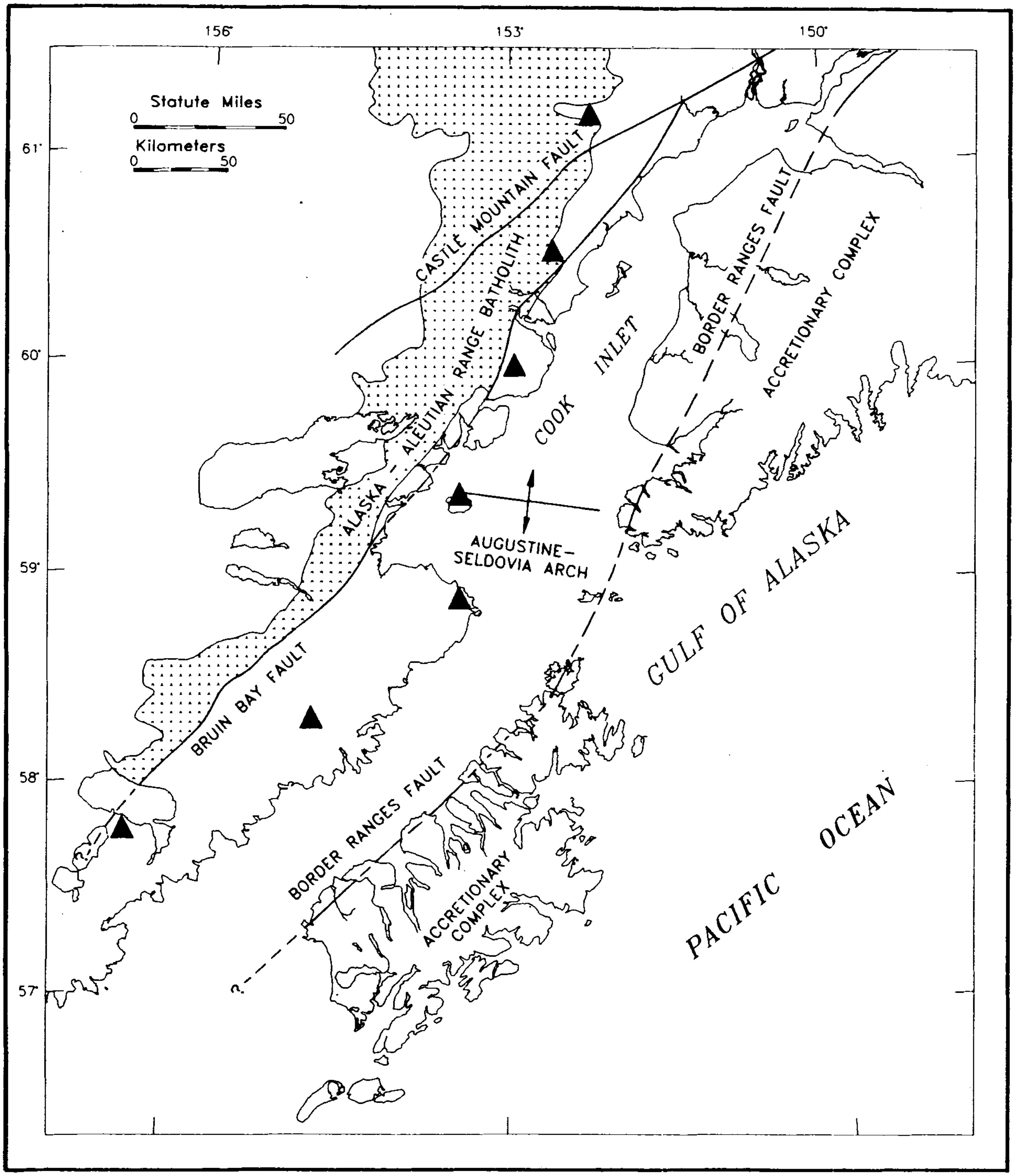

Figure 23.2: Map showing major structural features of the Cook Inlet region. Major Quaternary volcanoes are located as triangles.

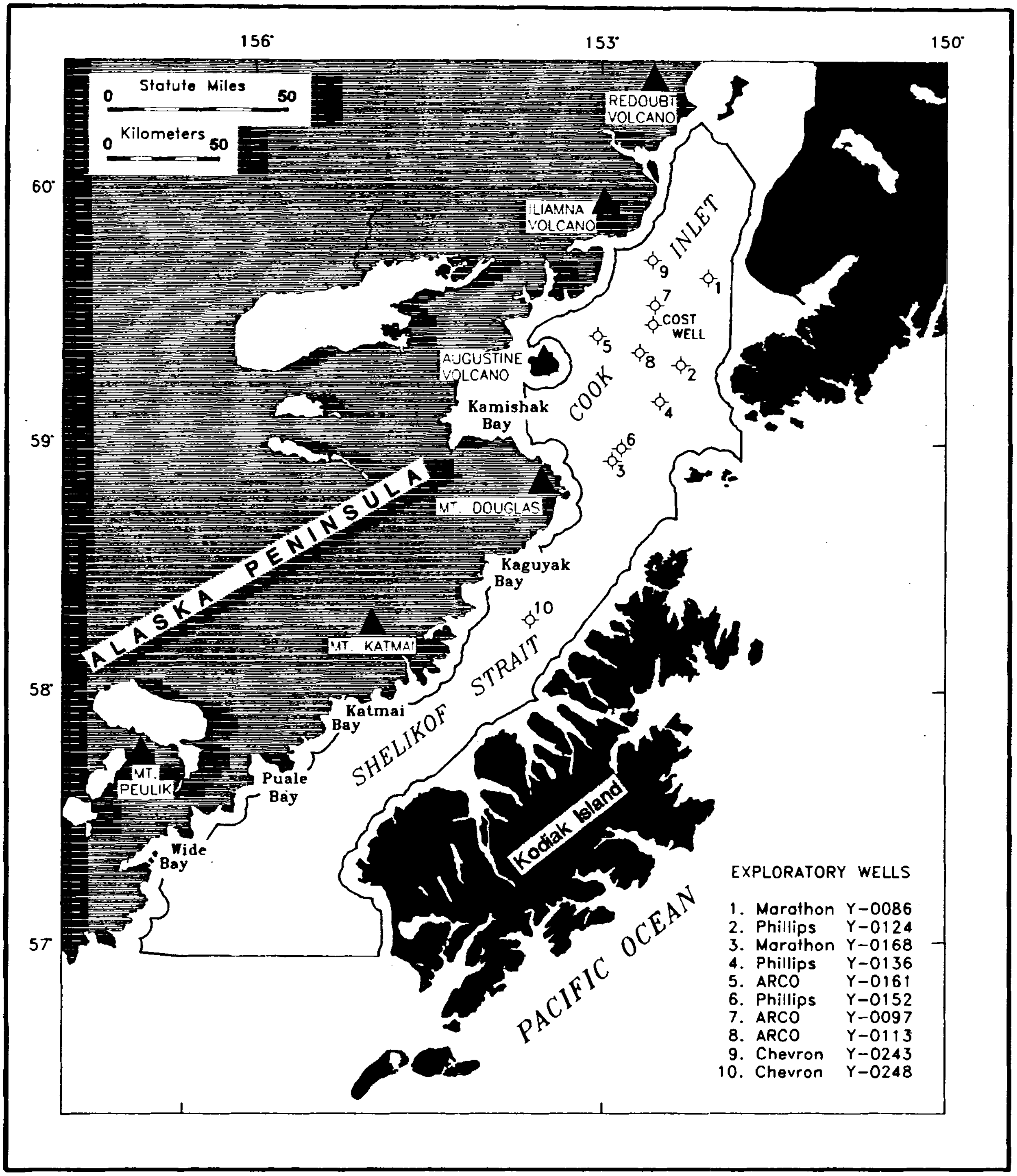

Figure 23.3: Map showing Cook Inlet assessment province with locations of exploratory wells and stratigraphic test (COST) well.

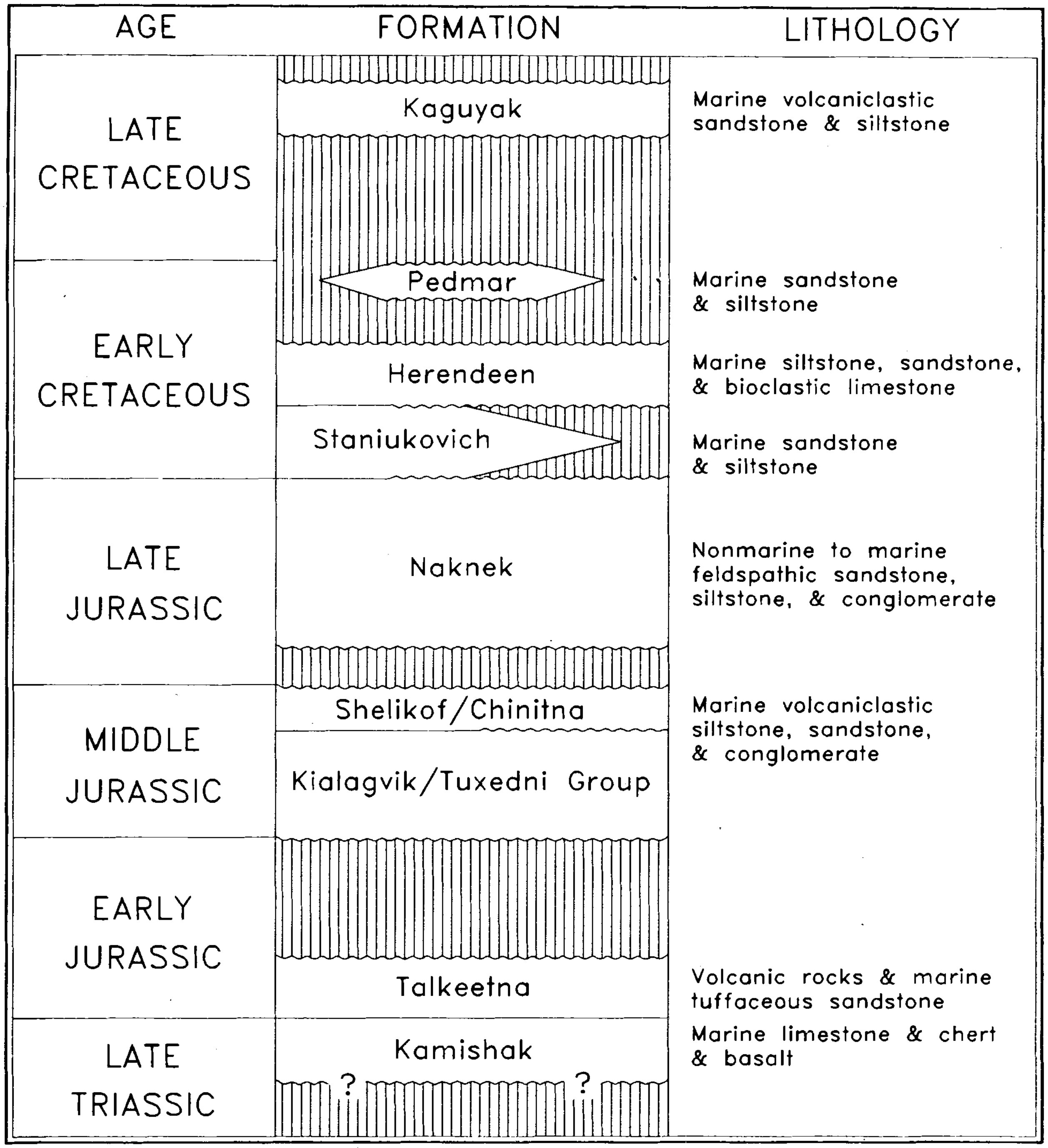

Figure 23.4: Generalized stratigraphic column for Mesozoic units in lower Cook Inlet and Shelikof Strait.

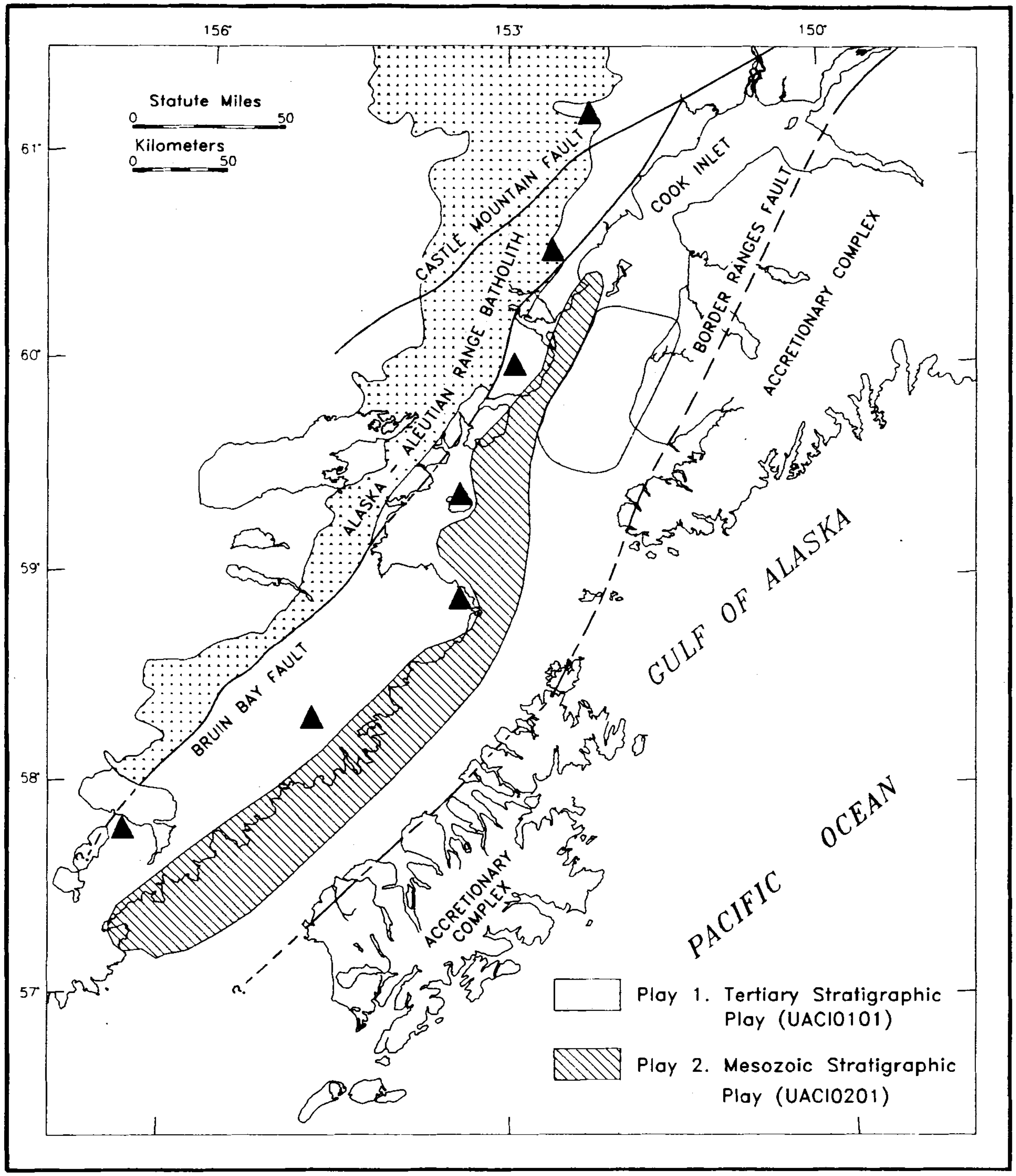

Figure 23.5: Map showing locations of play 1 (Tertiary stratigraphic) and play 2 (Mesozoic stratigraphic).

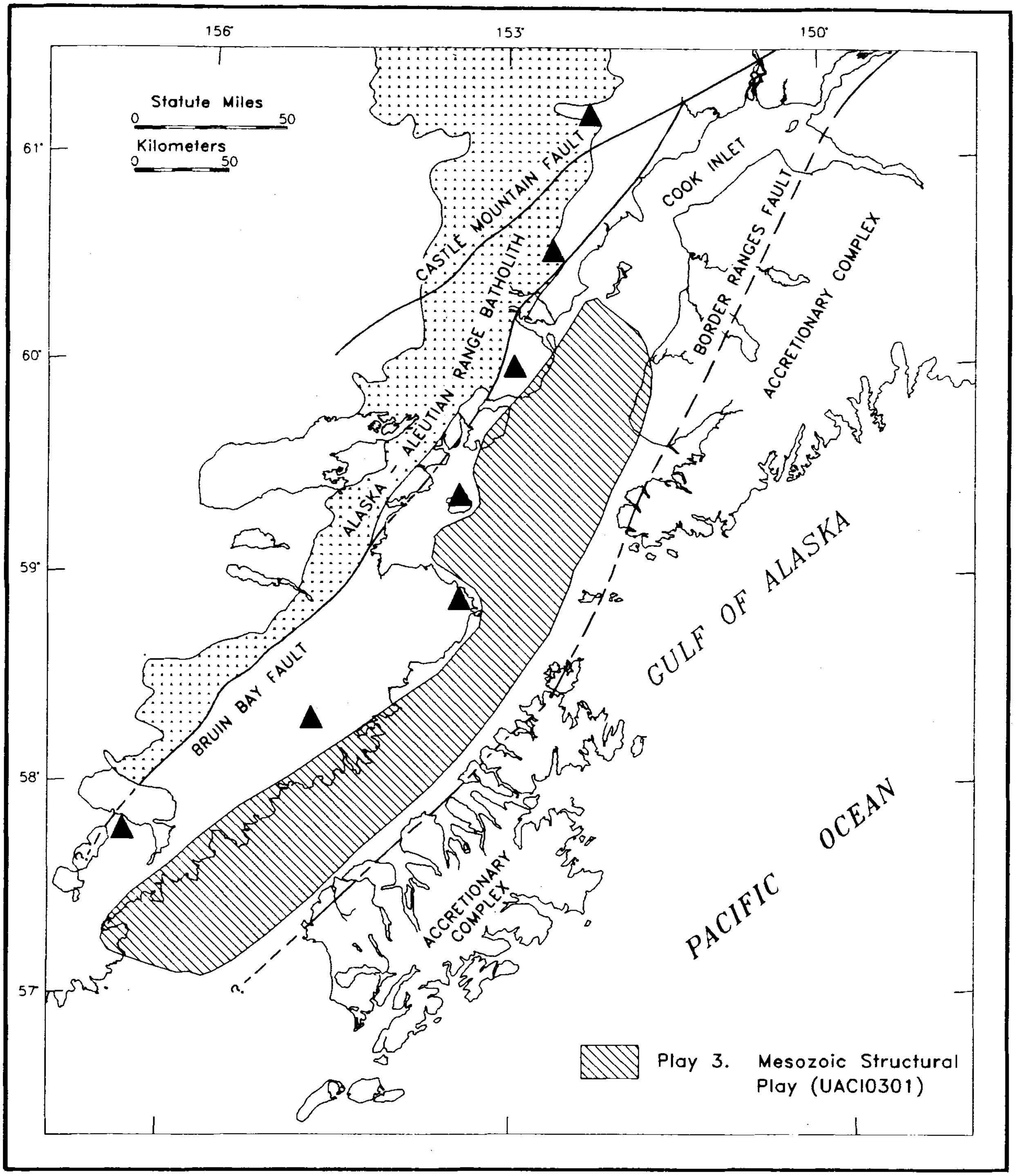

Figure 23.6: Map showing location of play 3 (Mesozoic structural).

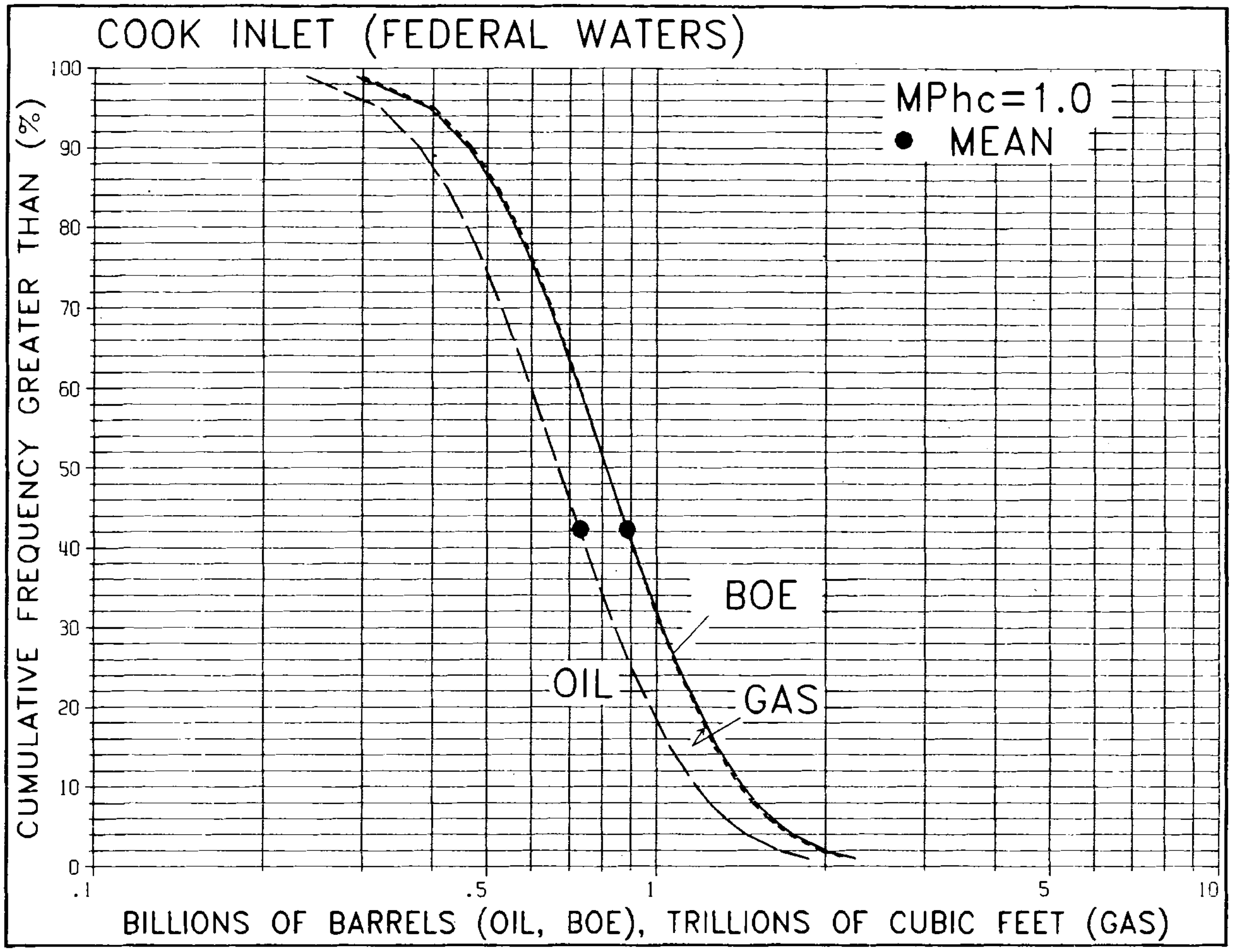

Figure 23.7: Cumulative probability curves for undiscovered, conventionally recoverable resources (oil, gas, and BOE) for Cook Inlet assessment province. ***BOE**, total oil and gas in energy-equivalent barrels, obtained by converting gas to energy-equivalent barrels (5,620 cubic feet per barrel) and adding to oil; **MPhc**, marginal probability for occurrence of pooled hydrocarbons in province.*

GEOLOGIC ASSESSMENT
1995 National Resource Assessment
Alaska Federal Offshore
U.S. Minerals Management Service

24. GULF OF ALASKA SHELF ASSESSMENT PROVINCE

by

John Larson and Gary Martin

LOCATION

The Gulf of Alaska shelf assessment province includes an 850-mile-long segment of the Alaska continental margin from near the southwest tip of the Kenai Peninsula on the west to Dixon Entrance at the U.S.-Canadian border on the southeast (fig. 24.1). It encompasses the outer continental shelf (OCS) and extends from the three-mile limit seaward to approximately the 1000-meter isobath (fig. 1.1, pl. 1.1). The continental shelf ranges in width from less than 15 miles adjacent to Baranof Island in the southeast to more than 60 miles near Middleton Island in the west.

GEOLOGIC SETTING

The Gulf of Alaska shelf assessment province includes three major tectonostratigraphic terranes or composite terranes. From northwest to southeast, these are the Chugach/Prince William composite terrane, the Yakutat terrane, and the Wrangell/Alexander composite terrane (fig. 24.1). The terranes all lie adjacent to the northwestwardly-moving Pacific plate and are separated from it on their seaward margins by the Aleutian subduction zone, the Transition fault, and the Fairweather-Queen Charlotte fault.

The Gulf of Alaska shelf assessment province is dominated by a very thick wedge of Tertiary-age rocks deposited on the Gulf of Alaska continental margin. The Tertiary strata overlie "basement" complexes composed of Cretaceous and older rocks of the various terranes identified in figure 24.1. All of the undiscovered oil and gas resources of the Gulf of Alaska are associated with the Tertiary strata. Regional stratigraphic relationships within Tertiary rocks are schematically illustrated in the stratigraphic panel of figure 24.4. Additional information for the geology of the Gulf of Alaska shelf may be found in Plafker and others (1978) and Risley and others (1992).

EXPLORATION HISTORY

Exploration in the Gulf of Alaska province began northwest of Kayak Island in 1901 with 44 wells eventually drilled in the Katalla oil field and nearby areas by 1932 (fig. 24.2). Production in the Katalla district yielded approximately 154,000 barrels of oil before production stopped in 1933. Over the next 30 years, 23 additional exploratory wells were drilled onshore in the area extending from north of Kayak Island to about 60 miles southeast of Yakutat Bay. One well was drilled in 1927 and 22 others between 1954 and 1963. None yielded producible quantities of hydrocarbons.

A stratigraphic test (COST[1]) well was drilled by an industry consortium in the Gulf of Alaska province midway between Kayak Island and Icy Bay in 1975. Following lease sales, 12 exploratory wells were drilled in the Gulf of Alaska. One well was drilled in State of Alaska waters near Middleton Island in 1969 (fig. 24.2). Ten exploratory wells were drilled on Federal OCS leases between Kayak Island and Icy Bay (fig. 24.1) from 1977 to 1978. Exploration of the Gulf of Alaska shelf finally concluded with the drilling of the ARCO OCS Y-0211 Yakutat No.1 well (fig. 24.3) offshore south of Yakutat Bay in 1983. None of the offshore wells encountered significant quantities of pooled hydrocarbons.

PLAY DESCRIPTIONS

The Gulf of Alaska assessment province is divided into six geologic plays that reflect the tectonic and stratigraphic histories of the diverse tectonic terranes that underlie the Gulf of Alaska shelf. These plays are: (1) the Middleton fold and thrust belt; (2) the Yakataga fold and thrust belt; (3) the Yakutat shelf - basal Yakataga Formation; (4) the Yakutat shelf - Kulthieth sands; (5) the Southeast Alaska shelf subbasin; and (6) the Subducting terrane. All of the known potential source rocks and reservoir rocks in these plays are Tertiary in age. Data used to characterize and model the Gulf of Alaska shelf plays are tabulated in Appendix A3.

Play 1 (UAGA0101[2]). Middleton Fold and Thrust Belt Play: Play 1 encompasses the offshore area extending west from the Kayak zone to approximately 149 degrees W. longitude (fig. 24.2). Traps are primarily asymmetric anticlinal closures formed on the upthrown sides of high-angle thrust or reverse faults during the late Neogene to Pleistocene. Reservoir objectives consist of sandstones in the lower part of the glaciomarine, late Miocene to Pleistocene Yakataga Formation, and sandstones locally developed in the underlying Oligocene to early Miocene Sitkinak Formation (fig. 24.4). Potential source rocks are the Sitkinak Formation (marginally mature to thermally immature) and the thermally mature Eocene Sitkalidak Formation. Both formations consist of deltaic to nonmarine sequences characterized by poor to marginal organic richness and gas-prone kerogen. The Tenneco Middleton Island State No. 1 well tested a structure in this play without recovering producible hydrocarbons. The area of play 1 is shown in figure 24.2.

Play 2 (UAGA0201). Yakataga Fold and Thrust Belt Play: Play 2 extends from the Kayak zone eastward to the Pamplona zone. Potential traps are primarily the large and widespread fault-bounded anticlinal structures of Pliocene and younger age, with some stratigraphic traps possibly formed adjacent to the structures. The most prospective reservoir objectives within drillable depths are sandstones of the Yakataga Formation (particularly the lower part) and locally-developed sandstones in the upper part of the underlying Poul Creek Formation (fig. 24.4). Two potential source rock sequences have been identified: 1) Eocene rocks of the nonmarine to deltaic Kulthieth Formation and its deeper marine equivalent facies; and 2) middle to upper Miocene rocks of the upper Poul Creek Formation (fig. 24.4). Oil has been encountered at several onshore seeps and well sites, including the oil at Katalla field. However, the organically richest potential source, the Miocene Poul Creek Formation, is thermally immature offshore. Eocene potential source rocks are mature offshore only where very deeply buried. Ten exploratory wells have tested several of the larger structures in this play and failed to discover recoverable hydrocarbons. The area of play 2 is shown in figure 24.2.

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[1]*Continental Offshore Stratigraphic Test*

[2]*The "UA" Code is the "Unique Assessment Identifier" for each play, and is the principal guide to GRASP data files.*

<u>Play 3 (UAGA0401). Yakutat Shelf - Basal Yakataga Formation Play</u>: This play encompasses the area from the Pamplona zone southeastward to just west of Cross Sound (fig. 24.3). There are a few large structural highs mapped in the area, but traps are mainly inferred to be stratigraphic and structural/stratigraphic in nature. These traps contain reservoir sandstones of the basal Yakataga and uppermost Poul Creek Formations (fig. 24.4) and are speculated to consist of up-dip pinchouts, basement onlap, lateral facies transitions, and up-dip truncations against normal faults. The source rocks are the same as in play 2 (Yakataga fold and thrust belt). Source intervals are deeply buried with moderate to relatively high thermal maturity in the northwest and are shallower with decreasing maturity to the south and east. The ARCO OCS Y-0211 (Yakutat No. 1) well (figs. 24.3, 24.4) tested the largest mapped structure in the play area and recorded minor oil shows. The area of play 3 is shown in figure 24.3.

<u>Play 4 (UAGA0501). Yakutat Shelf - Kulthieth Sands Play</u>: Play 4 partly underlies play 3, mostly in the northern Yakutat shelf (fig. 24.3), and is confined to the Eocene Kulthieth Formation. Play 4 has the same northwestern limit as the overlying play 3, but does not extend as far southeast. Trapping mechanisms are similar to those of overlying play 3, but with additional potential for unconformity and stratigraphic traps along the southeast margin and for fault traps in the southeastern corner of the play area near the Fairweather Ground uplift and rift zone (fig. 24.3). Potential source rocks consist of somewhat gas-prone shallow marine deltaic to basinal marine sediments in the lower part of the Kulthieth Formation and its equivalents (fig. 24.4). Relatively thick reservoir sands occur higher in the Kulthieth Formation. The ARCO OCS Y-0211 (Yakutat No. 1) well encountered minor oil and gas shows in Kulthieth Formation sandstones in play 4. The area of play 4 is shown in figure 24.3.

<u>Play 5 (Not Quantified). Southeast Alaska Shelf Subbasin Play</u>: Most of the narrow continental shelf of southeastern Alaska is not prospective for hydrocarbons because total sedimentary thicknesses there are generally less than 2,000 feet, too thin for effective hydrocarbon accumulation. However, the Southeast Alaska subbasin contains up to 20,000 feet of probable Cenozoic sediments that overlie a "basement" comprising metamorphic Mesozoic and Paleozoic basement rocks of the Wrangell/Alexander composite terrane. Southeast Alaska subbasin is fault-related and structurally isolated and about 35 miles wide and 65 miles long (located in figure 24.3). We estimate that thermal maturity for hydrocarbon generation is possible in the central portion of the subbasin at depths below 13,500 feet.

Sedimentary rocks correlative to the Tertiary fill in the Southeast Alaska subbasin are not preserved anywhere in the nearby islands where older "basement" rocks of the composite terrane are exposed. The nearest exposures of Tertiary rocks are the Neogene Skonun Formation on Queen Charlotte Island (and in the offshore Queen Charlotte basin) over 150 miles to the southeast in southwestern British Columbia. Skonun strata have favorable exploration potential in the southern part of the Queen Charlotte basin. There, Skonun sandstones overlie potential source rocks of Mesozoic age. However, 14 exploratory wells have been drilled in the Queen Charlotte basin with no discoveries of commercial quantities of hydrocarbon. The Skonun lithofacies in the Queen Charlotte area become increasingly nonmarine and gas-prone to the north and west, possibly predicting even poorer source rock potential for correlative rocks in the Southeast Alaska subbasin much farther north. Furthermore, pre-Tertiary rocks beneath the Southeast Alaska subbasin are metamorphosed and offer no source potential. Based upon this very sparse information, the overall likelihood for the occurrence of hydrocarbon accumulations in the Southeast Alaska subbasin is presently judged to be too low to justify quantification of play resources. Play 5 is therefore assessed as offering negligible potential for undiscovered, conventionally recoverable oil and gas resources.

Play 6 (UAGA0701), Subducting Terrane Play: Play 6 is located in the offshore area surrounding Kayak Island (fig. 24.2). In this area, Eocene to Miocene sedimentary rocks are apparently being subducted along the Kayak zone, or underthrust to the north and west beneath the "basement" rocks (deformed Orca Group metasediments) of the Prince William terrane (fig. 24.4). Oil and gas in seeps that occur along the onshore extension of the Kayak zone at Katalla are thought to originate at depth in the area, generated from subducted Poul Creek and Kultheith Formation source rocks and then migrated upward along fractures and fault surfaces.

Traps in this play are likely to consist of extensively folded and faulted structures similar to those exposed on Kayak Island. Hydrocarbon accumulations might also occur in up-dip stratigraphic/structural traps along the southeast margin of the play area. Potential reservoir rocks are Kulthieth and Yakataga Formation sandstones, perhaps with fracture-enhanced permeabilities (oil was produced from fractured shales and siltstones of the Poul Creek Formation in the abandoned Katalla field onshore).

RESULTS OF RESOURCE ASSESSMENT

Table 24.1 indicates that the undiscovered, conventionally recoverable oil and gas resources for the Gulf of Alaska assessment province average 0.630 billion barrels of oil and 4.180 trillion cubic feet of gas, but, could range over 1.4 billion barrels of oil and 10.5 trillion cubic feet of gas. Cumulative probability distributions for oil, gas, and BOE resources in the Gulf of Alaska shelf assessment province are shown in figure 24.5.

Oil forms 45.8 percent of the total BOE endowment for the assessment province. However, some plays are more gas prone than others. The GPROB (probability that any given accumulation will consist entirely of gas) input values vary from 0.9 in play 1 (Middleton fold and thrust belt) to 0.0 in the other 4 plays (complete data tabulated in Appendix A3). Nearly half of the undiscovered oil and gas

TABLE 24.1
OIL AND GAS ENDOWMENTS OF GULF OF ALASKA SHELF PLAYS
Risked, Undiscovered, Conventionally Recoverable Oil and Gas

PLAY NO.	PLAY NAME (UAI* CODE)	OIL (BBO)			GAS (TCFG)		
		F95	MEAN	F05	F95	MEAN	F05
1.	Middleton Fold and Thrust Belt (UAGA0101)	0.000	0.013	0.074	0.000	0.456	2.700
2.	Yakataga Fold and Thrust Belt (UAGA0201)	0.000	0.122	0.415	0.000	0.805	2.677
3.	Yakutat Shelf-Basal Yakataga Fm. (UAGA0401)	0.000	0.111	0.313	0.000	0.669	1.937
4.	Yakutat Shelf-Kulthieth Sands (UAGA0501)	0.000	0.308	0.778	0.000	1.967	5.397
5.	Southeast Alaska Shelf Subbasin	Negligible-Not Quantified Owing to Assessed High Risk					
6.	Subducting Terrane (UAGA0701)	0.000	0.076	0.222	0.000	0.282	0.926
	FASPAG AGGREGATION	***0.183***	***0.630***	***1.434***	***0.937***	***4.180***	***10.589***

* *Unique Assessment Identifier, code unique to play.*

endowments (0.308 billion barrels, 1.967 trillion cubic feet, respectively) occur in play 4 (Yakutat shelf - Kulthieth sands). Play 4 offers the greatest resource potential because reservoir sands lie closest to prospective source rocks and are anticipated to offer the highest porosities and permeabilities. Cumulative probability distributions and ranked pool-size plots for Gulf of Alaska shelf plays are presented in Appendix B3.

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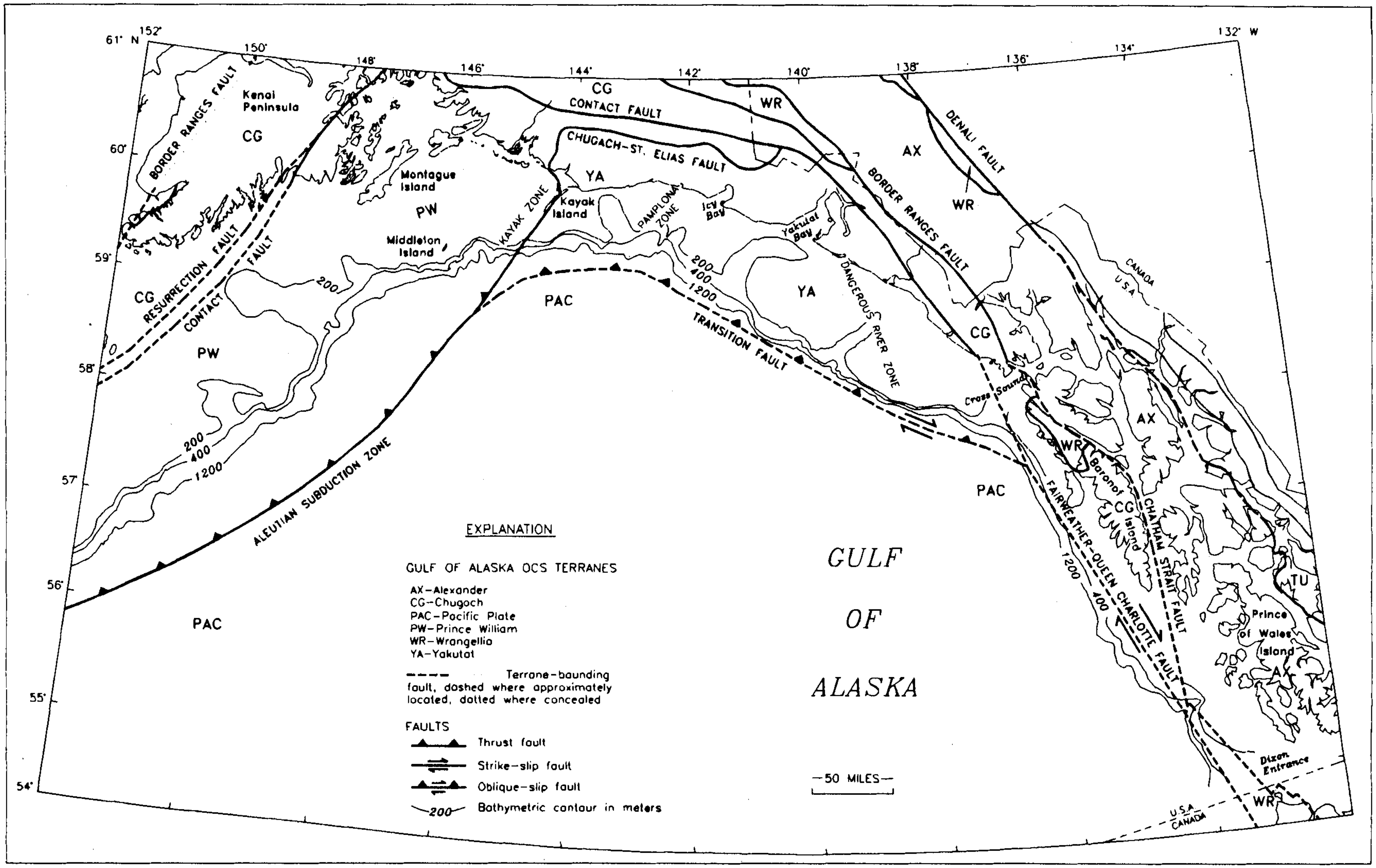

Figure 24.1: Geologic framework of the northern Gulf of Alaska region, including major faults, selected physiographic features, and tectonostratigraphic terranes and their boundaries.

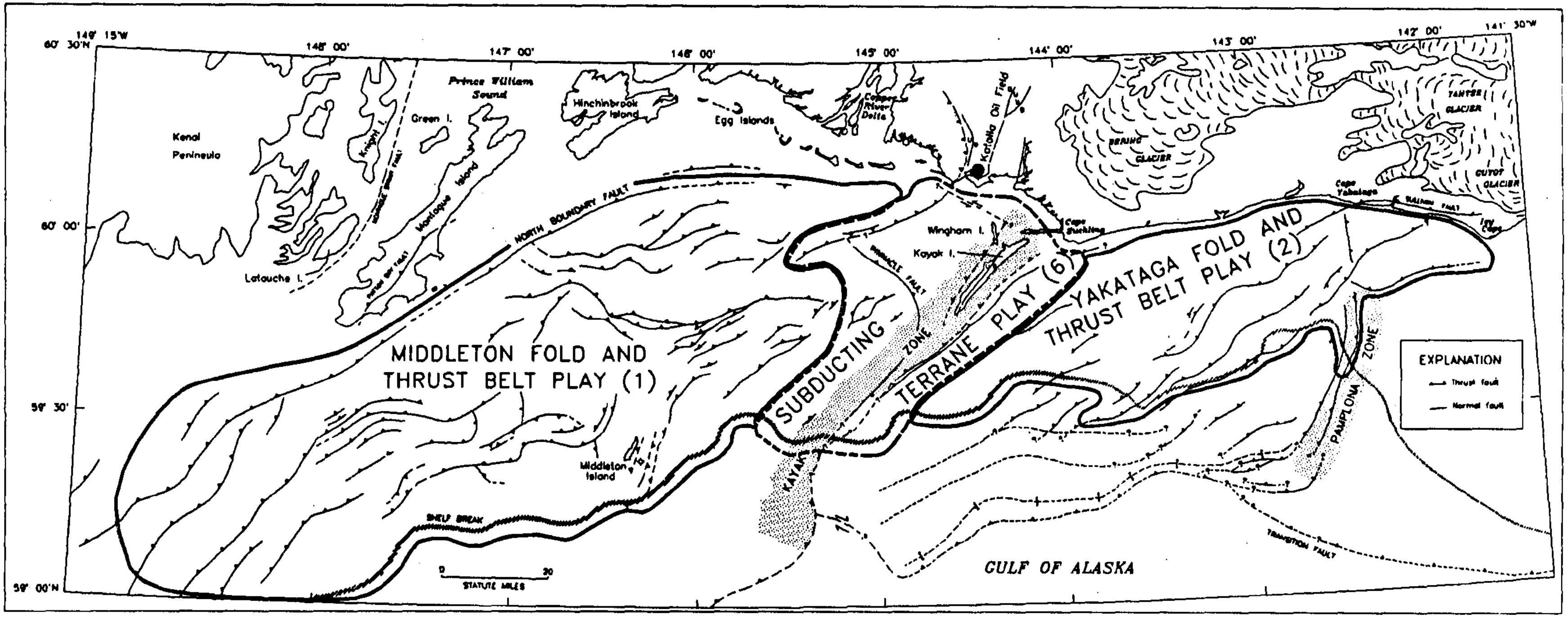

Figure 24.2: Location and tectonic setting of the Middleton (play 1) and Yakataga (play 2) fold and thrust belt plays and the Subducting terrane play (6). Play 1 lies west of the Kayak zone and overlies basement rocks of the Prince William terrane, whereas play 2 to the east overlies rocks of the Yakutat terrane. Play 6 includes the Kayak zone and is interpreted to be underlain at depth by underthrust Yakutat rocks.

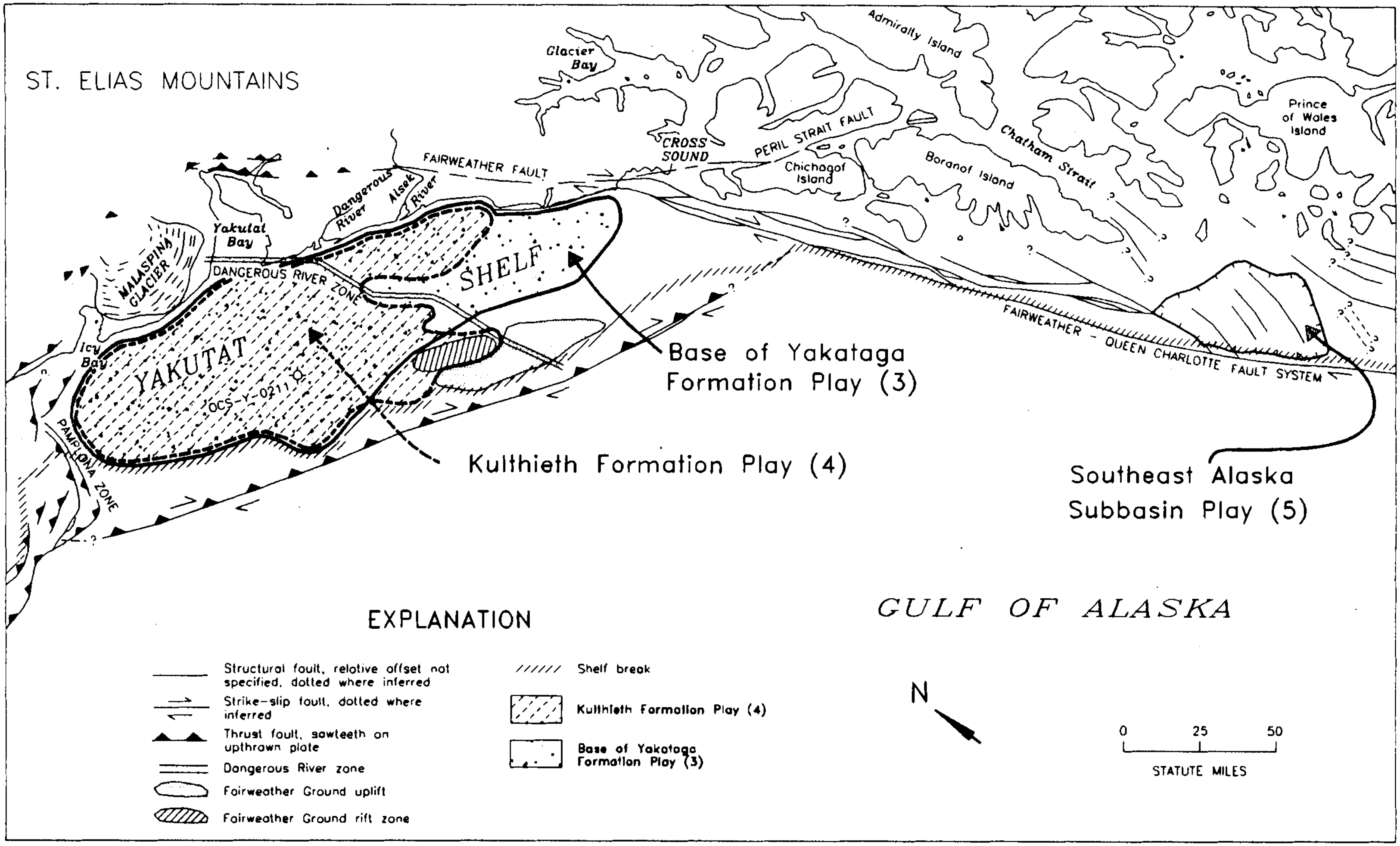

Figure 24.3: Location and tectonic setting of plays 3 and 4 on Yakutat shelf and play 5 in southeast Alaska. Potential hydrocarbon targets in the Yakutat shelf plays (3 and 4) include sandstones in the lower Yakataga/upper Poul Creek Formations and in the Kulthieth Formation. Tectonic features with potential for associated structural and stratigraphic traps include the Dangerous River zone, the Fairweather Ground rift zone, and a Paleogene basement high. The hydrocarbon potential of the Southeast Alaska subbasin (play 5) is thought to be negligible because of the small volume of possible mature source rocks and an apparent lack of trapping structures.

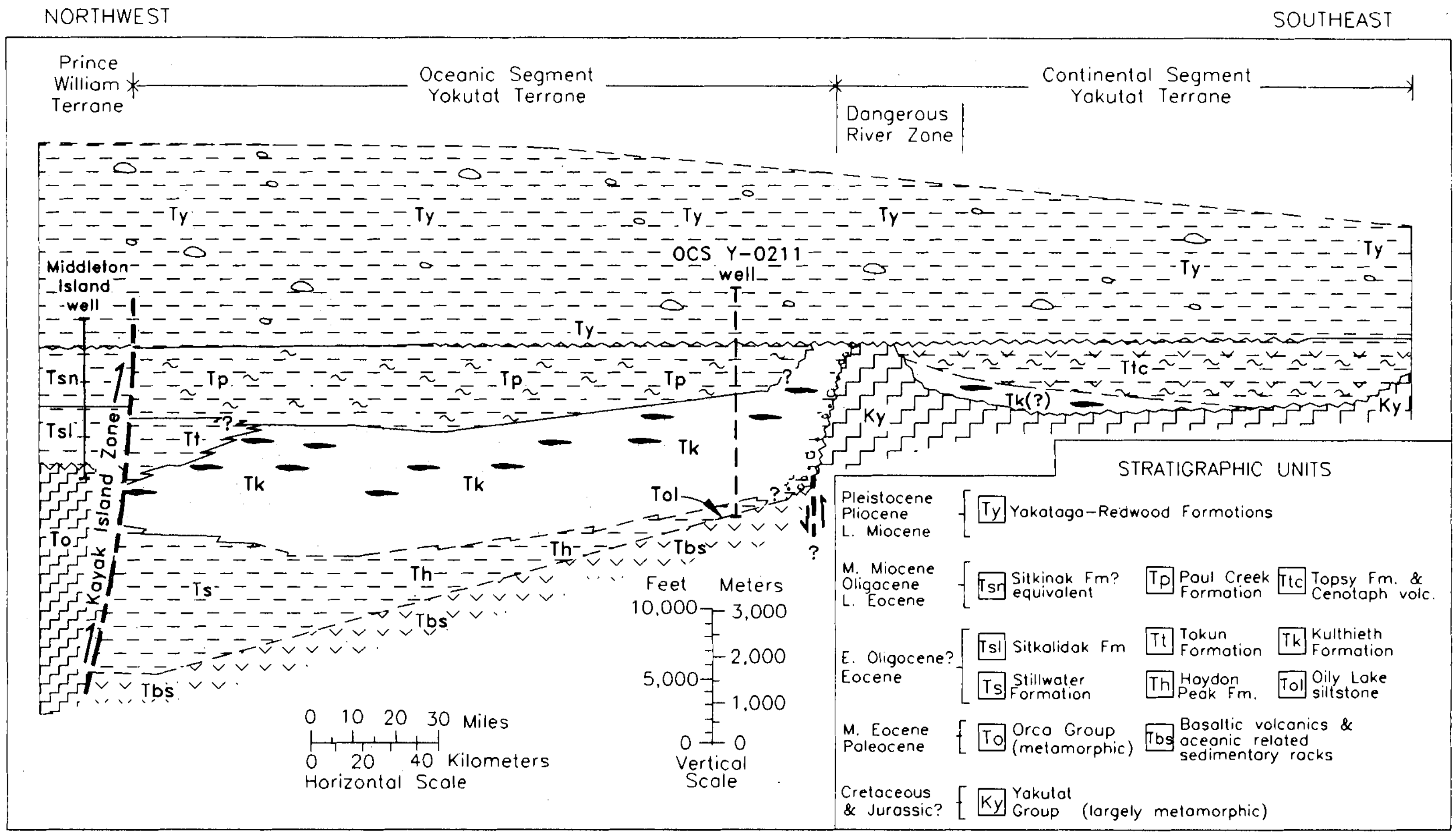

Figure 24.4: Diagrammatic stratigraphic section for the northern Gulf of Alaska coastal margin. The Tokun, Stillwater, and Haydon Peak Formations and the Oily Lake siltstone are offshore facies equivalents of the Kulthieth Formation. The Topsy Formation in the southeast is a somewhat sandier equivalent of the Poul Creek Formation. The Redwood Formation is a glacially derived unit locally present on Kayak Island and in the Katalla area. The Yakutat terrane is divided along the Dangerous River zone into areas of oceanic basement on the northwest and areas of continental basement on the southeast (fig. 24.3). Vertical exaggeration is approximately 17. (Diagram modified from Plafker and others, 1978.)

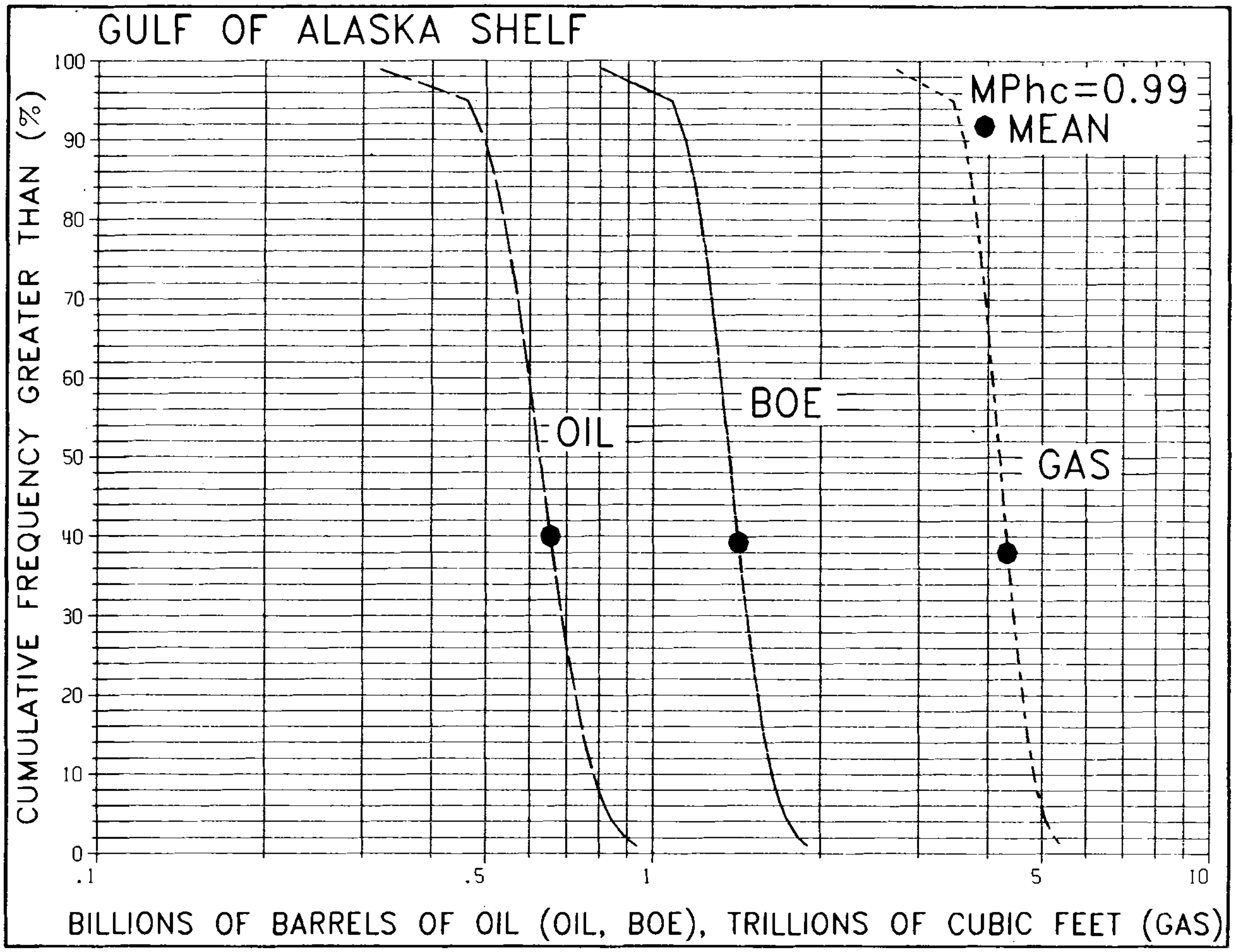

Figure 24.5: Cumulative probability curves for undiscovered, conventionally recoverable resources (oil, gas, and BOE) for Gulf of Alaska shelf assessment province. ***BOE**, total oil and gas in energy-equivalent barrels, obtained by converting gas to energy-equivalent barrels (5,620 cubic feet per barrel) and adding to oil; **MPhc**, marginal probability for occurrence of pooled hydrocarbons in province.*

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25. SHUMAGIN-KODIAK SHELF ASSESSMENT PROVINCE

by
Warren L. Horowitz, C. Drew Comer, and Kirk W. Sherwood

LOCATION

The Shumagin-Kodiak shelf assessment province comprises the Federal offshore lands on the continental shelf and slope surrounding the Kodiak archipelago and the Shumagin and Sanak Islands (fig. 25.1). The southeastern boundary is the 2,000 m isobath along the north wall of the Aleutian trench. The northeastern boundary with the Gulf of Alaska shelf assessment province follows the border between the Kodiak and Gulf of Alaska OCS Planning Areas, but also coincides with the Amatuli trough, a sea valley that transects the continental shelf seaward of the Kenai Peninsula. The Shumagin-Kodiak shelf assessment province extends about 750 miles southwest to the Sanak Islands where it meets the Aleutian (volcanic) arc assessment province (pl. 1.1, fig. 1.1).

GEOLOGIC SETTING

The Shumagin-Kodiak shelf assessment province is underlain by a broad accretionary complex that extends from the Border Ranges fault system to the Aleutian trench (fig. 25.1). These highly deformed rocks are truncated by a Miocene unconformity and overlain by relatively undeformed Neogene strata. Several Neogene depocenters, which formed as forearc and trench-slope basins, are superimposed on the accretionary complex. These depocenters are filled with Miocene and younger strata and occur throughout the continental shelf and slope in the assessment province. All of the undiscovered, conventionally recoverable oil and gas resources of the Shumagin-Kodiak shelf assessment province are associated with the Neogene sequence. Older rocks are thought to offer negligible potential for conventionally recoverable hydrocarbon resources.

The accretionary complex beneath the Neogene strata is divided into tectonostratigraphic terranes that are fault-bounded and that represent different episodes of accretion (Jones and others, 1987, Nokleberg, and others, 1994). The rocks in these terranes were formed by the accretion of offscraped trench deposits and underplated subduction complexes. Oceanic volcanic rocks, such as pillow basalt and andesitic tuff, are also present. The major terranes of southwestern Alaska are located in figure 25.1. Neogene strata of the Shumagin-Kodiak shelf directly overlap the Peninsular, Chugach, and Prince William terranes, which represent episodes of Mesozoic and Paleogene accretion, respectively. The accretionary complex was intruded by early Tertiary granitic plutons in an arcuate belt that extends from Sanak Island in the west to Baranof Island in southeast Alaska (Hudson, 1986).

The Peninsular terrane was a Mesozoic island arc system now represented by the granitic rocks of the Alaska-Aleutian Range batholith (located in fig. 23.2). The Peninsular terrane is separated from the Chugach terrane by the Border Ranges fault (fig. 25.1).

The Chugach terrane is primarily an Early Cretaceous mélange complex and a Late Cretaceous flysch sequence. These deep-water marine rocks have been metamorphosed and are highly deformed by imbricate thrust faults. The Chugach terrane is separated from the Prince William terrane by the Contact fault (fig. 25.1).

The Prince William terrane lies seaward of the Chugach terrane and includes accreted Paleocene to middle Eocene turbidites interbedded with oceanic volcanic rocks and minor pelagic sediments (Plafker, 1987). The base of the Prince William terrane on the Kodiak Islands is the highly deformed and metamorphosed Ghost Rocks Formation (fig. 25.2). It is overlain by the Eocene Sitkalidak Formation, which seldom exhibits a metamorphic grade higher than zeolite facies (Moore and Allwardt, 1980). Equivalent Eocene strata encountered in the offshore Kodiak wells are deformed (steep dips) but not metamorphosed, and, in fact, are thermally immature for petroleum generation (Turner and others, 1987).

The Oligocene Sitkinak Formation, comprised of nonmarine to deep-water volcaniclastic rocks, unconformably overlies the Sitkalidak Formation onshore. Oligocene strata were not present in the offshore Kodiak wells because of an angular unconformity at the base of the Miocene. This regional unconformity separates Neogene shelf sandstones and shales from Paleogene trench and slope deposits. Neogene strata onshore include the Miocene Narrow Cape Formation, comprised of relatively quartz-rich sandstones and shales deposited in a shelf environment, and the Plio-Pleistocene Tugidak Formation, comprised of glacio-marine sandstones and mudstones (fig. 25.2).

SEISMIC STRATIGRAPHY

Three major stratigraphic sequences were defined for the Shumagin-Kodiak shelf assessment province by integrating offshore seismic data, onshore outcrop data, and data from six stratigraphic test wells drilled on the Kodiak shelf (Fisher, 1980; Bruns and others, 1985; Turner and others, 1987; Horowitz and others, 1989). The sequences are compared to regional stratigraphy in figure 25.2 and are described below.

Sequence A (Economic Basement): This sequence includes the Cretaceous through Paleocene accretionary complex of the Chugach terrane and the Ghost Rocks Formation of the Prince William terrane. These highly deformed rocks are metamorphosed and have no source-rock or reservoir-rock potential.

Sequence B (Source Rock): This sequence includes the Eocene Sitkalidak Formation and equivalent strata offshore, which are volcaniclastic sedimentary rocks deposited in a trench-slope setting, now generally highly deformed by subduction-related tectonism of the Shumagin-Kodiak shelf. Although these rocks are the best potential regional candidates for petroleum sources, geochemical analyses of samples from wells on the Kodiak shelf indicate that sequence B strata are organically lean and unlikely to form sources for petroleum in that area. Furthermore, the sequence B rocks are gas-prone, with the predominant kerogen type being woody-herbaceous material. In the KSSD No. 3 well, the total organic carbon was less than 0.6 percent (poor source to nonsource) and vitrinite reflectance values were typically less than 0.6 percent (below threshhold for petroleum generation). Sequence B strata may reach thermal maturity beneath the deeper Neogene depocenters, but their distribution in the pre-Neogene structural complex is unknown. Sequence B strata reach maximum thicknesses less than 6,000 feet.

Sequence C (Reservoir Rock): This sequence includes the Miocene Narrow Cape Formation, the Plio-Pleistocene Tugidak Formation, and equivalent strata offshore. The sequence consists of Neogene sandstones and shales, deposited in inner to outer neritic depths, that are more quartz-rich than underlying strata. The best potential reservoir rocks encountered offshore are middle Miocene sandstones in the Kodiak Shelf Stratigraphic Drilling (KSSD) No. 3 well. Logs and cores from this section show relatively clean, though well-cemented, sandstones, with an aggregate thickness of 462 feet. The effective porosity indicated by logs and sidewall cores ranged from 13.3 to 27.2 percent. Sequence C strata unconformably overlie sequence B, and in places sequence A strata. Sequence C strata range from 2,000 to 20,000 feet thick. Sequence C strata typically thicken to the south and locally thicken within structurally controlled basins on the shelf. Sequence C strata thin over uplifted fault blocks and within folds and thrust faults. Most of these structures formed during widespread late Neogene deformation.

EXPLORATION HISTORY

Six stratigraphic test wells were drilled on the Kodiak shelf. The first series of wells, the Kodiak Shelf Stratigraphic Test (KSST) Program, were drilled in 1976 to shallow depths (4,000 feet or less) and obtained relatively limited data. The second series of wells, the Kodiak Shelf Stratigraphic Drilling (KSSD) Program, were drilled in 1977 to depths of 8,000 to 10,000 feet and acquired far more data (data summary provided by Turner and others, 1987).

PLAY DESCRIPTIONS

For the 1995 assessment, the potential resources of the Shumagin-Kodiak shelf province are consolidated into a single play—the Neogene structural play. Data used to characterize and model the Neogene structural play are tabulated in Appendix A3.

Play 1 (UASH0100[1]). Neogene Structural Play: The play encompasses the entire shelf and upper slope, but the most prospective areas are the Neogene depocenters on the shelf where Miocene and younger strata reach maximum thicknesses. Traps include thrust-faulted and normal-faulted anticlines formed by Neogene tectonism. The only speculated possibility for source rocks that might charge the play are Eocene strata that are markedly gas-prone and organically lean in the areas of well control. Source rocks therefore form a major risk element for the play. Hypothetical Eocene source rocks, if present, will be sufficiently thermally mature to generate petroleum only beneath the Neogene depocenters. Potential reservoir rocks are the overlying relatively quartz-rich sandstones of mostly middle Miocene age.

RESOURCE ASSESSMENT

The undiscovered, conventionally recoverable ***gas*** resources for the Shumagin-Kodiak shelf assessment province average 2.650 trillion cubic feet but could exceed 11.351 trillion cubic feet (table 25.1). The province was modeled as offering potential only for gas. The quantities reported as "oil" in table 25.1 are entirely natural gas liquids that would be obtained only as a by-product of gas production. Cumulative probability distributions for gas, natural gas liquids, and BOE resources in the Shumagin-Kodiak shelf assessment province are shown in figure 25.3. Cumulative probability distributions and a ranked pool-size plot for play 1 are shown in Appendix B3.

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[1]The "UA" Code is the "Unique Assessment Identifier" for each play, and is the principal guide to GRASP data files.

TABLE 25.1
OIL AND GAS ENDOWMENTS OF SHUMAGIN-KODIAK SHELF PLAY
Risked, Undiscovered, Conventionally Recoverable Oil and Gas

PLAY NO.	PLAY NAME (UAI* CODE)	OIL (BBO)**			GAS (TCFG)		
		F95	MEAN	F05***	F95	MEAN	F05***
1.	Neogene Structural Play (UASH0100)	0.000	0.070	0.250	0.000	2.650	9.089
	*FASPAG AGGREGATION****	*0.000*	*0.070*	*0.285*	*0.000*	*2.650*	*11.351*

* *Unique Assessment Identifier, code unique to play.*
** *entirely natural gas liquids derived from gas extraction; no pooled oil present*
*** *Differences in F05 values at play and basin levels reflect different mathematic methods for construction of probability distributions.*

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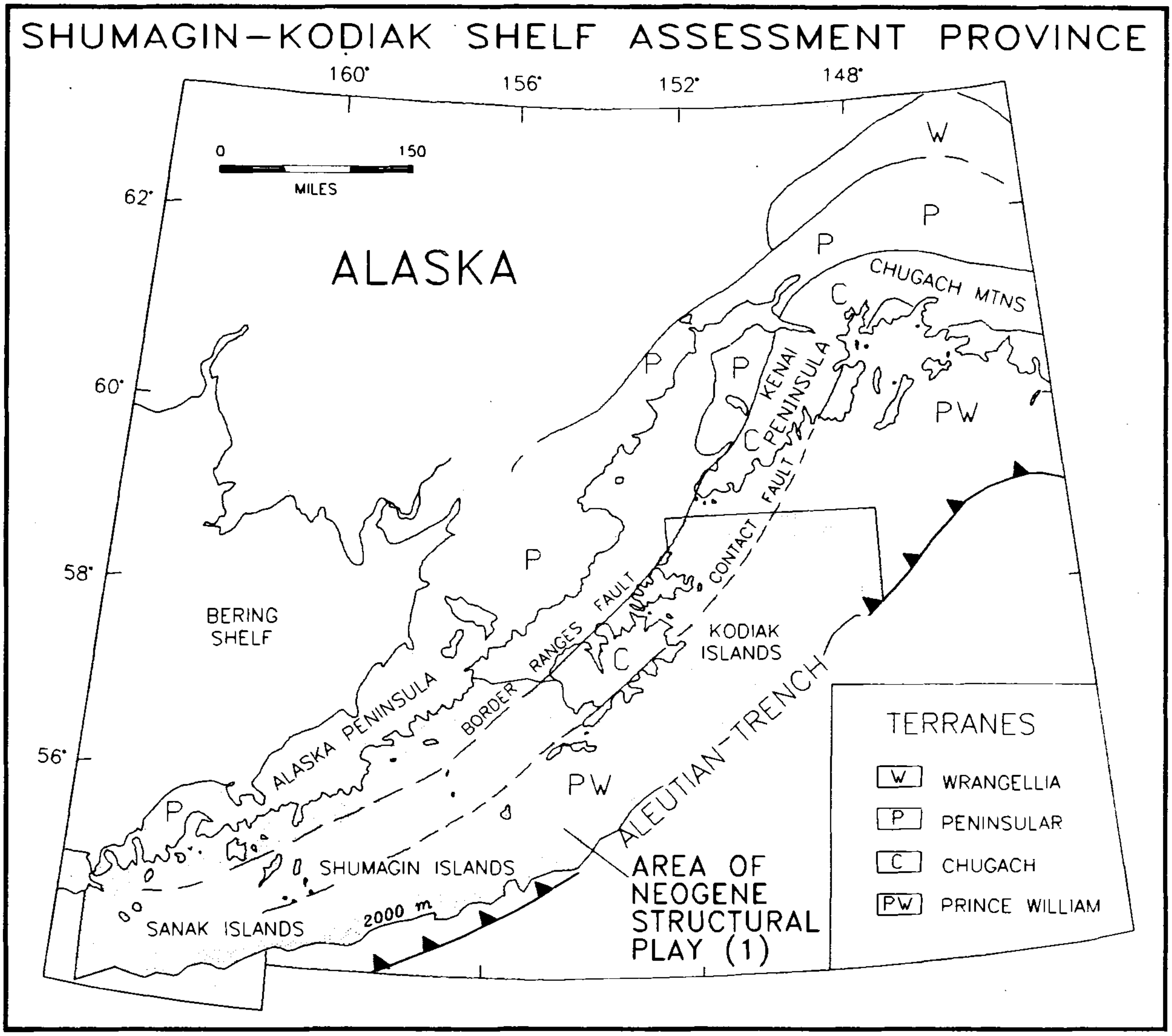

Figure 25.1: Map of the Shumagin-Kodiak shelf assessment province and area of play 1 (both within patterned area) with tectonostratigraphic terranes of the Pacific margin of Alaska.

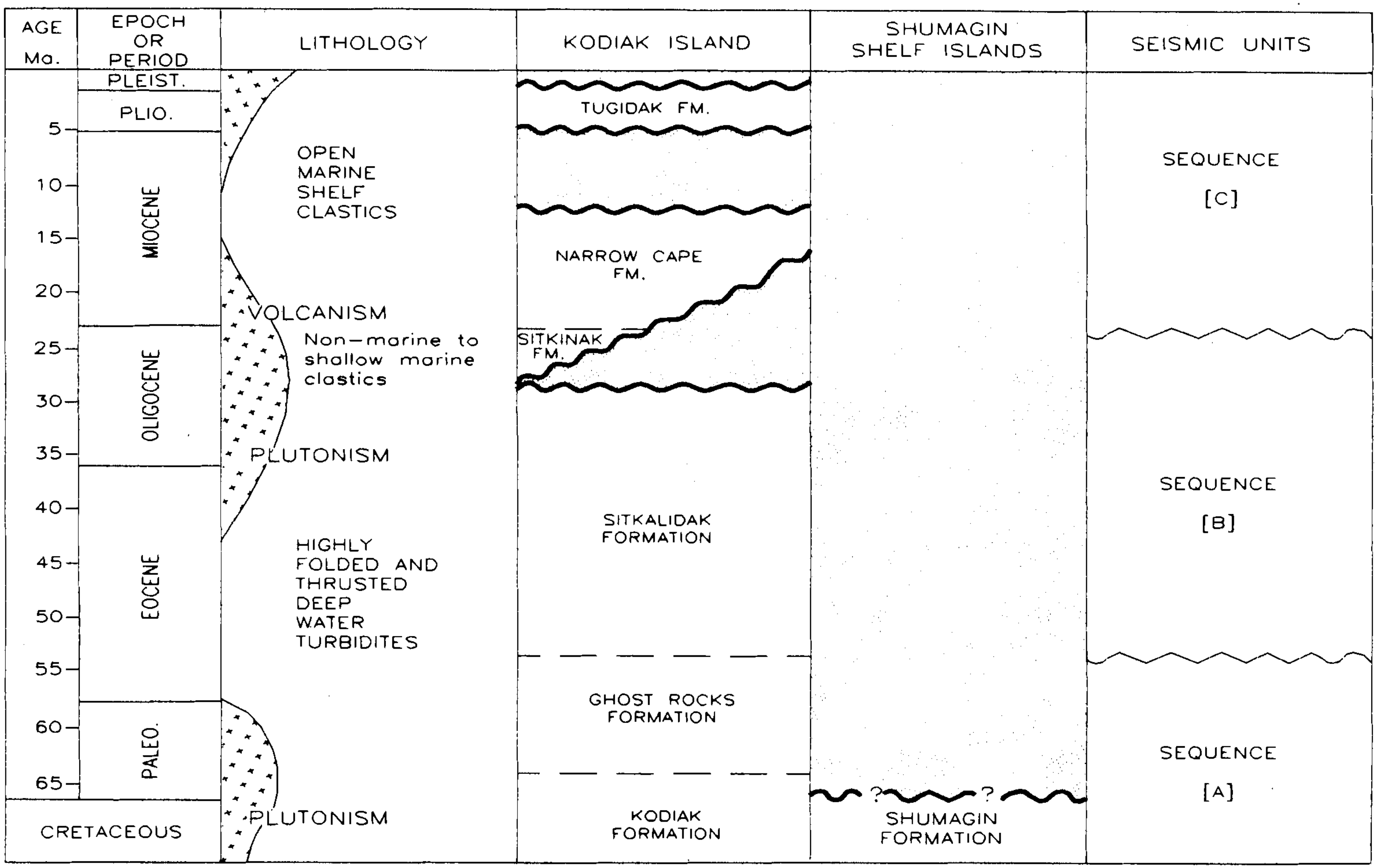

Figure 25.2: Generalized correlation chart for the Shumagin-Kodiak shelf assessment province. The Neogene structural play (1) primarily involves seismic sequence C.

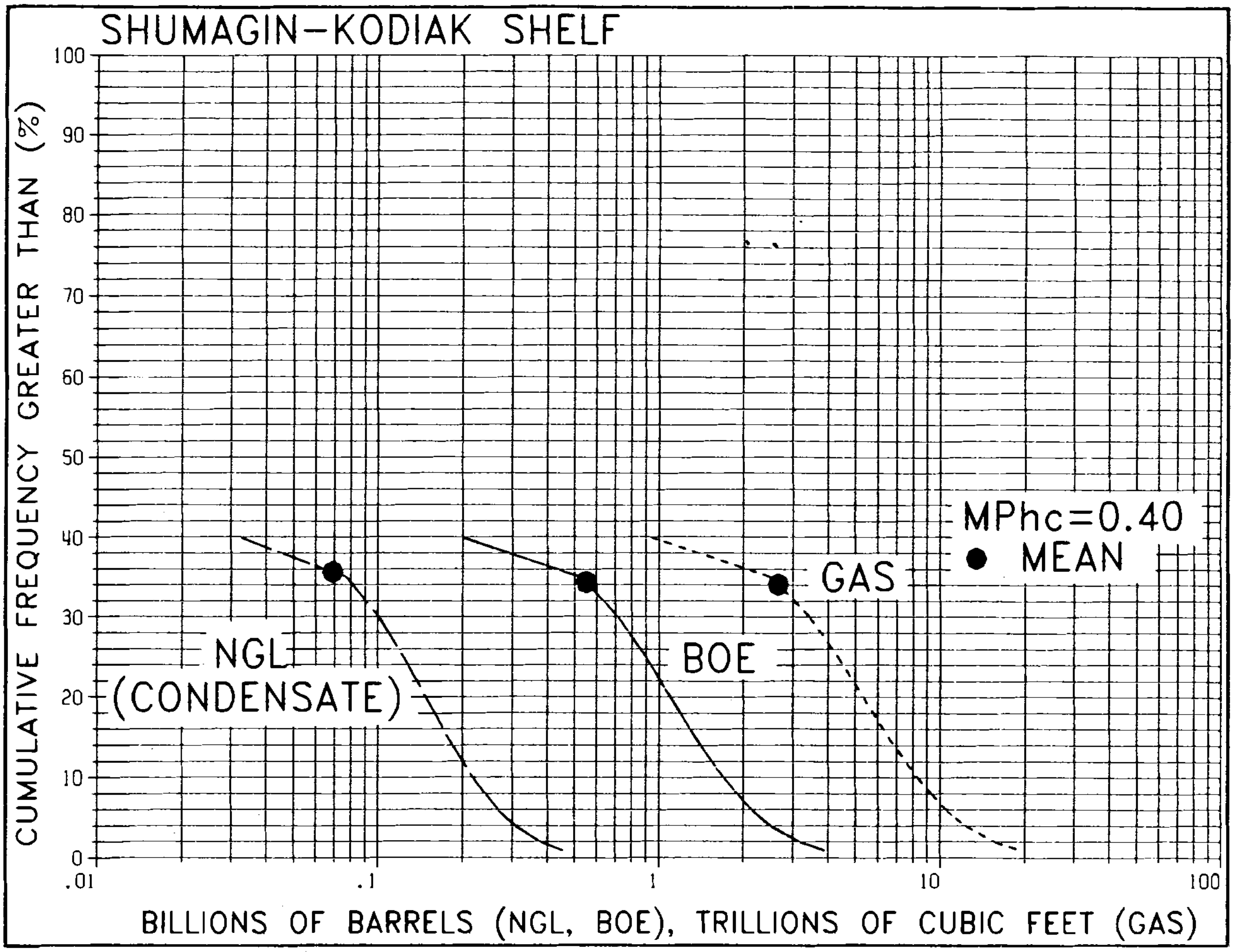

Figure 25.3: Cumulative probability curves for undiscovered, conventionally recoverable resources (oil, gas, and BOE) for Shumagin-Kodiak shelf assessment province. ***BOE**, total oil and gas in energy-equivalent barrels, obtained by converting gas to energy-equivalent barrels (5,620 cubic feet per barrel) and adding to oil; **MPhc**, marginal probability for occurrence of pooled hydrocarbons in province. **NGL**, natural gas liquids, obtained only as a by-product of gas production (Shumagin-Kodiak shelf assessment province was assessed as offering potential only for gas). NGL corresponds to "oil" quantities as reported in tables 22.1, 25.1, Appendix A3, and Appendix B3.*

ECONOMIC ASSESSMENT

ECONOMIC ASSESSMENT
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26. INFRASTRUCTURE SCENARIOS

by
James D. Craig

INTRODUCTION

Infrastructure scenarios are general plans for producing and transporting hydrocarbon resources. The hypothetical scenarios for the Alaskan offshore assessment are based largely on previous engineering feasibility studies contracted by industry and government during the 1980's (Selected References). Although the existing studies are somewhat dated, very little offshore petroleum development has occurred in Alaska, so these studies have not been tested under actual conditions. It is reasonable to assume that the initial development projects in these offshore provinces will generally follow the available feasibility studies. Realistic development scenarios, based on available feasibility studies, have been incorporated into Environmental Impact Statements (EIS) prepared for leasing in most of the assessment provinces. For the present assessment, current engineering technologies are considered when formulating infrastructure designs and production strategies. Clearly, there are alternatives, and perhaps equally feasible, infrastructure scenarios. The concepts adopted for the present assessment represent general conditions, and it is quite possible that future projects may utilize new technologies or be modified to accommodate site-specific conditions.

Development Assumptions

Several general assumptions regarding offshore development in the offshore frontier provinces in Alaska were made to provide consistency throughout the economic assessment.

- *Current conventional technology was assumed for resource recovery.* No attempt was made to estimate the effects of new engineering technologies or strategies that might be developed in response to high commodity prices in the future. Liquefied natural gas (LNG) technology was assumed for long-distance gas transportation, and new technologies, such as gas-to-liquids (GTL) conversion, were not analyzed in the present assessment.
- *Each province was modeled as a stand-alone case.* The cost of new infrastructure in each province was supported by resources in that province. Existing infrastructure was utilized wherever possible, and costs to utilize existing facilities were included as tariffs.
- *Infrastructure models were based on regional mapping of prospects and plays.* Offshore lease sales have been held in most of the Alaska assessment provinces. Seismic survey and well data have been collected by industry and acquired by MMS. This extensive database has been used in the assessment of conventionally recoverable

resources, as well as for the engineering layout for new infrastructure.

- *Infrastructure design concepts were biased according to resource potential.* To provide a realistic simulation, initial exploration and development infrastructure is centered around high resource plays. Infrastructure layouts were setup so that "good plays" (low risk and high resources) would not be excessively burdened by costs associated with "poor plays" (high risk and low potential).
- *Infrastructure models were designed to optimize the commercial viability of each province.* Preliminary modeling runs tested various production scenarios (oil-only; gas-only; oil-gas coproduction) to determine optimum economic viability. Typically, the dominant resource commodity (oil or gas) in the province has more favorable economics, and the secondary resource commodity acts as an economic burden. To provide a more realistic assessment, the development scenarios for each province were optimized to recover with the most economically attractive resources.
- *Provinces dominated by oil resources adopted an "oil-only" production model,* where gas was not marketed. Non-associated gas pools were not development. Associated and dissolved gas resources recovered with crude oil were assumed to be consumed as fuel for facilities or reinjected for reservoir pressure maintenance. At some later date, depleted oil reservoirs could be developed as gas fields. However, this delayed gas production scenario was beyond the time frame for the present assessment.
- *Provinces dominated by gas resources adopted a coproduction model.* Condensate recovered with wet-gas production is typically collected and marketed as a value-added commodity. Because the volumes of condensate liquids in gas-prone provinces were often equivalent to meager crude oil volumes, we assumed that both oil and condensate would be recovered and then transported together.
- *Full-cycle costs were assumed.* Exploration and delineation costs (including seismic surveys, site clearance surveys, rig mobilization, well drilling, and logging/testing) associated with each discovery were added to the simulated cash flow model. New regional transportation infrastructure, including trunk pipelines, processing facilities, and marine terminals, were included as capital costs supported by all successful prospects/plays in the province. The costs of lease acquisition and dry wells leading to the discoveries were not included. No attempt was made to estimate the number of wells required to confirm the total resource potential of each province.
- *The timing for discovery and development of each play was based on the risked resource potential and the number of prospects in the play.* Considering the logistical realities in most Alaska provinces, it would be nearly impossible to rapidly explore and develop a large number of prospects and plays. Even with aggressive efforts by numerous independent groups, exploration and development could take decades. A delay to discovery was used so that the "good plays" (high resources/low risk) were discovered and developed before the "poor plays" (low resources/high risk).

Transportation Assumptions

Petroleum operations in Alaska typically have high costs associated with transportation. The petroleum provinces often encompass large areas and there are great distances from Alaska to outside markets. As previously discussed, transportation scenarios were developed considering both engineering and economic feasibility. Transportation assumptions common to all assessment provinces are outlined as follows:

- *Oil and gas production from all provinces* *is shipped by tankers to United States and Asian markets.* Generally, production of both oil and gas would exceed the demand of the local Alaska market. Gas production was converted to LNG, and oil production was commingled with gas-condensate liquids.

- *Los Angeles is assumed to be the receiving port for hydrocarbon liquids (crude oil and condensates from natural gas).* We assumed that crude oil and condensate would be commingled for transportation in pipelines and tankers. Other west coast ports currently receive Alaska's oil exports; however, Los Angeles is the main delivery and refining destination.
- *Yokohama, Japan, is assumed to be the primary receiving port for Alaska LNG.* Receiving infrastructure (offloading terminal, regasification plant, and gas storage) is presently operating at the port of Yokohama. Other potential Pacific Rim markets for Alaska LNG (Korea, Taiwan, and China) do not have established LNG trade routes, but could have LNG deliveries in the future. These alternate delivery ports will have slightly higher transportation costs.
- *New infrastructure and operations/processing at the delivery point, such as receiving terminals, storage, and regasification plants, are not included in the transportation costs.* Capital cost recovery for loading and delivery systems (marine terminals and tankers) as well as their operating costs are included as transportation tariffs incurred by the producers. Transportation costs are subtracted from the landed market price to determine the wellhead price.
- *Whenever feasible, pipelines are favored as transportation systems within the Alaska region.* This assumption is consistent with Federal lease stipulations, which state that pipelines are the preferred system because of their safety record as compared to tankers. The choice between subsea pipelines and offshore loading terminals was made case-by-case, considering regulations, cost effectiveness, and engineering feasibility.
- *Offshore storage and loading of crude oil was employed for remote, deepwater provinces.* For the offshore loading scenarios, shuttle tankers are employed to move liquid hydrocarbons to the main export terminals in southern Alaska. It was assumed that third-party companies conduct the shuttle tanker operations and charge transportation tariffs.
- *Pipelines are used exclusively for gas transportation systems within Alaska.* All gas production was assumed to be processed by onshore LNG facilities and then exported to the Pacific Rim.. New LNG facilities and associated marine terminals were sited in optimum locations considering suitability of natural harbors, weather and sea conditions, accessibility, and engineering feasibility. These optimal locations could perhaps serve several offshore provinces.

The destination ports and transportation tariffs assumed for this study are listed in table 26.1. Only three tanker routes are currently in use to export Alaska oil and gas (gas as LNG). All potential markets are at great distances, ranging from 2,400 to 4,000 miles. Shuttle tanker routes connecting remote terminals to the main export terminals in southern Alaska range from 250 to 2,050 miles. Transportation components and costs are summarized in table 26.2. As expected, transportation distances and corresponding costs increase northward, from relatively low costs for the Gulf of Alaska province to very high costs for the Chukchi shelf province. The hypothetical transportation routes are shown in figures 26.1 (oil) and 26.2 (gas).

ARCTIC SUBREGION

The North Slope of Alaska and adjacent offshore shelves of the Beaufort and Chukchi Seas are challenging areas for petroleum operations. Only a small portion of this vast area

TABLE 26.1: TRANSPORTATION ROUTES AND TARIFFS

Transit and Destination Ports	Distance (miles)	Oil Tariff ($/bbl)	Gas Tariff ($/MCF)
Prudhoe to Valdez (TAPS)	800	3.25	
Valdez to Los Angeles	2400	1.40	
Valdez to Yokohama	4000		0.80
Kivalina to Valdez	2050	1.78	
Kivalina to Yokohama	3500		0.70
Nome to Valdez	1750	1.51	
Nome to Yokohama	3100		0.62
Navarin to Balboa Bay	1200	1.03	
St. George to Balboa Bay	400	0.52	
Balboa Bay to Los Angeles	2600	1.52	
Balboa Bay to Yokohama	3000		0.60
Kodiak Shelf to Valdez	250	0.22	
Cook Inlet to Los Angeles	2500	1.45	
Cook Inlet to Yokohama	3800		0.76
Yakutat to Yokohama	3700		0.74
Yakutat to Los Angeles	2200	1.28	

Notes: Existing routes are shown in italics. Balboa Bay is the hypothetical site of a new facility on the Alaska Peninsula. Distances are obtained from Defense Mapping Agency (1985) and are converted from nautical miles to statute miles (1.0 n.mi = 1.151 stat.mi). Shuttle tanker routes are estimated as great circle tracks. Oil tariffs are assumed to average $0.58/bbl-1000 mi. Oil shuttle tankers are 1.5x higher ($0.87/bbl-1000 mi). Gas tariffs are assumed to average $0.20/Mcf-1000 mi. LNG shuttles are 1.5x higher ($0.30/Mcf-1000 mi).

contains existing transportation infrastructure, and the ocean is covered by sea ice over most of the year. The central North Slope contains marine docking facilities, a jet airport, and overland road access; however, there are no deep-water ports or alternate coastal staging bases. Virtually no infrastructure capable of supporting offshore operations exists on the Chukchi coast. In the southern Chukchi Sea (Kotzebue Sound), marine docking facilities are currently supporting the Red Dog mining operation.

For past development activities on the North Slope, heavy production equipment was moved by barges towed from the West coast. The timing of this "sealift" was critical because of the short open-water period during mid-summer. Supplies and materials can be hauled year-round by trucks to the central North Slope facilities, but the land route is over 1,000 road miles from the main distribution centers in southern Alaska. Personnel and supplies can also be transported as air cargo, but severe weather during winter months can restrict flights. Onshore transportation on the North Slope is restricted by numerous rivers crossing the poorly drained tundra of a coastal plain. Structural engineering must contend with unique problems related to seasonal freezing and thawing of the tundra surface underlain up to 2,000 feet of permafrost (permanently frozen ground).

Offshore operating conditions are even more demanding. On the northern coastline, there is a short open-water season for 2 to 3 months during the summer, broken sea ice conditions in early summer and fall, and continuous sea ice cover during the remainder of each year. Offshore seismic surveys are typically scheduled for the brief open-water season for offshore sites in deep water. Drilling from bottom-founded platforms can be conducted year-round, but long-term production operations must be designed to withstand severe ice forces. Platforms in water depths greater than 45 feet will be stressed by movements of the Arctic ice pack, which could contain multi-year pressure ridges and ice islands. Ice conditions are progressively milder farther south, but are still considered to be a major environmental constraint in all areas north of the Bering Strait.

Production and transportation infrastructure on the North Slope is likely to be utilized by new offshore development (fig. 26.3). This infrastructure was initially constructed to support two huge oil fields (Prudhoe Bay and Kuparuk River) discovered in the late-1960's. The Trans-Alaska Pipeline System (TAPS) began operation in 1977 and has carried oil 800 miles south across Alaska to the ice-free port of Valdez for 2 decades. Relying heavily on the Prudhoe/Kuparuk infrastructure, over a dozen oil fields have been discovered and developed in the surrounding area. The TAPS throughput peaked at slightly over 2.0 million barrels per day (MMbpd) in 1988, and by 1995 the rate had dropped to 1.5 MMbpd (AK-DNR, 1997). Because the major North Slope fields are in decline, it is likely that excess capacity will be available in existing facilities and TAPS to receive oil from newly developed fields. The development scenarios for the offshore Beaufort and Chukchi shelf provinces are highly dependent on the continued operation of TAPS as the vital transportation system to outside markets. In contrast to the extensive oil development on the North Slope, gas resources have not been produced for outside market. Nearly 35 TCF of gas reserves (mostly in the Prudhoe Bay field) remain shut-in because of the lack of a gas transportation system. Various economic hurdles have precluded construction of a gas pipeline and LNG system estimated to cost $12-15 billion. Until a transportation system is constructed to carry North Slope gas, new development of offshore gas resources is not expected. Because there is no gas transportation system, the scenarios for the Beaufort and Chukchi provinces simulation "oil only" production.

Beaufort Shelf

For the foreseeable future, development in the Beaufort Sea will be restricted to relatively shallow water depths (< 600 ft) on the continental shelf. Production platform designs vary with water depths; where artificial gravel islands are the preferred platforms in shallow areas (< 50 ft depths), mobile gravity structures are the likely design in moderate depths (50-150 ft), and either conical floating platforms or subsea well systems will be employed on the outer shelf (> 150 ft). Exploration wells are likely to employ similar platform types, with emphasis on mobile designs (gravity cones or drillships).

The maximum number of wells that can be contained on a production platform varies with platform type. We assumed that space and topside weight are not limiting factors for artificial islands, so up to 90 well slots could be installed. For mobile gravity platforms, topside space is a limiting factor, so a maximum of 60 well slots was assumed. For floating conical platforms, both topside weight and space were limiting factors, so a maximum of 48 well slots was assumed.

The resource potential of the Beaufort province is contained in 23 geologic plays distributed widely over nearly 500 miles of the narrow continental shelf facing the Arctic Ocean. A regional pipeline network was devised to collect resources from these widespread plays into the TAPS pipeline near Prudhoe Bay (fig. 26.1). The hypothetical pipeline network consists of new overland main lines totaling 250 miles, in addition to an extensive network of offshore gathering lines (not shown). Five pipeline landfalls were located at optimum locations along the Beaufort and Chukchi coastlines. Offshore pipelines will be trenched as protection against seafloor ice gouging and are considerably more expensive to install than onshore pipelines. Consequently, onshore alignments were favored over offshore routes to gather oil production to TAPS.

Because only a few plays are likely to contain the majority of economically recoverable resources, the trunkline network was designed to support the rich (high resource/low risk) plays. Gathering lines required for oil production from the poor (low resource/high risk) plays were prorated by adjusting pipeline mileage according to mean resource volumes. Flowlines that collect oil production from prospects to central locations within the play area could range from 5-25 miles in length, depending on the distribution of prospects in each play. Larger diameter gathering lines (play pipelines) that deliver play resources to the trunkline systems vary from 10-120 miles (tbl. 26.2). It was usually assumed that "stacked plays" would be co-developed and produced through shared pipeline gathering systems.

New pipeline systems were treated as capital costs, with costs prorated (by mileage) according to mean resource potential of the plays sharing the system. The cost of using existing pipeline systems was included as tariffs. Transportation data are summarized in table 26.2.

Considering the logistical realities, it would be nearly impossible to rapidly discover and develop the large number of prospects and plays modeled in the Beaufort province. To stagger the development timing, we employed a delay before discovery based largely on resource potential. The staggered timing of future development would create a slow expansion of infrastructure, and the full development scenario may not be realized for decades.

Chukchi Shelf

The development scenario for the Chukchi province is similar in many ways to the Beaufort province, where sea ice is the dominant environmental constraint. Generally deeper water on the Chukchi shelf will require modifications in platform designs. Because much of the preceding discussion regarding platform and pipeline assumptions in the Beaufort province is also relevant to the Chukchi province, the following discussion will focus on key differences between these two Arctic provinces.

Chukchi province resource potential is contained in 22 plays, with prospects scattered widely over a province area of roughly 60,000 square miles. Because the continental shelf is wider in the Chukchi Sea, the central points in most of the play areas are 100 miles (or more) from the coastline. Water depths in the Chukchi province are generally greater, with much of the province lying at seafloor depths between 130 and 200 feet. At these water depths, bottom-founded gravity platforms must be larger or subsea production systems must be used. Neither platform designs or subsea systems have been tested in these water depths under harsh Arctic conditions. The maximum number of wells is influenced by platform type, but generally larger platforms or subsea arrays were assumed to

TABLE 26.2:
PIPELINE INFRASTRUCTURE AND TRANSPORTATION TARIFFS

Offshore Assessment Province	Basin Pipeline (miles)	Play Pipelines (miles)	Flow-lines (miles)	Oil Tariffs ($/bbl)	Gas Tariffs ($/MCF)
Beaufort	250	10-120	5-25	4.89	*not produced*
Chukchi	555	10-90	10-40	5.49	*not produced*
Hope	100	10-45	10-30	4.94	2.03
Norton	65	10-60	10-20	5.20	1.95
Navarin	700	30-60	10-20	3.53	1.92
St. George	340	10-150	10-35	3.30	2.00
North Aleutian	70	0	20	1.99	1.35
Shumagin-Kodiak	215	40	20	2.34	3.47
Cook Inlet	125	10-30	6-12	1.68	*not produced*
Gulf of Alaska	0	30-250	10-25	1.35	*not produced*

Notes: New pipelines are modeled as capital costs. Tariffs are used for using regional transportation systems and for postulated third-party operations. Basin pipelines are large-diameter trunklines and may include both overland and offshore segments. Play pipelines are gathering lines and may carry production from one or more plays. Flowlines are smaller diameter pipelines connecting platforms or fields to gathering points served by play pipelines. Oil tariffs are estimated transportation costs that could include tanker, terminal, and feeder pipeline charges. Gas tariffs are estimated transportation costs that could include LNG carriers, facility charges, and pipeline charges. Wellhead price is the market price minus the transportation cost. Provinces with oil/gas coproduction scenarios assume that crude oil and gas-condensate are commingled for transportation. Provinces showing gas "not produced" have gas infrastructure costs, which adversely affect commercial viability of oil.

include a maximum of 90 wells at each platform site. Pipeline systems were designed to collect oil production from the widely scattered plays in the province. The trunkline system consisted of both offshore and onshore segments. Offshore trunklines (135 miles in total length) ran from two centrally located offshore facilities to landfalls on the Chukchi coast. Overland trunklines (420 miles in total length) run from these coastal landfalls to TAPS at Pump station No. 2 (fig. 26.1). A more southerly overland route was chosen to avoid the poorly drained tundra and inlets of the northern coastal plain. Similar to the Beaufort province, offshore gathering systems were modeled as serving several plays (either stacked or in close proximity) with pipeline costs prorated by mileage according to risked mean resource potential. Because the Chukchi plays cover wide areas, play pipeline lengths vary between 12-90 miles. Prospects within play areas are also quite widespread, so flowline lengths vary between 10-40 miles (tbl. 26.2). Like the Beaufort, all offshore pipelines are assumed to be trenched as protection against seafloor ice gouging in water depths less than 150 ft.

Delays to discovery were formulated according to risked resource potential, where "good plays" (high resources/low risk) were assumed to be discovered and developed before "poor plays" (low resources/high risk). Development of the Chukchi province could take many decades, during which time oil production from this area is entirely dependent on continued operation of North Slope infrastructure, particularly TAPS. Like the Beaufort province, gas production and marketing is assumed not to occur until a North Slope gas transportation system is constructed.

Hope Basin

The Hope basin province was modeled for the production of gas and oil, although natural gas will primarily support initial development. Crude oil could be recovered if satellite oil pools are reachable from gas production platforms. Gas-condensates recovered as a byproduct of gas production could share crude oil transportation systems (fig. 26.1). At the present time, there are no petroleum operations in this remote area off northwestern Alaska. A small marine terminal currently is used to export partially refined ore from the Red Dog mine in Kotzebue Sound. We assumed that this industrial base could be expanded to accommodate petroleum operations.

Environmental conditions in the southern Chukchi Sea are considerably milder than in more northern Chukchi and Beaufort seas. Sea ice forms in the fall and covers the area for over half of the year. However, incursion of permanent Arctic ice pack does not occur. Sea ice movement is both rapid and erratic, requiring special design considerations for permanent platforms. Water depths are moderate, ranging from 50-180 feet.

In mobile sea ice conditions, large bottom-founded concrete platforms are the preferred design for production. However, considering the platform size required for these water depths, ice reinforced floating production platforms or subsea systems are likely to be favored. Exploration drilling would be conducted using drillships with icebreaker support vessels during the short open-water season. Offshore platforms will require extensive gas handling equipment, but fewer well slots are needed because subsurface drainage areas are generally larger for gas reservoirs. Also, fewer service wells are needed for gas fields.

The resource potential is contained in 4 geologic plays that generally cover similar areas in the province. Many of the prospects are located along prominent structural features. To optimize the development of the basin, the scenario assumed that co-located pipelines (gas and liquid) would carry production products from surrounding offshore fields to a centrally located offshore facility. Because the province is relatively small and the plays and prospects are grouped, offshore gathering systems to the main trunkline would range from 10-45 miles in length (tbl. 26.2). Gas and hydrocarbon liquids (condensate and crude oil) would be transported by a 100-mile subsea pipeline to a new onshore facility constructed adjacent to the Red Dog marine terminal (figs. 26.1).

Considerable expansion to the present coastal industrial site (Red Dog terminal) would be required, including a LNG facility, temporary storage tanks, and a petroleum loading terminal. Gas production would be converted to liquefied natural gas (LNG) and then shipped by LNG carriers to markets in the Pacific Rim (fig. 26.2). It was assumed that the principle delivery port is Yokohama, Japan, which is a 3,500 mile great circle shipping route. Surprisingly, this distance is comparable to the ocean route for current LNG shipments from the Cook Inlet to Japan (tbl. 26.1). Ice conditions in this northern area would require modifications to normal LNG carriers, including smaller size/shallower draft and moderate ice-breaking capabilities. Ice conditions are likely to require additional icebreaker support, although even with icebreakers LNG shipments might be curtailed during the winter.

For liquid hydrocarbon production, it was assumed that crude oil and gas-condensate would be commingled in a subsea pipeline connecting the central offshore facility to an onshore tank farm and loading terminal. Petroleum liquids, and additional natural gas liquids (ngl) separated in the LNG plant, would be transported by ice-reinforced shuttle tankers to a transshipment terminal in southern Alaska (Valdez). From Valdez, Hope basin oil would be added to North Slope crude oil and shipped to the U.S. West coast (fig. 26.1). Despite its remote location, the estimated transportation tariffs for oil produced in the Hope basin province are equivalent to the transportation tariffs for Beaufort Sea oil (tbl. 26.2).

Because of its location between other potential gas producing provinces (Chukchi shelf and Norton basin), future development of the Hope basin may be linked to development activities in adjacent provinces. The viability of small remote provinces could be improved considerably by coordinating development and transportation strategies. New technologies for gas transportation could also significantly change the scenario presented here. It is worthwhile to note that this offshore province has not been offered for leasing or drilled, and development scenarios could be delayed long into the future.

BERING SHELF SUBREGION

Offshore assessment provinces in the Bering Sea present a wide diversity of operating conditions. In the northern part of this subregion, sea ice is the major constraint to development in a relatively shallow water setting. Provinces in the western Bering Sea lie in deep water along the edge of the continental shelf where severe storms are frequent year-round and sea ice is present in the winter. The southern Bering Sea is less affected by sea ice cover, but earthquake and volcanic hazards are associated with the Alaska Peninsula and Aleutian Islands.

A major logistical factor affecting the Bering Shelf provinces is their remoteness. Existing infrastructure capable of supporting offshore petroleum activities is separated by hundreds of miles of open ocean. The two principle marine ports are in Nome and Dutch Harbor, separated by nearly 800 miles (fig. 26.1). Airports capable of serving large transports and jets are present in Nome and Cold Bay on the Alaska Peninsula (fig. 26.1). Exploration drilling activities in the Bering Sea in the mid-1980's generally utilized one or more of these locations as staging areas. Since then, there has been no leasing or petroleum exploration, and oil support has been dismantled. Infrastructure associated with the fishing industry has expanded to additional support bases (St. Paul Island in the Pribilof group). At present, commercial fishing is the dominant industrial activity in the Bering Sea.

Sea ice forms each fall in the Bering Sea and the edge of the seasonal ice pack moves progressively southward to a maximum near the Pribilof Islands by May. June through October are generally open-water months. Sea ice can form up to 3-feet thick, and erratic ice movements driven by wind and sea currents can place heavy loads on platform support structures. Superstructure icing during fall and winter storms is moderate to severe in the southeastern Bering Sea and can affect the buoyancy and stability of floating platforms.

Platform design is primarily influenced by water depth and seasonal ice conditions. Exploration drilling would employ jack-up rigs towed to drill sites in shallow water (<150 ft). In deeper water areas, semisubmersible rigs would be favored because they are more stable than drillships in rough seas. For production platforms, artificial islands are proven designs for shallow water areas with sea ice conditions. Gravel or caisson-retained islands could be selected for sites in water depths to about 50 feet. For deeper areas on the shelf (50-300 ft) bottom-founded platforms are the likely production platform types. Production platforms for fields in deep-water areas (> 300 ft) are likely to be floating types. Some fields could be developed using subsea wellhead templates with pipelines tied back to nearby production platforms. Recent deep-water platform designs used in more southern latitudes would have to be extensively modified to withstand both sea ice movement and superstructure icing conditions.

An important consideration to future development in the Bering subregion is that all provinces are expected to be gas-prone. Because potential markets are thousands of miles away, all gas production will have to be converted to some form suitable for shipping. LNG was the method selected because it is a proven commercial method. Considering gas resource potential, the future LNG facility would be of modest size, probably a single-train capable of processing 50-150 billion cubic feet per year (BCF/yr). However, initial costs of LNG facilities are very high (billions of dollars) and, using proven practices, will require an onshore location. Consequently, many of the Bering Shelf scenarios involve long subsea pipelines to coastal sites suitable for year-round marine terminals.

To formulate a realistic scenario, various criteria were considered before selecting a site for hypothetical new LNG facilities. Locations at optimum onshore sites could be used by several Bering Shelf provinces, although each province was analyzed as a stand-alone. Several sites on the Alaska Peninsula suitable for new year-round deep-water ports were identified by previous feasibility studies. One site is located at Morzhovoi Bay (near Cold Bay) and the other site is at Balboa Bay (near Port Moller). For the present assessment, Balboa Bay was selected because it has a more protected natural harbor (undeveloped at present). Hope basin and Norton basin provinces were modeled with small LNG facilities near existing infrastructure in their respective areas, whereas the Navarin, St. George, and North Aleutian provinces were modeled for common use of a new LNG facility at Balboa Bay (fig. 26.2).

Norton Basin

Norton basin province is located in the northeastern corner of the Bering Sea in the shallow waters of Norton Sound. This province is elongated east-west and is approximately 40 x 125 miles in dimension. Hydrocarbon resource recovery was modeled primarily for the production of natural gas because the geologic assessment concluded that no significant crude oil resources are present. Liquid hydrocarbons, in the form of gas-condensate, could be recovered as a byproduct of gas production.

Currently, there is no petroleum-related infrastructure. New infrastructure, including an LNG facility and marine loading terminal, is likely to be located in the vicinity of Nome with its existing airport and port facilities. The primary constraints to year-round operations of a marine terminal are sea ice (November-May) and the shallow water of Norton Sound. Special built LNG carriers with shallower draft and ice-reinforced hulls will be required to handle the conditions in Norton Sound.

Exploration drilling would be conducted using jack-up rigs during the summer open water season. Nome would be used as the principle staging area for operations in the Norton province. The development scenario assumes that gas would be recovered by concrete production platforms resting on prepared seafloor berms. Artificial gravel islands could be utilized as production platforms in very shallow water (< 50 ft). Gas production would be transported by trenched subsea pipelines to a central gathering platform, then transported by a 65 mile trunkline to shore-based facilities constructed near Nome (fig. 26.2). Subsea pipeline gathering systems are relatively short (10-60 miles) because the province is small and the plays/prospects generally overlap (tbl. 26-2).

Gas production would be converted to liquefied natural gas (LNG) and then shipped by marine carriers to Yokohama, Japan. By great-circle route, Nome is actually 700 miles closer to Yokohama than the route from the Phillips/Marathon LNG facility in the Cook Inlet (tbl. 26.1). Gas-condensate separated during the gas recovery would be transported by subsea pipeline to the facility near Nome. Ice-reinforced tankers would shuttle hydrocarbon liquids (condensate and ngls) to a transshipment terminal at Valdez, Alaska, where it would be commingled with North Slope crude oil and shipped to Los

Angeles. Transportation data for this province are summarized in table 26.3, with routes shown in figures 26.1 and 26.2.

Navarin Basin

Navarin basin is the most remote offshore province on the OCS of the United States. There is no existing infrastructure in the province, and support bases at Nome and Dutch Harbor lie 400 and 600 miles away, respectively (fig. 26.1). The nearest land (St. Matthew Island) is a protected wildlife refuge with no developed harbor facilities.

The resource potential is contained in 5 geologic plays that are widely spread across a province area of about 100 x 240 miles in dimensions. Water depths range from 200 feet on the outer continental shelf to over 4,000 feet for prospects on the continental slope. The average water depth for this broad distribution is 480 feet. This area is covered by variable concentrations of sea ice from January to June, with frequent changes in concentration and movement driven by strong currents. In the open-water season, storms are common and intervening quiet periods are characterized by low clouds and fog. The operational logistics for the Navarin province are truly formidable.

The Navarin basin province was modeled for the production of both gas and oil resources. Natural gas, as the dominant hydrocarbon, is assumed to largely support the development activities in the province, with crude oil and gas-condensates recovered from gas production platforms. New offshore infrastructure requirements for the province include: production platforms; a subsea pipeline network; a central oil storage and loading terminal; ice-reinforced shuttle tankers, icebreaker support vessels; and 700-mile subsea gas pipeline.

Exploration drilling would be conducted in the open-water season by semisubmersible drill rigs constructed for harsh environments. Production platforms could be either large monotowers or floating platforms with storage capacity. Topside area and stability restrictions would limit well slots to 60. Additional wells could be installed in subsea templates. Small satellite fields could be developed entirely with subsea systems with flowlines to nearby production platforms.

The development scenario assumes that gas produced from platforms would be transported by subsea pipeline to a new onshore facility on the Alaska Peninsula at Balboa Bay (fig. 26.2). Infrastructure at Balboa Bay would include: an LNG plant; tank farm, marine loading terminal; an airstrip; and a transshipment terminal for oil. Gas would be converted to LNG and then shipped to Japan. Using a great-circle tanker route, this terminal is 3,000 miles from Yokohama, Japan (tbl. 26.1).

Crude oil and gas-condensates produced in the Navarin province would be gathered to a centrally located offshore storage and loading terminal (OSLT). Ice-reinforced shuttle tankers would transport oil and condensate to the new transshipment terminal at Balboa Bay. From there, conventional tankers would carry crude oil, gas-condensates, and ngls to west coast markets (Los Angeles). Transportation data are summarized in table 26.3, with routes shown in figures 26.1 and 26.2.

From the preceding discussion it is apparent that very large resource volumes would be necessary to support very costly development in this remote province. Unfortunately, exploration results to date have been very disappointing. Small pool sizes and the gas-prone nature of the Navarin basin decrease the chances that commercial development will occur in the foreseeable future. New technologies for gas production in remote locations (so-called "stranded gas") could eliminate the need for long subsea pipelines and costly LNG facilities. Offshore gas processing coupled with offshore loading terminals would eliminate the long subsea pipeline and improve the commercial potential of this remote province.

TABLE 26.3:
SUMMARY OF TRANSPORTATION SCENARIOS FOR OFFSHORE ALASKA PROVINCES

Province	Transportation Scenario
Beaufort	**(oil)** 250-mile pipeline network to TAPS, tanker from Valdez to west coast (U.S.) (gas) not recovered for marketing until North Slope gas pipeline is built
Chukchi	**(oil)** 555-mile pipeline network to TAPS, then tanker from Valdez to west coast (gas) not recovered for marketing until North Slope gas pipeline is built
Hope	(oil) 100-mile subsea pipeline to Red Dog, shuttle tanker to Valdez, tanker to west coast **(gas)** 100-mile subsea pipeline to Red Dog port, LNG conversion, LNG transport to Japan
Norton	(oil) 65-mile subsea pipeline to Nome, shuttle tanker to Valdez, tanker to west coast **(gas)** 65-mile subsea pipeline to Nome, LNG conversion, LNG transport to Japan
Navarin	(oil) subsea pipelines gather to OSLT, shuttle tanker to Balboa Bay, tanker to west coast **(gas)** subsea pipelines gather to central GSPF, 700-mile subsea pipeline to Balboa Bay, LNG conversion, LNG transport to Japan
St. George	(oil) subsea pipelines gather to OSLT, shuttle tankers to Balboa Bay, tanker to west coast **(gas)** subsea pipelines gather to central GSPF, 340-mile subsea pipeline to Balboa Bay, LNG conversion, LNG transport to Japan
North Aleutian	(oil) 70-mile subsea pipeline to Balboa Bay, shuttle tanker to Valdez, tanker to west coast **(gas)** 70-mile subsea pipeline to Balboa Bay, LNG conversion, LNG transport to Japan
Shumagin-Kodiak	(oil) storage on platforms, offshore loading, shuttle tankers to Valdez, tanker to west coast **(gas)** 215-mile subsea pipeline to Cook Inlet, LNG conversion, LNG transport to Japan
Cook Inlet	**(oil)** 125-mile subsea pipeline to Kenai, tanker to west coast (gas) not produced because of negative economic burden on associated oil production
Gulf of Alaska	**(oil)** subsea pipelines gather oil to Yakutat, tanker to west coast (gas) not produced because of negative economic burden on associated oil production

Notes: Primary production commodity is shown in bold. Development scenario is formulated around the primary commodity. Oil scenarios in gas-prone provinces could include crude oil and gas-condensates. Oil and condensates are commingled for transportation. Pipeline mileage is for province trunklines, which could have overland and offshore segments. TAPS is the Trans-Alaska Pipeline System (Prudhoe Bay to Valdez) carrying North Slope crude oil. LNG is liquefied natural gas. OSLT is offshore storage and loading terminal (oil). GSPF is offshore gas storage and processing facility.

St. George Basin

St. George Basin lies in the southwest ern part of the Bering Sea near the edge of the continental shelf. There is no petroleum infrastructure in the province, and the nearest harbor facilities on St. Paul Island or Dutch Harbor are 50-150 miles away (fig. 26.1). The nearest large airport is Cold Bay on the Alaska Peninsula approximately 180 air-miles south. Potential markets for oil and gas are several thousands of miles away (tbl. 26.1).

Resource potential is contained in 4 geologic plays distributed along the margins of the St. George graben. This feature is approximately 50 miles wide and 200 miles long. Water depths range from 300 feet on the outer shelf to over a 1,000 feet on the continental slope. This province is generally unaffected by sea ice during winter months, as the southern edge of the seasonal ice formation is farther north near the Pribilof islands. The province is exposed to frequent storms accompanied by high winds and waves. Intervening quiet periods are usually associated with low clouds and fog. The operational logistics for the southern Bering Sea are similar to conditions in remote parts of the North Sea and somewhat less extreme than the Navarin basin.

The development scenarios for the St. George and Navarin provinces are similar in many ways. The St. George province was modeled for the production of both gas and oil resources. Natural gas, as the dominant hydrocarbon, is assumed to largely support the development activities in the province, with crude oil and gas-condensates recovered from gas production platforms. Because there is no infrastructure in the province, new systems include: production platforms; a subsea pipeline network; one offshore storage and loading terminal (oil); ice-reinforced shuttle tankers; and a 340-mile subsea gas pipeline to the Alaska Peninsula.

Exploration drilling would be conducted in the open-water season by semisubmersible drill rigs constructed for harsh environments. Production platforms could be either large monotowers or semisubmersibles, both with oil storage capacity. Topside area and stability restrictions would limit well slots to 60. Additional wells could be installed in subsea templates. Small satellite fields could be developed with subsea systems with flowlines to nearby production platforms.

The development scenario assumes that gas would be conditioned on production platforms and then be transported by subsea pipeline to a new LNG facility on the Alaska Peninsula (Balboa Bay). New onshore infrastructure requirements would include an LNG plant, tank farm, marine terminal, an airstrip, and a transshipment terminal for oil. Gas would be processed to LNG and then exported to Yokohama, Japan, over a tanker route of 3,000 miles (tbl. 26.1).

Crude oil and gas-condensates recovered as byproducts of gas production would be gathered by subsea pipeline to a centrally located OSLT. Shuttle tankers would transport oil and condensate to a new transshipment terminal at Balboa Bay, then by conventional tankers to west coast markets (Los Angeles) (fig. 26.1). Transportation data are summarized in table 26-3 and routes are shown in figures 26.1 and 26.2.

Difficult operating conditions suggest that very large resource volumes must be discovered to support offshore development in the St. George province. Overall costs are somewhat less than costs in the Navarin basin, but they are still significantly (perhaps 6-8 times) higher than costs for comparable production systems in the Gulf of Mexico. Exploration results to date have been disappointing. Small expected pool sizes and the gas-prone nature of the province decrease the likelihood that commercial development will occur in the foreseeable future. New technologies for gas production in remote locations (so-called "stranded gas") could eliminate the need for long subsea pipelines and costly onshore LNG facilities. Offshore gas processing coupled with marine loading terminals could reduce the infrastructure costs and improve the economic potential of this province.

North Aleutian Basin

The North Aleutian province is located in the southeastern Bering Sea, stretching several hundred miles along the north side of the Alaska Peninsula. The petroleum potential is largely confined to an area of 40-120 miles in the west ern part of the province. At present, there is no offshore infrastructure in the province, although several potential staging areas are located nearby. Dutch Harbor (200 miles to the southwest) is the principle deep-water port for the Bering Sea (fig. 26.1). This port currently supports a large commercial fishing industry and has been used as a staging area for previous oil exploration activities conducted throughout the Bering Sea. Cold Bay (80 miles southwest) has airport facilities capable of handling all sizes of aircraft (fig. 26.1). Air-lifted supplies and equipment could be shuttled from Cold Bay to support offshore activities in the North Aleutian province. Distance to land from potential offshore development sites is typically 30-50 miles.

Environmental conditions are less demanding than in provinces farther north. The area does experience sea ice in winter, but concentrations are somewhat less than more northerly areas. Water depths are relatively shallow (100-300 ft). The primary hazards affecting the design of platforms and facilities are superstructure icing problems from freezing spray, earthquakes, and potential debris fallout from active volcanoes on the Alaska Peninsula. Other logistical constraints include frequent fog and low visibility in summer and high sea states associated with storm systems.

Exploration drilling is likely to utilize jack-up rigs in shallow sites (< 150 feet) and semisubmersibles for deeper sites (> 150 feet). Late-winter months (January-March) would probably be avoided because of weather and sea ice conditions. Production platform types suitable for these conditions are gravity base structures or large monotowers constructed of steel. Steel is favored over concrete for flexibility in high seismic risk areas. Superstructure icing problems could preclude floating production platforms. Weather conditions are not favorable to offshore loading, and with short distances to shore, subsea pipelines would be the preferred transportation systems. Because platform topside areas would be small, a maximum of 60 well slots was assumed on each platform. Additional wells could be hooked up through subsea templates with flowlines to nearby production platforms.

The resources of the province are contained in one geologic play. Short distances between prospects in the basin and to land are reflected in the pipeline lengths (tbl. 26.2).

The development scenario was modeled for the production of both gas and oil resources. Natural gas, as the dominant hydrocarbon, is assumed to support the development activities in the province. We assumed that gas produced from offshore platforms would be transported by a 70-mile subsea pipeline, and 10-mile overland pipeline, to a new LNG plant and marine terminal in Balboa Bay on the south side of the Alaska Peninsula. After conversion to LNG, gas would be shipped by marine carriers to Japan. Using a great-circle tanker route, this terminal is 3,000 miles from Yokohama, Japan (tbl. 26.1).

Where possible, crude oil pools would be developed if they are reachable from the gas production platforms. Gas-condensates recovered as a byproduct of gas production would be commingled with crude oil and transported by subsea pipeline to the onshore facility. A new shorebase facility, with temporary storage (tank farm) and marine loading terminal, would be located near the new LNG plant. Liquid hydrocarbons (crude oil and gas-condensates) would be transported by shuttle tankers to Valdez, and then commingled with North Slope crude and shipped by conventional tankers to west coast markets (Los Angeles) (fig. 26.1).

A relatively mild setting (by Alaska standards) combined with a rich gas resource potential (6.8 TCFG mean conventionally recoverable gas resource) make the North Aleutian province the most attractive area in the Bering Sea for future petroleum exploration. However, oil and gas activities in this area are under Congressional moratorium, and previously leased tracts have been repurchased by the Federal Government. If exploration is allowed to resume, and sufficient gas reserves are proven by additional drilling, infrastructure development for North Aleutian gas production could be utilized by other gas projects in the Bering Sea. A shared development strategy would optimize the commercial viability for the generally low potential, gas-prone provinces in the Bering Shelf subregion.

PACIFIC MARGIN SUBREGION

Offshore assessment provinces along the Pacific margin of southern Alaska are far from support centers and exposed to the full force of

North Pacific weather systems. Past drilling activities involved towing rigs from as far away as the North Sea, although more typically, exploration rigs are either built in the Orient or towed to Alaska from the Gulf of Mexico. Offshore drilling rigs and production equipment modules were fabricated on the West coast (Portland or Seattle area) and then delivered to Alaska by marine barges. More recently, oil and gas production modules have been fabricated at facilities in the Cook Inlet . Future activities will probably include more in-state fabrication (in Cook Inlet region) and staging from Alaskan deep-water ports such as Valdez, Whittier, Seward, and Kodiak. Smaller harbors and airport facilities are present throughout the subregion for possible exploration staging areas.

Environmental conditions in the Pacific margin subregion are similar to those encountered in the North Sea. Offshore exploration drilling was safely conducted from 1969 to 1983, with 20 wells drilled in the Gulf of Alaska and Kodiak shelf and another 13 wells in the Cook Inlet and Shelikof Strait. Development activities will generally focus on the continental shelf where water depths are less than 600 feet. Seafloor morphology and sediment thickness are largely related to glacial processes which affected the emergent continental shelf during Pleistocene time. Glaciation produced a relatively thin sediment cover over hard substrate. Broad elevated areas (now seafloor banks) are crossed by transverse glacial valleys (now seafloor troughs), typically containing thick, and very unstable, silt deposits.

There are two groups of hazards to permanent facilities. One is associated with oceanography (violent storms, high waves, freezing spray, strong currents), and the other is associated with tectonics (seismicity, volcanism, tsunamis). Unlike most other offshore Alaska provinces, sea ice is not a significant constraint over most of the subregion, as seasonal ice formation is present only in the upper reaches of the Cook Inlet.

The northern Gulf of Alaska is exposed to weather systems emanating from the northern Pacific Ocean. Storms could occur year-round and are particularly intense in the fall and winter months when gale force winds and seas over 20 feet are common. Platform designs will handle waves to at least 60 feet high. Structural fatigue for bottom-founded platforms is an important consideration because of the accumulated effects of wave forces. Superstructure icing is a common winter hazard associated with high winds and freezing temperatures. This condition could alter the stability of most floating platforms, platforms under tow, and support vessels. High wind and waves during storms and low clouds/fog between storms create difficult conditions for offshore loading and marine transportation.

The Pacific margin of Alaska is one of the world's most seismically active regions, with earthquakes common above magnitude 6.0. The largest recorded earthquake in North America occurred under Prince William Sound in 1964 (8.5 magnitude). Extensive damage was sustained in coastal areas throughout the Pacific margin of southern Alaska. The maximum local uplift was 49 feet, the maximum local subsidence was 8 feet, and maximum horizontal movement on surface faults was measured at 64 feet. Tsunamis (seismic sea waves) are typically associated with earthquakes and submarine block displacements. Tsunamis and associated seiche waves can cause coastal flooding tens of feet above normal sea level. Although seismicity will impact bottom-founded platforms and subsea pipelines, more significant damage could occur on shorebase facilities. In the 1964 earthquake, the port facilities at Seward and Valdez were virtually destroyed.

All gas production, as in other Alaska provinces, will be converted to LNG for export to the Pacific Rim (Yokohama, Japan). While most other Alaska offshore provinces will require the construction of new LNG facilities and marine terminals, an LNG plant and terminal has been operating in the Cook Inlet since 1969 with a current capacity of approximately 60 BCF/y. Interestingly, the Phillips-Marathon facility at

Nikiski is the only LNG processing plant in the United States. New offshore gas development in the northwestern Gulf of Alaska could utilize a future LNG facility at Valdez proposed for North Slope gas production. However, completion of this new project is not expected for a decade (2005-2015 time frame).

Shumagin-Kodiak Shelf

The Shumagin-Kodiak province stretches for over 800 miles along the outer coast of southern Alaska. Although this vast area was assessed as a single geologic province, future developments will follow different plans. New offshore gas fields on the Shumagin shelf in the western part of the province would require a new LNG plant and marine terminal facility on the Alaska Peninsula. A new facility at Balboa Bay could be utilized by both the Bering Shelf provinces and provinces in the western portion of the Pacific Margin subregion. New offshore gas fields on the Kodiak shelf in the eastern part of the province are more likely to utilize the existing Phillips-Marathon LNG facility in the Cook Inlet. Depending on the timing of offshore gas development projects, large volumes of gas production from the Kodiak shelf would require an expansion of the Nikiski LNG facility.

The resource potential of the Shumagin-Kodiak province is dominated by gas, so the infrastructure model was formulated for gas production with hydrocarbon liquids (gas-condensate) were recovered as a byproduct. The geologic assessment includes no crude oil resources.

With larger undrilled prospects and its proximity to existing LNG infrastructure, the Kodiak shelf is more attractive for future petroleum exploration and commercial development. The western part of the province (Shumagin shelf) was not individually modeled in the present assessment.

The Kodiak shelf development scenario assumes that gas produced from offshore production platforms would be transported by 215-mile subsea pipeline to processing/export facilities in the Cook Inlet (fig. 26.2). It is assumed that gas production will be converted to LNG and exported by marine LNG carriers to Yokohama, Japan. Natural gas liquids, separated and stored on offshore production platforms, would be loaded to small shuttle tankers and transported to the terminal in Valdez, and then commingled with North Slope crude oil and shipped to the west coast (Los Angeles) (fig. 26.1).

Platform types would depend on water depth, which generally ranges from 100-600 feet. Platform designs would accommodate high sea states and seismicity as the major geologic hazards. Gas production platforms are likely to have storage/offloading capability for gas-condensate liquids, as long, small diameter subsea pipelines would not be cost effective. A hard seafloor substrate and generally shallow water on the Kodiak shelf would allow the use of steel jacket platforms in water depths to 300 feet. Floating platforms of various types (buoy-shaped platforms, tension-leg, or heavy-duty semi-submersibles) are likely types in deeper water (> 300 ft). Floating systems would be favored because they have the advantage of mobility and could be used to produce several marginal-sized gas fields in the province. Subsea wellheads connected with flowlines to nearby production platforms could be used for small satellite fields.

The entire province was modeled as only one geologic play, but prospects are scattered widely. We assumed that gas production would be gathered through subsea pipelines to a central offshore facility. Processing equipment at this offshore facility would condition and pressure-regulate gas prior to transport through a large diameter, 215-mile subsea pipeline. Gas-condensate would be offloaded to shuttle tankers and transported to Valdez. Transportation scenarios are summarized in table 26.3, with routes shown in figures 26.1 and 26.2.

Cook Inlet

The Cook Inlet assessment province extends for nearly 300 miles along inner coast of the Gulf of Alaska. It includes the Cook Inlet itself as well as the Shelikof Straits between the Alaska Peninsula and Kodiak Island. This province is located adjacent to the largest population center in the State of Alaska, with its associated roads, airports, and marine harbors. The industrial center for the oil industry is on the northern Kenai Peninsula in Kenai/Nikiski. Other harbor facilities are present at Anchorage, Homer (southern Kenai Peninsula), and on Kodiak Island.

Exploration in the Cook Inlet region began around the turn of the century on the Alaska Peninsula and continues to the present day. Oil production in the Cook Inlet region began in 1958 with the onshore Swanson River Field. From 1964-1968, 14 offshore platforms were installed in the Upper Cook Inlet and production from State submerged lands began in 1967 (Alaska Update, 1990). Through 1996, approximately 1.2 BBO of oil were produced through the Cook Inlet infrastructure (AK-DNR, 1997)(fig. 26.4). Oil production peaked in 1970 at 83 MMbbl and declined to 15.2 MMbbl annually in 1996.

Natural gas was first recovered as a byproduct of oil production at Swanson River and has been reinjected into oil reservoirs for pressure maintenance. Gas production from non-associated gas fields began in the late 1960's. LNG was first exported to Japan from the Phillips-Marathon LNG plant in 1969. Gas infrastructure now includes: offshore and onshore pipeline networks; an ammonia-urea plant, electric power generation plants, and gas transmission pipelines to consumers in south-central Alaska (mainly Anchorage, the State's largest city). Gas production peaked in 1990 at over 311 billion cubic feet (BCFG) annually, declining in 1996 to 265 BCFG (AK-DNR, 1997).

Two important assumptions were made to model the Cook Inlet province:

1. *The assessment assumed that oil production would be delivered to the West coast.* Historically, most of the oil production from the Cook Inlet has been exported to the west coast through UNOCAL's Drift River terminal facility. We recognize, however, that the local market for oil and gas is growing, and there is excess capacity in existing infrastructure for future production. Currently, Cook Inlet oil production is insufficient to satisfy demand and ANS (Alaska North Slope) oil is delivered by tanker from Valdez to the Tesoro oil refinery in Nikiski. Because the Cook Inlet market is actually tied to outside markets because of the availability of Alaska North Slope (ANS) crude oil, the prices received by Cook Inlet production reflect competitive market prices for ANS landed at west coast destinations. Using tanker tariffs for west coast delivery is one way to adjust local prices to world oil market prices.

2. *The Cook Inlet province was modeled for oil production only.* This decision was based on two main considerations. First, the hydrocarbon resources were modeled in the geologic assessment as associated pools, where oil reservoirs contain gas caps. Proper reservoir management practices dictate that pressure maintenance be used to maximize oil recovery. Accordingly, dissolved gas recovered with oil production is typically reinjected. This practice is common for associated oil/gas reservoirs in Alaska. Second, preliminary modeling runs indicated that there is a sizeable economic burden placed on oil production if associated gas resources are coproduced. Because the assessment attempted to optimize commercial viability, gas production was delayed until some future time when oil resources are depleted.

Exploration and development activities will encounter shallower water depths (< 600 ft) and less severe sea conditions as compared to more exposed areas facing the Pacific Ocean. In addition to the hazards associated with active volcanism and seismicity, other environmental factors are unique to the Cook Inlet province. A primary design factor is the strong currents associated with a large tidal flux. Tidal ranges vary from over 30 feet in the Upper Cook Inlet to 7 feet in the Shelikof Straits causing tidal currents that range up to 8 miles per hour (mph). Special methods of anchoring and corrosion protection are required for platform legs and subsea pipelines (Visser, 1992).

Exploration drilling could be conducted year-round in the Lower Cook Inlet, as seasonal sea ice is generally confined to the Upper Cook Inlet. Drilling rig types would depend primarily on water depths. In shallow water (< 150 feet), jack-up rigs would likely be selected. For deeper waters, semisubmersible rigs are likely to be employed.

Production platforms will be designed to handle these environmental factors. In shallow water (< 150 ft), steel jacket or monotower platforms, similar to designs proven in Upper Cook Inlet, would be employed. For deeper water sites (150-600 ft), various types of floating platforms or tension-leg structures could be used. These platforms are likely to contain storage tanks and have offshore loading capabilities at isolated fields. It is possible that heavy-duty semisubmersibles could be used as production platforms. Subsea templates connected by flowlines to nearby production platforms is another strategy to develop small satellite fields.

The resource potential of the Cook Inlet province is contained in 3 geologic plays, two of which cover most of the province. Development costs were prorated according to risked resource potential, and a 125-mile subsea trunkline was used to gather oil from scattered prospects to existing facilities on the Kenai Peninsula (fig. 26.1). Relatively short pipelines are needed to gather resources from the fields in the three plays to this subsea trunkline (tbl. 26.2). We assumed that pipelines will not be trenched, but would be coated and weighted to counteractive corrosion and strong bottom currents.

Declining oil and gas production from existing Cook Inlet fields, combined with an increasing consumer market, suggests that future production from this province will be utilized by the local Alaska market. Local marketing could improve the viability of both gas and oil development by eliminating higher transportation costs to distant outside markets (tbl. 26.1). However, the market price for oil in the Cook Inlet will continue to be largely regulated by the price for North Slope crude. Although the scenario for petroleum development in the near future is oil production, local market demand for gas production could prompt the development of gas fields in favorable locations (near shore, shallow water).

Gulf of Alaska Shelf

The Gulf of Alaska province is the southernmost assessment province in Alaska, although at a latitude of 60° N it is still over 1,500 miles north of any offshore production on the west coast. The province covers a broad area (450 miles) of the continental shelf and upper slope. Possible support bases for offshore oil and gas activities could include Seward, Whittier, Valdez, Kodiak, and Yakutat, all which have existing harbor facilities. These harbors currently support commercial fishing operations in the Gulf of Alaska. For the Gulf of Alaska shelf province, Yakutat is the likely shorebase for offshore development.

At present, there is no petroleum production and transportation infrastructure on the Gulf of Alaska shelf. The development scenario assumed that new infrastructure would be located in Yakutat (fig. 26.1), including a pipeline landfall, tank farm, and marine export terminal. Produced oil would be delivered to west coast by tankers (fig. 26.1). Los Angeles, the principle receiving port, is approximately 2,200 miles in tanker route from Yakutat (tbl. 26.1). The transportation scenario is shown in figure 26.1 and summarized in table 26.3.

Environmental hazards and anticipated operations in the Gulf of Alaska have been discussed under previous headings. Hazards can be grouped into two categories, one related to oceanography (violent storms, high waves, freezing spray, strong currents) and the other related to tectonic activity (seismicity, volcanism, tsunamis). Exploration drilling could be conducted year-round, but rig towing during fall and winter months would be avoided. Most exploration drilling operations will take 1-2 months to complete, so favorable weather windows can be utilized and seismicity hazards are not a serious consideration for temporary wellsites. Production platform types will largely depend on water depth, with bottom-founded platforms in shallow water (<300 feet) and floating platforms (buoy-shaped, tension-leg, or moored semisubmersibles) in deeper water. For production on the outer shelf or continental slope, subsea templates are likely to be installed, with subsea flowlines connected to platforms in shallower water.

The Gulf of Alaska shelf province was modeled for oil production only. Although significant gas resources are present, gas is unlikely to replace oil as the commodity of interest, largely because very costly LNG facilities are required for gas export. Preliminary modeling runs indicated that there is a sizeable economic burden placed on oil recovery if associated gas resources are coproduced. Secondly, the hydrocarbon resources were viewed in the geologic assessment as associated pools, where oil reservoirs contain gas caps. Proper reservoir management practices dictate that pressure maintenance be used to maximize oil recovery. Accordingly, dissolved gas recovered with oil production is typically consumed by equipment on platforms or reinjected. This practice is common for associated oil/gas reservoirs in Alaska. Although gas resources are not initially recovered, they would be available when oil pools are depleted and could be produced at some later time.

The resource potential is contained in 5 geologic plays, generally covering different areas of the continental shelf. The plays were modeled as supporting their own pipeline costs relative to their risked resource potential. Basin-level trunklines were not proposed so that low resource plays would not be subsidized by high resource plays. Subsea pipeline routes generally parallel the shoreline back to Yakutat, and play-level pipelines range from 30 to 250 miles in length (tbl. 26.2). Offshore loading was not employed because frequent storms in the Gulf of Alaska would create safety concerns to platforms and shuttle tankers. With short distances from the high potential play (play 3, Kulthieth sands) to Yakutat (30 miles), subsea pipelines are the most efficient transportation method. For more distant plays, subsea pipelines running parallel to shore would cross several active fault zones (Kayak and Pamploma zones). Special engineering considerations (and increased costs) would be required to ensure pipeline safety.

Difficult operating conditions suggest that very large resource volumes must be discovered to support offshore development in this province. Overall costs are somewhat less than costs in the Bering Shelf provinces, but they are still significantly (perhaps 3-5 times) higher than costs for comparable production systems in the Gulf of Mexico. Exploration results to date have been disappointing. Small expected pool sizes and the gas-prone nature of the province decrease the likelihood that commercial development will occur in the foreseeable future. New technologies for offshore gas processing coupled with marine loading terminals could reduce the infrastructure costs and improve the economic potential of this province.

SUMMARY

Infrastructure scenarios for Alaska's offshore provinces represent a wide diversity in possible strategies to move hydrocarbons from these remote areas to market. Other than the Beaufort and Cook Inlet provinces, none of the offshore provinces have existing transportation infrastructure for petroleum production. The small population of the State of Alaska cannot utilize large volumes of oil or gas production, so most future production will be transported to distant markets on the West coast and Pacific Rim. Future production and local marketing for the Cook Inlet province is a possible exception.

New infrastructure and transportation systems will have high costs, and future development timing will be greatly influenced by perceived commercial potential. Provinces with high resource potential and available infrastructure, such as the Beaufort shelf province, are much better positioned for future development than high-cost/low resource provinces, such as the Navarin basin.

The transportation scenarios envisioned imply that some provinces could share common infrastructure systems. Historical perspective from the North Slope provides a good example of infrastructure sharing. The initial development on the North Slope was supported by two huge oil fields (Prudhoe Bay and Kuparuk River are the largest oil fields in North America). Smaller fields were discovered and developed around these large fields over the past three decades. As infrastructure has expanded on the North Slope, previously non-commercial fields have been brought into production. This infrastructure expansion could eventually collect production from adjacent provinces, such as the Chukchi shelf.

Infrastructure sharing strategies could be vital to future development in the Bering Shelf subregion. For example, the scenarios for the Navarin, St. George, and North Aleutian provinces envision a new LNG facility and marine terminal on the Alaska Peninsula. The multibillion dollar cost for such a project could be shared by coordinated gas production projects. Together these provinces are estimated to hold nearly 16 TCFG of conventionally recoverable gas resources, enough to supply a long-term LNG export operation. Other transportation systems, such as the third-party shuttle tankers, assumed to carry minor volumes of oil and gas-condensates through the Bering Sea would benefit from production activities in several provinces.

New methods for recovering "stranded gas" from remote locations could eliminate the need for long subsea pipelines and large onshore LNG facilities. Technologies for converting gas to more transportable forms, either as liquids (GTL) or gas hydrate pellets, are now being researched. Offshore storage and loading systems have been improved with worldwide experience. Eliminating the need for distant shorebase facilities would decrease costs associated with long subsea pipelines and improve the economics for production in remote offshore locations.

Other strategies to lower infrastructure costs could include minimizing permanent installations. Floating platforms are mobile and possibly reusable. They could be moved from one small offshore project to the next. Tankers or semisubmersibles converted to floating production and storage systems could be used in some areas. Unmanned platforms or subsea systems could replace larger, and more costly, full-scale production platforms.

As stated in the beginning of this section, the infrastructure scenarios presented here are generalized models of possible future projects. Surely there are alternates, and perhaps equally feasible scenarios could be employed depending on site-specific conditions. Advancements in offshore technology, changes in economic conditions, or coordinated strategies could drastically change the scenarios for these offshore provinces.

One fundamental concept should be recognized. Future offshore development in Alaska will not take place unless extensive exploration programs are initiated fully assess the true resource potential in these Alaska offshore provinces. Proven *reserves*, not the undiscovered resource potential, will be the driving force for future petroleum development and production.

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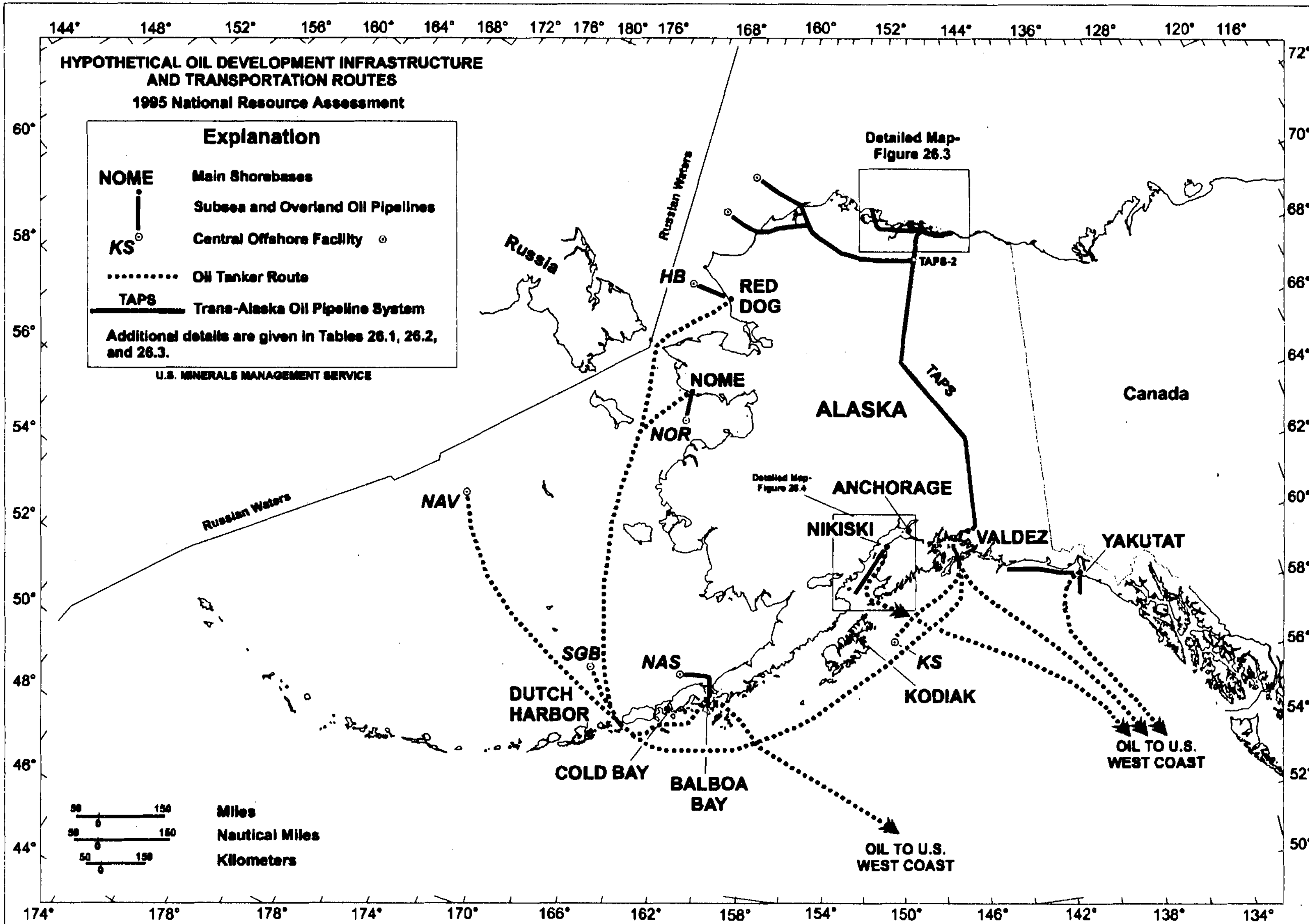


Figure 26.1: Hypothetical oil development infrastructure used for economic modeling in 1995 National Resource Assessment.

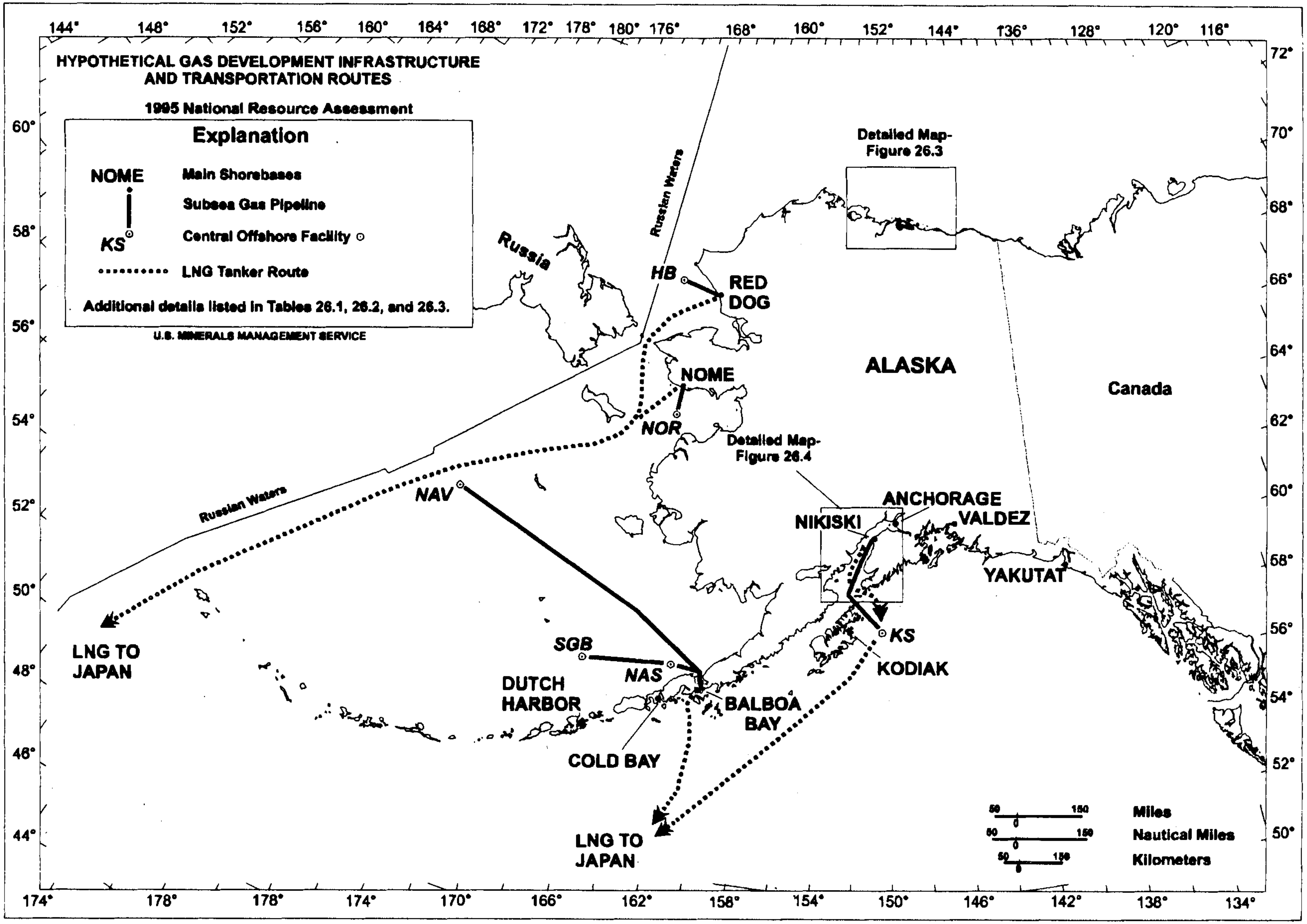


Figure 26.2: Hypothetical gas development infrastructure used for economic modeling in 1995 National Resource Assessment.

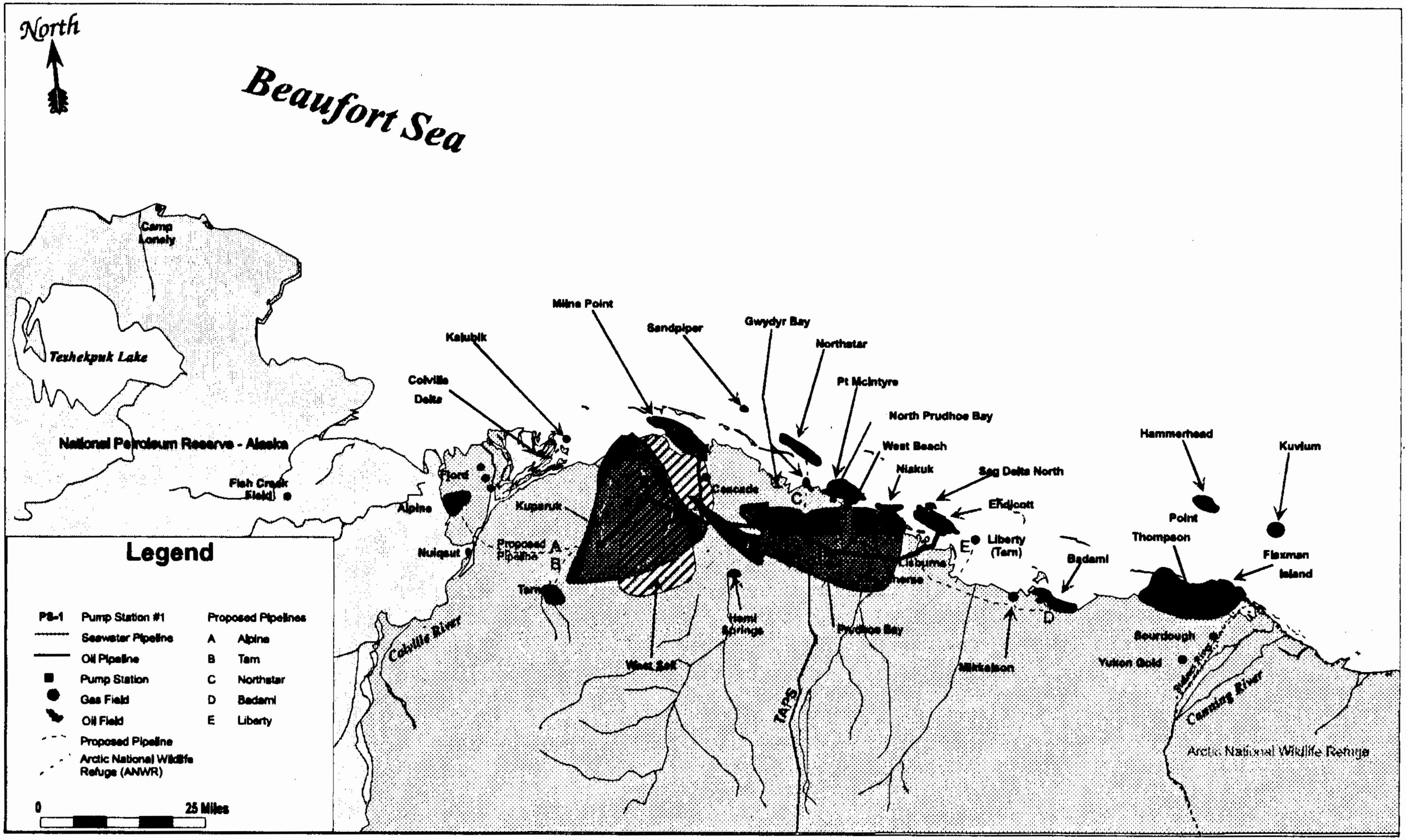


Figure 26.3: North Slope oil fields and associated infrastructure. Oil production through the TAPS pipeline began in 1977. North Slope gas reserves remain undeveloped because there is no transportation system to outside markets.

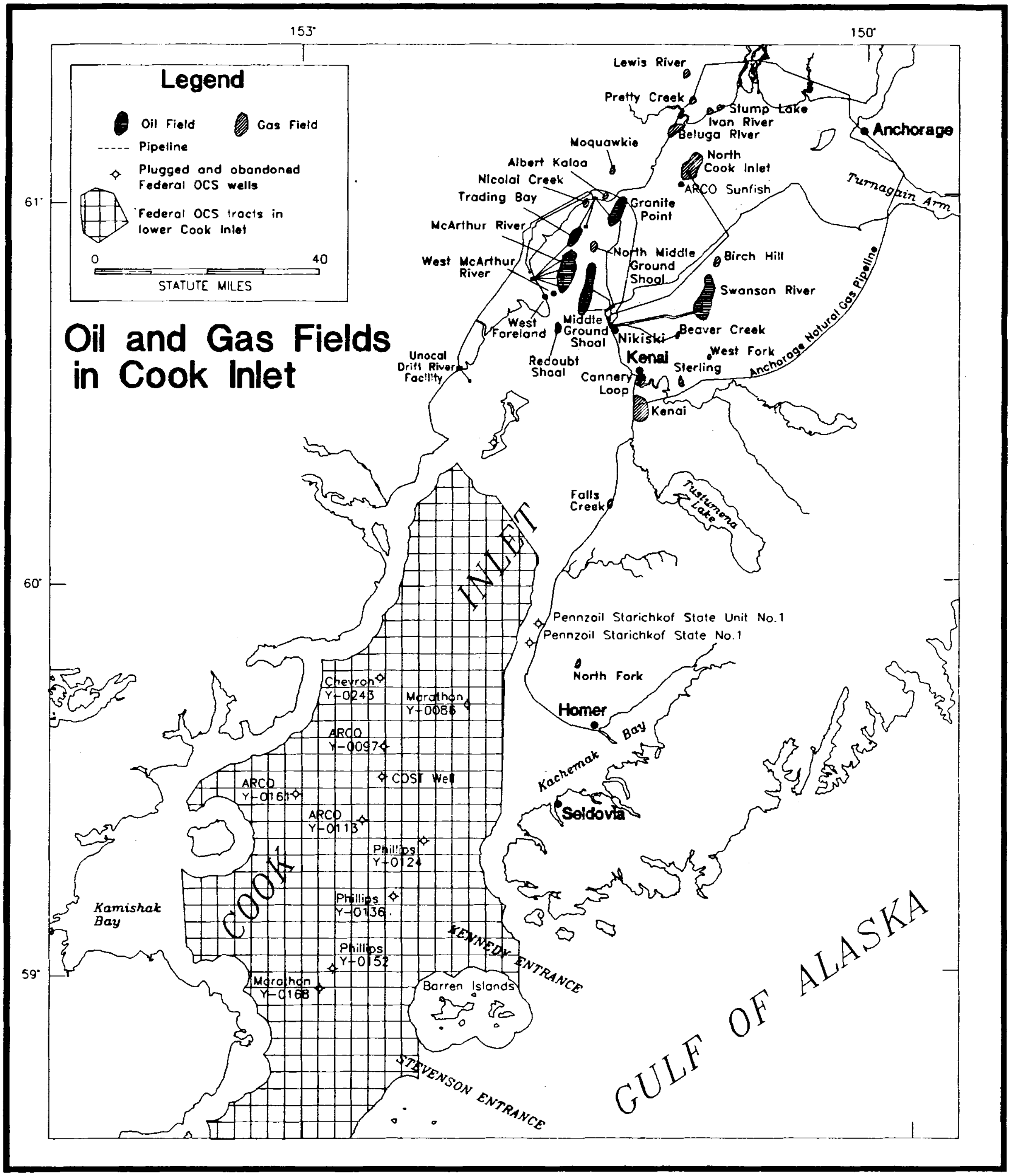


Figure 26.4: Oil and gas fields in Cook Inlet. Infrastructure is located in State waters in upper Cook Inlet. Previous drilling in Federal waters has resulted in no commercial discoveries.

ECONOMIC ASSESSMENT
1995 National Resource Assessment
Alaska Federal Offshore
U.S. Minerals Management Service

27. ECONOMIC ASSESSMENT RESULTS

by

James D. Craig

This chapter discusses the results of economic modeling in the 1995 National Assessment. This effort was a two-step process. The first step involved estimating the total amount of resources present and recoverable using present conventional technology. The second step involved a development/production simulation to determine the proportion of modeled resources (pools in plays) that could be profitably recovered under a given set of engineering and economic conditions. Generally, only a small fraction of the total endowment will be commercially viable because costs overwhelm net income from hydrocarbon production. The economic resource estimates discussed in this chapter can be viewed as a "reality check" for the optimistic, but unattainable, hydrocarbon resource volumes that form the conventionally recoverable endowment. It should be clearly recognized that both sets of estimates are for undiscovered resources. Neither model confirms that these resources will actually be discovered or developed within a specified time frame. Therefore, risked resource estimates should be viewed as indicators of opportunity rather than as available reserves ready to meet future demand.

RESULTS PRESENTATION FORMAT

The results for each province are summarized by the following graphs and tables: (1) cumulative probability plots for risked, conventionally recoverable resource distributions; (2) a table comparing risked, mean, conventionally recoverable resources with the risked, mean, economically recoverable resources at given prices; (3) a price-supply graph displaying the relationship between economically recoverable resources and commodity prices; and (4) a table listing play-specific, economically recoverable resource estimates for two price conditions. Economic results are reported for a "Base price" of $18 per-barrel of oil ($/bbl) and $2.11 per-thousand cubic feet of gas ($/MCFG) representing normal price conditions, and a "High price" of $30/bbl and $3.52/MCFG representing a less likely set of price conditions.

Risked Cumulative Probability Distributions

Cumulative probability distributions summarize the risked, undiscovered endowments of conventionally recoverable oil, gas, and barrels-of-oil-equivalent (BOE). These curves depict resource volumes in relation to "cumulative frequency greater than (%)." A cumulative frequency represents the probability that the resource endowment is equal or greater than the volume associated with that frequency value along one of the curves. For example, a 95 percent probability represents a 19 in 20 chance that the resource will equal, or be higher than, the volume indicated. Cumulative frequency values typically decrease as resource quantities increase. Accordingly, the probabilities for small resource volumes are high, and conversely, the probabilities for large resource volumes are low.

Table of Risked Play Resources

These tables provide a comparison between the conventionally recoverable endowment and the smaller quantity of economic resources that could be profitably recovered under current conditions. Current prices are represented as $18 per barrel-oil and $2.11 per MCF-gas. Tabulated resource volumes correspond to points on the cumulative probability distributions (conventionally recoverable resources, at page top) and points along the mean price-supply curve (economically recoverable resources, at page bottom). Resources listed as negligible (negl) have volumes lower than the significant figures shown. Not available (N/A) means that these resources are unlikely to be produced in the foreseeable future.

The ratio of economic to conventional resources (E/C) represents the fraction of the total undiscovered resource endowment that would be profitable to produce under given base price conditions. Although the *PRESTO* model simulates the discovery and development of all prospects, the modeling results do not imply discovery rates. Depending on a variety of factors, the estimated resources may never be discovered. The ratio of economic to conventional resources should be regarded as an indicator of economic opportunity, not as a direct index of available petroleum supply.

Price-Supply Curves

The results of the economic assessment are displayed as price-supply curves that represent the outcomes of numerous simulation trials. Price-supply curves allow interpretations that directly link the volumes of economically recoverable resources to commodity prices, where an increase in price typically results in an increase in recoverable resource volume. Economic resources represent risked volumes of oil and gas that could be recovered profitably under a given set of economic and engineering parameters (discussed in Chapter 11). At very high (perhaps unrealistic) prices, mean price-supply curves asymptotically approach the mean conventionally recoverable resource endowment.

The price-supply curves are generated by repetitive trials in the *PRESTO-5* computer program, with each trial simulating different conditions for development, production, and transportation of modeled hydrocarbon pools within a petroleum province. Economic viability depends on the interaction of many factors, including the sizes and locations of the hydrocarbon pools, the reservoir engineering characteristics, and economic variables relating expenditures to income from future production streams. This analytical model determines the resource volumes that are commercially viable under present conditions, and no attempt was made to upgrade engineering technology invented as a result of higher commodity prices.

The price-supply curves are fundamentally based on the development scenarios assumed for each province. All provinces were modeled on a stand-alone basis, with engineering assumptions designed for the primary hydrocarbon (oil or gas). Engineering scenarios assume that the primary hydrocarbon will drive initial development in a particular province. Oil-prone provinces were modeled as "oil-only" production, where gas is reinjected into reservoirs to maximize oil recovery. Gas-prone provinces were modeled with both gas and oil production because gas-condensate liquids are generally coproduced. All hydrocarbon liquids (crude oil and gas-condensate) are commingled in transportation systems for gas-prone provinces.

Price-supply graphs typically contain three curves, corresponding to "Low", "Mean", and "High" resource cases. The Low case corresponds to a 95 percent probability (19 in 20 chance) that the resources are equal to or exceed the volumes derived from the price-supply curves. Conversely, the High case represents a

5 percent probability (1 in 20 chance) that a large volume of resources could occur. The Mean case represents the average (or expected) volume based on a statistical sampling of the many simulation trials. The high combined geologic and economic risks in some provinces cause a statistical truncation of the output probability distributions at levels below 95 percent. In these provinces (Hope, Norton, Navarin, St. George, North Aleutian, and Shumagin-Kodiak) no economically recoverable resources at the 95 percent probability level are reported and only the Mean and High case curves are displayed.

Some additional guidelines for interpreting price-supply curves are listed below:

- *The economic model uses starting prices and development/production costs which are inflated, and then deflated, equally at 3 percent annually from a 1995 base year.* Because prices and costs are treated equally with respect to future inflation, the price aspect of the price-supply curve is considered to be flat (or constant dollars). This provides significant flexibility to estimate the effects of price and cost changes on resources. The price-supply curves have a timeless quality as long as the assumption of flat price-cost path holds true.
- *Inflation, followed by deflation to the base year, is used to capture the tax effects of depreciation of large capital investments.* The results are presented as after-tax present value in the base year (1995).
- *Following conventional practice, price-supply graphs are rotated from the usual mathematical display of X-Y plots.* Conceptually, price is the independent variable and resource is the dependent variable.
- *Price-supply curves are models of risked hydrocarbon resources.* Risk includes both the geologic risk that pooled resources are present and recoverable as well as the economic risk that commercial development is profitable under the assumed economic and engineering conditions. At low price levels, recoverable resource volumes are affected most by economic risks associated with development costs and reservoir performance factors. At higher price levels, recoverable resource volumes are affected most by geologic risks associated with occurrence and volumetric factors.
- *Price-supply curves present only one view of the timing of future discoveries and the conversion of undiscovered resources to production.* The scheduling of discovery and development is an important part of the discounted cash flow modeling. However, attainment of the full resource potential will require extensive future exploration. The resource volumes calculated by this assessment confirm only that the potential (or opportunity) exists for commercial production. There is no guarantee that any or all of the resource potential will ever be discovered or exploited in the future.

Play-specific Resources Table

The risked mean contribution for each geologic play in the province is tabulated under two price conditions. The Base price ($18/bbl; $2.11/MCFG) represents common conditions. The High price ($30/bbl; $3.52/MCFG) represents an upper limit of future starting prices (in real or constant dollars). Other economic parameters (for example, discount rate) were the same for both scenarios, as was engineering technology. The play number, name, and Unique Assessment Identifier (UAI) provide a link to the data presented in other chapters of this report. Hydrocarbon substances are distinguished as oil (includes crude oil and gas-condensate liquids), gas (includes non-associated, associated, and dissolved gas), and BOE (gas volume is converted to barrel of oil equivalent and added to oil volume).

ECONOMIC RESULTS FOR THE ARCTIC SUBREGION

The resource potential of the Arctic offshore subregion dominates the other offshore areas in Alaska. Approximately 90 percent of the conventionally recoverable oil resource occurs in the Chukchi Shelf province with 13 billion barrels of oil (BBO) and in the Beaufort Shelf province with 9 BBO. A similar trait is observed for economically recoverable resources, where 91 percent of the total economic oil resources in offshore Alaska is contained in these two provinces. The results are not surprising in view of the petroleum activities on the adjacent North Slope of Alaska. The North Slope is a proven petroleum province containing several of the largest oil and gas fields in North America. Through 1996, over 10 BBO have been produced and transported to market, leaving a reserve base in proven fields of approximately 7 BBO.

Production and transportation infrastructure is present on the North Slope and could be utilized by new offshore development in the Beaufort and Chukchi shelf provinces. The Trans-Alaska Pipeline System (TAPS) began operation in 1977 and for two decades has transported oil across Alaska to the ice-free port of Valdez. The TAPS throughput rate peaked at slightly over 2.0 million barrels per day (MMbpd) in 1988 and by 1995 had dropped to 1.5 MMbpd. Because most of the large North Slope fields are in decline, it is likely that excess capacity in TAPS will be available for future oil fields in northern Alaska. Offshore development in the adjacent Beaufort and Chukchi provinces hinges on this vital transportation system.

In contrast to the extensive oil development on the North Slope, gas resources have not been produced for outside market. An estimated 30-35 trillion cubic feet of gas (TCFG) reserves remain shut-in because of the lack of a gas transportation system. Various economic hurdles have inhibited the construction of a gas pipeline and liquefied natural gas (LNG) system with an estimated cost of $12-15 billion. At present, a new gas pipeline and LNG plant for North Slope gas production is being considered for the year 2005-2015 time frame. Until this project (or another system) is constructed to transport North Slope gas, no development of offshore gas resources is expected. Because of this lack of a gas transportation system, the scenarios for the Beaufort and Chukchi provinces include oil production only.

Hope basin is an exception to this northern Alaska scenario because its resource base is expected to be predominately natural gas. Exploiting Hope Basin gas resources is likely to involve a new LNG facility and marine transportation route to Japan similar to the future scenarios postulated for the gas-prone provinces in the Bering Sea. Gas production in Hope basin development is not expected to rely on North Slope infrastructure, but could be linked to new development strategies in adjacent provinces in northwestern Alaska (Chukchi and Norton).

Chukchi Shelf

Results for the Chukchi shelf province are summarized in figure 27.1. The cumulative frequency plot (fig. 27.1A) indicates that the undiscovered resource endowment could range from 6.8 to 21.9 BBO (at 95 percent and 5 percent levels, respectively). The mean conventionally recoverable estimate is 13.02 BBO. Past exploration drilling has indicated that pooled and recoverable hydrocarbons are present, so the marginal probability of hydrocarbons (MPhc) without regard to economic viability is assigned a value of 1.0.

Under Base price ($18/bbl) conditions, 1.14 BBO risked mean economically recoverable oil is estimated for the Chukchi shelf province. This represents only 9 percent of the mean conventionally recoverable oil resources (fig. 27.1B). None of the huge gas resources (51.8 TCFG, mean estimate) are commercially viable without a new regional gas transportation system. At High Price ($30/bbl) conditions, the Chukchi shelf province could hold economically recoverable resources ranging from 2.8 BBO (Mean) to 6.2 BBO (High, 5 percent chance) (fig. 27.1C).

As shown in table 27.1, the economic oil resources are contained in few of the 22 geologic plays identified on the Chukchi shelf. For the Base price ($18/bbl), 4 plays contain 90 percent of the economic oil resources. At the High price ($30/bbl), these same 4 plays contain 86 percent of the economic oil resources. Two of these plays (Rift-Active Margin, Play 7; U. Brookian-Paleovalleys, Play 21) were tested by exploration wells with favorable, although noncommercial, results. The other two plays (Endicott-Chukchi Platform, Play 1; N. Chukchi High-Sand Apron, Play 14) remain untested by wells and are considered speculative.

Very high development and transportation costs in this remote province severely decrease the otherwise very attractive petroleum potential. A limited exploration program (5 wells) that tested the largest structures in the province did not result in any commercial success. However, the Chukchi shelf province contains all of the key components for oil fields (traps, reservoirs, source rock), and the abundance of untested large prospects could attract future exploration.

Beaufort Shelf

Results for the Beaufort shelf province are summarized in figure 27.2. The cumulative frequency plot (fig. 27.2A) indicates that the undiscovered resource endowment could range from 6.3 to 12.0 BBO (at 95 percent and 5 percent levels, respectively). The mean conventionally recoverable oil estimate is 8.84 BBO. Past exploration has indicated that pooled and recoverable hydrocarbons are present (MPhc=1.0).

Under Base price conditions ($18/bbl), 2.27 BBO of risked mean economically recoverable oil is estimated for the Beaufort shelf province, placing it first among all Alaska offshore assessment provinces. This represents 26 percent of the total conventionally recoverable oil volume (8.84 BBO)(fig. 27.2B). None of the conventionally recoverable gas resources (43.50 TCFG) are economically viable in the absence of a gas transportation system. Under High price conditions ($30.00/bbl), the Beaufort shelf province could hold economic resources ranging from 3.3 BBO (Mean) to 5.6 BBO (High, 5 percent chance) (fig. 27.2C).

As shown in table 27.2, the economic oil resources are contained in only a few of the 23 geologic plays assessed on the Beaufort shelf. For the Base price ($18/bbl), 4 plays (plays 0601, 0701, 1302, and 1602) contain 94 percent of the economic oil resources. At the High price ($30/bbl), these same 4 plays contain 87 percent of the economic oil resources. Several of these Beaufort shelf plays (plays 0401, 0501, 0601, 0701, 1302, and 1502) are producing from fields on the adjacent North Slope. The Brookian plays of the outer shelf remain largely untested (plays 1000, 1400, and 1602), although oil and gas shows have been encountered in the few exploration wells drilled in this deep-water setting.

The multi-billion barrel resource potential and the existing infrastructure on the North Slope are two important factors that will attract future exploration efforts to the Beaufort Shelf. However, given the limited commercial success to-date, the ice-infested offshore area is clearly a high-risk/high-reward frontier province.

Hope Basin

Results for the Hope basin province are summarized in figure 27.3. The cumulative frequency plot (fig. 27.3A) indicates that conventionally recoverable gas resources could range from a mean of 4.1 TCFG upwards to 12.7 TCFG (at 5 percent level). Liquid hydrocarbons (both gas-condensate and crude oil) range from a mean of 0.11 BBO upwards to 0.34 BBO (at 5 percent level). Although no exploration drilling has occurred in the offshore province, wells have been drilled in adjacent onshore areas and the results were factored into

TABLE 27.1:
OIL AND GAS RESOURCES OF CHUKCHI SHELF PLAYS
Risked, Undiscovered, Economically Recoverable Oil and Gas

PLAY NO.	PLAY NAME (UAI* CODE)	BASE PRICE			HIGH PRICE		
		OIL	GAS	BOE	OIL	GAS	BOE
1.	Endicott-Chukchi Platform (UACS0100)	0.169	n/a	0.169	0.459	n/a	0.459
2.	Endicott-Arctic Platform (UACS0200)	0.000	n/a	0.000	0.000	n/a	0.000
3.	Lisburne Carbonates (UACS0300)	0.000	n/a	0.000	0.000	n/a	0.000
4.	Ellesmerian Deep Gas (UACS0400)	0.000	n/a	0.000	0.000	n/a	0.000
5.	Sadlerochit-Chukchi Platform (UACS0500)	0.001	n/a	0.001	0.005	n/a	0.005
6.	Sadlerochit-Arctic Platform (UACS0600)	0.035	n/a	0.035	0.129	n/a	0.129
7.	Rift - Active Margin (UACS0700)	0.495	n/a	0.495	1.170	n/a	1.170
8.	Rift - Stable Shelf (UACS0800)	0.069	n/a	0.069	0.233	n/a	0.233
9.	Rift - Deep Gas (UACS0900)	0.000	n/a	0.000	0.000	n/a	0.000
10.	Herald Arch (UACS1000)	0.000	n/a	0.000	0.000	n/a	0.000
11.	L. Brook. Foldbelt (UACS1100)	negl	n/a	negl	0.003	n/a	0.003
12.	L. Brook. Turbidites/Wrench Zn (UACS1200)	0.000	n/a	0.000	negl	n/a	negl
13.	L. Brook. Topset/Wrench Zn (UACS1300)	0.001	n/a	0.001	0.005	n/a	0.005
14.	N. Chukchi High/Sand Apron (UACS1400)	0.153	n/a	0.153	0.329	n/a	0.329
15.	L. Brook. Topset/N. Chukchi Basin (UACS1500)	0.000	n/a	0.000	negl	n/a	negl
16.	Brookian Deep Gas (UACS1600)	0.000	n/a	0.000	0.000	n/a	0.000
17.	L. Brookian/Turbidites/Arct. Plat. (UACS1700)	0.000	n/a	0.000	0.000	n/a	0.000
18.	L. Brookian/Topset/Arctic Platform (UACS1800)	0.000	n/a	0.000	negl	n/a	negl
19.	U. Brookian/Sag Phase/N. Chuk. Bsn. (UACS1900)	0.000	n/a	0.000	0.000	n/a	0.000
20.	U. Brookian/Turbidites/N.Chuk.Bsn. (UACS2000)	0.000	n/a	0.000	0.000	n/a	0.000
21.	U. Brookian/Paleovalleys (UACS2100)	0.211	n/a	0.211	0.489	n/a	0.489
22.	U. Brookian/Intervalley Highs (UACS2200)	0.002	n/a	0.002	0.023	n/a	0.023
	TOTAL	*1.136*	*n/a*	*1.136*	*2.845*	*n/a*	*2.845*

* *Unique Assessment Identifier, code unique to play.*

OIL is in billions of barrels (BBO). **GAS** is in trillion cubic feet (TCF).
BOE is barrel of oil equivalent barrels, where 5,260 cubic feet of gas = 1 equivalent barrel-oil

For direct comparisons among provinces, two prices are selected from a continuum of possible price/resource relationships illustrated on price-supply curves. **BASE PRICE** is defined as $18.00 per barrel for oil and $2.11 per thousand cubic feet for gas. **HIGH PRICE** is defined as $30.00 per barrel for oil and $3.52 per thousand cubic feet for gas. Both economic scenarios assume a 1995 base year, flat real prices and development costs, 3% inflation, 12% discount rate, 35% Federal corporate tax, and 0.66 gas price discount.

Shaded columns indicate the most likely substances to be developed in this province. Economic viability is indicated on price-supply curves which aggregate the play resources in each province.

N/A refers to "not available". Associated gas will be reinjected for pressure maintenance to maximize oil recovery or as fuel for production facilities. Coproduction of gas resources is not economically feasible because of the lack of a gas transportation system and over 25 TCF of proven and undeveloped gas reserves on the North Slope.

TABLE 27.2:
OIL AND GAS RESOURCES OF BEAUFORT SHELF PLAYS
Risked, Undiscovered, Economically Recoverable Oil and Gas

PLAY NO.	PLAY NAME (UAI* CODE)	BASE PRICE			HIGH PRICE		
		OIL	GAS	BOE	OIL	GAS	BOE
0101	Undeformed Pre-Miss. Bsmt (UABS0101)	0.000	n/a	0.000	0.000	n/a	0.000
0200	Pre-Devonian (UABS0200)	0.002	n/a	0.002	0.006	n/a	0.006
0401	Endicott w/o Portion Shared/Chukchi (UABS0401)	0.000	n/a	0.000	0.001	n/a	0.001
0501	Lisburne Play (Beaufort Only: UABS0501)	0.010	n/a	0.010	0.040	n/a	0.040
0601	Upper Ellesmerian (Beaufort Only: UABS0601)	0.466	n/a	0.466	0.544	n/a	0.544
0701	Rift (Beaufort Only: UABS0701)	0.256	n/a	0.256	0.391	n/a	0.391
0800	Brookian Faulted Western Topset (UABS0800)	0.000	n/a	0.000	0.000	n/a	0.000
0902	Brookian Unstructured Western Topset (UABS0902)	0.001	n/a	0.001	0.018	n/a	0.018
1000	Brookian Faulted Western Turbidites (UABS1000)	0.000	n/a	0.000	0.000	n/a	0.000
1102	Brookian Unstructured Western Turbidite (UABS1102)	0.000	n/a	0.000	0.002	n/a	0.002
1201	Brookian Faulted Eastern Topset (UABS1201)	0.023	n/a	0.023	0.097	n/a	0.097
1302	Brookian Unstructured Eastern Topset (UABS1302)	0.840	n/a	0.840	1.001	n/a	1.001
1400	Brookian Faulted Eastern Turbidites (UABS1400)	0.000	n/a	0.000	0.000	n/a	0.000
1502	Brookian Unstructured Eastern Turbidites (UABS1502)	0.000	n/a	0.000	negl.	n/a	negl.
1602	Brookian Foldbelt (UABS1602)	0.578	n/a	0.578	0.882	n/a	0.882
1800	Endicott-Overlaps Chukchi (UABS1800)	0.000	n/a	0.000	0.000	n/a	0.000
1900	Lisburne-Overlaps Chukchi (UABS1900)	0.000	n/a	0.000	0.000	n/a	0.000
2000	Ellesmerian Deep Gas-Overlaps Chukchi (UABS2000)	0.000	n/a	0.000	0.000	n/a	0.000
2100	Upper Ellesmerian-Overlaps Chukchi (UABS2100)	0.055	n/a	0.055	0.124	n/a	0.124
2200	Rift-Overlaps Chukchi (UABS2200)	0.032	n/a	0.032	0.087	n/a	0.087
2300	Sand Apron-Overlaps Chukchi (UABS2300)	0.011	n/a	0.011	0.028	n/a	0.028
2400	Turbidites (Torok)-Overlaps Chukchi (UABS2400)	0.000	n/a	0.000	0.000	n/a	0.000
2500	Topset (Nanushuk)-Overlaps Chukchi (UABS2500)	0.000	n/a	0.000	0.002	n/a	0.002
	TOTAL	***2.274***	***n/a***	***2.274***	***3.223***	***n/a***	***3.223***

* *Unique Assessment Identifier, code unique to play.*

OIL is in billions of barrels (BBO). **GAS** is in trillion cubic feet (TCF).
BOE is barrel of oil equivalent barrels, where 5,260 cubic feet of gas = 1 equivalent barrel-oil

For direct comparisons among provinces, two prices are selected from a continuum of possible price/resource relationships illustrated on price-supply curves. **BASE PRICE** is defined as $18.00 per barrel for oil and $2.11 per thousand cubic feet for gas. **HIGH PRICE** is defined as $30.00 per barrel for oil and $3.52 per thousand cubic feet for gas. Both economic scenarios assume a 1995 base year, flat real prices and development costs, 3% inflation, 12% discount rate, 35% Federal corporate tax, and 0.66 gas price discount.

Shaded columns indicate the most likely substances to be developed in this province. Economic viability is indicated on price-supply curves, which aggregate the play resources in each province.

N/A refers to "not available". Associated gas will be reinjected for pressure maintenance to maximize oil recovery or as fuel for production facilities. Coproduction of gas resources is not economically feasible because of the lack of a gas transportation system and over 25 TCF of proven and undeveloped gas reserves on the North Slope.

the present assessment. The marginal probability for pooled hydrocarbons (MPhc) without regard for economic viability is estimated at 61 percent.

The Hope basin province was modeled for the coproduction of gas and oil resources. Natural gas, as the primary hydrocarbon substance, presumably will support the initial development activities in the province, with non-associated crude oil and natural gas liquids (condensates) recovered as byproducts.

At the Base price ($2.11/MCFG), the Hope basin province contains an estimated 0.12 TCFG of risked mean economically recoverable gas and negligible volumes of liquid hydrocarbons (crude oil and gas-condensate). The economic resource base amounts to only 3 percent of the mean conventionally recoverable gas endowment (fig. 27.3B). At the High Price ($3.52/MCFG), the Hope basin province contains 0.249 TCFG (tbl. 27.3), which amounts to 6 percent of the mean conventionally recoverable endowment. The High Price condition is representative of current prices for LNG in Pacific Rim markets.

High development and transportation costs combine to impose an economic hurdle that will require prices of at least $5.00 per MCFG before significant volumes of gas resources are economically recoverable (fig. 27.3C). At $7.00 per MCFG (approximately twice the current LNG price), the mean economically recoverable gas estimate is 2.5 TCFG. For the High case (5 percent chance), approximately 8.5 TCFG would be economic to produce from the Hope Basin at prices of $7.00 per MCFG. This high case/high price volume might be considered a sufficient resource to support an expensive grassroots LNG project in this remote area. Because of high geologic and economic risks, economically recoverable resources are not available at the 95 percent probability level, so a Low case curve is not displayed.

Gas resources in the Hope basin occur in four geologic plays. However, as shown in table 27-3, one play (Late Sequence, Play 1) contains

TABLE 27.3:
OIL AND GAS RESOURCES OF HOPE BASIN PLAYS
Risked, Undiscovered, Economically Recoverable Oil and Gas

PLAY NO.	PLAY NAME (UAI* CODE)	BASE PRICE			HIGH PRICE		
		OIL	GAS	BOE	OIL	GAS	BOE
1.	Late Sequence (UAHB0101)	0.004	0.118	0.025	0.007	0.244	0.050
2.	Early Sequence (UAHB0201)	negl	0.001	negl	negl	0.003	0.001
3.	Shallow Basal Sands (UAHB0301)	negl	0.001	negl	negl	0.002	negl
4.	Deep Basal Sands (UAHB0401)	0.000	0.000	0.000	0.000	0.000	0.000
	TOTAL	***0.004***	***0.120***	***0.025***	***0.007***	***0.249***	***0.051***

* *Unique Assessment Identifier, code unique to play.*

OIL is in billions of barrels (BBO). **GAS** is in trillion cubic feet (TCF).
BOE is barrel of oil equivalent barrels, where 5,260 cubic feet of gas = 1 equivalent barrel-oil

For direct comparisons among provinces, two prices are selected from a continuum of possible price/resource relationships illustrated on price-supply curves. **BASE PRICE** is defined as $18.00 per barrel for oil and $2.11 per thousand cubic feet for gas. **HIGH PRICE** is defined as $30.00 per barrel for oil and $3.52 per thousand cubic feet for gas. Both economic scenarios assume a 1995 base year, flat real prices and development costs, 3% inflation, 12% discount rate, 35% Federal corporate tax, and 0.66 gas price discount.

Shaded columns indicate the most likely substances to be developed in this province. Economic viability is indicated on price-supply curves, which aggregate the play resources in each province.

98 percent of the economic gas resources under both Base and High price conditions. This untested play is estimated to have the highest number of large undiscovered pools as well as the most optimistic reservoir characteristics (thickness, porosity, permeability).

The economic modeling results suggest that a substantial increase in gas prices in addition to an active exploration program will be required to justify future development in the Hope basin province. Gas production is likely to hinge on infrastructure-sharing strategies with adjacent provinces (Chukchi and Norton). Future industry interest will be driven by perceptions of high-side potential, which accepts high investment risks for high rewards, innovative new technologies, and infrastructure sharing with other gas-prone provinces.

ECONOMIC RESULTS FOR THE BERING SHELF SUBREGION

The hydrocarbon resource potential in the Bering subregion is dominated by natural gas. Minor amounts of crude oil and condensate from gas could be recovered, but typically, new offshore development will be based largely on gas production. Because local Alaska markets cannot assimilate large new gas supplies, future gas production will be shipped to distant outside markets. To process natural gas to a transportable form, a Liquefied natural gas (LNG) method was selected because it is a proven commercial practice. The gas transportation scenarios discussed in Chapter 26 (Infrastructure Scenarios) generally involve the delivery of gas production by subsea pipelines to an onshore LNG facility served by a marine terminal. LNG is then shipped by marine LNG carriers to markets in Japan or other Pacific Rim countries. Gas-condensate and crude oil would be delivered by subsea pipelines to offshore storage and loading terminals or an onshore terminal. Eventually, all liquid hydrocarbon production would be delivered to the West Coast to conventional tankers.

At present, no infrastructure is present in the Bering Sea, and billions of dollars of investment would be required for gas production projects in this subregion. Economic hurdles could be lowered somewhat by shared development strategies, particularly for LNG facilities, marine terminals, and LNG carriers. This strategy would lower costs and spread economic risks among several frontier provinces. However, because the timing of development is key to any shared infrastructure strategies and because it is difficult to speculate that industry will again actively explore these Bering Sea provinces, province was evaluated on a stand-alone basis.

Offshore leasing and exploration programs have occurred in many of the Bering Shelf provinces, but exploration results have not been encouraging. In view of costly infrastructure requirements and a low, gas-prone resource potential, future industry activity in these provinces could hinge on new technologies for gas transportation, higher gas prices, or different (more optimistic) perceptions of resource potential.

Navarin Basin

Results for the Navarin basin province are summarized in figure 27.4. The cumulative frequency plot (fig. 27.4A) indicates that conventionally recoverable gas resources range from a mean of 6.15 TCFG upwards to 18.2 TCFG (at 5 percent level). Liquid hydrocarbons (gas condensates and crude oil) range from a mean of 0.50 BBO upwards to 1.2 BBO (at 5 percent level). Limited exploration drilling (9 wells) has failed to encounter significant oil or gas shows. Despite the negative results to date, the marginal probability for pooled and recoverable hydrocarbons (MPhc) without regard to economic viability is estimated to be 88 percent.

The Navarin basin province was modeled for the coproduction of gas and oil resources. Natural gas, as the primary hydrocarbon substance, is assumed to largely support the development activities in the province, with non-associated crude oil and gas condensate liquids recovered as byproducts. As there is no petroleum infrastructure in the Bering Sea, new transportation facilities are required both in the province as well as on the Alaska Peninsula.

Under the Base price condition ($2.11/MCFG), the Navarin basin province contains an estimated 0.04 TCFG of risked mean economically recoverable gas and negligible volumes of liquid hydrocarbons (fig. 27.4B). Economic resources are a negligible portion of the mean conventionally recoverable gas endowment. At the High price ($3.52/MCFG), this province contains 0.075 TCFG of economically recoverable gas, still only 1.2 percent of the mean gas endowment (tbl. 27.4). The lack of economic viability can be attributed to small hydrocarbon pool size, poor reservoir properties, and very high development and transportation costs.

High development and transportation costs impose an economic hurdle requiring prices greater than $7.00 per MCFG before significant volumes of gas resources are economically recoverable (fig. 27.4C). This price hurdle is roughly twice the current LNG price in Pacific Rim markets. At $8.00 per MCFG, the economically recoverable gas resource in the Mean resource case is 1.8 TCFG. For the High resource case (5 percent chance), 7.7 TCFG would be economic to produce, if discovered, in the Navarin basin. This high case/high price volume might be considered a sufficient resource to support a grassroots LNG project in this remote area. Because of high geologic and economic basin risks, economically recoverable resources are not available at the 95 percent probability level, so a Low case curve is not displayed.

TABLE 27.4:
OIL AND GAS RESOURCES OF NAVARIN BASIN PLAYS
Risked, Undiscovered, Economically Recoverable Oil and Gas

PLAY NO.	PLAY NAME (UAI* CODE)	BASE PRICE			HIGH PRICE		
		OIL	GAS	BOE	OIL	GAS	BOE
1.	Miocene Transgressive Shelf Sands (UANA0100)	negl	0.002	negl	negl	0.004	0.001
2.	Regressive Shelf Sands (UANA0200)	0.000	0.000	0.000	0.001	0.014	0.003
3.	Oligocene Tectonic Sands (UANA0300)	0.000	0.000	0.000	0.000	0.000	0.000
4.	Turbidite and Submarine Fan Sands (UANA0400)	0.001	0.034	0.007	0.002	0.057	0.012
5.	Eocene Transgressive Shelf Sands (UANA0500)	0.000	0.000	0.000	0.000	0.000	0.000
	TOTAL	***0.001***	***0.036***	***0.007***	***0.003***	***0.075***	***0.016***

* *Unique Assessment Identifier, code unique to play.*

OIL is in billions of barrels (BBO). **GAS** is in trillion cubic feet (TCF).
BOE is barrel of oil equivalent barrels, where 5,260 cubic feet of gas = 1 equivalent barrel-oil

For direct comparisons among provinces, two prices are selected from a continuum of possible price/resource relationships illustrated on price-supply curves. **BASE PRICE** is defined as $18.00 per barrel for oil and $2.11 per thousand cubic feet for gas. **HIGH PRICE** is defined as $30.00 per barrel for oil and $3.52 per thousand cubic feet for gas. Both economic scenarios assume a 1995 base year, flat real prices and development costs, 3% inflation, 12% discount rate, 35% Federal corporate tax, and 0.66 gas price discount.

Shaded columns indicate the most likely substances to be developed in this province. Economic viability is indicated on price-supply curves which aggregate the play resources in each province.

The gas resources in the Navarin basin occur in five geologic plays, with one play (Turbidite and Submarine Fan, Play 4) containing most of the economically recoverable gas resources under both price conditions (94 percent at Base price; 76 percent at High price)(tbl. 27.4). This play is estimated to have the highest number of large undiscovered pools, with individual gas pools ranging in volume up to 1.2 TCFG. However, given that no wells have tested this play, this resource potential is highly speculative.

These economic results suggest that gas production from the Navarin basin province is very unlikely on a stand-alone basis. It is also unlikely that oil development in the Navarin basin would be economically viable, at foreseeable prices, without the benefit of gas production infrastructure (production platforms, subsea pipeline corridors). Coordinated development strategies with other gas-prone provinces in the Bering Sea could be employed to share infrastructure, thereby improving the commercial possibilities for this province. For example, the subsea gas pipeline could be partially supported by gas production from the St. George basin. Utilizing an existing LNG plant and marine terminal on the Alaska Peninsula would spread a multi-billion dollar capital cost over a greater resource base. Future exploration interest is likely to be driven by the high-side potential, which accepts higher rewards at higher risks, presumably focusing on the untested turbidite reservoirs of Play 4.

North Aleutian Basin

Assessment results for the North Aleutian basin province are summarized in figure 27.5. The cumulative frequency plot (fig. 27.5A) indicates that conventionally recoverable gas resources range from a mean of 6.79 TCFG upwards to 17.33 TCFG (at 5 percent level). Liquid hydrocarbons (gas condensates and crude oil) range from a mean of 0.23 BBO upwards to 0.57 BBO (at 5 percent level). The marginal probability for pooled and recoverable hydrocarbons (MPhc) without regard to economic viability is estimated at 72 percent.

The North Aleutian province was modeled for the coproduction of gas and oil resources. Natural gas, as the primary hydrocarbon substance, is assumed to largely support the development activities in the province, with non-associated crude oil and gas condensate liquids recovered as byproducts. As there is no petroleum infrastructure in the Bering Sea, new transportation facilities are required both in the offshore province and on the Alaska Peninsula.

Under the Base price condition ($2.11 per MCFG), the North Aleutian basin province contains an estimated 0.88 TCFG of risked mean economically recoverable gas resources, representing 13 percent of the conventionally recoverable endowment (fig. 27.5B). Liquid hydrocarbons (primarily gas condensate) amounting to 0.02 BBO could be recovered along with the gas production. At the High price ($3.52 per MCFG), the province could contain 1.27 TCFG of economically recoverable gas (tbl. 27.5). This volume represents 19 percent of the mean conventionally recoverable gas endowment. For the High resource case (5 percent chance), 12.0 TCFG would be economic to produce given the engineering and cost assumptions. Because of high geologic and economic basin risks, economically recoverable resources are not available at the 95 percent probability level, so a Low case curve is not displayed.

The hydrocarbon resources in the North Aleutian basin are assigned to one geologic play (Oligocene-Miocene Play), which has been tested offshore by only one stratigraphic test well. The main attractions of this play are large anticlinal structures and abundant, high-quality reservoir sands. These factors contribute to mean gas pool sizes ranging up to 2.5 TCFG. Because the resources are undiscovered, exploration drilling will be required to confirm these optimistic estimates. However, leasing and exploration in the North Aleutian basin province is presently prohibited by Congressional moratorium.

TABLE 27.5:
OIL AND GAS RESOURCES OF NORTH ALEUTIAN BASIN PLAY
Risked, Undiscovered, Economically Recoverable Oil and Gas

PLAY NO.	PLAY NAME (UAI* CODE)	BASE PRICE			HIGH PRICE		
		OIL	GAS	BOE	OIL	GAS	BOE
1.	Oligocene-Miocene (UANB0100)	0.024	0.880	0.180	0.036	1.272	0.263
	TOTAL	***0.024***	***0.880***	***0.180***	***0.036***	***1.272***	***0.263***

* *Unique Assessment Identifier, code unique to play.*

OIL is in billions of barrels (BBO). **GAS** is in trillion cubic feet (TCF).
BOE is barrel of oil equivalent barrels, where 5,260 cubic feet of gas = 1 equivalent barrel-oil

For direct comparisons among provinces, two prices are selected from a continuum of possible price/resource relationships illustrated on price-supply curves. **BASE PRICE** is defined as $18.00 per barrel for oil and $2.11 per thousand cubic feet for gas. **HIGH PRICE** is defined as $30.00 per barrel for oil and $3.52 per thousand cubic feet for gas. Both economic scenarios assume a 1995 base year, flat real prices and development costs, 3% inflation, 12% discount rate, 35% Federal corporate tax, and 0.66 gas price discount.

Shaded columns indicate the most likely substances to be developed in this province. Economic viability is indicated on price-supply curves which aggregate the play resources in each province.

The North Aleutian basin province contains 89 percent of the economic gas resources in the entire Bering Sea subregion. Economic viability in this province can be attributed to both reservoir characteristics (shallow, high porosity reservoirs) and favorable development logistics (shallow water, short pipelines, mild sea-ice conditions). Gas production is viable on a stand-alone basis under current market prices for LNG delivered to Japan. At a price of $3.50 per MCFG, approximately 1.2 TCF of gas would be economic for the mean case. It is unlikely that oil reservoirs will be produced in the North Aleutian province unless they can be developed from platforms installed primarily for gas production. The high-side potential (5 percent chance) in this province far exceeds the cost hurdle imposed by new gas production and transportation infrastructure, and nearly 12.0 TCFG of gas could be recoverable at current LNG prices in Pacific Rim markets.

The development of this province and associated LNG infrastructure on the Alaska Peninsula is perhaps the key to additional development activities in other gas-prone provinces in the Bering Sea (Navarin, St. George) or Pacific Margin (Shumagin) subregions. However, future industry efforts will only proceed only if the present Congressional moratorium is discontinued.

St. George Basin

Assessment results for the St. George basin province are summarized in figure 27.6. The cumulative frequency plot (fig. 27.6A) indicates that conventionally recoverable gas resources range from a mean of 3.00 TCFG upwards to 9.72 TCFG (at 5 percent level). Liquid hydrocarbons (gas condensates and crude oil) range from a mean of 0.13 BBO upwards to 0.41 BBO (at 5 percent level). The province has been tested by a total of 10 exploration and 2 stratigraphic test wells. All exploration wells were plugged and abandoned without encountering significant hydrocarbon shows. Despite the negative results to date, the marginal probability for pooled and recoverable hydrocarbons (MPhc) without regard to economic viability is estimated at 94 percent.

The St. George province was modeled for the coproduction of gas and oil resources. Natural gas, as the primary hydrocarbon substance, is assumed to largely support the development activities in the province, with non-associated crude oil and gas condensate liquids recovered as byproducts. As there is no petroleum infrastructure in the Bering Sea, new transportation facilities are required both in the offshore province and on the Alaska Peninsula.

At the Base price ($2.11/MCFG), the St. George province contains an estimated 0.05 TCFG of risked mean economically recoverable gas and negligible volumes of liquid hydrocarbons (fig. 27.6B). Economic gas resources represent 2 percent of the mean conventionally recoverable gas endowment. At the High Price ($3.52/MCFG), the province contains 0.103 TCFG of economically recoverable gas, still only 3.4 percent of the mean gas endowment (tbl. 27.6).

Poor economic viability is attributed to relative small pool sizes combined with high development and transportation costs for gas production. Significant volumes of gas resources are economically recoverable above a price hurdle of approximately $8.00 per MCFG (fig. 27.4C). This price hurdle is over twice the current LNG price in Pacific Rim markets. At $10.00 per MCFG, the economically recoverable gas resource in the Mean case is 0.5 TCFG. For the High case (5 percent chance), 5.2 TCFG would be economic to produce. This high case/high price volume might be considered a sufficient resource to support a grassroots LNG project in this remote area. Because of high geologic and economic basin risks, economically recoverable resources are not available at the 95 percent probability level, so a Low case curve is not shown.

Gas resources in the St. George Basin occur in 4 geologic plays, however, one play (South Platform, Play 2) contains most of the economically recoverable gas resources under both price conditions (90 percent at the Base

TABLE 27.6:
OIL AND GAS RESOURCES OF ST. GEORGE BASIN PLAYS
Risked, Undiscovered, Economically Recoverable Oil and Gas

PLAY NO.	PLAY NAME (UAI* CODE)	BASE PRICE			HIGH PRICE		
		OIL	GAS	BOE	OIL	GAS	BOE
1.	St. George Graben (UASG0101)	0.000	0.000	0.000	negl	0.004	0.001
2.	South Platform (UASG0201)	0.002	0.044	0.009	0.003	0.084	0.018
3.	North Platform (UASG0301)	negl	0.004	0.001	0.001	0.013	0.003
4.	Pribilof Basin (UASG0401)	negl	0.001	negl	negl	0.002	negl
	TOTAL	*0.002*	*0.049*	*0.010*	*0.004*	*0.103*	*0.022*

* *Unique Assessment Identifier, code unique to play.*

OIL is in billions of barrels (BBO). **GAS** is in trillion cubic feet (TCF).
BOE is barrel of oil equivalent barrels, where 5,260 cubic feet of gas = 1 equivalent barrel-oil

For direct comparisons among provinces, two prices are selected from a continuum of possible price/resource relationships illustrated on price-supply curves. **BASE PRICE** is defined as $18.00 per barrel for oil and $2.11 per thousand cubic feet for gas. **HIGH PRICE** is defined as $30.00 per barrel for oil and $3.52 per thousand cubic feet for gas. Both economic scenarios assume a 1995 base year, flat real prices and development costs, 3% inflation, 12% discount rate, 35% Federal corporate tax, and 0.66 gas price discount.

Shaded columns indicate the most likely substances to be developed in this province. Economic viability is indicated on price-supply curves which aggregate the play resources in each province.

price; 82 percent at the High price). The dominance of Play 2 is explained by large structural prospects and abundant reservoir sands. These factors contribute to gas pool sizes ranging up to 2.3 TCFG (mean).

The economic modeling indicates that gas production from the St. George basin province is unlikely on a stand-alone basis because of the high costs associated with gas transportation infrastructure. However, coordinated development strategies with adjacent provinces might improve the economic opportunity in this province. For example, a subsea gas pipeline and LNG facility on the Alaska Peninsula built for other Bering Sea provinces (Navarin or North Aleutian) could be utilized by subsequent development in the St. George basin. It is very unlikely that oil reservoirs will be developed in the St. George basin unless they can be developed from platforms installed primarily for gas production.

Future production from this offshore province will require a substantial increase in gas prices as well as an aggressive exploration program to discover these resources. Future exploration interest is likely to be driven by the high-side potential (which accepts higher investment risks in anticipation of higher rewards), particularly focused on Play 2 in the South Platform area.

Norton Basin

Results for the Norton basin province are summarized in figure 27.7. The cumulative frequency plot (fig. 27.7A) indicates that conventionally recoverable gas resources could range from a mean of 2.71 TCFG upwards to 8.74 TCFG (at 5 percent level). Liquid hydrocarbons (all gas condensates) range from a mean of 0.05 BBO upwards to 0.15 BBO (at 5 percent level). Exploration drilling has failed to discover commercial hydrocarbon pools (6 exploration and 2 stratigraphic test wells). The marginal probability for pooled and recoverable hydrocarbons (MPhc) without regard to economic viability is estimated at 72 percent.

The Norton province was modeled for the production of gas. Natural gas, as the primary hydrocarbon substance, is assumed to support the development activities in the province, and gas-condensates could be recovered as a byproduct.. The geologic resource model includes no crude oil resources in the Norton basin. At present, there is no petroleum-related infrastructure in this province, and new facilities are likely to be constructed near Nome which has an airport and marine port facilities.

At the Base price ($2.11/MCFG), the Norton basin province contains an estimated 0.02 TCFG of risked mean economically recoverable gas, which is a negligible fraction of the mean conventionally recoverable gas endowment (fig. 27.7B). At the High price ($3.52/MCFG), this province contains economic gas resources of 0.07 TCFG, still only 2.5 percent of the mean gas endowment (tbl. 27.7).

At current LNG prices equivalent to the High price ($3.52/MCFG), the economic resource volume is insufficient to support development of a grassroots project in this remote area. The high development and transportation costs are overcome at a price hurdle of approximately $6.00 per MCFG, above which significant volumes of gas resources are recoverable in both the Mean and High resource cases. Because of high geologic and economic basin risks, economically recoverable resources are not available at the 95 percent probability level, so a Low case curve is not displayed. At $7.00 per MCFG (approximately twice the current LNG price in the Pacific Rim), the mean economically recoverable gas resource is 0.6 TCFG and there is a 5 percent chance for gas resources of 3.5 TCFG (fig. 27.7C). This production scenario would require a substantial increase in real gas prices as well as an aggressive exploration program to discover these resources.

Gas resources in the Norton Basin occur in 4 geologic plays, however, one play (West Subbasin, Play 3) contains most of the economically recoverable gas resources under both price conditions (96 percent at the Base

Price; 86 percent at the High Price)(tbl. 27.7). The West Subbasin play has been tested by one exploration and one stratigraphic test well. Five exploration wells and a stratigraphic test well (all plugged and abandoned without encountering significant hydrocarbon shows) were located in eastern parts of the Norton basin province. The West Subbasin is estimated to contain the largest number of undiscovered pools and has a better opportunity for marine source rocks. Consequently, this subbasin was assigned the best exploration chance of all plays in the Norton basin province.

Gas production from the Norton basin province is unlikely on a stand-alone basis because of its relatively low resource endowment and high transportation costs. However, shared infrastructure strategies with adjacent provinces (Navarin, Hope) would improve the economic viability of this province. Future exploration interest is likely to be driven by the high-side potential (which accepts higher investment risk for high rewards), particularly in the untested West Subbasin.

ECONOMIC RESULTS FOR THE PACIFIC MARGIN SUBREGION

Offshore provinces in the Pacific Margin subregion contain only modest endowments of oil and gas, but the opportunity for economic recovery is improved by the proximity to existing infrastructure. Oil and gas exploration of this subregion began in late 1800's, and the first commercial petroleum discovery in Alaska was made near Katalla (onshore Gulf of Alaska province) in 1902. In 1957, a commercial oil discovery was made at Swanson River on the Kenai Peninsula (onshore Cook Inlet basin). Offshore production from the Upper Cook Inlet began in 1967, and several processing and terminal facilities for oil and gas have been in operation in the Cook Inlet for decades.

TABLE 27.7:
OIL AND GAS RESOURCES OF NORTON BASIN PLAYS
Risked, Undiscovered, Economically Recoverable Oil and Gas

PLAY NO.	PLAY NAME (UAI* CODE)	BASE PRICE			HIGH PRICE		
		OIL	GAS	BOE	OIL	GAS	BOE
1.	Upper Tertiary Basin Fill (UANO0101)	negl	0.001	negl	negl	0.006	0.001
2.	Mid Tertiary East Subbasin Fill (UANO0201)	0.000	0.000	0.000	negl	0.004	0.001
3.	Mid Tertiary West Subbasin Fill (UANO0301)	negl	0.023	0.004	0.001	0.062	0.012
4.	Lower Tertiary Subbasin Fill (UANO0401)	0.000	0.000	0.000	0.000	0.000	0.000
	TOTAL	*negl*	*0.024*	*0.004*	*0.001*	*0.072*	*0.014*

* *Unique Assessment Identifier, code unique to play.*

OIL is in billions of barrels (BBO). **GAS** is in trillion cubic feet (TCF).
BOE is barrel of oil equivalent barrels, where 5,260 cubic feet of gas = 1 equivalent barrel-oil

For direct comparisons among provinces, two prices are selected from a continuum of possible price/resource relationships illustrated on price-supply curves. **BASE PRICE** is defined as $18.00 per barrel for oil and $2.11 per thousand cubic feet for gas. **HIGH PRICE** is defined as $30.00 per barrel for oil and $3.52 per thousand cubic feet for gas. Both economic scenarios assume a 1995 base year, flat real prices and development costs, 3% inflation, 12% discount rate, 35% Federal corporate tax, and 0.66 gas price discount.

Shaded columns indicate the most likely substances to be developed in this province. Economic viability is indicated on price-supply curves which aggregate the play resources in each province.

Exploration efforts in offshore Federal waters also began in this part of the State, with initial leasing and stratigraphic test wells drilled in the mid-1970's. Although the focus of industry interest has shifted to Arctic Alaska, low levels of industry activity continue in the Pacific Margin subregion to the present.

As in other Alaska offshore provinces, gas production is assumed to be exported as LNG to the Pacific Rim (Yokohama, Japan, as the principle destination) because local markets are unable to utilize large new gas supplies at the present time. However, while most other offshore provinces will require costly new LNG facilities and marine terminals, an LNG plant and export terminal has been operating in the Cook Inlet since 1969. This facility is the only LNG processing plant in the United States. The Phillips-Marathon LNG plant has an export capacity of approximately 60 billion cubic feet (BCF) per year. Outside of the Cook Inlet area, future offshore gas development in the northwestern Gulf of Alaska could use a new LNG facility at Valdez proposed for North Slope gas. Completion of the new LNG facility at Valdez is not expected for at least a decade (2005-2015 time frame).

Although the development scenarios assumed that oil and gas would primarily be exported, future market conditions could favor local consumption. Considering the proximity to Alaska's largest population center, the declining production in the Upper Cook Inlet, modest remaining resource volumes, and the existing infrastructure, it is likely that most of the future oil and gas production will be refined and marketed in south-central Alaska.

In more distant provinces along the Pacific Margin, there is no production and transportation infrastructure. For the Gulf of Alaska shelf province, new infrastructure would be located in Yakutat Bay, and produced oil would be delivered to U.S. West Coast ports by tankers. Future gas production from the Kodiak shelf could require an expansion of the Phillips-Marathon LNG facility in the Cook Inlet. Minor amounts of gas-condensates coproduced with natural gas production are likely to utilize offshore storage and loading systems. Shuttle tankers could transport hydrocarbon liquids to the tanker terminal in Valdez, where they would be commingled with North Slope crude oil and shipped to the West Coast. Gas production from the Shumagin shelf (western part of Shumagin-Kodiak province) would require a new LNG plant and marine terminal on the Alaska Peninsula, perhaps utilizing a facility shared with other Bering Sea provinces. These infrastructure requirements pose large economic hurdles, which are not easily satisfied by current commodity prices. Future industry interest in these provinces may depend on new technology for gas transportation, higher gas prices, changing industry perceptions of geologic resource potential.

Cook Inlet

Results for the Cook Inlet province are summarized in figure 27.8. The cumulative frequency plot (fig. 27.8A) indicates that conventionally recoverable oil resources could range from 0.32 BBO (at 95 percent level) upwards to 1.39 BBO (at 5 percent level), with a mean of 0.74 BBO. Gas resources could range from 0.40 TCFG (at 95 percent level) upwards to 1.65 TCFG (at 5 percent level), with a mean of 0.89 TCFG. Past exploration has indicated that pooled and recoverable hydrocarbons are present, so the marginal probability (MPhc) without regard to economic viability is 1.0.

The Cook Inlet province was modeled for the production of oil only, and gas production is not reported in the present assessment. This decision was based on two considerations. First, the hydrocarbon resources were modeled to be associated oil and gas pools (oil reservoirs overlain by gas caps). Normally, oil fields reinject recovered associated/dissolved gas to optimize oil recovery or utilize recovered gas as fuel for platform equipment. Second, preliminary simulation runs showed that there is a negative economic impact on oil recovery if associated gas resources are coproduced. Although the focus of initial commercial development is oil production, reinjected or by-passed gas resources would be available at some future time when oil resources are depleted. Gas recovery decades into the future is beyond the scope of the present assessment.

At Base price conditions ($18/bbl), the Cook Inlet province contains 0.27 BBO of risked mean economically recoverable oil. This volume represents 36 percent of the total conventionally recoverable oil resources (fig. 27.8B). At the High price ($30.00/bbl), the Cook Inlet could hold economic resources ranging from 0.45 BBO (Mean case) to 0.92 BBO (High case) (fig. 27.8C).

The ratio of economic to conventionally recoverable resources (E/C=0.36) is the highest ratio of all Alaska offshore provinces. This indicator suggests that a significant fraction of undiscovered Cook Inlet resources could occur in commercial-sized pools. The proximity to existing infrastructure and relatively mild operating conditions (by Alaska standards) are two explanations for the commercial viability despite the generally small petroleum accumulations expected in the Cook Inlet province.

Economic oil resources are expected in all three Cook Inlet plays, although 83 percent of economic resources at the Base price ($18/bbl) occurs in stratigraphic plays (Plays 1 and 2; tbl. 27.8). Previous exploration efforts (13 exploration wells) have concentrated on structural prospects, and current production in the northern Cook Inlet is from Tertiary anticlines. New seismic data collection and processing technology is now focusing on the potential of subtle stratigraphic prospects.

A 40-year history of oil and gas production in the Cook Inlet region, with its associated infrastructure, and a local consumer market are the primary factors favoring future exploration

TABLE 27.8:
OIL AND GAS RESOURCES OF COOK INLET PLAYS
Risked, Undiscovered, Economically Recoverable Oil and Gas

PLAY NO.	PLAY NAME (UAI* CODE)	BASE PRICE			HIGH PRICE		
		OIL	GAS	BOE	OIL	GAS	BOE
1.	Tertiary Stratigraphic (UACI0101)	0.163	n/a	0.163	0.223	n/a	0.223
2.	Mesozoic Stratigraphic (UACI0201)	0.060	n/a	0.060	0.114	n/a	0.114
3.	Mesozoic Structural (UACI0301)	0.045	n/a	0.045	0.121	n/a	0.121
	TOTAL	***0.268***	***n/a***	***0.268***	***0.458***	***n/a***	***0.458***

* *Unique Assessment Identifier, code unique to play.*

OIL is in billions of barrels (BBO). **GAS** is in trillion cubic feet (TCF).
BOE is barrel of oil equivalent barrels, where 5,260 cubic feet of gas = 1 equivalent barrel-oil

For direct comparisons among provinces, two prices are selected from a continuum of possible price/resource relationships illustrated on price-supply curves. **BASE PRICE** is defined as $18.00 per barrel for oil and $2.11 per thousand cubic feet for gas. **HIGH PRICE** is defined as $30.00 per barrel for oil and $3.52 per thousand cubic feet for gas. Both economic scenarios assume a 1995 base year, flat real prices and development costs, 3% inflation, 12% discount rate, 35% Federal corporate tax, and 0.66 gas price discount.

Shaded columns indicate the most likely substances to be developed in this province. Economic viability is indicated on price-supply curves which aggregate the play resources in each province.

N/A refers to "not available". Associated gas will be reinjected for pressure maintenance to maximize oil recovery.

and development in the Cook Inlet province.

Gulf of Alaska

Results for the Gulf of Alaska Shelf province are summarized in figure 27.9. The cumulative frequency plot (fig. 27.9A) indicates that conventionally recoverable oil resources could range from 0.18 BBO (at 95 percent level) upwards to 1.43 BBO (at 5 percent level), with a mean of 0.63 BBO. Gas resources could range from 0.94 TCFG (at 95 percent level) upwards to 10.59 TCFG (at 5 percent level), with a mean of 4.18 TCFG. Past exploration efforts have indicated that pooled and recoverable hydrocarbons are likely to be present. Accordingly, a high marginal probability (MPhc=0.99) is assigned to the province for recoverable, but not necessarily commercially viable, petroleum resources.

The Gulf of Alaska province was modeled for the production of oil only, and economic gas resources are not reported in the present assessment. This decision was based on two considerations. First, the hydrocarbon resources were modeled to be associated oil and gas pools (oil reservoirs overlain by gas caps). Normally, oil fields reinject recovered associated/dissolved gas to optimize oil recovery or utilize recovered gas as fuel for platform equipment. Second, preliminary simulation runs showed that there is a negative economic impact on oil recovery if associated gas resources are coproduced. Although the focus of initial commercial development is oil production, reinjected or by-passed gas resources would be available at some future time when oil resources are depleted. Gas recovery decades into the future is beyond the scope of the present assessment.

Under Base Price conditions ($18/bbl), the Gulf of Alaska province contains 0.05 BBO of risked mean economically recoverable oil. This volume represents only 8 percent of the total conventionally recoverable oil resources (fig. 27.9B). At the High price ($30/bbl) condition, the Gulf of Alaska province could hold economic resources ranging from 0.12 BBO (Mean case) to 0.47 BBO (High case) (fig. 27.9C). If we assume both the High price ($30/bbl) and a High case (5 percent chance), 0.30 BBO of risked economic oil is estimated to be recoverable from this province. Because high development costs are coupled with meager oil resources, economically recoverable resources are not available at the 95 percent probability level, so a Low case curve is not displayed.

Economic oil resources are modeled in four of the five geologic plays in the Gulf of Alaska shelf province, the exception being the Middleton Fold and Thrust Belt (Play 5) which is a gas-prone play (tbl. 27.9). However, 70 percent of the economic resources under the Base price ($18/bbl) occurs in Kulthieth Sand play (Play 4). For the High price condition ($30/bbl), 76 percent of the economic oil resource occurs in the overlapping Basal Yakataga Formation (Play 3) and Kulthieth Sands (Play 4) plays. Previous exploration efforts in the Gulf of Alaska shelf province have concentrated on easily identified structural prospects, and 12 exploration wells failed to discover commercial quantities of oil or gas. Future exploration interest is likely to be driven by expectations of high-side potential (which accepts higher investment risks for higher rewards), higher future commodity prices, and perhaps improved seismic techniques focused on stratigraphic prospects in plays 3 and 4.

Although the conventionally recoverable oil endowment in the Gulf of Alaska province is comparable to the Cook Inlet province, the likelihood of commercial oil production is far lower. A low E/C ratio (8 percent) ratio suggests that most of oil resources occur in small pools that cannot support the cost of new infrastructure in this remote province. However, considering that on a BOE basis gas resources account for roughly half of the total hydrocarbon endowment, future developments might involve independent production scenarios for geographically separate oil and gas fields. For example, offshore gas production from gas-prone plays in the northwestern part of the province

TABLE 27.9:
OIL AND GAS RESOURCES OF GULF OF ALASKA SHELF PLAYS
Risked, Undiscovered, Economically Recoverable Oil and Gas

PLAY NO.	PLAY NAME (UAI* CODE)	BASE PRICE			HIGH PRICE		
		OIL	GAS	BOE	OIL	GAS	BOE
1.	Middleton Fold and Thrust Belt (UAGA0101)	0.000	n/a	0.000	0.000	n/a	0.000
2.	Yakataga Fold and Thrust Belt (UAGA0201)	0.004	n/a	0.004	0.017	n/a	0.017
3.	Yakutat Shelf-Basal Yakataga Fm. (UAGA0401)	0.007	n/a	0.007	0.021	n/a	0.021
4.	Yakutat Shelf-Kulthieth Sands (UAGA0501)	0.032	n/a	0.032	0.069	n/a	0.069
5.	Southeast Alaska Shelf Subbasin	n/e	n/e	n/e	n/e	n/e	n/e
6.	Subducting Terrane (UAGA0701)	0.003	n/a	0.003	0.012	n/a	0.012
	TOTAL	***0.046***	***n/a***	***0.046***	***0.119***	***n/a***	***0.119***

* *Unique Assessment Identifier, code unique to play.*

OIL is in billions of barrels (BBO). **GAS** is in trillion cubic feet (TCF).
BOE is barrel of oil equivalent barrels, where 5,260 cubic feet of gas = 1 equivalent barrel-oil

For direct comparisons among provinces, two prices are selected from a continuum of possible price/resource relationships illustrated on price-supply curves. **BASE PRICE** is defined as $18.00 per barrel for oil and $2.11 per thousand cubic feet for gas. **HIGH PRICE** is defined as $30.00 per barrel for oil and $3.52 per thousand cubic feet for gas. Both economic scenarios assume a 1995 base year, flat real prices and development costs, 3% inflation, 12% discount rate, 35% Federal corporate tax, and 0.66 gas price discount.

Shaded columns indicate the most likely substances to be developed in this province. Economic viability is indicated on price-supply curves which aggregate the play resources in each province.

N/A refers to "not available". Associated gas will be reinjected for pressure maintenance to maximize oil recovery. Coproduction of gas resources severely affects the value of oil resources because of the high costs for LNG infrastructure.

N/E refers to "not evaluated". Play has very high geologic risk.

would become particularly attractive if a new LNG facility was constructed in Valdez to handle gas production from the North Slope. Offshore oil development is more likely to occur in oil-prone plays in the central part of the province, with onshore facilities and a marine terminal constructed in Yakutat.

Shumagin-Kodiak

Results for the Shumagin-Kodiak shelf province are summarized in figure 27.10. The cumulative frequency plot (fig. 27.10A) indicates that conventionally recoverable gas resources could range from a mean of 2.65 TCFG upwards to 11.35 TCFG (at 5 percent level). Liquid hydrocarbons (all gas condensates) range from a mean of 0.07 BBO upwards to 0.29 BBO (at 5 percent level). Exploration drilling in the eastern part of the province has failed to discover pooled hydrocarbons, so the marginal probability of recoverable hydrocarbons (MPhc) is estimated at 0.40 without regard to economic considerations.

The Shumagin-Kodiak shelf province was modeled for the production of gas, and gas-condensates would be recovered as a byproduct. Natural gas, as the primary hydrocarbon substance, is assumed to support the development activities in the province. The geologic resource model includes no crude oil resources in the province. At present, there is no petroleum production or transportation infrastructure available in the western parts of the province (Shumagin shelf), although the eastern areas (Kodiak shelf) could utilize existing processing and transportation infrastructure in the Cook Inlet.

Under the Base price condition ($2.11/MCFG), the Shumagin-Kodiak shelf province contains a negligible volume (<0.01 TCFG) of mean economically recoverable gas and condensate resources (fig. 27.10B). At the High price condition ($3.52 per MCFG), this province has economic gas resources of 0.45 TCFG, or 17 percent of the mean conventionally recoverable gas endowment (tbl. 27.10).

An economic price hurdle imposed by high development and transportation costs occurs at approximately $3.00 per MCFG, above which significant volumes of gas resources are recoverable (fig. 27.10c). Gas potential is particularly attractive for the High resource case (5 percent chance). At $7.00 per MCFG (approximately twice the current overseas market price), the High case indicates that 6.7 TCFG of economically recoverable gas could occur in the Shumagin-Kodiak shelf province. This undiscovered gas resource is comparable to the 7.4 TCFG of proven gas reserves in the Cook Inlet. Because of high geologic and economic basin risks, economically recoverable resources are not available at the 95 percent probability level, so a Low case curve is not displayed. A development scenario for the Shumagin-Kodiak province would require an aggressive exploration program to discover these resources.

Gas resources in the Shumagin-Kodiak shelf are modeled in one geologic play, called the Neogene Structural Play. The Kodiak shelf province has been tested by three deep stratigraphic test wells (plus three shallow wells) and no exploration wells, whereas the Shumagin shelf has yet to be drilled. Information from the Kodiak shelf COST wells leads to the conclusion that this province is gas-prone. The Neogene Structural play is estimated to contain gas pools ranging in mean size up to 2.0 TCFG.

Future gas production from the Shumagin-Kodiak shelf province is likely to utilize existing LNG facilities in the Cook Inlet, as well as the oil terminals in either Valdez or Kenai. The proximity to existing infrastructure and the high-side potential (which accepts high investment risks for high rewards) are two primary incentives for future exploration on the Shumagin-Kodiak Shelf.

TABLE 27.10:
OIL AND GAS RESOURCES OF SHUMAGIN-KODIAK SHELF PLAY
Risked, Undiscovered, Economically Recoverable Oil and Gas

PLAY NO.	PLAY NAME (UAI* CODE)	BASE PRICE			HIGH PRICE		
		OIL	GAS	BOE	OIL	GAS	BOE
1.	Neogene Structural Play (UASH0100)	negl	0.004	0.001	0.013	0.449	0.093
	TOTAL	*negl*	*0.004*	*0.001*	*0.013*	*0.449*	*0.093*

* *Unique Assessment Identifier, code unique to play.*

OIL is in billions of barrels (BBO). **GAS** is in trillion cubic feet (TCF).
BOE is barrel of oil equivalent barrels, where 5,260 cubic feet of gas = 1 equivalent barrel-oil

For direct comparisons among provinces, two prices are selected from a continuum of possible price/resource relationships illustrated on price-supply curves. **BASE PRICE** is defined as $18.00 per barrel for oil and $2.11 per thousand cubic feet for gas. **HIGH PRICE** is defined as $30.00 per barrel for oil and $3.52 per thousand cubic feet for gas. Both economic scenarios assume a 1995 base year, flat real prices and development costs, 3% inflation, 12% discount rate, 35% Federal corporate tax, and 0.66 gas price discount.

Shaded columns indicate the most likely substances to be developed in this province. Economic viability is indicated on price-supply curves, which aggregate the play resources in each province

CONCLUSIONS

The undiscovered petroleum potential is not uniformly distributed through the offshore Alaska provinces. Only a few provinces contain the majority of the economic potential.

The economic resource estimates for the Alaska offshore provinces are summarized in tables 27.11 and 27.12. At the mean resource level, 91 percent of the total economic oil volume (3.75 BBO) is contained in two of the ten Alaska offshore provinces (Beaufort and Chukchi). Of the total economic gas potential (1.11 TCF), 79 percent is contained in the North Aleutian province. Similar trends were observed with respect to plays within individual provinces. For example, 94 percent of the economic oil potential in the Beaufort shelf province is contained in only 4 of the 23 geologic plays evaluated.

The results suggest that most of the undiscovered resource potential could be confirmed (or refuted) by a focused exploration program. However, a successful exploration program will require two basic conditions: (1) That high potential areas are open to exploration, and (2) That industry is interested in further exploration in these areas. Although leasing has been conducted previously in the Beaufort and Chukchi provinces, the scheduling and areas offered in future OCS sales is uncertain. Leasing in the North Aleutian province is presently excluded by Congressional moratoria and tracts previously leased to industry have been repurchased by the Federal Government. With respect to future exploration effort, many of the large structural traps have been tested by drilling without finding commercial-sized fields. However, the resource potential in many provinces might occur in stratigraphic traps, which are difficult to define using conventional (2-D) seismic data. Given past experiences with Alaskan exploration and competing worldwide opportunities, industry could abandon costly exploration programs if the first few wells do not encounter commercial fields in a frontier province.

The Beaufort shelf and Cook Inlet provinces present the best opportunities for future development among the 10 offshore assessment provinces. The Chukchi shelf and North Aleutian basin provinces are attractive secondary opportunities.

The ratios of economic to conventionally recoverable resources (E/C ratios) can be used as an indicator of the chance for economic success. Low E/C ratios suggest that high costs and/or small resource endowments generally result in higher proportions of non-economic pools. High E/C ratios suggest that more pools will be commercially viable, if discovered. The Cook Inlet (E/C=0.36) and Beaufort shelf (E/C=0.26) are the most attractive with respect to commercial potential. Two other offshore provinces deserve mention. The Chukchi shelf province (E/C=0.09) has a very large undiscovered oil endowment (13 BBO), which may attract future exploration despite very high costs. The North Aleutian basin province (E/C=0.13) contains significant economic gas potential in a good location relative to Asian markets for LNG. The high-side potential of nearly 12.0 TCFG in the North Aleutian province (5 percent chance at current prices of $3.50/MCFG) is certainly large enough to support a grassroots LNG project.

The results of the economic modeling using PRESTO are strongly influenced by the preceding geologic assessment that utilized the GRASP computer model.

The characteristics of hydrocarbon pools are defined by the variables selected by geologic assessment teams, and key products of the GRASP computer program are fed directly into the PRESTO computer model (risking hierarchy, pool rank sizes). Engineering input variables for

TABLE 27.11
RISKED, UNDISCOVERED, ECONOMICALLY RECOVERABLE OIL AND GAS

AREA	OIL (BBO)			GAS (TCFG)			BOE (BBO)			E/C
	F95	MEAN	F05	F95	MEAN	F05	F95	MEAN	F05	
ALASKA OFFSHORE	1.41	3.75	7.65	0.02	1.11	4.33	1.43	3.95	8.20	0.08
ARCTIC SUBREGION	1.15	3.41	7.25	0.00	0.12	0.00	1.15	3.44	7.31	0.09
BERING SHELF SUBREGION	0.00	0.02	0.22	0.00	0.99	10.82	0.00	0.19	2.11	0.04
PACIFIC MARGIN SUBREGION	0.00	0.32	0.79	0.00	negl	0.01	0.00	0.32	0.80	0.11
ARCTIC SUBREGION										
CHUKCHI SHELF	0.00	1.14	4.48	N/A	N/A	N/A	0.00	1.14	4.48	0.05
BEAUFORT SHELF	0.72	2.27	4.44	N/A	N/A	N/A	0.00	2.27	4.44	0.14
HOPE BASIN	0.00	negl	0.00	0.00	0.12	0.00	0.00	0.03	0.00	0.04
BERING SHELF SUBREGION										
NAVARIN BASIN	0.00	negl	0.00	0.00	0.04	0.00	0.00	negl	0.00	negl
N. ALEUTIAN BASIN	0.00	0.02	0.20	0.00	0.88	7.71	0.00	0.18	1.77	0.13
ST. GEORGE BASIN	0.00	negl	0.00	0.00	0.05	0.00	0.00	0.01	0.00	0.02
NORTON BASIN	0.00	negl	0.00	0.00	0.02	0.00	0.00	negl	0.00	negl
ST. MATTHEW-HALL	N/E	N/E	N/E	N/E	N/E	N/E	N/E	N/E	N/E	N/E
PACIFIC MARGIN SUBREGION										
COOK INLET	0.00	0.27	0.71	N/A	N/A	N/A	0.00	0.27	0.71	0.30
GULF OF ALASKA	0.00	0.05	0.30	0.00	negl	negl	0.00	0.05	0.30	0.04
SHUMAGIN-KODIAK	0.00	negl	0.00	0.00	negl	0.00	0.00	negl	0.00	negl

*ECONOMIC ASSUMPTIONS: 1995 base year, $18 per barrel oil price, $2.11 per thousand cubic feet (MCF) gas price, 0.66 gas value discount, flat real prices and costs, 3% inflation, 12% discount rate, 35% Federal tax rate; units of **BBO**, billions of barrels; **TCFG**, trillions of cubic feet; **BOE**, total oil and gas in billions of energy-equivalent barrels (5,620 cubic feet of gas=1 energy-equivalent barrel of oil). Oil resources include crude oil and gas-condensate liquids. Gas resources include nonassociated dry gas and associated solution gas. All provinces analyzed on a stand-alone basis. N/A refers to Not Available (lacking transportation infrastructure and/or market). N/E refers to Not Evaluated because of very low resource potential. Negl refers to negligible (less than significant figures listed). E/C is ratio of risked, mean economically recoverable BOE to risked, mean conventionally recoverable BOE (from tbl. 2.1). Mean values for provinces may not sum to values shown for subregions and region because of rounding.*

TABLE 27.12
SUMMARY OF ECONOMIC ASSESSMENT
Mean Economically Recoverable Resources

ASSESSMENT PROVINCE	BASE PRICE			HIGH PRICE		
	OIL	GAS	BOE	OIL	GAS	BOE
CHUKCHI SHELF	1.136	N/A	1.136	2.845	N/A	2.845
BEAUFORT SHELF	2.274	N/A	2.274	3.223	N/A	3.223
HOPE BASIN	0.004	0.120	0.025	0.007	0.249	0.051
NAVARIN BASIN	0.001	0.036	0.007	0.003	0.075	0.016
NORTH ALEUTIAN BASIN	0.024	0.880	0.180	0.036	1.272	0.263
ST. GEORGE BASIN	0.002	0.049	0.010	0.004	0.103	0.022
NORTON BASIN	negl	0.024	0.004	0.001	0.072	0.014
COOK INLET	0.268	N/A	0.268	0.458	N/A	0.458
GULF OF ALASKA SHELF	0.046	N/A	0.046	0.119	N/A	0.119
SHUMAGIN-KODIAK SHELF	negl	0.004	0.001	0.013	0.449	0.093
TOTALS	*3.755*	*1.113*	*3.951*	*6.709*	*2.220*	*7.104*

NOTES: Base price is $18 per barrel (oil) and $2.11 per thousand cubic feet (gas). High price is $30.00 per barrel (oil) and $3.52 per thousand cubic feet (gas). BOE is total oil and gas in billions of energy-equivalent barrels (5,620 cubic feet of gas = 1 energy equivalent barrel of oil). Totals are given in units of billions of barrels (oil) and trillions of cubic feet (gas). Oil resource totals include crude oil and gas-condensate liquids. Gas resource totals include nonassociated and solution gas. N/A refers to Not Available (lacking transportation infrastructure and/or market). Negl refers to negligible (less than significant figures listed). Shading distinguishes the most likely hydrocarbon type to be commercially developed (if discovered) in each province.

the PRESTO computer program must be consistent with geologic data. Consequently, the economic modeling results are largely predetermined by pool size, reservoir quality, and risk. Small pool volumes or low grade reservoirs generally cannot overcome the high costs for development and transportation in remote offshore provinces of Alaska. Although many of the Alaska provinces assessed do not contain economic resources at mean (expected) probability levels, there is far more potential with higher prices and lower probability levels.

This economic assessment represents a current view of the MMS regarding undiscovered hydrocarbon resource volumes, petroleum technology, infrastructure requirements, and market conditions.

With time, it is reasonable to expect that one or more of these major factors will change, thus affecting the results of future economic modeling. For example, the transportation of oil from the Beaufort and Chukchi provinces depends on the continued operation of TAPS. At the present time, this trunkline has been in service for 20 years and its design life, although undetermined, has some limit. If the TAPS pipeline is decommissioned, all unproduced oil reserves are likely to be shut-in, and undiscovered resources will have no economic potential. On the other hand, if a major new gas transportation system from the North Slope is constructed, the huge gas volumes (both proven and undiscovered) in the Arctic could have significant economic potential.

The present assessment focused on the hydrocarbon commodity most likely to be commercially attractive.

Development scenarios were based primarily on the primary hydrocarbon resource thought to be present in the province, although logistics, availability of infrastructure, and market factors were also considered. In this way, the assessment attempts to provide a realistic appraisal of possible future commercial activity. It is apparent, however, that many of the Alaska offshore provinces contain no economic potential at mean resource levels and current commodity prices. Future offshore leasing and exploration in these poorer provinces will be driven by industry perceptions of high-side potential and will assume greater rewards at higher investment risks.

Due to the high costs for new infrastructure, the timing of future commercial activities is likely to be influenced by perceived economic resource potential.

Development costs must be balanced by high production rates and recoverable volumes to support commercially viable operations. Provinces with high resource potential and reasonably accessible infrastructure, such as the Chukchi province, are much better positioned for future development than low resource potential basins without nearby infrastructure, such as the Navarin province.

The stand-alone development assumption greatly affected the economic results.

A stand-alone assumption is reasonable because, historically, most initial development in high-cost frontier provinces is supported by the first large discovery. Subsequent development expands on this initial infrastructure, allowing progressively smaller fields to be commercial. Similarly, coordinated development strategies or shared infrastructure could significantly improve the commerciality of adjacent provinces that are uneconomic as stand-alone developments. Several obvious examples for shared infrastructure can be envisioned. The scenarios for Navarin, St. George, and North Aleutian provinces assumed that a LNG facility and marine terminal on the Alaska Peninsula would be required to deliver natural gas (as LNG) to Pacific Rim markets. The multi-billion dollar cost of a new LNG facility could be partially offset by coordinated development in several of the gas-prone Bering Sea provinces. Gas transportation (LNG) infrastructure shared by the Hope and Norton basin provinces is another example. It is probably safe to conclude that without coordinated strategies and shared infrastructure, any future development of the gas-prone offshore provinces in Alaska is unlikely. Possible exceptions are the North Aleutian province (with favorable economics), the Chukchi province (with huge gas resources), and the Cook Inlet (with existing gas infrastructure and a local market).

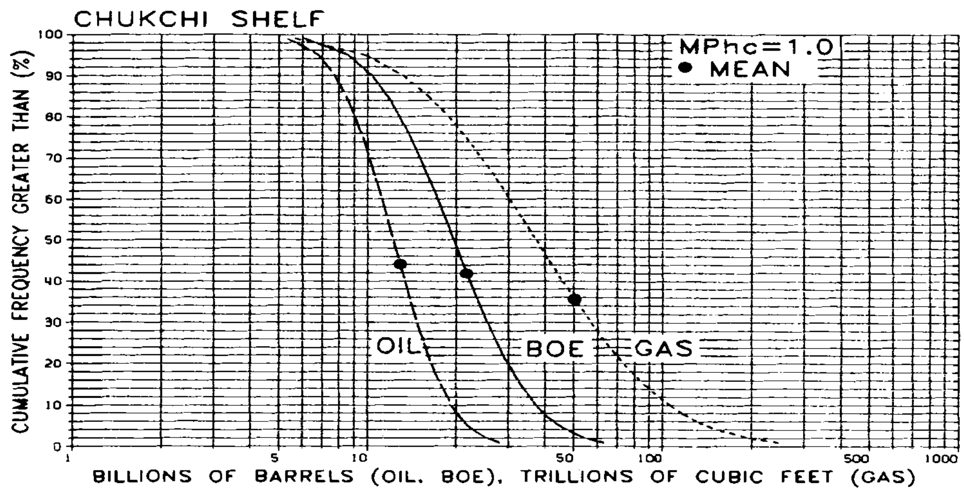
In the absence of significantly higher commodity prices, new technologies will be required to reduce production costs to bring marginal fields into profitability.

New methods for recovering "stranded gas" from remote locations could eliminate the need for long subsea pipelines and large onshore LNG facilities. Technologies for converting gas to more transportable forms, either as liquids (LNG or gas-to-liquids, GTL) or solids (gas hydrate pellets), are now being studied. Offshore processing, storage, and loading systems will continually be improved with experience in worldwide operations. Eliminating the need for shorebase facilities would decrease upfront project costs and generally improve the economics for production in remote offshore locations. Other strategies to lower infrastructure costs could include minimizing permanent production installations. Mobile floating platforms could be reused for several marginal offshore projects. Tankers or semi-submersibles converted to floating production and storage systems could be used in some deep-water areas. Unmanned platforms or subsea systems could replace large, costly fixed platforms in hostile settings, such as in deeper-water areas beneath the Arctic pack ice.

Eventual development and production of the economic resource potential will require extensive exploration drilling programs promoted by Federal OCS leasing.

Proven reserves, not the undiscovered resource potential, will be the driving force for future petroleum development. Given the low chance for commercial success and the high cost of offshore exploration programs, many of the Alaska offshore provinces may not be adequately explored in the foreseeable future. Estimates of economically recoverable resources should be viewed as indicators of opportunity, rather than readily available hydrocarbon supplies.

A.



B.

CHUKCHI SHELF PROVINCE		
RESOURCE TYPE	MEAN OIL (BBO)	MEAN GAS (TCFG)
CONVENTIONALLY RECOVERABLE	13.02	51.84
ECONOMICALLY RECOVERABLE ($18)	1.14	N/A
RATIO ECONOMIC/CONVENTIONAL	0.09	N/A

C.

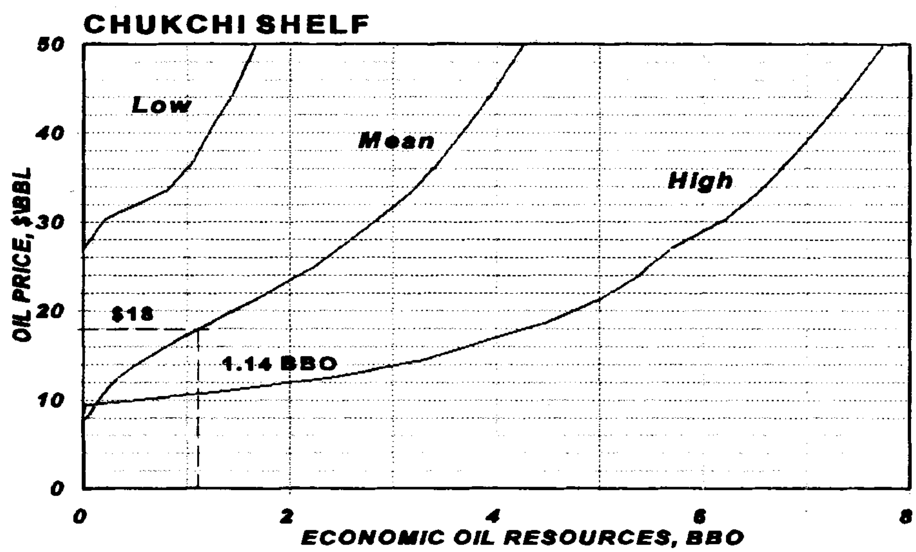
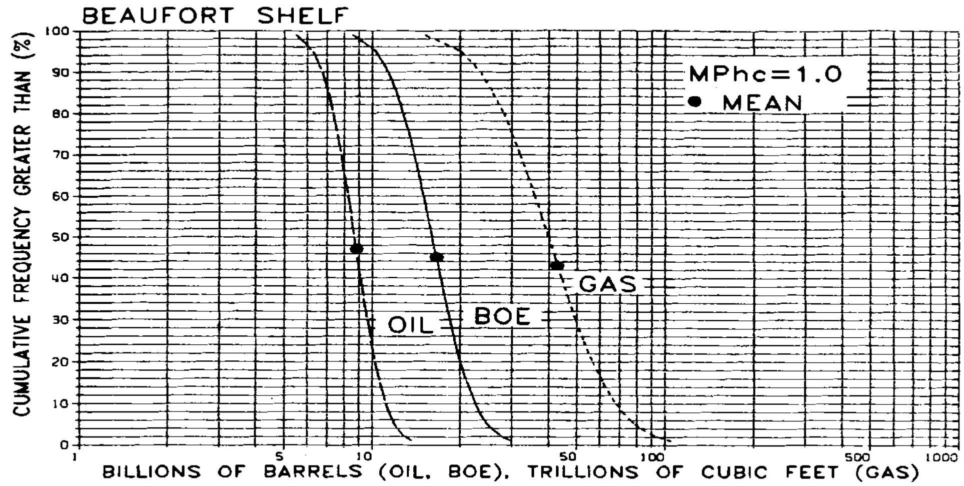


Figure 27.1: Economic Results for Chukchi shelf assessment province. (A) Cumulative frequency distributions for **risked, undiscovered conventionally recoverable resources**; (B) Table comparing results for conventionally and economically recoverable oil and gas; (C) Price-supply curves for **risked, economic oil** at low (F95), mean, and high (F05) resource cases.

BOE, total oil and gas in energy-equivalent barrels; MPhc, marginal probability for occurrence of pooled hydrocarbons in basin; BBO, billions of barrels; TCFG, trillions of cubic feet.

A.



B.

BEAUFORT SHELF PROVINCE		
RESOURCE TYPE	MEAN OIL (BBO)	MEAN GAS (TCFG)
CONVENTIONALLY RECOVERABLE	8.84	43.50
ECONOMICALLY RECOVERABLE ($18)	2.27	N/A
RATIO ECONOMIC/CONVENTIONAL	0.26	N/A

C.

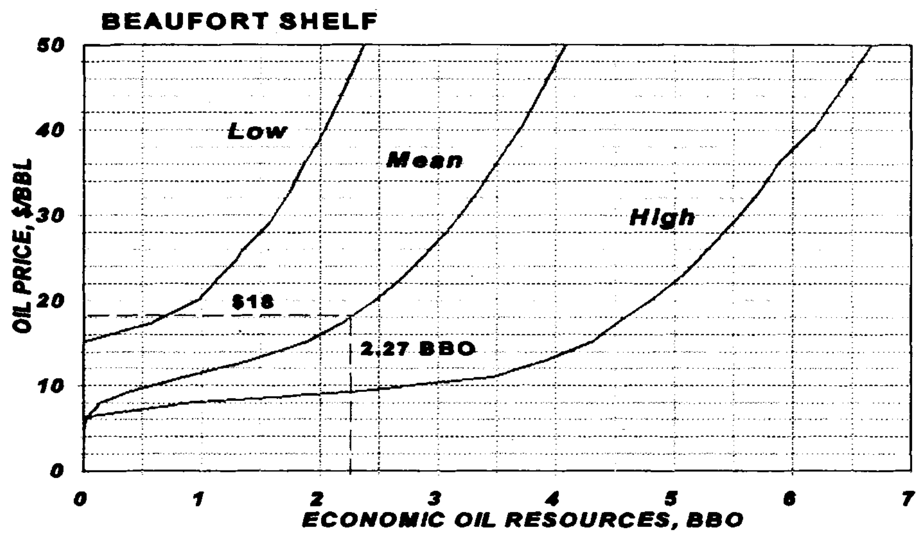
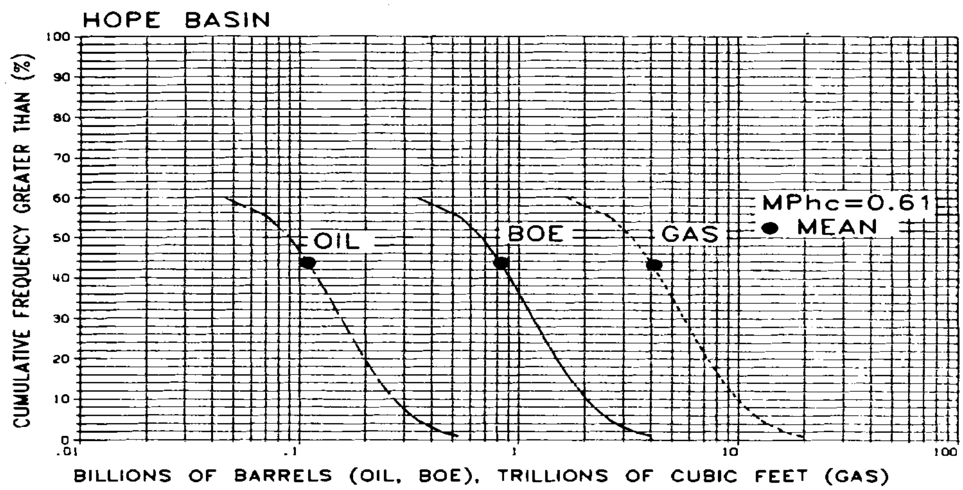


Figure 27.2: Economic Results for Beaufort shelf assessment province. (A) Cumulative frequency distributions for **risked, undiscovered conventionally recoverable resources**; (B) Table comparing results for conventionally and economically recoverable oil and gas; (C) Price-supply curves for **risked, economic oil** at low (F95), mean, and high (F05) resource cases.

BOE, total oil and gas in energy-equivalent barrels; MPhc, marginal probability for occurrence of pooled hydrocarbons in basin; BBO, billions of barrels; TCFG, trillions of cubic feet.

A.



B.

HOPE BASIN PROVINCE		
RESOURCE TYPE	**MEAN OIL (BBO)**	**MEAN GAS (TCFG)**
CONVENTIONALLY RECOVERABLE	**0.11**	**4.06**
ECONOMICALLY RECOVERABLE ($18)	**negl**	**0.12**
RATIO ECONOMIC/CONVENTIONAL	**negl**	**0.03**

C.

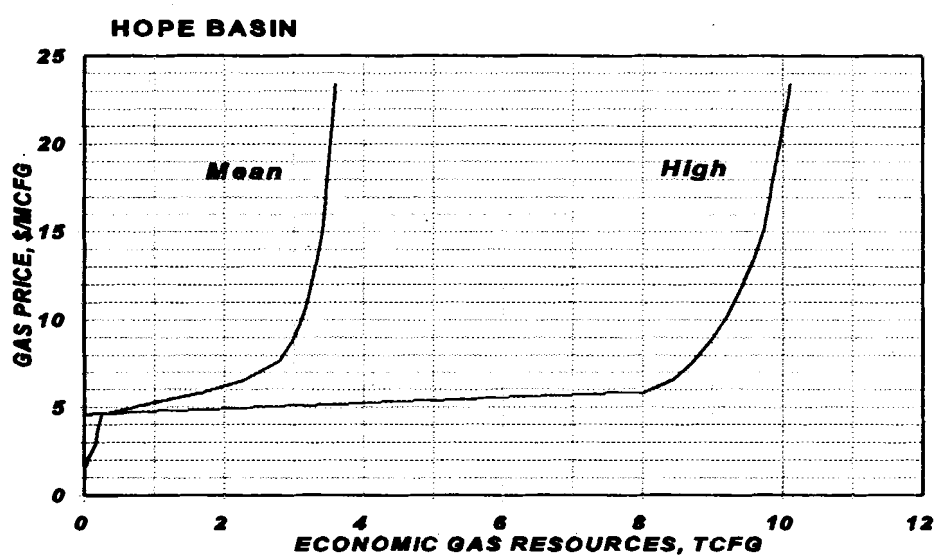
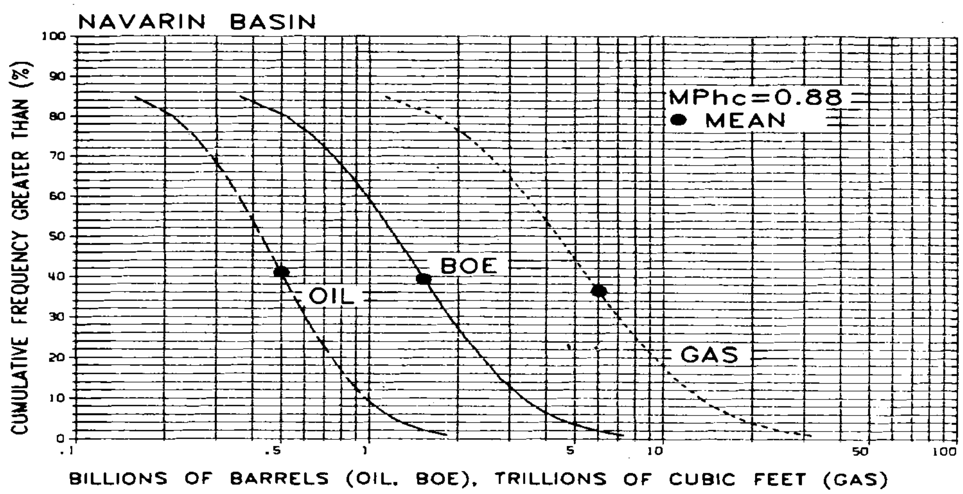


Figure 27.3: Economic Results for Hope Basin assessment province. (A) Cumulative frequency distributions for **risked, undiscovered conventionally recoverable resources**; (B) Table comparing results for conventionally and economically recoverable oil and gas; (C) Price-supply curves for **risked, economic gas** at mean and high (F05) resource cases.

BOE, total oil and gas in energy-equivalent barrels; MPhc, marginal probability for occurrence of pooled hydrocarbons in basin; BBO, billions of barrels; TCFG, trillions of cubic feet.

A.



B.

NAVARIN BASIN PROVINCE		
RESOURCE TYPE	MEAN OIL (BBO)	MEAN GAS (TCFG)
CONVENTIONALLY RECOVERABLE	0.50	6.15
ECONOMICALLY RECOVERABLE ($18)	negl	0.04
RATIO ECONOMIC/CONVENTIONAL	negl	negl

C.

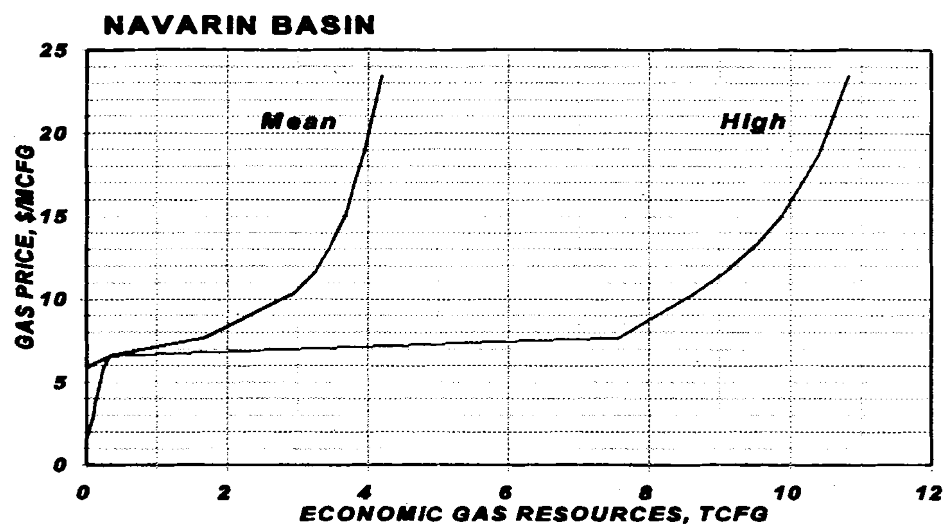
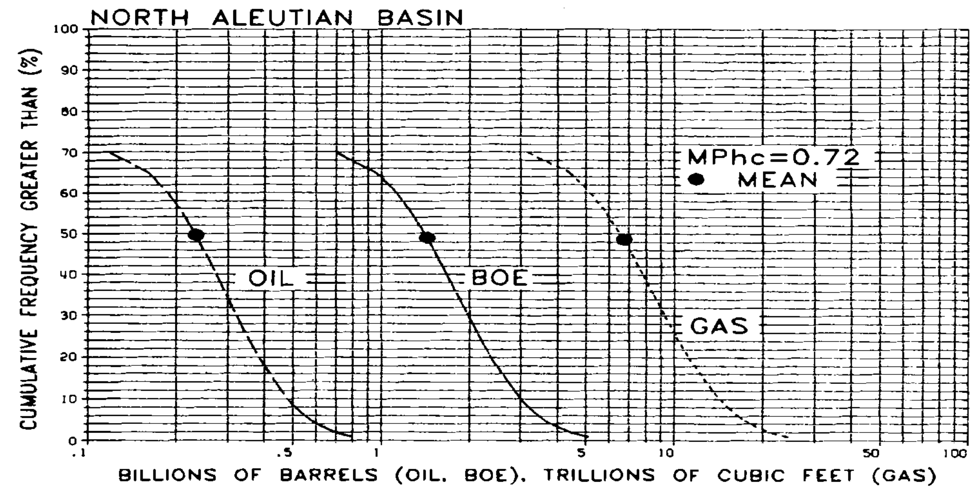


Figure 27.4: Economic Results for Navarin basin assessment province. (A) Cumulative frequency distributions for **risked, undiscovered conventionally recoverable resources**; (B) Table comparing results for conventionally and economically recoverable oil and gas; (C) Price-supply curves for **risked, economic gas** at mean and high (F05) resource cases.

BOE, total oil and gas in energy-equivalent barrels; MPhc, marginal probability for occurrence of pooled hydrocarbons in basin; BBO, billions of barrels; TCFG, trillions of cubic feet.

A.



B.

NORTH ALEUTIAN BASIN PROVINCE		
RESOURCE TYPE	MEAN OIL (BBO)	MEAN GAS (TCFG)
CONVENTIONALLY RECOVERABLE	0.23	6.79
ECONOMICALLY RECOVERABLE ($18)	0.02	0.88
RATIO ECONOMIC/CONVENTIONAL	0.09	0.13

C.

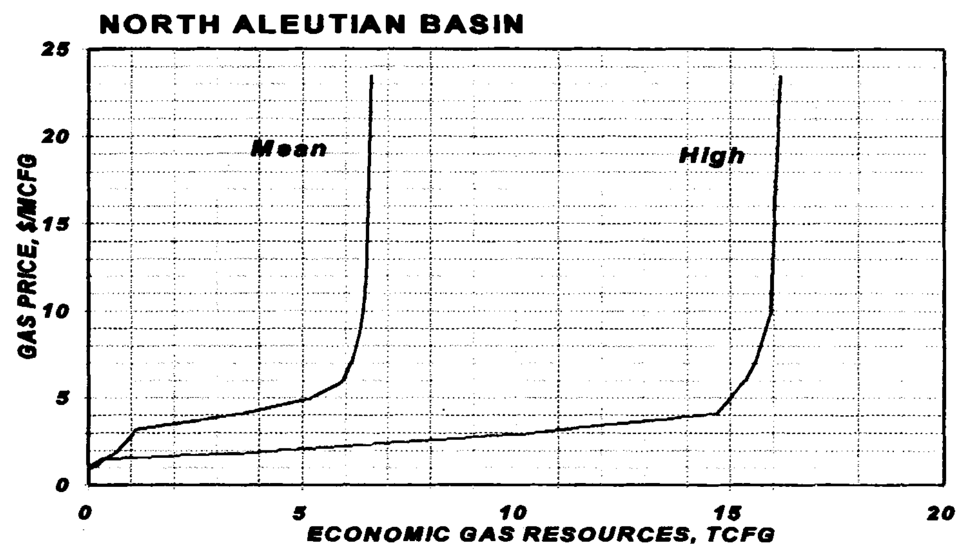
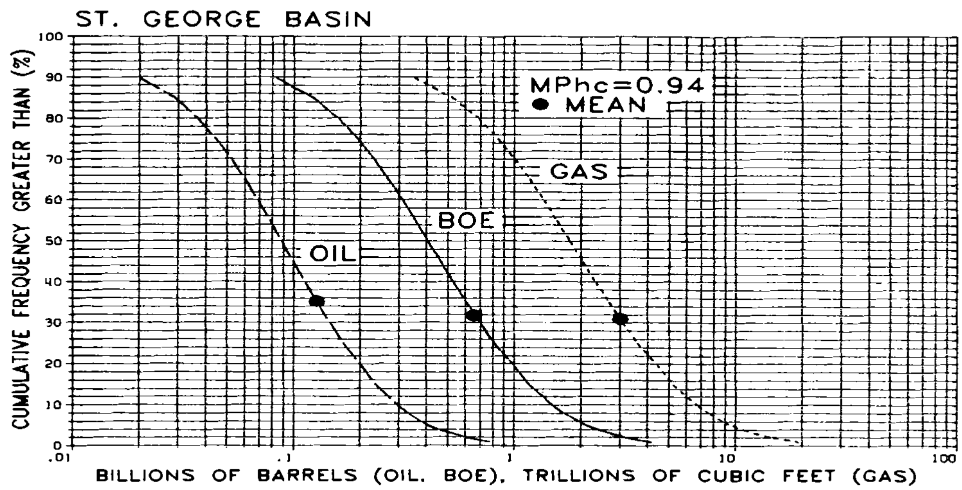


Figure 27.5: Economic Results for North Aleutian basin assessment province. (A) Cumulative frequency distributions for **risked, undiscovered conventionally recoverable resources**; (B) Table comparing results for conventionally and economically recoverable oil and gas; (C) Price-supply curves for **risked, economic gas** at mean and high (F05) resource cases.

BOE, total oil and gas in energy-equivalent barrels; MPhc, marginal probability for occurrence of pooled hydrocarbons in basin; BBO, billions of barrels; TCFG, trillions of cubic feet.

A.



B.

ST. GEORGE BASIN PROVINCE		
RESOURCE TYPE	MEAN OIL (BBO)	MEAN GAS (TCFG)
CONVENTIONALLY RECOVERABLE	0.13	3.00
ECONOMICALLY RECOVERABLE ($18)	negl	0.05
RATIO ECONOMIC/CONVENTIONAL	negl	0.02

C.

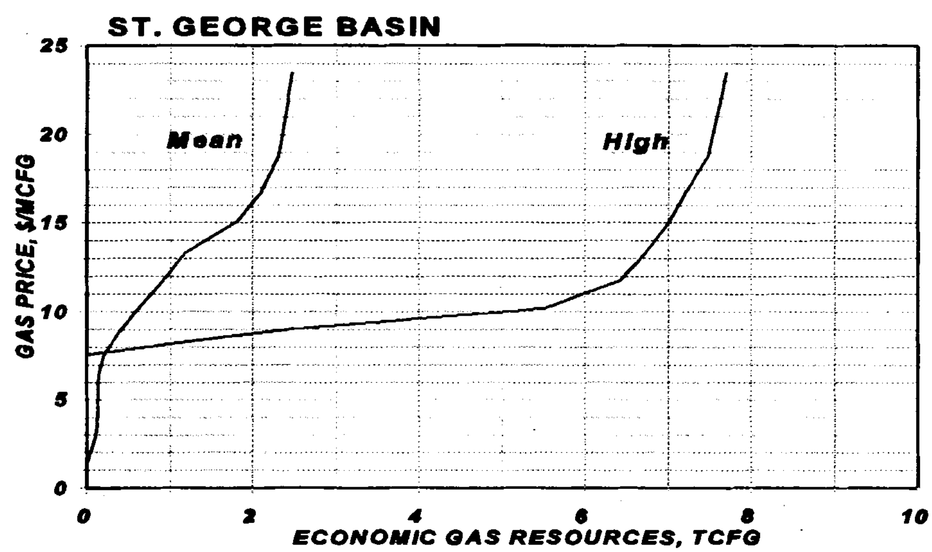
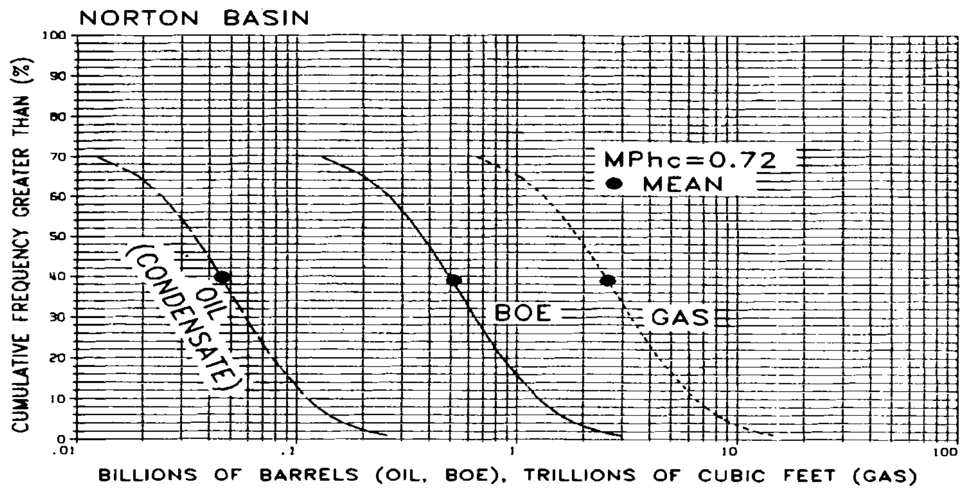


Figure 27.6: Economic Results for St. George basin assessment province. (A) Cumulative frequency distributions for **risked, undiscovered conventionally recoverable resources**; (B) Table comparing results for conventionally and economically recoverable oil and gas; (C) Price-supply curves for **risked, economic gas** at mean and high (F05) resource cases.

BOE, total oil and gas in energy-equivalent barrels; MPhc, marginal probability for occurrence of pooled hydrocarbons in basin; BBO, billions of barrels; TCFG, trillions of cubic feet.

A.



B.

NORTON BASIN PROVINCE		
RESOURCE TYPE	MEAN OIL (BBO)	MEAN GAS (TCFG)
CONVENTIONALLY RECOVERABLE	0.05	2.71
ECONOMICALLY RECOVERABLE ($18)	negl	0.02
RATIO ECONOMIC/CONVENTIONAL	negl	negl

C.

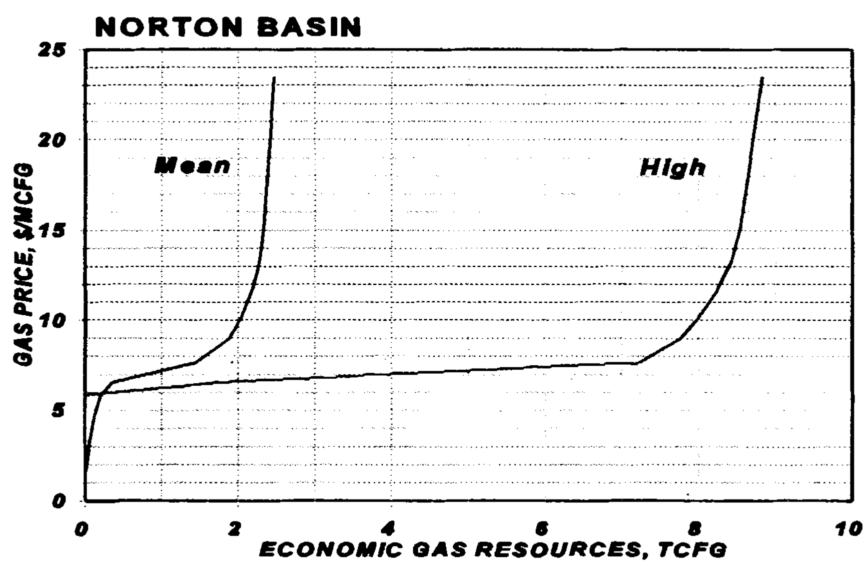
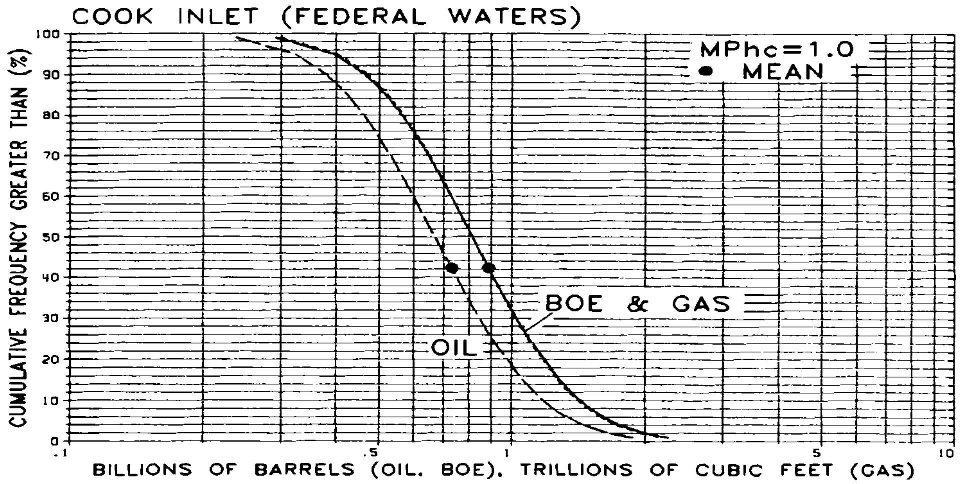


Figure 27.7: Economic Results for Norton basin assessment province. (A) Cumulative frequency distributions for **risked, undiscovered conventionally recoverable resources**; (B) Table comparing results for conventionally and economically recoverable oil and gas; (C) Price-supply curves for **risked, economic gas** at mean and high (F05) resource cases.

BOE, total oil and gas in energy-equivalent barrels; MPhc, marginal probability for occurrence of pooled hydrocarbons in basin; BBO, billions of barrels; TCFG, trillions of cubic feet.

A.



B.

COOK INLET PROVINCE		
RESOURCE TYPE	MEAN OIL (BBO)	MEAN GAS (TCFG)
CONVENTIONALLY RECOVERABLE	0.74	0.89
ECONOMICALLY RECOVERABLE ($18)	0.27	N/A
RATIO ECONOMIC/CONVENTIONAL	0.36	N/A

C.

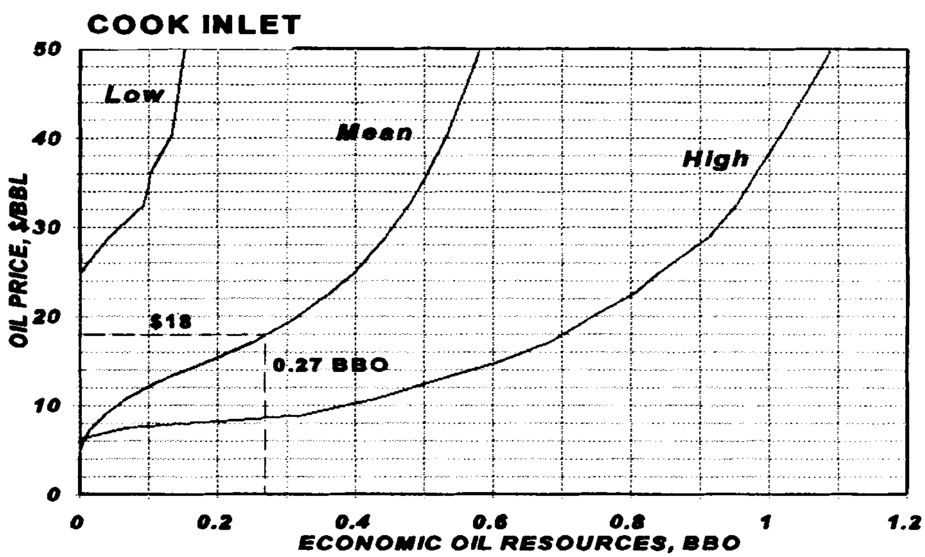
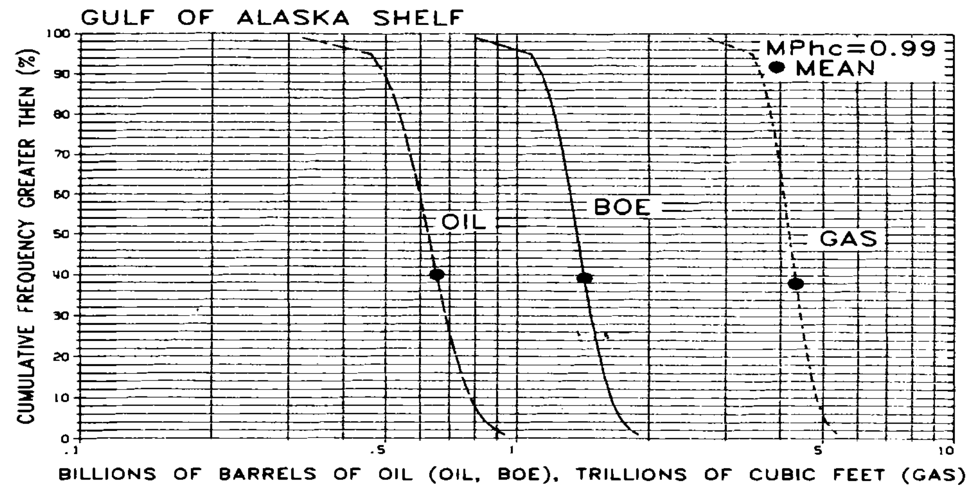


Figure 27.8: Economic Results for Cook Inlet assessment province. (A) Cumulative frequency distributions for **risked, undiscovered conventionally recoverable resources**; (B) Table comparing results for conventionally and economically recoverable oil and gas; (C) Price-supply curves for **risked, economic oil** at low (F95), mean, and high (F05) resource cases.

BOE, total oil and gas in energy-equivalent barrels; MPhc, marginal probability for occurrence of pooled hydrocarbons in basin; BBO, billions of barrels; TCFG, trillions of cubic feet.

A.



B.

GULF OF ALASKA SHELF PROVINCE		
RESOURCE TYPE	MEAN OIL (BBO)	MEAN GAS (TCFG)
CONVENTIONALLY RECOVERABLE	0.63	4.18
ECONOMICALLY RECOVERABLE ($18)	0.05	N/A
RATIO ECONOMIC/CONVENTIONAL	0.08	N/A

C.

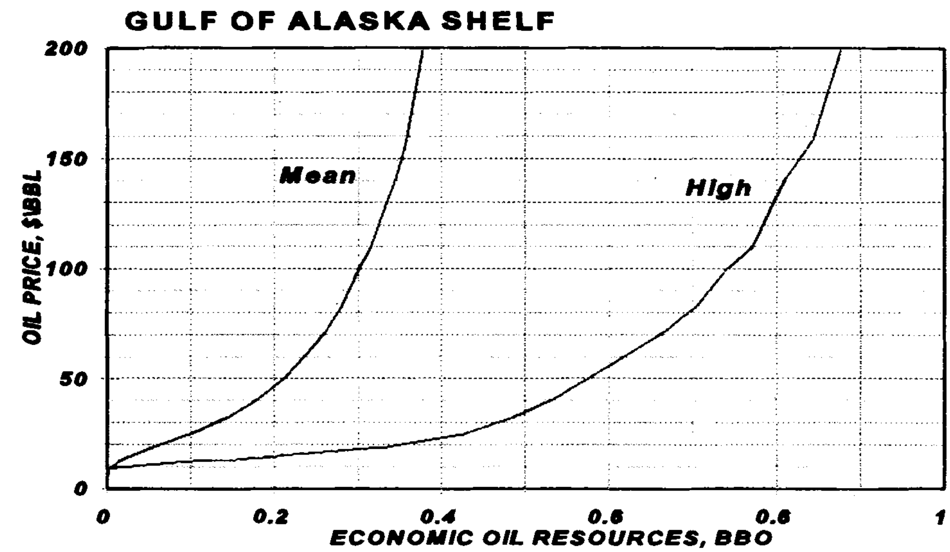
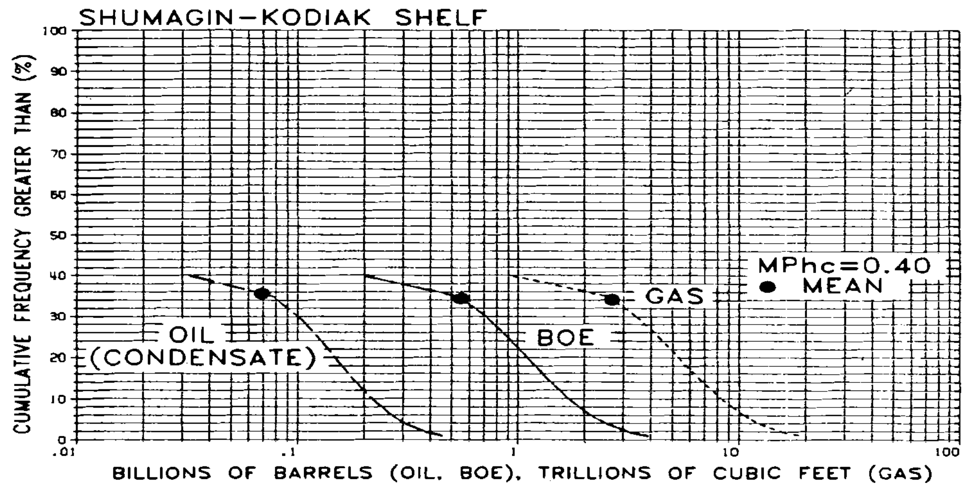


Figure 27.9: Economic Results for Gulf of Alaska shelf assessment province. (A) Cumulative frequency distributions for **risked, undiscovered conventionally recoverable resources**; (B) Table comparing results for conventionally and economically recoverable oil and gas; (C) Price-supply curves for **risked, economic oil** at mean and high (F05) resource cases.

BOE, total oil and gas in energy-equivalent barrels; MPhc, marginal probability for occurrence of pooled hydrocarbons in basin; BBO, billions of barrels; TCFG, trillions of cubic feet.

A.



B.

SHUMAGIN-KODIAK SHELF PROVINCE		
RESOURCE TYPE	MEAN OIL (BBO)	MEAN GAS (TCFG)
CONVENTIONALLY RECOVERABLE	0.07	2.65
ECONOMICALLY RECOVERABLE ($18)	negl	negl
RATIO ECONOMIC/CONVENTIONAL	negl	negl

C.

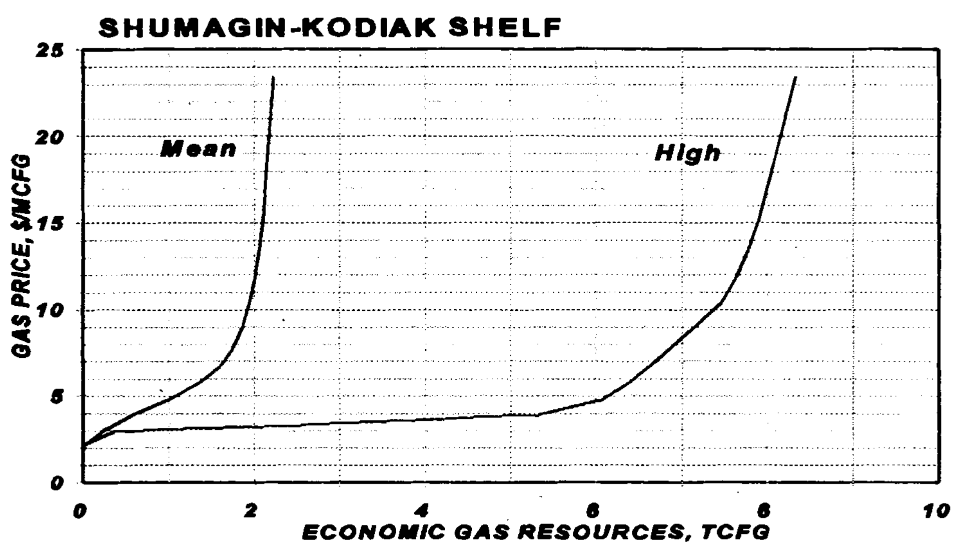


Figure 27.10: Economic Results for Shumagin-Kodiak shelf assessment province. (A) Cumulative frequency distributions for **risked, undiscovered conventionally recoverable resources**; (B) Table comparing results for conventionally and economically recoverable oil and gas; (C) Price-supply curves for **risked, economic gas** at mean and high (F05) resource cases.

BOE, total oil and gas in energy-equivalent barrels; MPhc, marginal probability for occurrence of pooled hydrocarbons in basin; BBO, billions of barrels; TCFG, trillions of cubic feet.

APPENDICES

A. Play Results and Input Data

B. Summaries of Assessment Results for Plays

APPENDIX A: PLAY RESULTS AND INPUT DATA

Appendix A Table of Contents

EXPLANATION OF DATA TABLES IN APPENDICES

RESULTS

LOG-N PARAMS (PORE)	Key mathematic parameters that describe log-normal probability distributions for volume of hydrocarbon-bearing rock, in acre-feet, for each play as reported in the **PORE** module of **GRASP**.
mu	Natural logarithm of F50 value of log-normal distribution for volume of hydrocarbon-bearing rock, or "μ", for the subject play. **mu** = ln F50. [Note: distribution **mean** = $e^{(\mathrm{mu} + 0.5[\mathrm{sig.\ sq.}])}$.]
sig. sq.	The variance of the log-normal distribution for volume of hydrocarbon-bearing rock, or "σ^2", for the subject play. **sig. sq.** = $\{\ln [0.5((F50/F16)+(F84/F50))]\}^2$.
N (MPRO)	Number of hydrocarbon pools calculated for the plays by the **MPRO** module of **GRASP** from inputs for probability distributions of prospect numbers and geologic chances of success (approximately the product of play and prospect chances of success). The maximum (**Max**) number of pools for each play was entered into the **MONTE1** module of **GRASP** to fix the number of pools aggregated to calculate play resources.
Reserves	Sums of recoverable oil and gas volumes for pools within the play, including both proven and inferred reserve categories. A "prop" entry indicates that the reserve data are proprietary.
BCF	Billions of cubic feet of gas, recoverable, at standard (surface) conditions (here fixed at a temperature of 60° Fahrenheit or 520° Rankine, and 14.73 psi atmospheric pressure).
MMB	Millions of barrels of oil, recoverable, at standard (surface) conditions.
Undiscovered Potential	Risked, undiscovered, conventionally recoverable oil and gas resources of the play, here reported as **Means** of probability distributions.

EXPLANATION OF DATA TABLES IN APPENDICES

Mean Pool Sizes of Ranks 1 to 3 Unrisked (or conditional) mean volumes of recoverable oil and gas in the three largest pools in the play.

PLAY INPUT DATA

F100.....F00 Fractiles for values within probability distributions entered to **GRASP** for calculations of play resources. Four-point distributions (F100, F50, F02, F00) generally indicate that calculations were conducted using log-normal mathematics. Eight-point distributions generally indicate that calculations were conducted using Monte Carlo mathematics. Choice of mathematic approach was in most cases the option of the assessor.

Prospect Area Maximum area of prospect closure, or area within spill contour, in acres. Probability distributions for prospect areas were generally based on distributions assembled independently for each play from large numbers of prospects mapped with seismic reflection data.

Trap Fill Trap fill fraction, or fraction of prospect area in which the reservoir is predicted to be saturated by hydrocarbons.

Pool Area Areal extent of hydrocarbon-saturated part of prospect, in acres. Calculated using **PRASS**, or **SAMPLER** module of **GRASP**, to integrate input probability distributions for prospect areas and trap fill fractions.

Pay Thickness Thickness of hydrocarbon-productive part of reservoir within pool areas, in feet. Probability distributions for prospect areas, trap fill fractions, and pay thicknesses are integrated in the **PORE** module of **GRASP**, to calculate a probability distribution for volume of hydrocarbon-bearing rock, in feet, within the play as reported above under **LOG-N PARAMS (PORE)**.

EXPLANATION OF DATA TABLES IN APPENDICES

Oil Yield (Recov. B/Acre-Feet)	Oil, in barrels at standard (surface) conditions, recoverable from a volume of one acre-foot of oil-saturated reservoir in the subsurface. Oil yield probability distributions were generally calculated in a separate exercise using **PRASS** to integrate input probability distributions for porosities, oil saturations, oil shrinkage factors (or "Formation Volume Factors"), and oil recovery efficiencies.
Gas Yield (MMCF/Ac.-Ft.)	Gas, in millions of cubic feet at standard (surface) conditions, recoverable from a volume of one acre-foot of gas-saturated reservoir in the subsurface. Distributions were generally calculated in a separate exercise using **PRASS** to integrate input probability distributions for porosities, gas saturations, reservoir pressures, reservoir temperatures (in degrees Rankine), gas deviation ("Z") factors, combustible fractions (that exclude noncombustibles such as carbon dioxide, nitrogen, etc.), and gas recovery efficiencies.
Solution Gas-Oil Ratio (CF/B)	Quantity of gas dissolved in oil in the reservoir that separates from the oil when brought to standard (surface) conditions, in cubic feet recovered per barrel of produced oil.
Gas Cond. (B/MMCF)	Quantity of liquids or condensate dissolved in gas in the reservoir that separates from the gas when brought to standard (surface) conditions, in barrels recovered per million cubic feet of produced gas.
Number of Prospects.......	Probability distributions for numbers of prospects in plays, generally ranging from minimum values (F99) representing the numbers of mapped prospects, to maximum values (F00) that include speculative estimates for the numbers of additional prospects that remain unidentified (generally stratigraphic prospects, geophysically indefinite prospects, or prospects expected in areas with no seismic coverage).

EXPLANATION OF DATA TABLES IN APPENDICES

Probabilities for Oil, Gas, or Mixed Pools

Oil (OPROB)	Fraction of hydrocarbon pools that consist entirely of oil, with no free gas present. Typically, an undersaturated oil pool.
Gas (GPROB)	Fraction of hydrocarbon pools consisting entirely of gas, with no free oil present.
Mixed (MXPROB)	Fraction of hydrocarbon pools that contain both oil and gas as free phases, the gas usually present as a gas cap overlying the oil.
Fraction of Net Pay to Oil (OFRAC)	When a hydrocarbon pool is modeled as a mixed case, with both oil and gas present, the fraction of pool volume that is saturated by oil in the subsurface.
Play Chance Success	Probability that the play contains at least one pool of technically-recoverable hydrocarbons (that would flow into a conventional wellbore in a flow test or during production).
Prospect Chance Success	The fraction of prospects within the play that are predicted to contain hydrocarbon pools, given the condition that at least one pool of technically recoverable hydrocarbons occurs within the play.
Play Type (E-F-C)	Play classification scheme.
E	**Established** play, in which significant numbers of fields have been discovered, providing the assessor with data for pool size distributions and reservoirs sufficient to allow the assessor to model the play with confidence.
F	**Frontier** play, where exploration activities are at an early stage. Some wells have already been drilled to test the play concept but no commercial fields have been established.
C	**Conceptual** play, hypothesized by analysts based on the subsurface geologic knowledge of the area. Such plays remain hypothetical and the play concept has not been tested.

APPENDIX A

ARCTIC SUBREGION INPUT DATA

CHUKCHI SHELF
BEAUFORT SHELF
HOPE BASIN

CHUKCHI SHELF

				Log-N Params.							
				PORE		N (MPRO)		Reserves		Undiscovered Potential	
Play				Ac/Ft	Ac/Ft	No. Pools		Gas	Oil	Gas	Oil
No.	Area	UAI Code	Name	mu	sig. sq.	Mean	Max	(BCF)	(MMB)	(BCF)	(MMB)
1	CHUKCHI	UACS0100	Endicott Clastics-Chuk. Plat.	13.931	1.441	22	89	- -	- -	9762	3001
2	CHUKCHI	UACS0200	Endicott Clastics-Arct. Plat.	12.174	2.018	0.3	7	- -	- -	35	2
3	CHUKCHI	UACS0300	Lisburne Carbonates	12.724	1.347	2	18	- -	- -	137	41
4	CHUKCHI	UACS0400	Ellesmerian "Deep Gas"	12.836	0.963	9	61	- -	- -	629	16
5	CHUKCHI	UACS0500	Sadlerochit Gp.-Chuk. Plat.	13.452	1.468	13	33	- -	- -	2993	537
6	CHUKCHI	UACS0600	Sadlerochit Gp.-Arct. Plat.	13.638	1.055	6	28	- -	- -	1935	660
7	CHUKCHI	UACS0700	Rift Seq.-Active Margin Clastics	13.150	1.883	31	78	- -	- -	8547	4136
8	CHUKCHI	UACS0800	Rift Seq.-Stable Marine Shelf	13.081	1.632	27	76	- -	- -	5026	1645
9	CHUKCHI	UACS0900	Rift Seq.-"Deep Gas"	11.694	0.473	4	17	- -	- -	108	3
10	CHUKCHI	UACS1000	Herald Arch, Thrust Zone	10.525	0.418	0.2	8	- -	- -	1	0
11	CHUKCHI	UACS1100	Foreland Foldbelt	13.097	1.405	17	42	- -	- -	4491	265
12	CHUKCHI	UACS1200	Torok Turbs.-Chuk. Wrench Zn.	12.430	1.357	10	39	- -	- -	635	147
13	CHUKCHI	UACS1300	Nanushuk-Chuk. Wrench Zn.	12.342	1.476	2	19	- -	- -	326	110
14	CHUKCHI	UACS1400	Sand Apron - N. Chuk. High	13.971	2.343	7	33	- -	- -	13082	1182
15	CHUKCHI	UACS1500	L.Brook. Topset-N. Chuk. Bsn.	12.182	1.543	15	54	- -	- -	1491	99
16	CHUKCHI	UACS1600	Brookian "Deep Gas"	12.547	0.846	3	36	- -	- -	237	6
17	CHUKCHI	UACS1700	Torok Turbs.-Arct. Plat.	12.669	0.337	0.2	5	- -	- -	8	3
18	CHUKCHI	UACS1800	Nanushuk-Arct. Plat.	12.232	0.640	1	8	- -	- -	34	45
19	CHUKCHI	UACS1900	U.Brookian Sag Seq.-N. Chuk. Bsn.	10.978	1.352	1	10	- -	- -	38	2
20	CHUKCHI	UACS2000	U. Brookian Turbs.-N. Chuk. Bsn.	12.063	0.932	6	36	- -	- -	484	27
21	CHUKCHI	UACS2100	U. Brookian-Paleovalley Fill	13.034	1.059	5	34	- -	- -	1637	886
22	CHUKCHI	UACS2200	U. Brookian-Intervalley Highs	12.026	1.305	3	20	- -	- -	203	204

CHUKCHI SHELF

PLAY		MEAN POOL SIZES OF RANKS 1 TO 3						INPUT DATA					
		Pool #1		Pool #2		Pool #3		Prospect Area (Acres)					
		Gas	Oil	Gas	Oil	Gas	Oil						
No.	Name	(BCF)	(MMB	(BCF)	(MMB)	(BCF)	(MMB)	F100	F95	F75	F50	F25	F05
1	Endicott Clastics-Chuk. Plat.	3022	924	1742	541	1151	347	302			18650		
2	Endicott Clastics-Arct. Plat.	123	6	32	2	20	1	42			6430		
3	Lisburne Carbonates	149	42	66	19	35	10	242			11150		
4	Ellesmerian "Deep Gas"	286	7	140	4	117	3	472			12480		
5	Sadlerochit Gp.-Chuk. Plat.	1035	189	525	98	317	58	220			16160		
6	Sadlerochit Gp.-Arct. Plat.	1077	369	601	210	378	129	260			9730		
7	Rift Seq.-Active Margin Clastics	2383	1108	1216	580	766	358	120			13300		
8	Rift Seq.-Stable Marine Shelf	1375	421	732	230	468	143	117			11150		
9	Rift Seq.-"Deep Gas"	48	1	25	1	21	1	1670			13930		
10	Herald Arch, Thrust Zone	3	0	1	0	1	0	420			3000		
11	Foreland Foldbelt	1569	39	755	19	551	14	304			13220		
12	Torok Turbs.-Chuk. Wrench Zn.	226	57	112	30	66	17	200			9240		
13	Nanushuk-Chuk. Wrench Zn.	335	124	140	55	74	27	110			7610		
14	Sand Apron - N. Chuk. High	9418	231	3011	590	1798	313	40			8590		
15	L.Brook. Topset-N. Chuk. Bsn.	1042	26	275	29	219	20	70			5090		
16	Brookian "Deep Gas"	235	6	114	3	92	2	280			6540		
17	Torok Turbs.-Arct. Plat.	52	18	36	13	28	10	1370			7400		
18	Nanushuk-Arct. Plat.	48	60	27	35	19	24	560			6820		
19	U.Brookian Sag Seq.-N. Chuk. Bsn.	95	2	20	5	13	3	70			4500		
20	U. Brookian Turbs.-N. Chuk. Bsn.	305	8	111	10	60	7	120			3420		
21	U. Brookian-Paleovalley Fill	904	499	474	267	288	159	160			4840		
22	U. Brookian-Intervalley Highs	218	203	100	95	56	52	140			7770		

CHUKCHI SHELF

PLAY		INPUT DATA											
		Prospect Area (Acres)			Trap Fill (Dec. Frac.)								
No.	Name	F02	F01	F00	F100	F95	F75	F50	F25	F05	F02	F01	F00
1	Endicott Clastics-Chuk. Plat.	181800		1151000	0.08			0.43			0.68		1.00
2	Endicott Clastics-Arct. Plat.	103500		985000	0.08			0.43			0.68		1.00
3	Lisburne Carbonates	92400		514000	0.08			0.43			0.68		1.00
4	Ellesmerian "Deep Gas"	77000		330000	0.08			0.43			0.68		1.00
5	Sadlerochit Gp.-Chuk. Plat.	173600		1190000	0.08			0.43			0.68		1.00
6	Sadlerochit Gp.-Arct. Plat.	69400		341000	0.08			0.43			0.68		1.00
7	Rift Seq.-Active Margin Clastics	176500		1437000	0.08			0.43			0.68		1.00
8	Rift Seq.-Stable Marine Shelf	138000		1100000	0.08			0.43			0.68		1.00
9	Rift Seq.-"Deep Gas"	45000		116000	0.08			0.43			0.68		1.00
10	Herald Arch, Thrust Zone	8000		22000	0.12			0.25			0.35		0.50
11	Foreland Foldbelt	106200		575000	0.12			0.25			0.35		0.50
12	Torok Turbs.-Chuk. Wrench Zn.	77600		436000	0.08			0.43			0.68		1.00
13	Nanushuk-Chuk. Wrench Zn.	78300		519000	0.08			0.43			0.68		1.00
14	Sand Apron - N. Chuk. High	172600		1900000	0.17			0.66			0.87		1.00
15	L.Brook. Topset-N. Chuk. Bsn.	55400		384000	0.09			0.25			0.38		0.60
16	Brookian "Deep Gas"	37100		152000	0.08			0.43			0.68		1.00
17	Torok Turbs.-Arct. Plat.	18800		40000	0.08			0.43			0.68		1.00
18	Nanushuk-Arct. Plat.	27100		83000	0.08			0.43			0.68		1.00
19	U.Brookian Sag Seq.-N. Chuk. Bsn.	45000		292000	0.09			0.25			0.38		0.60
20	U. Brookian Turbs.-N. Chuk. Bsn.	21500		95000	0.09			0.25			0.38		0.60
21	U. Brookian-Paleovalley Fill	32140		149000	0.08			0.43			0.68		1.00
22	U. Brookian-Intervalley Highs	71250		430000	0.08			0.43			0.68		1.00

CHUKCHI SHELF

PLAY		INPUT DATA													
		Pool Area (Acres)									Pay Thickness (Feet)				
No.	Name	F100	F95	F75	F50	F25	F05	F02	F01	F00	F100	F95	F75	F50	F25
1	Endicott Clastics-Chuk. Plat.	120			8020			81800		538000	30			140	
2	Endicott Clastics-Arct. Plat.	17			2770			46200		453000	10			70	
3	Lisburne Carbonates	95			4800			42000		241000	23			70	
4	Ellesmerian "Deep Gas"	183			5370			35000		157000	18			70	
5	Sadlerochit Gp.-Chuk. Plat.	90			6950			76000		550000	34			100	
6	Sadlerochit Gp.-Arct. Plat.	110			4190			31500		162000	100			200	
7	Rift Seq.-Active Margin Clastics	50			5700			79000		665000	14			90	
8	Rift Seq.-Stable Marine Shelf	50			4800			62000		492000	34			100	
9	Rift Seq.-"Deep Gas"	610			5990			21100		59000	6			20	
10	Herald Arch, Thrust Zone	90			750			2400		6300	17			50	
11	Foreland Foldbelt	60			3250			30200		184000	25			150	
12	Torok Turbs.-Chuk. Wrench Zn.	80			3980			35000		205000	10			63	
13	Nanushuk-Chuk. Wrench Zn.	40			3270			35200		242000	18			70	
14	Sand Apron - N. Chuk. High	20			5840			127500		1550000	60			200	
15	L.Brook. Topset-N. Chuk. Bsn.	20			1300			15000		109000	40			150	
16	Brookian "Deep Gas"	110			2810			16900		73000	34			100	
17	Torok Turbs.-Arct. Plat.	490			3180			9000		21000	34			100	
18	Nanushuk-Arct. Plat.	210			2930			12560		41000	18			70	
19	U.Brookian Sag Seq.-N. Chuk. Bsn.	20			1170			11760		76000	16			50	
20	U. Brookian Turbs.-N. Chuk. Bsn.	30			870			5700		26000	66			200	
21	U. Brookian-Paleovalley Fill	60			2080			14600		71000	50			220	
22	U. Brookian-Intervalley Highs	60			3340			32100		201000	16			50	

CHUKCHI SHELF

PLAY		INPUT DATA															
PLAY		Pay Thickness (Feet)				Oil Yield (Recov. B/Acre-Foot)								Gas Yield (MMCF/Ac.-Ft)			
No.	Name	F05	F02	F01	F00	F100	F95	F75	F50	F25	F05	F01	F00	F100	F95	F75	F50
1	Endicott Clastics-Chuk. Plat.		320		700	3	16	32	53	86	177	292	813	0.015	0.070	0.142	0.232
2	Endicott Clastics-Arct. Plat.		150		350	2	11	23	39	85	137	231	668	0.005	0.030	0.065	0.110
3	Lisburne Carbonates		190		430	2	7	14	23	37	73	118	314	0.006	0.029	0.059	0.098
4	Ellesmerian "Deep Gas"		150		280	--	--	--	--	--	--	--	--	0.001	0.011	0.030	0.058
5	Sadlerochit Gp.-Chuk. Plat.		180		290	2	9	16	25	39	75	117	293	0.020	0.077	0.146	0.229
6	Sadlerochit Gp.-Arct. Plat.		370		610	6	25	47	73	114	215	335	833	0.017	0.081	0.170	0.285
7	Rift Seq.-Active Margin Clastics		250		570	11	38	69	103	156	282	427	997	0.025	0.108	0.212	0.340
8	Rift Seq.-Stable Marine Shelf		180		290	5	18	34	53	83	157	247	618	0.013	0.065	0.139	0.236
9	Rift Seq.-"Deep Gas"		38		65	--	--	--	--	--	--	--	--	0.004	0.024	0.058	0.107
10	Herald Arch, Thrust Zone		92		150	--	--	--	--	--	--	--	--	0.001	0.003	0.009	0.020
11	Foreland Foldbelt		400		890	6	20	32	45	65	110	160	330	0.036	0.107	0.178	0.255
12	Torok Turbs.-Chuk. Wrench Zn.		170		380	2	8	16	26	43	87	143	396	0.006	0.037	0.087	0.158
13	Nanushuk-Chuk. Wrench Zn.		150		280	7	30	58	93	147	287	458	1192	0.007	0.052	0.130	0.245
14	Sand Apron - N. Chuk. High		370		650	8	33	66	107	174	348	567	1535	0.007	0.049	0.125	0.239
15	L.Brook. Topset-N. Chuk. Bsn.		310		560	1	5	11	18	31	65	110	324	0.009	0.052	0.118	0.209
16	Brookian "Deep Gas"		180		290	--	--	--	--	--	--	--	--	0.003	0.019	0.049	0.094
17	Torok Turbs.-Arct. Plat.		180		290	6	19	33	48	70	122	179	392	0.031	0.097	0.165	0.238
18	Nanushuk-Arct. Plat.		150		280	47	113	170	225	300	448	597	1070	0.006	0.028	0.057	0.094
19	U.Brookian Sag Seq.-N. Chuk. Bsn.		93		155	15	47	81	117	170	291	424	916	0.050	0.165	0.290	0.429
20	U. Brookian Turbs.-N. Chuk. Bsn.		370		610	2	9	17	26	41	78	122	305	0.025	0.095	0.176	0.269
21	U. Brookian-Paleovalley Fill		500		970	33	100	168	240	344	577	829	1740	0.044	0.190	0.379	0.612
22	U. Brookian-Intervalley Highs		93		155	65	145	212	276	359	524	683	1176	0.085	0.221	0.346	0.471

CHUKCHI SHELF

PLAY		INPUT DATA															
		Gas Yield (MMCF/Ac.-Ft)				Solution Gas Oil Ratio (CF/B)								Gas Cond. (B/MMCF)			
No.	Name	F25	F05	F01	F00	F100	F95	F75	F50	F25	F05	F01	F00	F100	F95	F75	F50
1	Endicott Clastics-Chuk. Plat.	0.382	0.777	1.279	3.546	260	750	1200	1500	2000	3200	4200	6000	20	35	42	52
2	Endicott Clastics-Arct. Plat.	0.189	0.408	0.702	2.127	170	520	800	1100	1500	2300	3100	7000	20	35	42	52
3	Lisburne Carbonates	0.162	0.336	0.560	1.591	230	750	1300	1700	2300	3800	5200	10000	20	35	42	52
4	Ellesmerian "Deep Gas"	0.115	0.305	0.605	2.454	--	--	--	--	--	--	--	--	10	17	22	25
5	Sadlerochit Gp.-Chuk. Plat.	0.358	0.679	1.067	2.680	1000	1600	2200	2500	3000	3800	4200	5000	20	35	42	52
6	Sadlerochit Gp.-Arct. Plat.	0.477	1.000	1.684	4.879	220	600	900	1200	1600	2500	3100	6000	20	35	42	52
7	Rift Seq.-Active Margin Clastics	0.544	1.069	1.720	4.541	190	420	590	730	900	1300	1600	3000	20	35	42	52
8	Rift Seq.-Stable Marine Shelf	0.400	0.856	1.181	4.361	250	680	1000	1300	1600	2700	3600	7000	20	35	42	52
9	Rift Seq.-"Deep Gas"	0.196	0.469	0.865	3.024	--	--	--	--	--	--	--	--	10	17	22	25
10	Herald Arch, Thrust Zone	0.045	0.141	0.317	1.646	--	--	--	--	--	--	--	--	10	17	22	25
11	Foreland Foldbelt	0.364	0.609	0.874	1.829	800	980	1050	1100	1200	1250	1300	1500	10	17	22	25
12	Torok Turbs.-Chuk. Wrench Zn.	0.285	0.665	1.206	4.074	280	700	1050	1300	1800	2600	3600	7000	20	35	42	52
13	Nanushuk-Chuk. Wrench Zn.	0.461	1.149	2.181	8.081	100	400	720	1100	1700	3000	4500	10000	20	35	42	52
14	Sand Apron - N. Chuk. High	0.458	1.166	2.248	8.598	800	1700	2200	2800	3300	4400	5500	9000	10	17	22	25
15	L.Brook. Topset-N. Chuk. Bsn.	0.368	0.832	1.476	4.758	100	380	700	1100	1700	3200	5000	10000	10	17	22	25
16	Brookian "Deep Gas"	0.180	0.459	0.885	3.387	--	--	--	--	--	--	--	--	10	17	22	25
17	Torok Turbs.-Arct. Plat.	0.345	0.585	0.849	1.814	900	1020	1070	1100	1120	1140	1200	1300	20	35	42	52
18	Nanushuk-Arct. Plat.	0.155	0.318	0.526	1.474	490	530	550	570	590	600	620	680	20	35	42	52
19	U.Brookian Sag Seq.-N. Chuk. Bsn.	0.635	1.115	1.656	3.716	100	270	400	540	700	1140	1450	3000	10	17	22	25
20	U. Brookian Turbs.-N. Chuk. Bsn.	0.414	0.767	1.182	2.865	3000	3700	3900	4000	4300	4700	5000	5700	10	17	22	25
21	U. Brookian-Paleovalley Fill	0.988	1.967	3.190	8.573	100	270	410	590	780	1300	1700	3400	20	35	42	52
22	U. Brookian-Intervalley Highs	0.643	1.005	1.375	2.610	130	230	300	330	400	500	600	900	20	35	42	52

CHUKCHI SHELF

PLAY		INPUT DATA											
		Gas Cond. (B/MMCF)				Number of Prospects in Play							
No.	Name	F25	F05	F01	F00	F99	F95	F75	F50	F25	F05	F01	F00
1	Endicott Clastics-Chuk. Plat.	55	68	75	100	35	40	50	59	67	81	96	140
2	Endicott Clastics-Arct. Plat.	55	68	75	100	10	11	13	16	17	20	23	30
3	Lisburne Carbonates	55	68	75	100	39	40	43	48	52	56	63	78
4	Ellesmerian "Deep Gas"	28	35	40	50	86	100	125	150	185	240	285	430
5	Sadlerochit Gp.-Chuk. Plat.	55	68	75	100	32	33	36	40	43	49	52	64
6	Sadlerochit Gp.-Arct. Plat.	55	68	75	100	32	35	39	42	46	50	55	64
7	Rift Seq.-Active Margin Clastics	55	68	75	100	33	34	41	46	52	63	70	99
8	Rift Seq.-Stable Marine Shelf	55	68	75	100	24	27	34	40	46	57	66	96
9	Rift Seq.-"Deep Gas"	28	35	40	50	16	18	22	24	27	32	36	48
10	Herald Arch, Thrust Zone	28	35	40	50	2	3	6	8	13	23	36	102
11	Foreland Foldbelt	28	35	40	50	57	59	67	72	79	88	93	114
12	Torok Turbs.-Chuk. Wrench Zn.	55	68	75	100	41	44	57	66	77	96	115	164
13	Nanushuk-Chuk. Wrench Zn.	55	68	75	100	93	98	105	120	130	150	160	186
14	Sand Apron - N. Chuk. High	28	35	40	50	54	62	73	80	90	105	115	153
15	L.Brook. Topset-N. Chuk. Bsn.	28	35	40	50	60	63	68	70	73	79	81	91
16	Brookian "Deep Gas"	28	35	40	50	47	55	69	80	91	110	130	188
17	Torok Turbs.-Arct. Plat.	55	68	75	100	3	4	6	6	7	9	10	15
18	Nanushuk-Arct. Plat.	55	68	75	100	9	10	11	13	14	17	19	27
19	U.Brookian Sag Seq.-N. Chuk. Bsn.	28	35	40	50	20	22	27	30	33	40	44	60
20	U. Brookian Turbs.-N. Chuk. Bsn.	28	35	40	50	12	14	18	21	26	33	40	60
21	U. Brookian-Paleovalley Fill	55	68	75	100	27	30	40	48	57	68	89	135
22	U. Brookian-Intervalley Highs	55	68	75	100	13	15	18	20	22	26	30	39

CHUKCHI SHELF

No.	PLAY Name	INPUT DATA: Probabilities for Oil, Gas, or Mixed Pools: Oil (OPROB)	Gas (GPROB)	Mixed (MXPROB)	Fraction of Net Pay to Oil (OFRAC)	Play Chance Success	Prospect Chance Success	Play Type E - F - C
1	Endicott Clastics-Chuk. Plat.	0.00	0.00	1.00	0.70	0.72	0.51	C
2	Endicott Clastics-Arct. Plat.	0.00	0.90	0.10	0.70	0.40	0.05	C
3	Lisburne Carbonates	0.00	0.00	1.00	0.70	0.49	0.10	C
4	Ellesmerian "Deep Gas"	0.00	1.00	0.00	0.00	0.54	0.10	C
5	Sadlerochit Gp.-Chuk. Plat.	0.00	0.00	1.00	0.70	1.00	0.32	C
6	Sadlerochit Gp.-Arct. Plat.	0.00	0.00	1.00	0.70	0.60	0.24	C
7	Rift Seq.-Active Margin Clastics	0.00	0.00	1.00	0.70	1.00	0.64	C
8	Rift Seq.-Stable Marine Shelf	0.00	0.00	1.00	0.70	1.00	0.64	C
9	Rift Seq.-"Deep Gas"	0.00	1.00	0.00	0.00	1.00	0.15	C
10	Herald Arch, Thrust Zone	0.00	1.00	0.00	0.00	1.00	0.02	C
11	Foreland Foldbelt	0.36	0.64	0.00	0.00	1.00	0.23	C
12	Torok Turbs.-Chuk. Wrench Zn.	0.00	0.00	1.00	0.70	1.00	0.14	C
13	Nanushuk-Chuk. Wrench Zn.	0.00	0.00	1.00	0.70	0.49	0.04	C
14	Sand Apron - N. Chuk. High	0.34	0.43	0.23	0.50	0.64	0.13	C
15	L.Brook. Topset-N. Chuk. Bsn.	0.34	0.43	0.23	0.50	0.50	0.42	C
16	Brookian "Deep Gas"	0.00	1.00	0.00	0.00	0.30	0.12	C
17	Torok Turbs.-Arct. Plat.	0.00	0.00	1.00	0.70	0.50	0.05	C
18	Nanushuk-Arct. Plat.	0.00	0.00	1.00	0.70	1.00	0.06	C
19	U.Brookian Sag Seq.-N. Chuk. Bsn.	0.34	0.43	0.23	0.50	0.40	0.05	C
20	U. Brookian Turbs.-N. Chuk. Bsn.	0.34	0.43	0.23	0.50	0.64	0.40	C
21	U. Brookian-Paleovalley Fill	0.00	0.00	1.00	0.70	0.70	0.15	C
22	U. Brookian-Intervalley Highs	0.00	0.00	1.00	0.70	0.48	0.28	C

BEAUFORT SHELF

Play				Log-N Params. PORE Ac/Ft mu	PORE Ac/Ft sig. sq.	N (MPRO) No. Pools Mean	N (MPRO) No. Pools Max	Reserves Gas (BCF)	Reserves Oil (MMB)	Undiscovered Potential Gas (BCF)	Undiscovered Potential Oil (MMB)
No.	Area	UAI Code	Name								
101	Beaufort Shelf	UABS0101	Undeformed Pre-Mississippian Basement	10.312	2.9727	1	7	0	0	28	6
200	Beaufort Shelf	UABS0200	Pre-Devonian	14.061	1.4114	7	19	0	0	3534	173
401	Beaufort Shelf	UABS0401	Endicott w/o portion shared w/ Chukchi	11.652	2.1036	2	4	prop	prop	109	37
501	Beaufort Shelf	UABS0501	Lisburne w/o portion shared w/ Chukchi	11.742	3.4314	3	16	0	0	452	208
601	Beaufort Shelf	UABS0601	Upper Ellesmer. w/o portion shared w/ Chukchi	13.069	2.4728	5	15	prop	prop	1834	763
701	Beaufort Shelf	UABS0701	Rift w/o portion shared w/ Chukchi	12.461	2.5452	40	78	0	0	2559	910
800	Beaufort Shelf	UABS0800	Brookian Faulted Western Topset	11.662	2.6113	4	26	0	0	1570	82
902	Beaufort Shelf	UABS0902	Brookian Unstructured Western Topset	12.171	2.5478	1	6	0	0	211	146
1000	Beaufort Shelf	UABS1000	Brookian Faulted Western Turbidite	11.740	1.4290	2	13	0	0	601	29
1102	Beaufort Shelf	UABS1102	Brookian Unstructured Western Turbidite	11.803	1.5497	1	6	0	0	133	57
1201	Beaufort Shelf	UABS1201	Brookian Faulted Eastern Topset	12.230	2.4715	18	53	0	0	16074	1048
1302	Beaufort Shelf	UABS1302	Brookian Unstructured Eastern Topset	12.379	2.2277	3	9	prop	prop	813	1648
1400	Beaufort Shelf	UABS1400	Brookian Faulted Eastern Turbidite	11.562	1.8586	17	53	0	0	3585	183
1502	Beaufort Shelf	UABS1502	Brookian Unstructured Eastern Turbidite	11.249	2.4943	1	4	0	0	90	42
1602	Beaufort Shelf	UABS1602	Brookian Foldbelt	12.085	1.9114	20	45	0	0	3188	2038
1800	Beaufort Shelf	UABS1800	Endicott portion shared w/ Chukchi	12.174	2.0180	0	5	0	0	12	1
1900	Beaufort Shelf	UABS1900	Lisburne portion shared w/ Chukchi	12.724	1.3470	1	11	0	0	65	18
2000	Beaufort Shelf	UABS2000	Ellesmerian deep gas shared w/ Chukchi	12.836	0.9630	2	19	0	0	150	4
2100	Beaufort Shelf	UABS2100	Upper Ellsemerian portion shared w/ Chukchi	13.638	1.0550	5	22	0	0	1391	497
2200	Beaufort Shelf	UABS2200	Rift portion shared w/ Chukchi	13.081	1.6320	10	31	0	0	2166	606
2300	Beaufort Shelf	UABS2300	Sand Apron shared w/ Chukchi	13.971	2.3430	2	17	0	0	4895	291
2400	Beaufort Shelf	UABS2400	Turbidites (Torok) shared w/ Chukchi	12.669	0.3370	0	5	0	0	8	3
2500	Beaufort Shelf	UABS2500	Topset (Nanushuk) shared w/ Chukchi	12.232	0.6400	1	8	0	0	34	44

BEAUFORT SHELF

PLAY		MEAN POOL SIZES OF RANKS 1 TO 3						INPUT DATA					
		Pool #1		Pool #2		Pool #3		Prospect Area (Acres)					
		Gas	Oil	Gas	Oil	Gas	Oil						
No.	Name	(BCF)	(MMB	(BCF)	(MMB)	(BCF)	(MMB)	F100	F95	F75	F50	F25	F05
101	Undeformed Pre-Mississippian Basement	84	21	24	6	11	3	1	39	197	609	1879	9505
200	Pre-Devonian	1891	39	876	21	554	12	1400	12000	40000	52000	100000	240000
401	Endicott w/o portion shared w/ Chukchi	disc. (Tern Is.)		94	34	44	16	100	800	2000	4000	8000	20000
501	Lisburne w/o portion shared w/ Chukchi	347	155	76	32	30	13	6	185	922	2812	8579	42692
601	Upper Ellesmer. w/o portion shared w/ Chukchi	1665	662	disc. (Seal Is.)		154	60	16	396	1732	4833	13484	58990
701	Rift w/o portion shared w/ Chukchi	not computed						Pool size dist. from fields in play.					
800	Brookian Faulted Western Topset	1304	57	370	17	174	8	18	315	1191	3000	7558	28556
902	Brookian Unstructured Western Topset	285	182	67	44	6	26	32	543	2012	5000	12429	46063
1000	Brookian Faulted Western Turbidite	508	22	191	9	108	5	163	1099	2683	4990	9280	22655
1102	Brookian Unstructured Western Turbidite	137	86	47	23	27	13	142	1072	2752	5200	10208	26211
1201	Brookian Faulted Eastern Topset	6908	305	2791	128	1701	76	38	597	2165	5300	12978	47067
1302	Brookian Unstructured Eastern Topset	201	905	disc. (Kuvlum)		229	182	60	800	2677	6200	14360	48079
1400	Brookian Faulted Eastern Turbidite	1393	62	649	30	427	19	69	676	1972	4150	8734	25477
1502	Brookian Unstructured Eastern Turbidite	100	47	23	11	11	5	22	343	1233	3000	7301	26246
1602	Brookian Foldbelt	1041	681	484	317	309	210	108	1107	3286	7000	14911	44259
1800	Endicott portion shared w/ Chukchi	98	5	32	2	18	1	42			6434		
1900	Lisburne portion shared w/ Chukchi	100	28	39	11	23	7	242			11148		
2000	Ellesmerian deep gas shared w/ Chukchi	143	4	67	2	44	1	472			12477		
2100	Upper Ellsemerian portion shared w/ Chukchi	939	315	472	158	306	106	277			9733		
2200	Rift portion shared w/ Chukchi	840	253	372	112	228	71	117			11153		
2300	Sand Apron shared w/ Chukchi	4598	114	1352	248	627	114	42			8519		
2400	Turbidites (Torok) shared w/ Chukchi	52	18	35	12	29	10	1370			7393		
2500	Topset (Nanushuk) shared w/ Chukchi	47	60	26	33	19	25	559			6819		

BEAUFORT SHELF

PLAY		INPUT DATA											
		Prospect Area (Acres)			Trap Fill (Dec. Frac.)								
No.	Name	F02	F01	F00	F100	F95	F75	F50	F25	F05	F02	F01	F00
101	Undeformed Pre-Mississippian Basement		18821	29677	0.10	0.14	0.29	0.50	0.76	0.95		0.99	1.00
200	Pre-Devonian		420000	860000	0.05	0.05	0.08	0.10	0.15	0.19		0.20	0.20
401	Endicott w/o portion shared w/ Chukchi		40000	50000	0.10	0.14	0.29	0.50	0.76	0.95		0.99	1.00
501	Lisburne w/o portion shared w/ Chukchi		131760	150000	0.10	0.14	0.29	0.50	0.76	0.95		0.99	1.00
601	Upper Ellesmer. w/o portion shared w/ Chukchi		109870	166320	0.10	0.14	0.29	0.50	0.76	0.95		0.99	1.00
701	Rift w/o portion shared w/ Chukchi	Pool size dist. from fields in play.											
800	Brookian Faulted Western Topset		72635	489440	0.10	0.14	0.29	0.50	0.76	0.95		0.99	1.00
902	Brookian Unstructured Western Topset		115590	757600	0.10	0.14	0.29	0.50	0.76	0.95		0.99	1.00
1000	Brookian Faulted Western Turbidite		42404	152670	0.10	0.14	0.29	0.50	0.76	0.95		0.99	1.00
1102	Brookian Unstructured Western Turbidite		50829	196740	0.10	0.14	0.29	0.50	0.76	0.95		0.99	1.00
1201	Brookian Faulted Eastern Topset		116320	739080	0.10	0.14	0.29	0.50	0.76	0.95		0.99	1.00
1302	Brookian Unstructured Eastern Topset		112340	636340	0.10	0.14	0.29	0.50	0.76	0.95		0.99	1.00
1400	Brookian Faulted Eastern Turbidite		54034	251150	0.10	0.14	0.29	0.50	0.76	0.95		0.99	1.00
1502	Brookian Unstructured Eastern Turbidite		64446	404420	0.10	0.14	0.29	0.50	0.76	0.95		0.99	1.00
1602	Brookian Foldbelt		95023	452840	0.10	0.14	0.29	0.50	0.76	0.95		0.99	1.00
1800	Endicott portion shared w/ Chukchi	103530		984920	0.08			0.43			0.68		1.00
1900	Lisburne portion shared w/ Chukchi	92425		513590	0.08			0.43			0.68		1.00
2000	Ellesmerian deep gas shared w/ Chukchi	76087		329600	0.08			0.43			0.68		1.00
2100	Upper Ellsemerian portion shared w/ Chukchi	69421		341470	0.08			0.43			0.68		1.00
2200	Rift portion shared w/ Chukchi	137970		1060600	0.08			0.43			0.68		1.00
2300	Sand Apron shared w/ Chukchi	190620		1896300	0.17			0.66			0.87		1.00
2400	Turbidites (Torok) shared w/ Chukchi	18756		39901	0.08			0.43			0.68		1.00
2500	Topset (Nanushuk) shared w/ Chukchi	27127		83112	0.08			0.43			0.68		1.00

BEAUFORT SHELF

PLAY		INPUT DATA													
PLAY		Pool Area (Acres)									Pay Thickness (Feet)				
No.	Name	F100	F95	F75	F50	F25	F05	F02	F01	F00	F100	F95	F75	F50	F25
101	Undeformed Pre-Mississippian Basement	1			301			8720		133640	14			100	
200	Pre-Devonian	170			6269			45900		230610	16			204	
401	Endicott w/o portion shared w/ Chukchi	30			1915			19032		122500	2			60	
501	Lisburne w/o portion shared w/ Chukchi	2			1397			46814		87088	8			90	
601	Upper Ellesmer. w/o portion shared w/ Chukchi	9			2371			52465		646250	38			200	
701	Rift w/o portion shared w/ Chukchi	50			6454			95000		840820	1			40	
800	Brookian Faulted Western Topset	6			1451			34229		371230	13			80	
902	Brookian Unstructured Western Topset	10			2413			54546		574970	13			80	
1000	Brookian Faulted Western Turbidite	33			2368			21209		117930	7			53	
1102	Brookian Unstructured Western Turbidite	30			2523			25305		151560	7			53	
1201	Brookian Faulted Eastern Topset	12			2561			54956		561290	13			80	
1302	Brookian Unstructured Eastern Topset	16			2973			53685		484580	13			80	
1400	Brookian Faulted Eastern Turbidite	17			1982			25933		192300	7			53	
1502	Brookian Unstructured Eastern Turbidite	7			1449			30584		307220	7			53	
1602	Brookian Foldbelt	26			3343			45715		346470	7			53	
1800	Endicott portion shared w/ Chukchi	17			2767			46221		453330	10			70	
1900	Lisburne portion shared w/ Chukchi	95			4794			41742		241380	23			70	
2000	Ellesmerian deep gas shared w/ Chukchi	183			5365			34643		157190	18			70	
2100	Upper Ellsemerian portion shared w/ Chukchi	108			4185			31468		161540	100			200	
2200	Rift portion shared w/ Chukchi	47			4795			61836		491560	34			100	
2300	Sand Apron shared w/ Chukchi	22			5844			127540		1553400	60			200	
2400	Turbidites (Torok) shared w/ Chukchi	485			3179			8973		20814	34			100	
2500	Topset (Nanushuk) shared w/ Chukchi	210			2932			12561		40867	18			70	

BEAUFORT SHELF

PLAY		INPUT DATA															
		Pay Thickness (Feet)				Oil Yield (Recov. B/ Acre-Foot)								Gas Yield (MMCF/Ac.-Ft)			
No.	Name	F05	F02	F01	F00	F100	F95	F75	F50	F25	F05	F01	F00	F100	F95	F75	F50
101	Undeformed Pre-Mississippian Basement		300		731	11	27	40	52	69	103	136	242	0.074	0.143	0.195	0.241
200	Pre-Devonian		636		2624	5	13	20	59	92	174	272	682	0.006	0.033	0.072	0.124
401	Endicott w/o portion shared w/ Chukchi		400		1862	34	94	149	207	286	458	636	1245	0.107	0.286	0.452	0.621
501	Lisburne w/o portion shared w/ Chukchi		350		1053	24	55	81	105	138	203	267	464	0.019	0.060	0.104	0.151
601	Upper Ellesmer. w/o portion shared w/ Chukchi		500		1051	28	74	117	162	223	355	491	953	0.081	0.224	0.361	0.503
701	Rift w/o portion shared w/ Chukchi		260		1186	32	81	125	169	228	351	476	884	0.048	0.173	0.317	0.483
800	Brookian Faulted Western Topset		220		500	115	220	298	367	453	613	758	1171	0.178	0.424	0.637	0.845
902	Brookian Unstructured Western Topset		220		500	59	118	163	204	255	352	442	702	0.173	0.414	0.623	0.828
1000	Brookian Faulted Western Turbidite		160		392	42	98	145	190	250	371	488	858	0.128	0.364	0.592	0.830
1102	Brookian Unstructured Western Turbidite		160		392	42	98	145	190	250	371	488	858	0.122	0.343	0.558	0.781
1201	Brookian Faulted Eastern Topset		220		500	133	249	333	408	500	669	821	1248	0.211	0.534	0.825	1.117
1302	Brookian Unstructured Eastern Topset		220		500	68	133	182	227	282	385	479	750	0.224	0.439	0.601	0.747
1400	Brookian Faulted Eastern Turbidite		160		392	29	73	111	149	200	306	412	756	0.128	0.331	0.517	0.704
1502	Brookian Unstructured Eastern Turbidite		160		392	29	73	111	149	200	306	412	756	0.118	0.305	0.476	0.648
1602	Brookian Foldbelt		160		392	61	133	192	248	320	462	598	1012	0.051	0.234	0.477	0.782
1800	Endicott portion shared w/ Chukchi		150		350	2	11	23	39	65	137	231	668	0.005	0.030	0.065	0.110
1900	Lisburne portion shared w/ Chukchi		190		427	2	7	14	23	37	73	118	314	0.006	0.029	0.059	0.098
2000	Ellesmerian deep gas shared w/ Chukchi		150		278	not used								0.001	0.011	0.030	0.058
2100	Upper Ellsemerian portion shared w/ Chukchi		370		609	6	25	47	73	114	215	335	833	0.017	0.081	0.170	0.285
2200	Rift portion shared w/ Chukchi		180		290	5	18	34	53	83	157	247	618	0.013	0.065	0.139	0.236
2300	Sand Apron shared w/ Chukchi		370		650	8	33	66	107	174	348	567	1535	0.007	0.049	0.125	0.239
2400	Turbidites (Torok) shared w/ Chukchi		180		290	6	19	33	48	70	122	179	392	0.031	0.097	0.165	0.238
2500	Topset (Nanushuk) shared w/ Chukchi		150		278	47	113	170	225	299	448	597	1069	0.006	0.028	0.057	0.094

BEAUFORT SHELF

INPUT DATA

PLAY		Gas Yield (MMCF/Ac.-Ft)				Solution Gas Oil Ratio (CF/B)								Gas Cond. (B/MMCF)			
No.	Name	F25	F05	F01	F00	F100	F95	F75	F50	F25	F05	F01	F00	F100	F95	F75	F50
101	Undeformed Pre-Mississippian Basement	0.298	0.405	0.502	0.779	19	165	449	900	1806	4917	9938	41850	14	42	70	100
200	Pre-Devonian	0.231	0.465	0.803	2.460	19	165	449	900	1806	4917	9938	41850	0	2	5	10
401	Endicott w/o portion shared w/ Chukchi	0.855	1.350	1.870	3.600	19	165	449	900	1806	4917	9938	41850	0	3	8	15
501	Lisburne w/o portion shared w/ Chukchi	0.220	0.379	0.555	1.210	19	164	449	900	1806	4917	9938	41850	0	2	5	10
601	Upper Ellesmer. w/o portion shared w/ Chukchi	0.699	1.130	1.570	3.110	19	165	449	900	1806	4917	9938	41850	0	2	5	10
701	Rift w/o portion shared w/ Chukchi	0.735	1.350	2.060	4.900	19	165	449	900	1806	4917	9938	41850	0	3	8	15
800	Brookian Faulted Western Topset	1.122	1.685	2.242	4.019	38	96	148	200	270	417	565	1051	8	19	30	40
902	Brookian Unstructured Western Topset	1.099	1.653	2.202	3.955	38	96	148	200	270	417	565	1051	8	19	30	40
1000	Brookian Faulted Western Turbidite	1.165	1.896	2.668	5.368	68	229	404	800	891	1573	2347	5309	8	19	30	40
1102	Brookian Unstructured Western Turbidite	1.095	1.778	2.500	5.014	68	229	404	600	891	1573	2347	5309	8	19	30	40
1201	Brookian Faulted Eastern Topset	1.511	2.335	3.169	5.918	38	96	148	200	270	417	565	1051	8	19	30	40
1302	Brookian Unstructured Eastern Topset	0.930	1.273	1.587	2.490	38	96	148	200	270	417	565	1051	8	19	30	40
1400	Brookian Faulted Eastern Turbidite	0.958	1.495	2.043	3.867	68	229	404	600	891	1573	2347	5309	8	19	30	40
1502	Brookian Unstructured Eastern Turbidite	0.883	1.379	1.885	3.570	68	229	404	600	891	1573	2347	5309	8	19	30	40
1602	Brookian Foldbelt	1.284	2.619	4.322	12.022	38	96	148	200	270	417	565	1051	8	19	30	40
1800	Endicott portion shared w/ Chukchi	0.189	0.408	0.703	2.127	170	520	800	1100	1500	2300	3100	7000	20	35	42	52
1900	Lisburne portion shared w/ Chukchi	0.162	0.336	0.560	1.594	230	750	1300	1700	2300	3800	5200	10000	20	35	42	52
2000	Ellesmerian deep gas shared w/ Chukchi	0.115	0.305	0.605	2.454	not used								10	17	22	25
2100	Upper Ellsemerian portion shared w/ Chukchi	0.477	1.000	1.684	4.879	220	600	900	1200	1600	2500	3100	6000	20	35	42	52
2200	Rift portion shared w/ Chukchi	0.400	0.856	1.181	4.361	250	680	1000	1300	1800	2700	3600	7000	20	35	42	52
2300	Sand Apron shared w/ Chukchi	0.458	1.166	2.248	8.595	800	1700	2200	2800	3300	4400	5500	9000	10	17	22	25
2400	Turbidites (Torok) shared w/ Chukchi	0.345	0.585	0.849	1.814	900	1020	1070	1100	1120	1140	1200	1300	20	35	42	52
2500	Topset (Nanushuk) shared w/ Chukchi	0.155	0.318	0.526	1.474	490	530	550	570	590	600	620	680	20	35	42	52

BEAUFORT SHELF

INPUT DATA

No.	PLAY Name	Gas Cond. (B/MMCF) F25	F05	F01	F00	Number of Prospects in Play F99	F95	F75	F50	F25	F05	F01	F00
101	Undeformed Pre-Mississippian Basement	143	241	347	731	7	9	14	21	28	34	35	36
200	Pre-Devonian	22	85	140	682	9	10	11	13	15	17	18	19
401	Endicott w/o portion shared w/ Chukchi	28	70	133	491	5	7	11	18	25	32	33	34
501	Lisburne w/o portion shared w/ Chukchi	22	65	140	682	23	27	33	39	43	53	61	62
601	Upper Ellesmer. w/o portion shared w/ Chukchi	22	65	140	682	31	34	41	44	50	56	62	63
701	Rift w/o portion shared w/ Chukchi	28	70	133	491	27	32	41	46	54	70	81	82
800	Brookian Faulted Western Topset	54	83	113	210	9	11	13	14	16	19	21	27
902	Brookian Unstructured Western Topset	54	83	113	210	2	2	3	3	4	5	5	7
1000	Brookian Faulted Western Turbidite	54	83	113	210	6	7	8	8	9	10	11	14
1102	Brookian Unstructured Western Turbidite	54	83	113	210	2	2	3	3	4	5	5	7
1201	Brookian Faulted Eastern Topset	54	83	113	210	33	37	40	43	46	51	55	62
1302	Brookian Unstructured Eastern Topset	54	83	113	210	3	5	5	6	6	7	8	10
1400	Brookian Faulted Eastern Turbidite	54	83	113	210	33	36	39	42	45	50	54	61
1502	Brookian Unstructured Eastern Turbidite	54	83	113	210	1	1	2	2	2	3	3	4
1602	Brookian Foldbelt	54	83	113	210	37	40	46	49	53	60	65	77
1800	Endicott portion shared w/ Chukchi	55	68	75	100	4	4.5	5	6	6.2	7	8	10
1900	Lisburne portion shared w/ Chukchi	55	68	75	100	17	18	20	22	23	27	28	35
2000	Ellesmerian deep gas shared w/ Chukchi	28	35	40	50	18	22	28	33	39	50	60	90
2100	Upper Ellsemerian portion shared w/ Chukchi	55	68	75	100	24	26	28	31	33	37	40	47
2200	Rift portion shared w/ Chukchi	55	68	75	100	9	10	13	15	17	22	25	36
2300	Sand Apron shared w/ Chukchi	28	35	40	50	20	22	26	30	33	39	44	57
2400	Turbidites (Torok) shared w/ Chukchi	55	68	75	100	3	3.6	5.6	5.7	8.6	9	10	15
2500	Topset (Nanushuk) shared w/ Chukchi	55	68	75	100	8	9	11	13	14	17	19	26

BEAUFORT SHELF

PLAY		INPUT DATA						
		Probabilities for Oil, Gas, or Mixed Pools			Fraction of Net	Play	Prospect	
		Oil	Gas	Mixed	Pay to Oil	Chance	Chance	Play Type
No.	Name	(OPROB)	(GPROB)	(MXPROB)	(OFRAC)	Success	Success	E - F - C
101	Undeformed Pre-Mississippian Basement	0.00	0.00	1.00	0.50	1.00	0.24	E
200	Pre-Devonian	0.00	0.67	0.33	0.76	0.75	0.66	F
401	Endicott w/o portion shared w/ Chukchi	0.00	0.00	1.00	0.75	1.00	0.75	E
501	Lisburne w/o portion shared w/ Chukchi	0.00	0.00	1.00	0.75	1.00	0.30	E
601	Upper Ellesmer. w/o portion shared w/ Chukchi	0.00	0.00	1.00	0.80	1.00	0.45	E
701	Rift w/o portion shared w/ Chukchi	0.45	0.45	0.10	0.75	1.00	0.81	E
800	Brookian Faulted Western Topset	0.00	0.80	0.20	0.75	0.80	0.32	F
902	Brookian Unstructured Western Topset	0.50	0.10	0.40	0.75	0.80	0.40	F
1000	Brookian Faulted Western Turbidite	0.00	0.90	0.10	0.75	0.80	0.32	F
1102	Brookian Unstructured Western Turbidite	0.00	0.00	1.00	0.75	1.00	0.32	F
1201	Brookian Faulted Eastern Topset	0.00	0.80	0.20	0.75	1.00	0.42	F
1302	Brookian Unstructured Eastern Topset	0.60	0.00	0.40	0.75	1.00	0.50	E
1400	Brookian Faulted Eastern Turbidite	0.00	0.90	0.10	0.75	0.90	0.43	F
1502	Brookian Unstructured Eastern Turbidite	0.00	0.00	1.00	0.75	1.00	0.49	E
1602	Brookian Foldbelt	0.00	0.00	1.00	0.75	1.00	0.32	F
1800	Endicott portion shared w/ Chukchi	0.00	0.90	0.10	0.70	0.40	0.05	C
1900	Lisburne portion shared w/ Chukchi	0.00	0.00	1.00	0.70	0.49	0.10	C
2000	Ellesmerian deep gas shared w/ Chukchi	0.00	1.00	0.00	0.00	0.54	0.10	C
2100	Upper Ellsemerian portion shared w/ Chukchi	0.00	0.00	1.00	0.70	0.60	0.24	C
2200	Rift portion shared w/ Chukchi	0.00	0.00	1.00	0.70	1.00	0.64	C
2300	Sand Apron shared w/ Chukchi	0.34	0.43	0.23	0.50	0.64	0.13	C
2400	Turbidites (Torok) shared w/ Chukchi	0.00	0.00	1.00	0.70	0.50	0.05	C
2500	Topset (Nanushuk) shared w/ Chukchi	0.00	0.00	1.00	0.70	1.00	0.06	C

HOPE BASIN

Play				Log-N Params. PORE		N (MPRO)		Reserves		Undiscovered Potential	
				Ac/Ft	Ac/Ft	No. Pools		Gas	Oil	Gas	Oil
No.	Area	UAI Code	Name	mu	sig. sq.	Mean	Max	(BCF)	(MMB)	(BCF)	(MMB)
1	Hope	UAHB0101	Late Sequence Play	12.843	1.1839	8.7	40	0	0	3341	90
2	Hope	UAHB0201	Early Sequence Play	12.100	1.0140	5.4	34	0	0	387	11
3	Hope	UAHB0301	Shallow Basal Sands Play	11.628	0.9317	5.9	48	0	0	333	9
4	Hope	UAHB0401	Deep Basal Sands Play	11.619	0.8951	0.2	6	0	0	4	0.1

PLAY		MEAN POOL SIZES OF RANKS 1 TO 3 Pool #1		Pool #2		Pool #3		INPUT DATA Prospect Area (Acres)					
		Gas	Oil	Gas	Oil	Gas	Oil						
No.	Name	(BCF)	(MMB)	(BCF)	(MMB)	(BCF)	(MMB)	F100	F95	F75	F50	F25	F05
1	Late Sequence Play	1784	46	979	26	704	18	330	2600	6000	10000	19000	45000
2	Early Sequence Play	272	7	152	4	110	3	300	2500	5500	10000	19000	45000
3	Shallow Basal Sands Play	235	6	140	4	106	3	470	3300	7000	12000	21000	47000
4	Deep Basal Sands Play	30	1	15	0	10	0	470	3300	7000	12000	21000	47000

PLAY		INPUT DATA Prospect Area (Acres)			Trap Fill (Dec. Frac.)								
No.	Name	F02	F01	F00	F100	F95	F75	F50	F25	F05	F02	F01	F00
1	Late Sequence Play		79000	150000	0.05	0.10	0.13	0.15	0.19	0.25		0.30	0.45
2	Early Sequence Play		83000	170000	0.05	0.10	0.13	0.15	0.19	0.25		0.30	0.45
3	Shallow Basal Sands Play		80000	150000	0.05	0.10	0.13	0.15	0.19	0.25		0.30	0.45
4	Deep Basal Sands Play		80000	150000	0.05	0.10	0.13	0.15	0.19	0.25		0.30	0.45

HOPE BASIN

INPUT DATA

No.	PLAY Name	Pool Area (Acres) F100	F95	F75	F50	F25	F05	F02	F01	F00	Pay Thickness (Feet) F100	F95	F75	F50	F25
1	Late Sequence Play	41			1609			12139		62489	42			235	
2	Early Sequence Play	47			1636			11666		57370	34			110	
3	Shallow Basal Sands Play	63			1869			12158		55499	18			60	
4	Deep Basal Sands Play	67			1854			11568		51050	18			60	

INPUT DATA

No.	PLAY Name	Pay Thickness (Feet) F05	F02	F01	F00	Oil Yield (Recov. B/Acre-Foot) F100	F95	F75	F50	F25	F05	F01	F00	Gas Yield (MMCF/Ac.-Ft) F100	F95	F75	F50
1	Late Sequence Play		610		1322	20	71	127	192	289	520	786	1830	0.058	0.182	0.310	0.449
2	Early Sequence Play		210		355	31	68	97	125	161	231	298	500	0.023	0.075	0.129	0.189
3	Shallow Basal Sands Play		115		195	11	40	71	107	160	286	431	993	0.018	0.074	0.142	0.223
4	Deep Basal Sands Play		115		195	4	10	16	21	29	46	63	122	0.026	0.064	0.098	0.131

INPUT DATA

No.	PLAY Name	Gas Yield (MMCF/Ac.-Ft) F25	F05	F01	F00	Solution Gas Oil Ratio (CF/B) F100	F95	F75	F50	F25	F05	F01	F00	Gas Cond. (B/MMCF) F100	F95	F75	F50
1	Late Sequence Play	0.651	1.110	1.614	3.471	37	105	170	235	330	570	740	1400	6	13	19	24
2	Early Sequence Play	0.276	0.477	0.700	1.535	44	122	202	285	405	670	949	1920	6	13	19	24
3	Shallow Basal Sands Play	0.350	0.671	1.061	2.701	83	192	285	369	485	720	949	1670	6	13	19	24
4	Deep Basal Sands Play	0.176	0.269	0.363	0.666	970	1080	1125	1180	1220	1290	1323	1430	6	13	19	24

HOPE BASIN

PLAY		INPUT DATA											
		Gas Cond. (B/MMCF)				Number of Prospects in Play							
No.	Name	F25	F05	F01	F00	F99	F95	F75	F50	F25	F05	F01	F00
1	Late Sequence Play	31	46	60	110	60	64	71	75	80	88	95	110
2	Early Sequence Play	31	46	60	110	53	57	63	68	73	80	87	100
3	Shallow Basal Sands Play	31	46	60	110	87	95	108	120	130	150	164	200
4	Deep Basal Sands Play	31	46	60	110	8	9	10	10	11	13	14	16

PLAY		INPUT DATA						
		Probabilities for Oil, Gas, or Mixed Pools			Fraction of Net	Play	Prospect	
		Oil	Gas	Mixed	Pay to Oil	Chance	Chance	Play Type
No.	Name	(OPROB)	(GPROB)	(MXPROB)	(OFRAC)	Success	Success	E - F - C
1	Late Sequence Play	0	0.9	0.1	0.05	0.50	0.23	C
2	Early Sequence Play	0	0.9	0.1	0.05	0.40	0.20	C
3	Shallow Basal Sands Play	0	0.9	0.1	0.05	0.30	0.16	C
4	Deep Basal Sands Play	0	0.9	0.1	0.05	0.27	0.05	C

APPENDIX A

BERING SHELF SUBREGION INPUT DATA

NAVARIN BASIN
NORTH ALEUTIAN BASIN
ST. GEORGE BASIN
NORTON BASIN
ST. MATTHEW-HALL BASIN

NAVARIN BASIN

Play				Log-N Params. PORE		N (MPRO)		Reserves		Undiscovered Potential	
				Ac/Ft	Ac/Ft	No. Pools		Gas	Oil	Gas	Oil
No.	Area	UAI Code	Name	mu	sig. sq.	Mean	Max	(BCF)	(MMB)	(BCF)	(MMB)
1	Navarin Basin	UANA0100	Miocene Transgressive Shelf Sands	11.21	2.64	11.9	44	-	-	666	78
2	Navarin Basin	UANA0200	Regressive Shelf Sands	11.41	2.52	32.2	81	-	-	2432	272
3	Navarin Basin	UANA0300	Oligocene Tectonic Sands	11.38	1.30	6.7	32	-	-	196	20
4	Navarin Basin	UANA0400	Turbidite and Submarine Fan Sands	12.19	2.01	18.1	56	-	-	2518	116
5	Navarin Basin	UANA0500	Eocene Transgressive Shelf Sands	11.95	1.81	4.6	24	-	-	336	11

PLAY		MEAN POOL SIZES OF RANKS 1 TO 3 — Pool #1		Pool #2		Pool #3		INPUT DATA — Prospect Area (Acres)					
		Gas	Oil	Gas	Oil	Gas	Oil						
No.	Name	(BCF)	(MMB)	(BCF)	(MMB)	(BCF)	(MMB)	F100	F95	F75	F50	F25	F05
1	Miocene Transgressive Shelf Sands	553	24	131	41	85	24	18	381	1800	4350	11800	49700
2	Regressive Shelf Sands	1261	55	355	84	250	55	15	276	1090	2850	7410	29400
3	Oligocene Tectonic Sands	146	6	45	10	33	7	118	878	2250	4320	8310	21300
4	Turbidite and Submarine Fan Sands	1224	44	503	19	308	23	45	497	1530	3360	7370	22800
5	Eocene Transgressive Shelf Sands	285	10	105	4	66	2	45	540	1740	3910	8790	28200

PLAY		INPUT DATA — Prospect Area (Acres)			Trap Fill (Dec. Frac.)								
No.	Name	F02	F01	F00	F100	F95	F75	F50	F25	F05	F02	F01	F00
1	Miocene Transgressive Shelf Sands	91100	136400	1072600	.10	.17	.21	.24	.30	.37	.40	.41	.50
2	Regressive Shelf Sands	52400	77200	556200	.10	.18	.22	.26	.32	.40	.48	.50	.60
3	Oligocene Tectonic Sands	31600	41200	158700	.20	.32	.41	.50	.58	.71	.78	.85	1.00
4	Turbidite and Submarine Fan Sands	36600	50300	253900	.10	.21	.30	.38	.48	.63	.76	.81	1.00
5	Eocene Transgressive Shelf Sands	46100	64000	341300	.30	.44	.52	.60	.69	.80	.88	.92	1.00

NAVARIN BASIN

INPUT DATA

PLAY No.	Name	Pool Area (Acres) F100	F95	F75	F50	F25	F05	F02	F01	F00	Pay Thickness (Feet) F100	F95	F75	F50	F25
1	Miocene Transgressive Shelf Sands	3	86	396	1150	3340	15500	29500	45400	409300	16	34	50	64	83
2	Regressive Shelf Sands	3	68	295	821	2280	9950	18500	28000	231500	19	51	80	110	151
3	Oligocene Tectonic Sands	45	392	1080	2190	4440	12300	18800	25000	107600	8	19	28	40	54
4	Turbidite and Submarine Fan Sands	11	159	553	1320	3130	10900	18400	26100	156300	16	56	100	150	224
5	Eocene Transgressive Shelf Sands	26	305	1010	2410	5830	19400	34200	49300	243700	16	34	50	64	83

INPUT DATA

PLAY No.	Name	Pay Thickness (Feet) F05	F02	F01	F00	Oil Yield (Recov. B/Acre-Foot) F100	F95	F75	F50	F25	F05	F01	F00	Gas Yield (MMCF/Ac.-Ft) F100	F95	F75	F50
1	Miocene Transgressive Shelf Sands	120	140	155	264	8	27	48	72	108	194	292	677	.018	.064	.116	.175
2	Regressive Shelf Sands	239	290	330	636	11	31	51	72	101	166	234	476	.036	.104	.169	.238
3	Oligocene Tectonic Sands	83	100	113	210	4	15	28	43	66	122	189	458	.014	.052	.098	.150
4	Turbidite and Submarine Fan Sands	400	510	600	1378	3	11	20	31	48	92	144	362	.008	.043	.096	.167
5	Eocene Transgressive Shelf Sands	120	140	155	264	3	9	16	22	32	54	79	167	.015	.052	.095	.143

INPUT DATA

PLAY No.	Name	Gas Yield (MMCF/Ac.-Ft) F25	F05	F01	F00	Solution Gas Oil Ratio (CF/B) F100	F95	F75	F50	F25	F05	F01	F00	Gas Cond. (B/MMCF) F100	F95	F75	F50
1	Miocene Transgressive Shelf Sands	.265	.481	.730	1.713	170	260	300	320	380	430	500	550	19	30	38	41
2	Regressive Shelf Sands	.334	.545	.769	1.554	170	300	380	420	500	630	740	900	19	30	38	41
3	Oligocene Tectonic Sands	.232	.433	.671	1.642	150	290	360	410	500	630	740	900	19	30	38	41
4	Turbidite and Submarine Fan Sands	.291	.646	1.130	3.545	390	600	730	820	950	1250	1300	1400	15	26	31	38
5	Eocene Transgressive Shelf Sands	.216	.392	.594	1.393	150	360	490	600	750	1000	1200	1500	13	25	29	32

NAVARIN BASIN

PLAY		INPUT DATA											
		Gas Cond. (B/MMCF)				Number of Prospects in Play							
No.	Name	F25	F05	F01	F00	F99	F95	F75	F50	F25	F05	F01	F00
1	Miocene Transgressive Shelf Sands	50	60	79	80	97	102	110	115	120	126	134	135
2	Regressive Shelf Sands	50	60	79	80	167	170	175	180	185	195	199	200
3	Oligocene Tectonic Sands	50	60	79	80	122	130	140	145	150	158	161	162
4	Turbidite and Submarine Fan Sands	40	50	58	70	109	112	130	140	150	170	178	180
5	Eocene Transgressive Shelf Sands	39	48	51	60	137	140	145	150	155	160	168	170

PLAY		INPUT DATA						
		Probabilities for Oil, Gas, or Mixed Pools			Fraction of Net	Play	Prospect	
		Oil	Gas	Mixed	Pay to Oil	Chance	Chance	Play Type
No.	Name	(OPROB)	(GPROB)	(MXPROB)	(OFRAC)	Success	Success	E - F - C
1	Miocene Transgressive Shelf Sands	0	.4	.6	0.4	.56	.18	C
2	Regressive Shelf Sands	0	.4	.6	0.4	.64	.28	C
3	Oligocene Tectonic Sands	0	.4	.6	0.4	.51	.09	C
4	Turbidite and Submarine Fan Sands	0	.5	.5	0.2	.65	.20	C
5	Eocene Transgressive Shelf Sands	0	.75	.25	0.1	.58	.05	C

NORTH ALEUTIAN BASIN

Play				Log-N Params. PORE Ac/Ft mu	PORE Ac/Ft sig. sq.	N (MPRO) No. Pools Mean	N (MPRO) No. Pools Max	Reserves Gas (BCF)	Reserves Oil (MMB)	Undiscovered Potential Gas (BCF)	Undiscovered Potential Oil (MMB)
No.	Area	UAI Code	Name								
1	N.Aleutian	UANB0100	Oligocene-Miocene	12.929	1.5454	7.89	32	0	0	6790.878	232.9515

PLAY		MEAN POOL SIZES OF RANKS 1 TO 3						INPUT DATA					
		Pool #1		Pool #2		Pool #3		Prospect Area (Acres)					
		Gas	Oil	Gas	Oil	Gas	Oil						
No.	Name	(BCF)	(MMB	(BCF)	(MMB)	(BCF)	(MMB)	F100	F95	F75	F50	F25	F05
1	Oligocene-Miocene	3708.1	93.653	1726.8	44.087	1110.7	28.148	241	1891	4957	9688	18932	49638

PLAY		INPUT DATA											
		Prospect Area (Acres)			Trap Fill (Dec. Frac.)								
No.	Name	F02	F01	F00	F100	F95	F75	F50	F25	F05	F02	F01	F00
1	Oligocene-Miocene		97681	135000	0.10	0.15	0.21	0.25	0.35	0.81		0.95	1.00

PLAY		INPUT DATA													
		Pool Area (Acres)									Pay Thickness (Feet)				
No.	Name	F100	F95	F75	F50	F25	F05	F02	F01	F00	F100	F95	F75	F50	F25
1	Oligocene-Miocene	76	479	1282	2748	6729	20785		36948	73652	20	66	115	150	188

PLAY		INPUT DATA															
		Pay Thickness (Feet)				Oil Yield (Recov. B/Acre-Foot)								Gas Yield (MMCF/Ac.-Ft)			
No.	Name	F05	F02	F01	F00	F100	F95	F75	F50	F25	F05	F01	F00	F100	F95	F75	F50
1	Oligocene-Miocene	310		380	400	108	217	300	376	471	652		1305	0.327	0.577	0.751	0.902

NORTH ALEUTIAN BASIN

PLAY		INPUT DATA															
		Gas Yield (MMCF/Ac.-Ft)				Solution Gas Oil Ratio (CF/B)								Gas Cond. (B/MMCF)			
No.	Name	F25	F05	F01	F00	F100	F95	F75	F50	F25	F05	F01	F00	F100	F95	F75	F50
1	Oligocene-Miocene	1.080	1.410		2.490	375	440	480	500	520	575		620	10	17	22	25

PLAY		INPUT DATA											
		Gas Cond. (B/MMCF)				Number of Prospects in Play							
No.	Name	F25	F05	F01	F00	F99	F95	F75	F50	F25	F05	F01	F00
1	Oligocene-Miocene	28	35		50	31		41	54	67			80

PLAY		INPUT DATA						
		Probabilities for Oil, Gas, or Mixed Pools			Fraction of Net	Play	Prospect	
		Oil	Gas	Mixed	Pay to Oil	Chance	Chance	Play Type
No.	Name	(OPROB)	(GPROB)	(MXPROB)	(OFRAC)	Success	Success	E - F - C
1	Oligocene-Miocene	0.10	0.80	0.10	0.10	0.72	0.20	F

ST. GEORGE BASIN

Play				Log-N Params. PORE Ac/Ft		N (MPRO) No. Pools		Reserves		Undiscovered Potential	
No.	Area	UAI Code	Name	mu	sig. sq.	Mean	Max	Gas (BCF)	Oil (MMB)	Gas (BCF)	Oil (MMB)
1	St. George	UASG0101	St. George Graben	12.60	0.63	5.48	31	0	0	1007	59
2	St. George	UASG0201	South Platform	13.10	3.08	1.78	16	0	0	898	34
3	St. George	UASG0301	North Platform	13.05	1.79	1.86	15	0	0	676	25
4	St. George	UASG0401	Pribilof Basin	13.67	0.72	1.29	10	0	0	414	17

PLAY		MEAN POOL SIZES OF RANKS 1 TO 3						INPUT DATA Prospect Area (Acres)					
		Pool #1		Pool #2		Pool #3							
No.	Name	Gas (BCF)	Oil (MMB	Gas (BCF)	Oil (MMB)	Gas (BCF)	Oil (MMB)	F100	F95	F75	F50	F25	F05
1	St. George Graben	523	19.9	302	11.6	219	8.3	976	4113		12497		39916
2	South Platform	2292	86.5	557	21.5	248	9.5	66	1792		24450		333680
3	North Platform	796	30.1	278	10.7	153	5.8	118	2608		18271		127981
4	Pribilof Basin	497	19	252	9.7	174	6.6	2043	11871		35838		108189

PLAY		INPUT DATA Prospect Area (Acres)			Trap Fill (Dec. Frac.)								
No.	Name	F02	F01	F00	F100	F95	F75	F50	F25	F05	F02	F01	F00
1	St. George Graben			163650	0.06	0.12		0.20		0.33			0.71
2	South Platform			9007800	0.02	0.07		0.12		0.23			0.63
3	North Platform			2841696	0.06	0.12		0.20		0.33			0.71
4	Pribilof Basin			628665	0.06	0.12		0.20		0.33			0.71

ST. GEORGE BASIN

INPUT DATA

PLAY		Pool Area (Acres)									Pay Thickness (Feet)				
No.	Name	F100	F95	F75	F50	F25	F05	F02	F01	F00	F100	F95	F75	F50	F25
1	St. George Graben	101	666		2532		9762			43552	48	80		120	
2	South Platform	9	199		3227		53099			1668000	44	85		145	
3	North Platform	13	469		3860		33285			673851	48	80		120	
4	Pribilof Basin	250	1963		7192		27448			262039	48	80		120	

INPUT DATA

PLAY		Pay Thickness (Feet)				Oil Yield (Recov. B/Acre-Foot)								Gas Yield (MMCF/Ac.-Ft)			
No.	Name	F05	F02	F01	F00	F100	F95	F75	F50	F25	F05	F01	F00	F100	F95	F75	F50
1	St. George Graben	181			303	28	59		104		185		382	0.032	0.117		0.332
2	South Platform	246			477	38	80		143		256		532	0.038	0.120		0.303
3	North Platform	181			303	39	80		141		251		519	0.037	0.109		0.255
4	Pribilof Basin	181			303	31	65		116		205		424	0.049	0.115		0.229

INPUT DATA

PLAY		Gas Yield (MMCF/Ac.-Ft)				Solution Gas Oil Ratio (CF/B)								Gas Cond. (B/MMCF)			
No.	Name	F25	F05	F01	F00	F100	F95	F75	F50	F25	F05	F01	F00	F100	F95	F75	F50
1	St. George Graben		0.940		3.491	89	230		486		1028		2644	20	35		52
2	South Platform		0.763		2.444	64	163		344		725		1856	10	17		25
3	North Platform		0.600		1.760	67	160		321		644		1550	10	17		25
4	Pribilof Basin		0.456		1.084	112	176		253		363		572	20	35		52

ST. GEORGE BASIN

PLAY		INPUT DATA											
		Gas Cond. (B/MMCF)				Number of Prospects in Play							
No.	Name	F25	F05	F01	F00	F99	F95	F75	F50	F25	F05	F01	F00
1	St. George Graben		68		100	16	18		25		52		57
2	South Platform		35		50	10	11		17		28		30
3	North Platform		35		50	9	10		15		26		27
4	Pribilof Basin		68		100	4	5		7		11		12

PLAY		INPUT DATA						
		Probabilities for Oil, Gas, or Mixed Pools			Fraction of Net	Play	Prospect	
		Oil	Gas	Mixed	Pay to Oil	Chance	Chance	Play Type
No.	Name	(OPROB)	(GPROB)	(MXPROB)	(OFRAC)	Success	Success	E - F - C
1	St. George Graben	0.00	0.80	0.20	0.7	0.64	0.30	C
2	South Platform	0.00	0.95	0.05	0.7	0.28	0.20	C
3	North Platform	0.00	0.90	0.10	0.7	0.56	0.20	C
4	Pribilof Basin	0.00	0.80	0.20	0.7	0.56	0.30	C

NORTON BASIN

Play				Log-N Params. PORE Ac/Ft mu	Ac/Ft sig. sq.	N (MPRO) No. Pools Mean	Max	Reserves Gas (BCF)	Oil (MMB)	Undiscovered Potential Gas (BCF)	Oil (MMB)
No.	Area	UAI Code	Name								
1	Norton	UANO0101	Upper Tertiary Basin Fill	11.987	1.7811	3	23	0	0	745.14	13.67
2	Norton	UANO0201	Mid Tertiary East Subbasin Fill	12.101	1.6755	1	16	0	0	305.50	5.32
3	Norton	UANO0301	Mid Tertiary West Subbasin Fill	11.924	2.2642	6	32	0	0	1617.47	27.74
4	Norton	UANO0401	Lower Tertiary Subbasin Fill	11.813	1.5671	0	9	0	0	39.65	0.72
5	Norton		Basement	Not Quantified							

PLAY		MEAN POOL SIZES OF RANKS 1 TO 3 Pool #1 Gas (BCF)	Oil (MMB)	Pool #2 Gas (BCF)	Oil (MMB)	Pool #3 Gas (BCF)	Oil (MMB)	INPUT DATA Prospect Area (Acres) F100	F95	F75	F50	F25	F05
No.	Name												
1	Upper Tertiary Basin Fill	890.84	16.20	362.70	6.67	212.36	3.88	30	550	1800	4050	9300	31000
2	Mid Tertiary East Subbasin Fill	619.43	11.27	227.86	4.19	127.92	2.34	35	515	1600	3500	7950	24000
3	Mid Tertiary West Subbasin Fill	1681.00	30.58	675.48	12.42	404.59	7.39	40	290	1100	2700	6800	25000
4	Lower Tertiary Subbasin Fill	153.62	2.79	57.20	1.05	34.71	0.63	25	370	1250	2750	5000	19000
5	Basement	Not Quantified											

PLAY		INPUT DATA Prospect Area (Acres) F02	F01	F00	Trap Fill (Dec. Frac.) F100	F95	F75	F50	F25	F05	F02	F01	F00
No.	Name												
1	Upper Tertiary Basin Fill		72000	185000	0.1	0.2	0.26	0.32	0.39	0.51		0.62	1.00
2	Mid Tertiary East Subbasin Fill		5100	130000	0.1	0.2	0.26	0.32	0.39	0.51		0.62	1.00
3	Mid Tertiary West Subbasin Fill		65000	185000	0.1	0.2	0.26	0.32	0.39	0.51		0.62	1.00
4	Lower Tertiary Subbasin Fill		41000	130000	0.1	0.2	0.26	0.32	0.39	0.51		0.62	1.00
5	Basement	Not Quantified											

NORTON BASIN

PLAY		INPUT DATA													
		Pool Area (Acres)									Pay Thickness (Feet)				
No.	Name	F100	F95	F75	F50	F25	F05	F02	F01	F00	F100	F95	F75	F50	F25
1	Upper Tertiary Basin Fill	5	179	617	1460	3453	11915	20080		80270	20	58	85	110	143
2	Mid Tertiary East Subbasin Fill	10	149	509	1200	2827	9696	16300		62000	40	100	127	150	177
3	Mid Tertiary West Subbasin Fill	12	79	328	887	2395	10002	18265		72000	40	102	138	170	209
4	Lower Tertiary Subbasin Fill	10	123	397	900	2039	6610	10850		68122	50	90	121	150	185
5	Basement	Not Quantified													

PLAY		INPUT DATA															
		Pay Thickness (Feet)				Oil Yield (Recov. B/Acre-Foot)								Gas Yield (MMCF/Ac.-Ft)			
No.	Name	F05	F02	F01	F00	F100	F95	F75	F50	F25	F05	F01	F00	F100	F95	F75	F50
1	Upper Tertiary Basin Fill	209	245		380	na	na	na	na	na	na	na	na	0.182	0.337	0.449	0.549
2	Mid Tertiary East Subbasin Fill	226	250		350	na	na	na	na	na	na	na	na	0.203	0.362	0.475	0.573
3	Mid Tertiary West Subbasin Fill	282	320		490	na	na	na	na	na	na	na	na	0.193	0.349	0.459	0.556
4	Lower Tertiary Subbasin Fill	251	285		400	na	na	na	na	na	na	na	na	0.099	0.197	0.272	0.340
5	Basement	Not Quantified															

PLAY		INPUT DATA															
		Gas Yield (MMCF/Ac.-Ft)				Solution Gas Oil Ratio (CF/B)								Gas Cond. (B/MMCF)			
No.	Name	F25	F05	F01	F00	F100	F95	F75	F50	F25	F05	F01	F00	F100	F95	F75	F50
1	Upper Tertiary Basin Fill	0.669	0.892		1.650	na	na	na	na	na	na	na	na	7.5	13	16	18
2	Mid Tertiary East Subbasin Fill	0.691	0.905		1.610	na	na	na	na	na	na	na	na	7.5	13	16	18
3	Mid Tertiary West Subbasin Fill	0.674	0.687		1.590	na	na	na	na	na	na	na	na	7.5	13	16	18
4	Lower Tertiary Subbasin Fill	0.425	0.567		1.170	na	na	na	na	na	na	na	na	7.5	13	16	18
5	Basement	Not Quantified															

NORTON BASIN

PLAY		INPUT DATA											
		Gas Cond. (B/MMCF)				Number of Prospects in Play							
No.	Name	F25	F05	F01	F00	F99	F95	F75	F50	F25	F05	F01	F00
1	Upper Tertiary Basin Fill	20	25		33	52	54	60	63	68	80		82
2	Mid Tertiary East Subbasin Fill	20	25		33	25	27	34	36	40	53		55
3	Mid Tertiary West Subbasin Fill	20	25		33	96	99	109	113	116	118		136
4	Lower Tertiary Subbasin Fill	20	25		33	5	6	8	10	12	19		20
5	Basement	Not Quantified											

PLAY		INPUT DATA						
		Probabilities for Oil, Gas, or Mixed Pools			Fraction of Net	Play	Prospect	
		Oil	Gas	Mixed	Pay to Oil	Chance	Chance	Play Type
No.	Name	(OPROB)	(GPROB)	(MXPROB)	(OFRAC)	Success	Success	E - F - C
1	Upper Tertiary Basin Fill	0	1	0	0	0.40	0.12	C
2	Mid Tertiary East Subbasin Fill	0	1	0	0	0.30	0.10	C
3	Mid Tertiary West Subbasin Fill	0	1	0	0	0.42	0.12	C
4	Lower Tertiary Subbasin Fill	0	1	0	0	0.30	0.10	C
5	Basement	Not Quantified				0.09		C

ST. MATTHEW-HALL BASIN

				Log-N Params.							
				PORE		N (MPRO)		Reserves		Undiscovered Potential	
Play				Ac/Ft	Ac/Ft	No. Pools		Gas	Oil	Gas	Oil
No.	Area	UAI Code	Name	mu	sig. sq.	Mean	Max	(BCF)	(MMB)	(BCF)	(MMB)
1	St. Matthew-Hall	UASM0100	Rift Sequence Play	11.072	1.421	0.6	10	- -	- -	8	0.1
2	St. Matthew-Hall	UASM0200	Sag Sequence Play	10.505	4.458	1	15	- -	- -	147	1.5

		MEAN POOL SIZES OF RANKS 1 TO 3											
		Pool #1		Pool #2		Pool #3		INPUT DATA					
PLAY		Gas	Oil	Gas	Oil	Gas	Oil	Prospect Area (Acres)					
No.	Name	(BCF)	(MMB	(BCF)	(MMB)	(BCF)	(MMB)	F100	F95	F75	F50	F25	F05
1	Rift Sequence Play	22	0.2	7	0.1	5	<0.1	100			4200		
2	Sag Sequence Play	375	4	59	0.6	22	0.2	10			4600		

		INPUT DATA											
PLAY		Prospect Area (Acres)			Trap Fill (Dec. Frac.)								
No.	Name	F02	F01	F00	F100	F95	F75	F50	F25	F05	F02	F01	F00
1	Rift Sequence Play	35400		50000	0.04			0.20			0.49		1.00
2	Sag Sequence Play	330000		450000	0.04			0.09			0.14		0.20

		INPUT DATA													
PLAY		Pool Area (Acres)									Pay Thickness (Feet)				
No.	Name	F100	F95	F75	F50	F25	F05	F02	F01	F00	F100	F95	F75	F50	F25
1	Rift Sequence Play	20			920			8000		46000	10			70	
2	Sag Sequence Play	30			460			28300		52300	10			80	

ST. MATTHEW-HALL BASIN

PLAY		INPUT DATA															
		Pay Thickness (Feet)				Oil Yield (Recov. B/Acre-Foot)								Gas Yield (MMCF/Ac.-Ft)			
No.	Name	F05	F02	F01	F00	F100	F95	F75	F50	F25	F05	F01	F00	F100	F95	F75	F50
1	Rift Sequence Play		220		300	--	--	--	--	--	--	--	--	0.006	0.024	0.046	0.072
2	Sag Sequence Play		300		400	--	--	--	--	--	--	--	--	0.060	0.148	0.226	0.304

PLAY		INPUT DATA															
		Gas Yield (MMCF/Ac.-Ft)				Solution Gas Oil Ratio (CF/B)								Gas Cond. (B/MMCF)			
No.	Name	F25	F05	F01	F00	F100	F95	F75	F50	F25	F05	F01	F00	F100	F95	F75	F50
1	Rift Sequence Play	0.114	0.218	0.345	0.877	--	--	--	--	--	--	--	--	10	10	10	10
2	Sag Sequence Play	0.407	0.622	0.836	1.534	--	--	--	--	--	--	--	--	10	10	10	10

PLAY		INPUT DATA											
		Gas Cond. (B/MMCF)				Number of Prospects in Play							
No.	Name	F25	F05	F01	F00	F99	F95	F75	F50	F25	F05	F01	F00
1	Rift Sequence Play	10	10	10	10	32	33	36	37	39	42	43	50
2	Sag Sequence Play	10	10	10	10	70	72	77	80	82	89	91	100

PLAY		INPUT DATA						
		Probabilities for Oil, Gas, or Mixed Pools			Fraction of Net	Play	Prospect	
		Oil	Gas	Mixed	Pay to Oil	Chance	Chance	Play Type
No.	Name	(OPROB)	(GPROB)	(MXPROB)	(OFRAC)	Success	Success	E - F - C
1	Rift Sequence Play	0.00	1.00	0.00	0.00	0.30	0.05	C
2	Sag Sequence Play	0.00	1.00	0.00	0.00	0.30	0.05	C

APPENDIX A

PACIFIC MARGIN SUBREGION INPUT DATA

COOK INLET
GULF OF ALASKA SHELF
SHUMAGIN-KODIAK SHELF

COOK INLET

Play				Log-N Params. PORE Ac/Ft		N (MPRO) No. Pools		Reserves		Undiscovered Potential	
No.	Area	UAI Code	Name	mu	sig. sq.	Mean	Max	Gas (BCF)	Oil (MMB)	Gas (BCF)	Oil (MMB)
1	Cook Inlet	UACI0101	TERTIARY STRATIGRAPHIC	12.203	0.8270	3.26	22	0	0	294	276
2	Cook Inlet	UACI0201	MESOZOIC STRATIGRAPHIC	12.165	0.9407	3.35	24	0	0	240	195
3	Cook Inlet	UACI0301	MESOZOIC STRUCTURAL	12.113	1.0394	5.31	21	0	0	364	266

PLAY		MEAN POOL SIZES OF RANKS 1 TO 3: Pool #1		Pool #2		Pool #3		INPUT DATA: Prospect Area (Acres)					
No.	Name	Gas (BCF)	Oil (MMB)	Gas (BCF)	Oil (MMB)	Gas (BCF)	Oil (MMB)	F100	F95	F75	F50	F25	F05
1	TERTIARY STRATIGRAPHIC	184.5	173.63	97.79	92.051	69.269	65.629	400	1727		4700		12788
2	MESOZOIC STRATIGRAPHIC	154	124.55	79.916	64.709	56.782	46.221	313	1385		4500		14623
3	MESOZOIC STRUCTURAL	163.28	122.81	78.974	59.46	51.402	38.927	134	1069		5549		22647

PLAY		INPUT DATA: Prospect Area (Acres)			Trap Fill (Dec. Frac.)								
No.	Name	F02	F01	F00	F100	F95	F75	F50	F25	F05	F02	F01	F00
1	TERTIARY STRATIGRAPHIC			20000	0.2	0.24		0.4		0.75			1.00
2	MESOZOIC STRATIGRAPHIC			24000	0.2	0.24		0.4		0.75			1.00
3	MESOZOIC STRUCTURAL			32007	0.2	0.24		0.4		0.75			1.00

PLAY		INPUT DATA: Pool Area (Acres)									Pay Thickness (Feet)				
No.	Name	F100	F95	F75	F50	F25	F05	F02	F01	F00	F100	F95	F75	F50	F25
1	TERTIARY STRATIGRAPHIC	105	542		1994		7342			37984	19	48		100	
2	MESOZOIC STRATIGRAPHIC	81	474		1920		7785			45485	18	47		100	
3	MESOZOIC STRUCTURAL	85	552		2430		10692			69255	13	34		75	

COOK INLET

INPUT DATA

PLAY		Pay Thickness (Feet)				Oil Yield (Recov. B/Acre-Foot)								Gas Yield (MMCF/Ac.-Ft)			
No.	Name	F05	F02	F01	F00	F100	F95	F75	F50	F25	F05	F01	F00	F100	F95	F75	F50
1	TERTIARY STRATIGRAPHIC	208			526	154	235		328		459		700	0.236	0.389		0.576
2	MESOZOIC STRATIGRAPHIC	215			564	131	176		222		281		377	0.287	0.416		0.559
3	MESOZOIC STRUCTURAL	165			443	106	147		191		247		343	0.287	0.416		0.559

INPUT DATA

PLAY		Gas Yield (MMCF/Ac.-Ft)				Solution Gas Oil Ratio (CF/B)								Gas Cond. (B/MMCF)			
No.	Name	F25	F05	F01	F00	F100	F95	F75	F50	F25	F05	F01	F00	F100	F95	F75	F50
1	TERTIARY STRATIGRAPHIC		0.855		1.405	450	520	550	675	698	730		800	20	35	42	52
2	MESOZOIC STRATIGRAPHIC		0.750		1.088	450	520	550	675	698	730		800	20	35	42	52
3	MESOZOIC STRUCTURAL		0.751		1.090	450	520	550	675	698	730		800	20	35	42	52

INPUT DATA

PLAY		Gas Cond. (B/MMCF)				Number of Prospects in Play							
No.	Name	F25	F05	F01	F00	F99	F95	F75	F50	F25	F05	F01	F00
1	TERTIARY STRATIGRAPHIC	55	68		100	5	6		15		37		40
2	MESOZOIC STRATIGRAPHIC	55	68		100	5	6		15		46		50
3	MESOZOIC STRUCTURAL	55	68		100	18	19		25		48		50

INPUT DATA

PLAY		Probabilities for Oil, Gas, or Mixed Pools			Fraction of Net	Play	Prospect	
		Oil	Gas	Mixed	Pay to Oil	Chance	Chance	Play Type
No.	Name	(OPROB)	(GPROB)	(MXPROB)	(OFRAC)	Success	Success	E - F - C
1	TERTIARY STRATIGRAPHIC	0	0	100	0.7	0.75	0.25	C
2	MESOZOIC STRATIGRAPHIC	0	0	100	0.7	0.75	0.23	C
3	MESOZOIC STRUCTURAL	0	0	100	0.7	1	0.18	F

GULF OF ALASKA

				Log-N Params. PORE		N (MPRO)		Reserves		Undiscovered Potentia	
Play				Ac/Ft	Ac/Ft	No. Pools		Gas	Oil	Gas	Oil
No.	Area	UAI Code	Name	mu	sig. sq.	Mean	Max	(BCF)	(MMB)	(BCF)	(MMB)
1	Gulf of Alaska	UAGA0101	Middleton Fold and Thrust Belt	11.62	2.17	3.3	54	**	**	456	13
2	Gulf of Alaska	UAGA0201	Yakataga Fold and Thrust Belt	11.99	1.84	3.5	26	**	**	805	122
3	Gulf of Alaska	UAGA0401	Yakutat Shelf- Base of Yakataga Fm.	11.42	1.98	6.0	33	**	**	669	111
4	Gulf of Alaska	UAGA0501	Yakutat Shelf-Kulthieth Sands	12.09	2.05	7.3	34	**	**	1967	308
6	Gulf of Alaska	UAGA0701	Subducting Terrane	11.62	1.96	2.9	15	**	**	282	76

		MEAN POOL SIZES OF RANKS 1 TO 3						INPUT DATA					
		Pool #1		Pool #2		Pool #3		Prospect Area (Acres)					
PLAY		Gas	Oil	Gas	Oil	Gas	Oil						
No.	Name	(BCF)	(MMB	(BCF)	(MMB)	(BCF)	(MMB)	F100	F95	F75	F50	F25	F05
1	Middleton Fold and Thrust Belt	900	25	389	11	246	7	140	1270	3560	7290	14900	41700
2	Yakataga Fold and Thrust Belt	722	111	270	42	149	24	100	1100	2700	5250	10000	27000
3	Yakutat Shelf- Base of Yakataga Fm.	471	83	186	33	108	19	100	480	1350	2800	6700	16500
4	Yakutat Shelf-Kulthieth Sands	1210	179	486	70	264	40	100	980	2600	5000	9700	26000
6	Subducting Terrane	234	56	75	18	39	10	150	690	1900	3700	7500	20000

		INPUT DATA											
PLAY		Prospect Area (Acres)			Trap Fill (Dec. Frac.)								
No.	Name	F02	F01	F00	F100	F95	F75	F50	F25	F05	F02	F01	F00
1	Middleton Fold and Thrust Belt	64400	86000	130000	0.03	0.06	0.10	0.15	0.20	0.33	0.45	0.49	0.70
2	Yakataga Fold and Thrust Belt	39000	49800	100000	0.08	0.15	0.20	0.30	0.40	0.56	0.67	0.70	0.94
3	Yakutat Shelf- Base of Yakataga Fm.	24000	33000	100000	0.08	0.15	0.20	0.30	0.40	0.55	0.67	0.70	0.95
4	Yakutat Shelf-Kulthieth Sands	38000	49000	101000	0.08	0.15	0.20	0.30	0.40	0.55	0.67	0.70	0.95
6	Subducting Terrane	30000	39000	84000	0.08	0.15	0.20	0.30	0.40	0.55	0.67	0.70	0.95

GULF OF ALASKA

INPUT DATA

PLAY		Pool Area (Acres)									Pay Thickness (Feet)				
No.	Name	F100	F95	F75	F50	F25	F05	F02	F01	F00	F100	F95	F75	F50	F25
1	Middleton Fold and Thrust Belt	11	143	478	1110	2580	8640	14400	20200	115000	5	28	59	100	170
2	Yakataga Fold and Thrust Belt	26	260	763	1610	3410	10000	15700	21300	99900	5	28	59	100	170
3	Yakutat Shelf- Base of Yakataga Fm.	12	133	415	915	2020	6280	10100	13900	71200	5	28	59	100	170
4	Yakutat Shelf-Kulthieth Sands	24	238	703	1490	3160	9320	14700	19900	94100	4	27	65	120	220
6	Subducting Terrane	15	165	508	1110	2430	7470	12000	16500	82700	5	28	59	100	170

INPUT DATA

PLAY		Pay Thickness (Feet)				Oil Yield (Recov. B/Acre-Foot)								Gas Yield (MMCF/Ac.-Ft)			
No.	Name	F05	F02	F01	F00	F100	F95	F75	F50	F25	F05	F01	F00	F100	F95	F75	F50
1	Middleton Fold and Thrust Belt	363	500	619	1844	29	61	86	110	141	200	256	425	0.046	0.137	0.226	0.322
2	Yakataga Fold and Thrust Belt	363	500	619	1844	32	72	106	139	182	267	350	609	0.088	0.267	0.450	0.646
3	Yakutat Shelf- Base of Yakataga Fm.	363	500	619	1844	34	78	115	150	196	289	378	658	0.041	0.152	0.280	0.428
4	Yakutat Shelf-Kulthieth Sands	526	760	971	3395	47	97	137	174	221	312	397	650	0.070	0.222	0.382	0.557
6	Subducting Terrane	363	500	619	1844	32	72	106	139	182	267	350	609	0.053	0.165	0.280	0.406

INPUT DATA

PLAY		Gas Yield (MMCF/Ac.-Ft)				Solution Gas Oil Ratio (CF/B)								Gas Cond. (B/MMCF)			
No.	Name	F25	F05	F01	F00	F100	F95	F75	F50	F25	F05	F01	F00	F100	F95	F75	F50
1	Middleton Fold and Thrust Belt	0.457	0.757	1.080	2.230	380	600	810	1010	1290	1770	2250	2760	11	19	24	28
2	Yakataga Fold and Thrust Belt	0.929	1.560	2.260	4.770	470	720	960	1190	1460	1850	2300	2850	20	35	42	52
3	Yakutat Shelf- Base of Yakataga Fm.	0.653	1.200	1.840	4.410	370	600	810	1020	1320	1900	2300	2900	20	35	42	52
4	Yakutat Shelf-Kulthieth Sands	0.812	1.400	2.040	4.460	300	520	730	960	1250	1800	2250	3000	20	35	42	52
6	Subducting Terrane	0.586	0.995	1.440	3.080	300	520	730	960	1250	1800	2250	3000	20	35	42	52

GULF OF ALASKA

		INPUT DATA											
PLAY		Gas Cond. (B/MMCF)				Number of Prospects in Play							
No.	Name	F25	F05	F01	F00	F99	F95	F75	F50	F25	F05	F01	F00
1	Middleton Fold and Thrust Belt	31	38	44	55	22	26	32	37	43	52	81	88
2	Yakataga Fold and Thrust Belt	55	68	75	100	9	11	16	19	23	30	36	54
3	Yakutat Shelf- Base of Yakataga Fm.	55	68	75	100	16	20	24	29	33	41	46	67
4	Yakutat Shelf-Kulthieth Sands	55	68	75	100	19	22	28	32	38	46	54	79
6	Subducting Terrane	55	68	75	100	7	8	10	12	14	17	20	28

		INPUT DATA						
		Probabilities for Oil, Gas, or Mixed Pools			Fraction of Net	Play	Prospect	
PLAY		Oil	Gas	Mixed	Pay to Oil	Chance	Chance	Play Type
No.	Name	(OPROB)	(GPROB)	(MXPROB)	(OFRAC)	Success	Success	E - F - C
1	Middleton Fold and Thrust Belt	0	0.9	0.1	0.10	0.18	0.48	C
2	Yakataga Fold and Thrust Belt	0	0	1	0.40	0.60	0.29	C
3	Yakutat Shelf- Base of Yakataga Fm.	0	0	1	0.35	0.65	0.31	C
4	Yakutat Shelf-Kulthieth Sands	0	0	1	0.30	0.80	0.27	C
6	Subducting Terrane	0	0	1	0.45	0.90	0.25	C

SHUMAGIN-KODIAK SHELF

Play				Log-N Params. PORE		N (MPRO)		Reserves		Undiscovered Potential	
				Ac/Ft	Ac/Ft	No. Pools		Gas	Oil	Gas	Oil
No.	Area	UAI Code	Name	mu	sig. sq.	Mean	Max	(BCF)	(MMB)	(BCF)	(MMB)
1	Shumagin-Kodiak	UASH0100	Neogene Structural Play	12.178	2.143	11	71	- -	- -	2650	7

PLAY		MEAN POOL SIZES OF RANKS 1 TO 3						INPUT DATA					
		Pool #1		Pool #2		Pool #3		Prospect Area (Acres)					
		Gas	Oil	Gas	Oil	Gas	Oil						
No.	Name	(BCF	(MMB)	(BCF)	(MMB)	(BCF)	(MMB)	F100	F95	F75	F50	F25	F05
1	Neogene Structural Play	2007	52	845	23	600	16	309			7460		

PLAY		INPUT DATA											
		Prospect Area (Acres)			Trap Fill (Dec. Frac.)								
No.	Name	F02	F01	F00	F100	F95	F75	F50	F25	F05	F02	F01	F00
1	Neogene Structural Play	116200		180000	0.10			0.30			0.75		1.00

PLAY		INPUT DATA													
		Pool Area (Acres)									Pay Thickness (Feet)				
No.	Name	F100	F95	F75	F50	F25	F05	F02	F01	F00	F100	F95	F75	F50	F25
1	Neogene Structural Play	15			2110			32300		295000	9			90	

PLAY		INPUT DATA															
		Pay Thickness (Feet)				Oil Yield (Recov. B/Acre-Foot)								Gas Yield (MMCF/Ac.-Ft)			
No.	Name	F05	F02	F01	F00	F100	F95	F75	F50	F25	F05	F01	F00	F100	F95	F75	F50
1	Neogene Structural Play		330		480	- -	- -	- -	- -	- -	- -	- -	- -	0.032	0.115	0.206	0.310

SHUMAGIN-KODIAK SHELF

PLAY		INPUT DATA															
		Gas Yield (MMCF/Ac.-Ft)				Solution Gas Oil Ratio (CF/B)								Gas Cond. (B/MMCF)			
No.	Name	F25	F05	F01	F00	F100	F95	F75	F50	F25	F05	F01	F00	F100	F95	F75	F50
1	Neogene Structural Play	0.467	0.839	1.266	2.936	- -	- -	- -	- -	- -	- -	- -	- -	6	13	19	24

PLAY		INPUT DATA											
		Gas Cond. (B/MMCF)				Number of Prospects in Play							
No.	Name	F25	F05	F01	F00	F99	F95	F75	F50	F25	F05	F01	F00
1	Neogene Structural Play	31	46	60	110	65	71	100	130	190	230	238	240

PLAY		INPUT DATA						
		Probabilities for Oil, Gas, or Mixed Pools			Fraction of Net	Play	Prospect	
		Oil	Gas	Mixed	Pay to Oil	Chance	Chance	Play Type
No.	Name	(OPROB)	(GPROB)	(MXPROB)	(OFRAC)	Success	Success	E - F - C
1	Neogene Structural Play	0.00	1.00	0.00	0.00	0.40	0.20	C

APPENDIX B: SUMMARIES OF ASSESSMENT RESULTS FOR PLAYS

Appendix B Table of Contents

EXPLANATION OF PLAY SUMMARIES, APPENDIX B

Appendix B consists of page-size compilations of graphics that summarize the results of ***GRASP*** modeling of the undiscovered, conventionally recoverable oil and gas endowments of each of the 74 plays identified and assessed in the Alaska offshore. Each play summary features a plot for risked cumulative probability distributions for oil, gas, and BOE (gas in oil-equivalent barrels added to oil), a table of results, and a plot showing ranked sizes (oil and gas shown separately) of individual hypothetical pools. These three components of the play summaries are each described below.

RISKED CUMULATIVE PROBABILITY DISTRIBUTIONS FOR PLAYS

Each play summary provides, at page top, cumulative probability distributions for risked, undiscovered endowments of conventionally recoverable oil, gas, and BOE. Oil and BOE quantities are shown in billions of barrels (B bbl). Gas quantities are reported in trillions of cubic feet (Tcf). Resource quantities are plotted against "Cumulative frequency greater than %." A cumulative frequency value represents the probability that the play resource endowment will exceed the quantity associated with the frequency value along one of the curves (fig. B1). Cumulative frequency values along the curves decrease as resource quantities increase. Accordingly, the cumulative frequencies, or "probabilities for exceedance," of small resource quantities are high, and conversely, the probabilities for exceedance of large resource quantities are low.

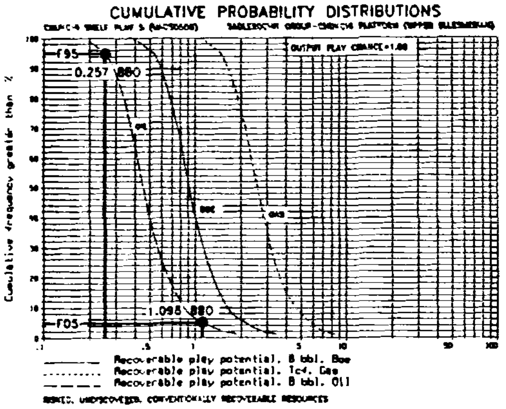
The cumulative probability distributions are risked and curves are truncated approximately at the output play chance. In most plays, the output play chance is equal to the input play chance for success. However, in plays with very small numbers of pools, the output play chance may be significantly **lower** than the input play chance for success.

The output play chance is derived from MPRO, a module within ***GRASP*** which uses inputs for geologic chance of success to convert probability distributions for numbers of ***prospects*** to probability distributions for numbers of ***pools***. The output play chance is obtained as a mathematic extrapolation to the probability at which the numbers of pools meets or exceeds zero. In plays with five or more pools at the mean, this probability usually equals the input play chance for success. In plays with less than five pools at the mean, the zero-pool probability (or output play chance) may be much less than the input play chance. Deviation between the output play chance and the input play chance is greatest in those plays with mean numbers of pools less than unity. Such highly risky plays contribute very little resources to overall province endowments.

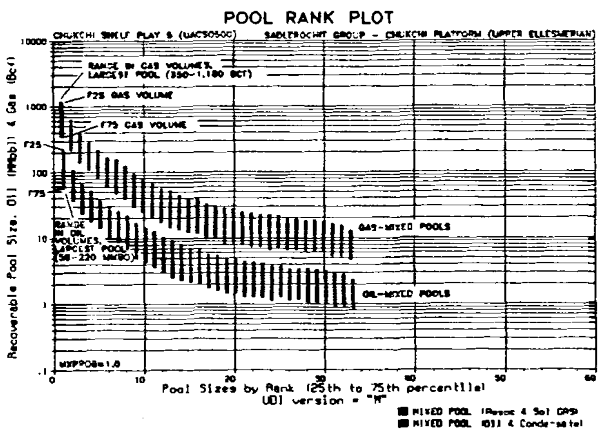
Identification numbers beginning with "UA" in the graphics labels are codes unique to each of the 74 plays in the ***GRASP*** data bases.

TABLE FOR RISKED PLAY RESOURCE ENDOWMENTS

Each play summary provides, at page center, a table for risked, undiscovered play endowments of oil, gas, and BOE. Quantities are reported at the **mean**, **F95** (a low estimate having a 95-percent frequency of exceedance), and **F05** (a high estimate having a 5-percent frequency of exceedance). Tabulated resource quantities are risked and therefore correspond to points on the cumulative probability distributions shown at page top. For plays with chances for success (play level) less than 0.95, the risked resource quantities reported at **F95** are zero.



CHUKCHI SHELF PLAY 5 (UAC50500)			
FRACTILES	F95	MEAN	F05
GAS (TCFG)	1.478	2.993	5.823
OIL (BBO)	0.257	0.537	1.098
BOE (BBO)	0.530	1.069	2.125



The upper graph and the table report the volumes of risked, undiscovered, conventionally recoverable resources for the play. The graph, called a ***cumulative probability distribution***, shows three curves (oil, BOE, and gas) and reports the output play chance at upper right. The output play chance for Chukchi shelf play 5 is 1.0, meaning that there is a 100-percent chance that at least one hydrocarbon pool exists somewhere within the play. To illustrate how to read the graphs, dots have been placed on the ***oil*** curve at cumulative frequency values (vertical axis) of 95 percent and 5 percent. The corresponding oil quantities are 0.257 and 1.098 billions of barrels of oil. Thus, for Chukchi shelf play 5, there is a 95-percent chance that at least 0.257 billion barrels of oil are present and a 5-percent chance that more than 1.098 billion barrels are present. These same oil quantities are listed at F95 and F05 in the table.

The lower graph provides information about pool volumes and is called a ***pool rank plot***. This graph shows two sets of vertical bars, representing the quantities of oil and gas occurring ***together*** in 33 pools, the maximum number estimated to occur within this play. All pools in play 5 are modeled as mixed, that is, containing oil with a gas cap; other plays may also have all-gas or all-oil pools and show six separate commodities. Each pair of gas-oil bars in the play 5 pool rank plot shows the volume of oil in the pool and the volume of gas in the cap. The vertical bars extend across a range of possible volumes for each pool. The lower end of each bar represents the F75 resource quantity, meaning that the pool, if it exists, has a 75 percent chance of exceeding the corresponding resource quantity. Likewise, the upper end of each bar represents the F25 resource quantity. In Chukchi play 5, the largest pool offers oil volumes in the range from about 58 (F75) to 220 (F25) million barrels and gas volumes in the range from 350 (F75) to 1,180 (F25) billion cubic feet.

Figure B1: Sample play summary, Chukchi shelf play 5.

RANKED POOL SIZE DISTRIBUTIONS FOR PLAYS

Each play summary provides, at page bottom, a plot showing pool sizes ranked according to size in BOE. The numbers of pools shown in the rank plots correspond to the maximum numbers of pools estimated to occur within the plays (tabulated under "N(MPRO)-Max" in Appendix A). Each pool in a pool rank plot is represented by a pair of adjoining vertical bars. The left bar of each pair represents the range (from **F75** to **F25** in the output probability distribution) of gas recoverable from the pool, and may include non-associated gas from an all-gas pool or associated gas from a gas cap and/or solution gas from oil, depending on pool type. The right bar of each pair represents the range (from **F75** to **F25**) of petroleum liquids recoverable from the same pool, and may include free oil, condensate from a gas cap, or condensate from a gas-only pool.

Volumes are shown in millions of barrels (MMbbl) of oil and billions of cubic feet (Bcf) of gas.

Extreme sizes outside the range between F75 and F25 volumes are not shown, but all pools offer (at low probabilities) high-side potential that may be several multiples of their median sizes (F50 or centers of vertical bars). For example, the largest pool in the pool rank plot in figure B1 shows F75-F25 ranges in oil volumes from 58 to 220 millions of barrels and gas volumes from 350 to 1,180 billions of cubic feet. But, these ranges do not capture the largest possible sizes of pool rank 1. This same pool has a 5-percent chance of containing over 600 million barrels of oil and 3,070 billion cubic feet of gas, or a 1-percent chance of containing over 1,140 million barrels of oil and 6,180 billion cubic feet of gas!

Although it might be interesting to portray the improbable yet extreme-high potential sizes of pools, choosing fractiles ranging up to F01 results in an uninformative plot where all pools nearly reach the top of the plot. For this presentation, a range based on F75-F25 values was chosen for visual clarity while still giving some impression of variance or spread.

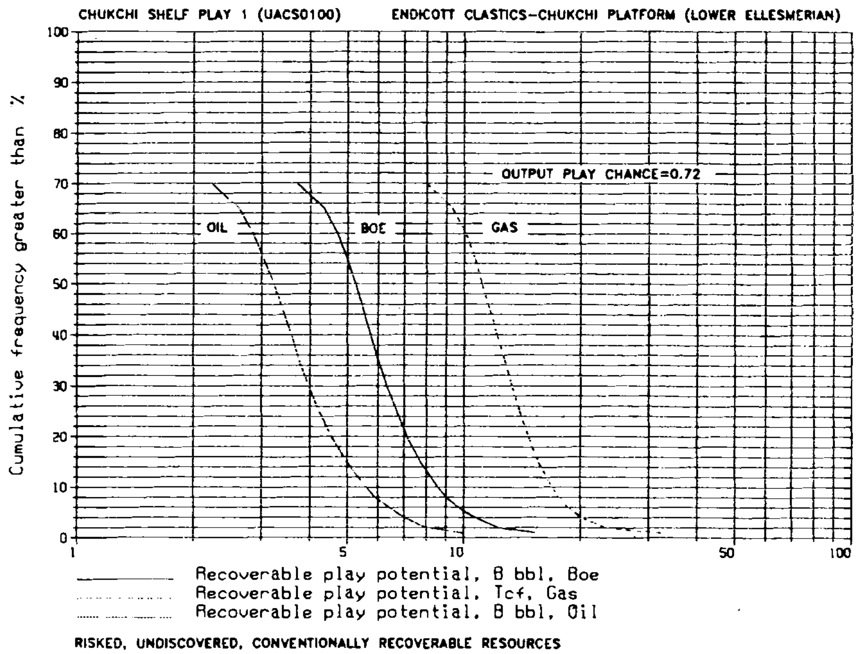
Pool volumes shown in the ranked plots are conditional upon success at the play level (i.e., a hydrocarbon pool existing ***somewhere*** within the play). The sizes of the pools posted in the rank plot have not been "risked", or multiplied against play chance of success. Therefore, except where the play chance of success equals 1.0, the sum of the mean sizes of the pools in the rank plot will exceed the risked mean play endowment that is reported in the table at page center. In fact, several of the largest pools, or even just the largest pool, may post conditional resources exceeding the risked play endowment. The mean sizes of the three largest pools in each play are listed under "Mean Pool Sizes of Ranks 1 to 3" in Appendix A.

Designation of pool types (oil-only, versus oil with gas cap, versus gas-only) within the play model was controlled by three data entries. Each play was assigned probabilities for (or frequencies of) occurrence of any of three pool types within the play— "OPROB" for oil-only pools, "GPROB" for gas-only pools, and "MXPROB" for mixed (oil and gas cap) pools. As the model recognizes only these three pool types, these three probability values always sum to 1.0. The three probability values control frequency of pool type sampling during ***GRASP*** runs, and, with a random number generator in ***GRASP***, ultimately dictate the sequence of pool types that appear in the play pool rank plots in Appendix B. The OPROB, GPROB, and/or MXPROB values that were used in the play models are posted, as appropriate, in the lower left corner of each pool rank plot.

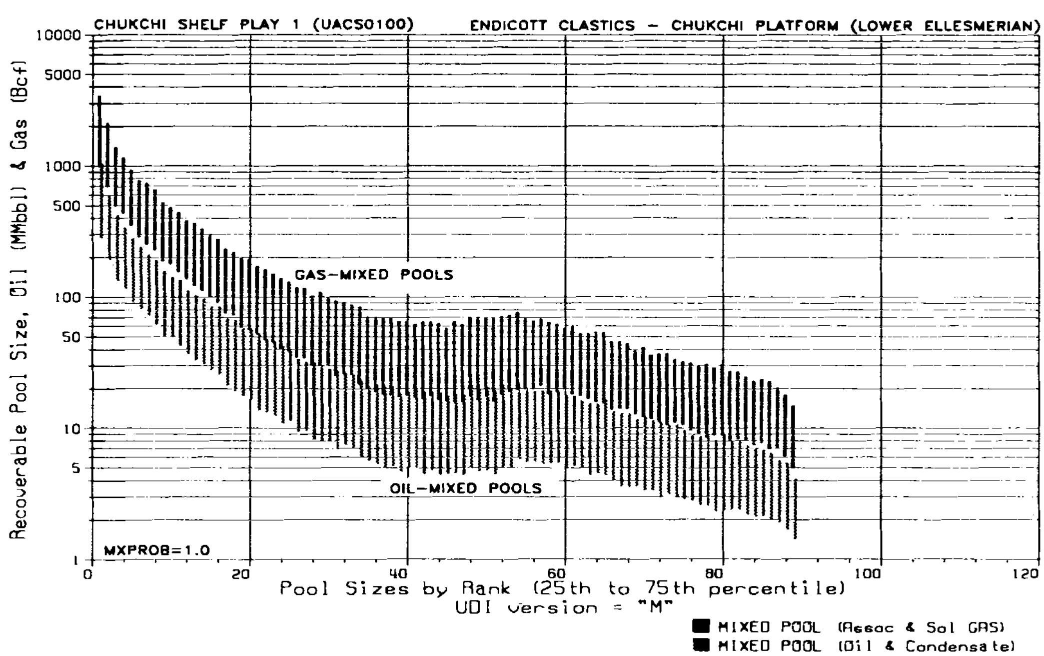
APPENDIX B

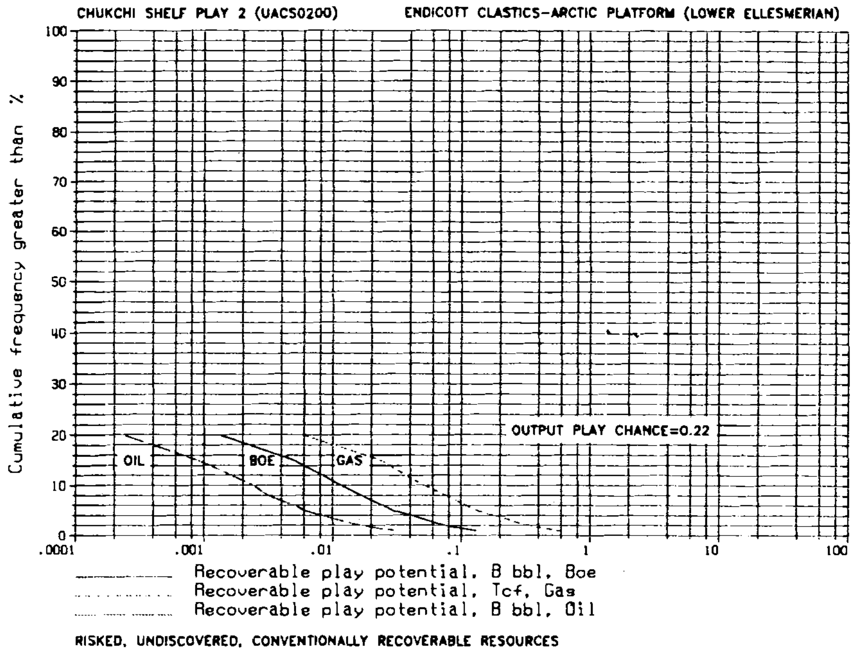
ARCTIC SUBREGION PLAY SUMMARIES

CHUKCHI SHELF
BEAUFORT SHELF
HOPE BASIN

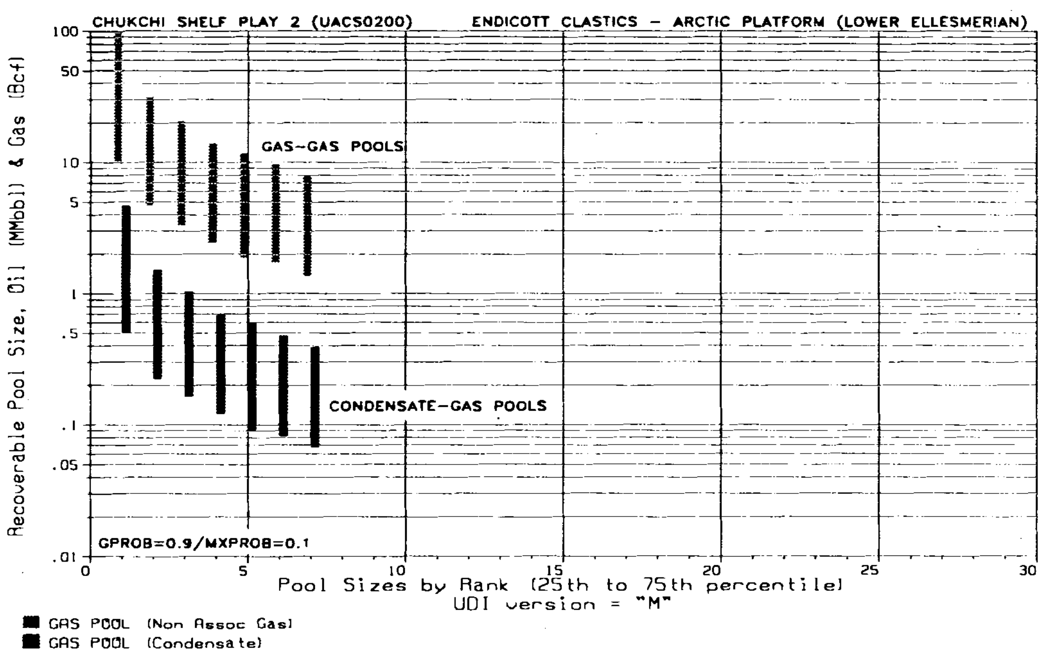


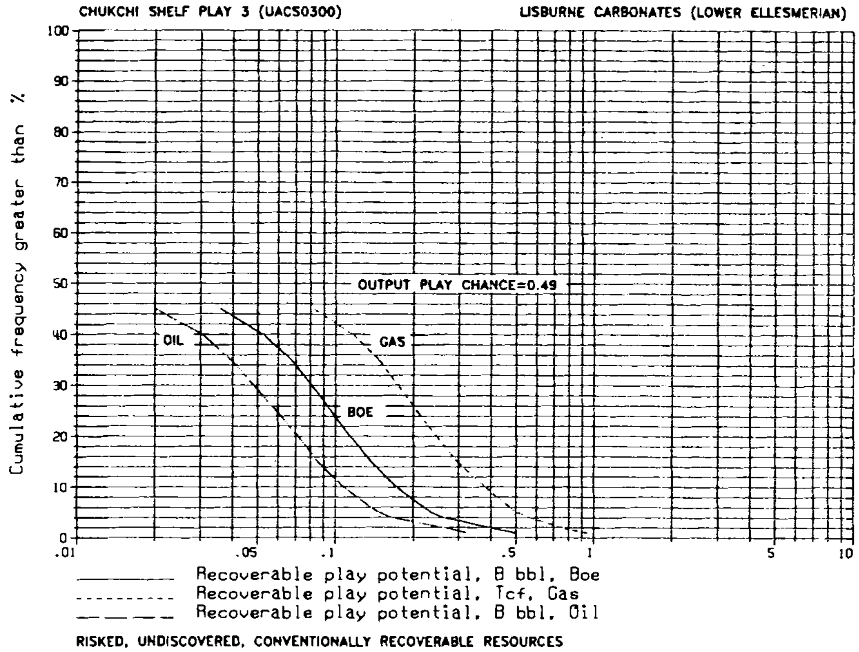
CHUKCHI SHELF PLAY 1 (UACS0100)			
FRACTILES	**F95**	**MEAN**	**F05**
GAS (TCFG)	**0.000**	**9.762**	**19.377**
OIL (BBO)	**0.000**	**3.001**	**6.696**
BOE (BBO)	**0.000**	**4.738**	**10.140**



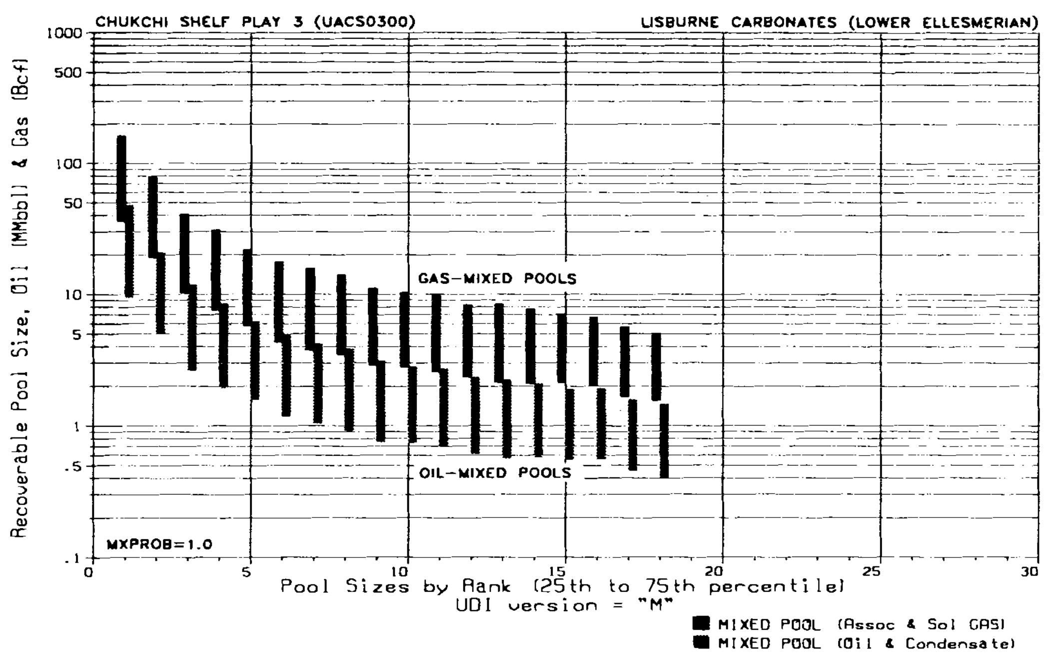


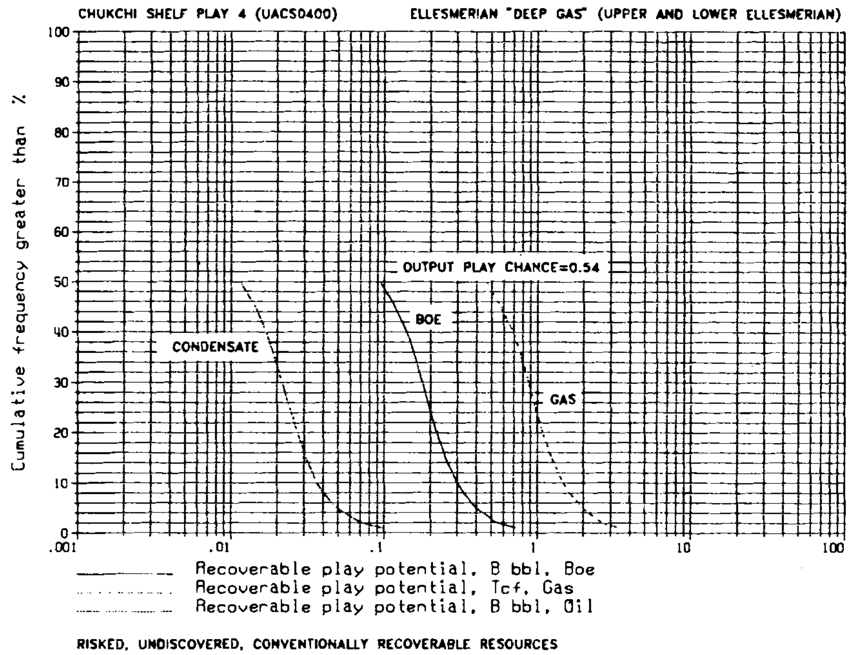
CHUKCHI SHELF PLAY 2 (UACS0200)			
FRACTILES	**F95**	**MEAN**	**F05**
GAS (TCFG)	**0.000**	**0.035**	**0.133**
OIL (BBO)	**0.000**	**0.002**	**0.006**
BOE (BBO)	**0.000**	**0.008**	**0.030**



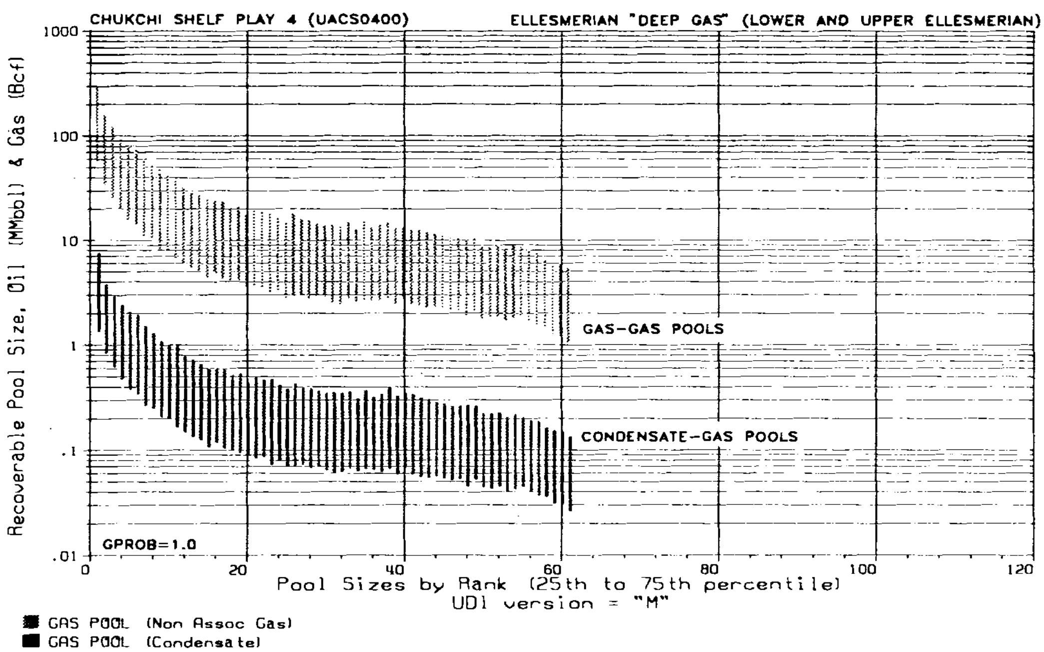


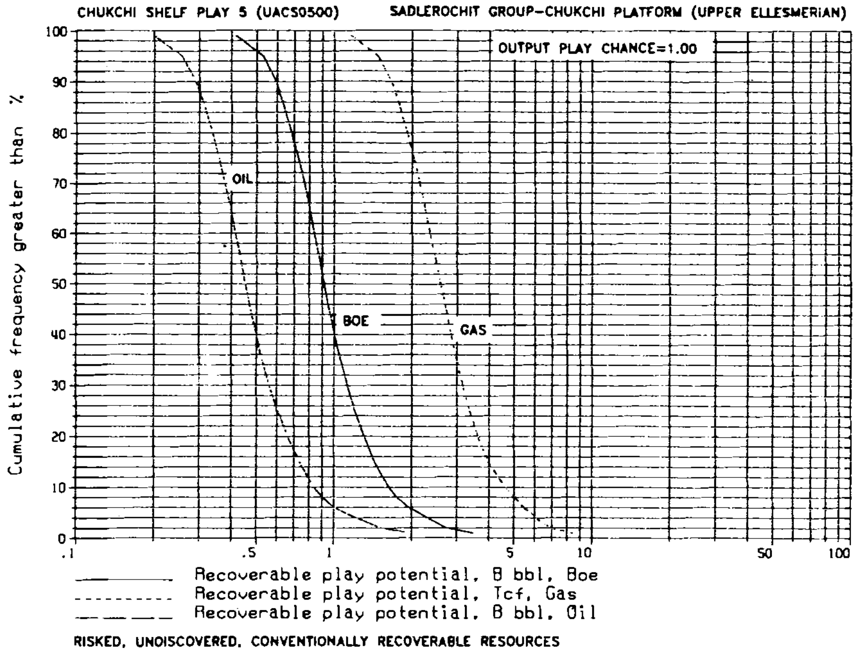
CHUKCHI SHELF PLAY 3 (UACS0300)			
FRACTILES	**F95**	**MEAN**	**F05**
GAS (TCFG)	**0.000**	**0.137**	**0.509**
OIL (BBO)	**0.000**	**0.041**	**0.149**
BOE (BBO)	**0.000**	**0.065**	**0.236**



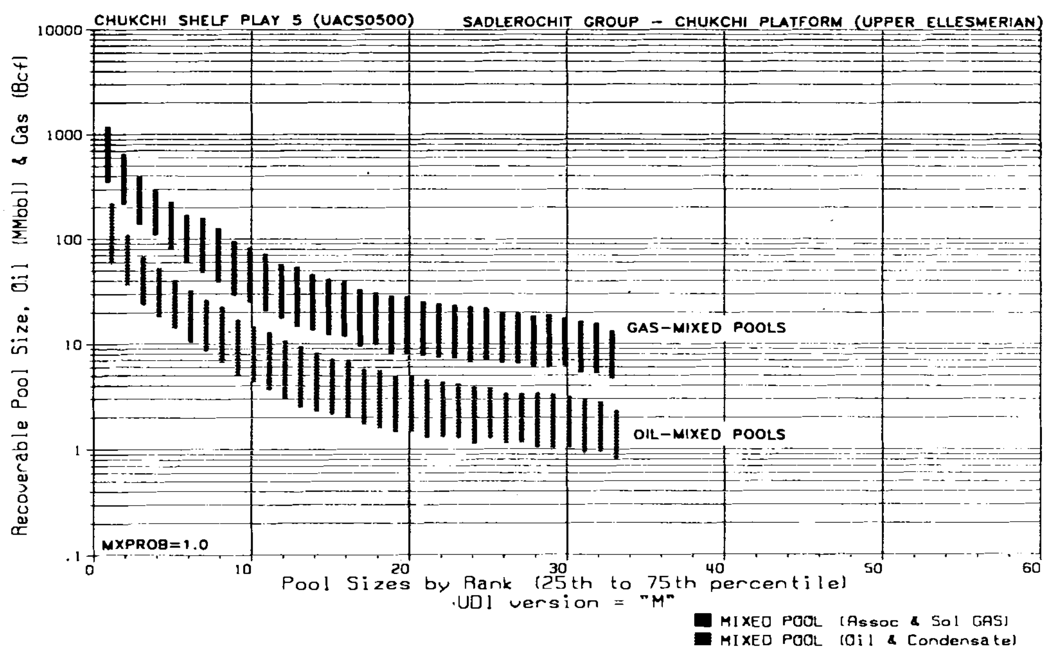


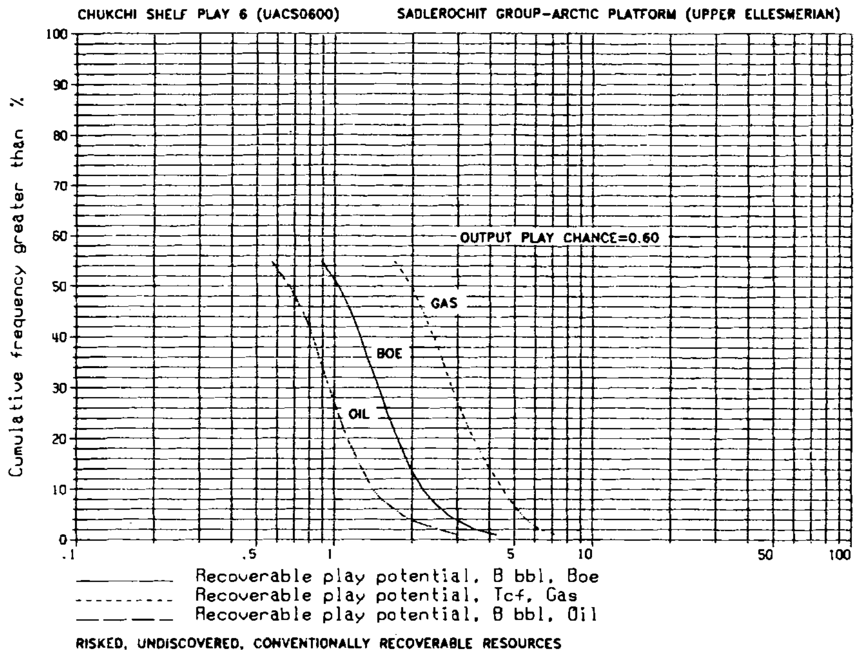
CHUKCHI SHELF PLAY 4 (UACS0400)			
FRACTILES	**F95**	**MEAN**	**F05**
GAS (TCFG)	**0.000**	**0.629**	**1.962**
OIL (BBO)	**0.000**	**0.016**	**0.049**
BOE (BBO)	**0.000**	**0.128**	**0.399**



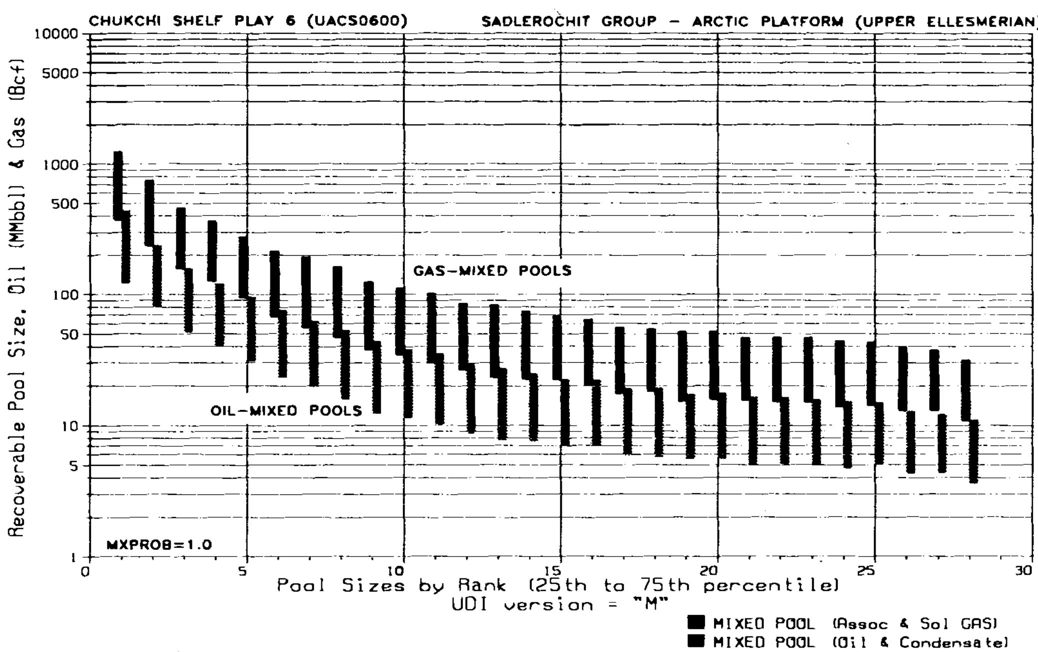


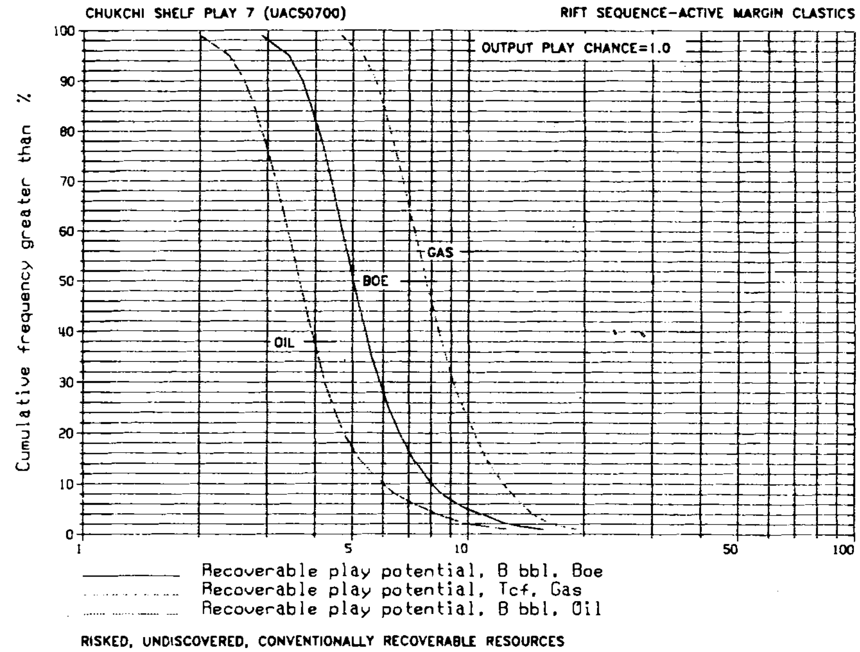
CHUKCHI SHELF PLAY 5 (UACS0500)			
FRACTILES	**F95**	**MEAN**	**F05**
GAS (TCFG)	**1.478**	**2.993**	**5.823**
OIL (BBO)	**0.257**	**0.537**	**1.098**
BOE (BBO)	**0.530**	**1.069**	**2.125**



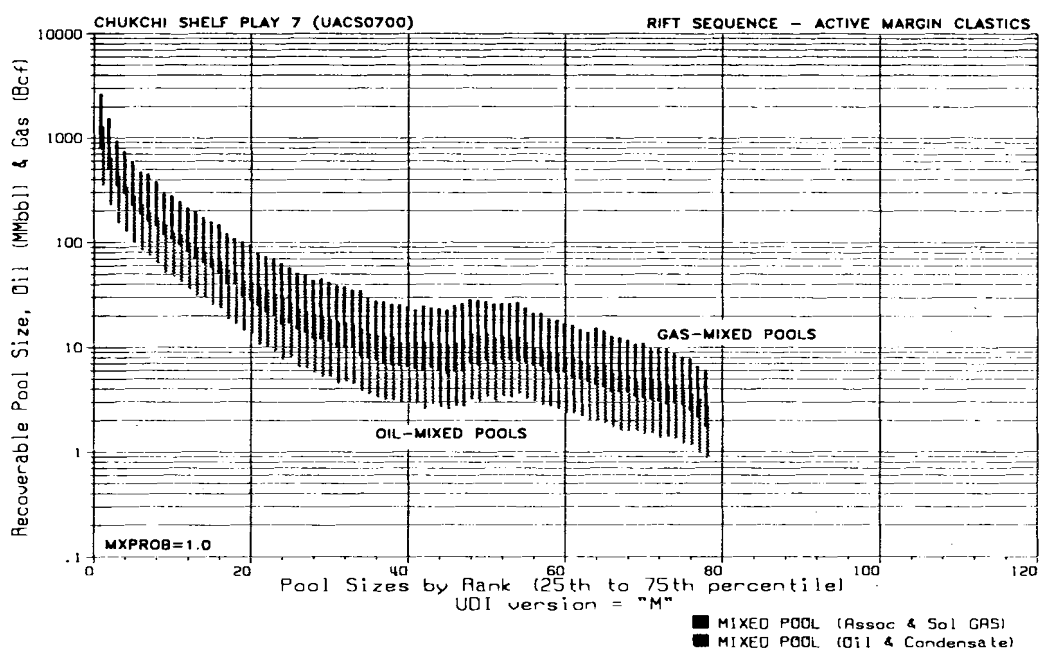


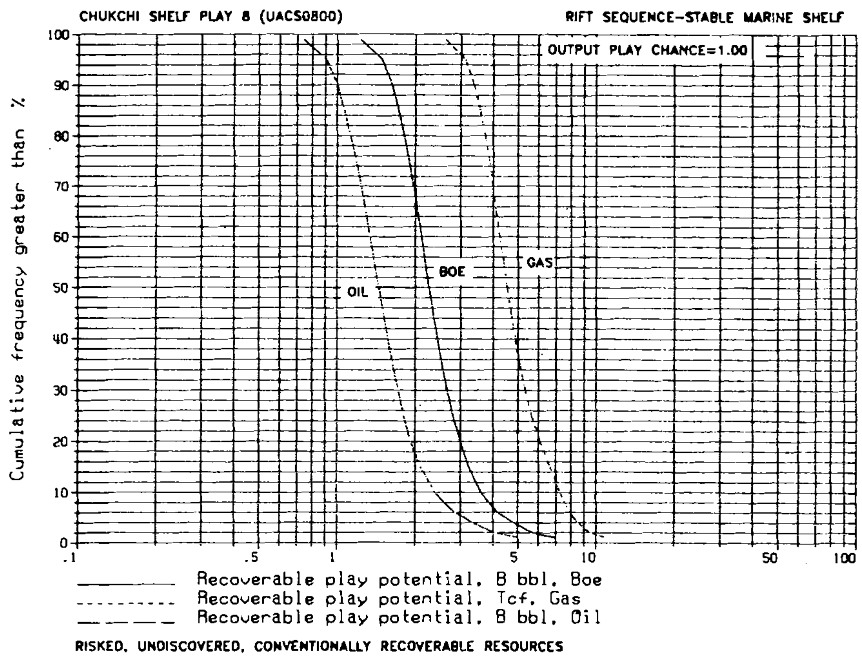
CHUKCHI SHELF PLAY 6 (UACS0600)			
FRACTILES	**F95**	**MEAN**	**F05**
GAS (TCFG)	**0.000**	**1.935**	**5.314**
OIL (BBO)	**0.000**	**0.660**	**1.818**
BOE (BBO)	**0.000**	**1.005**	**2.737**



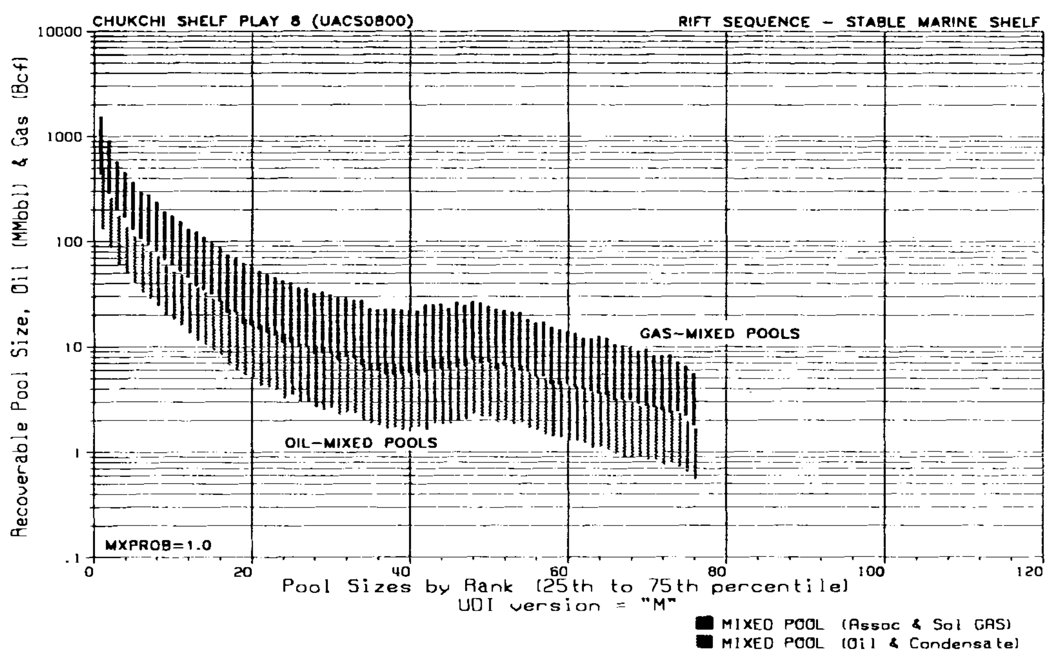


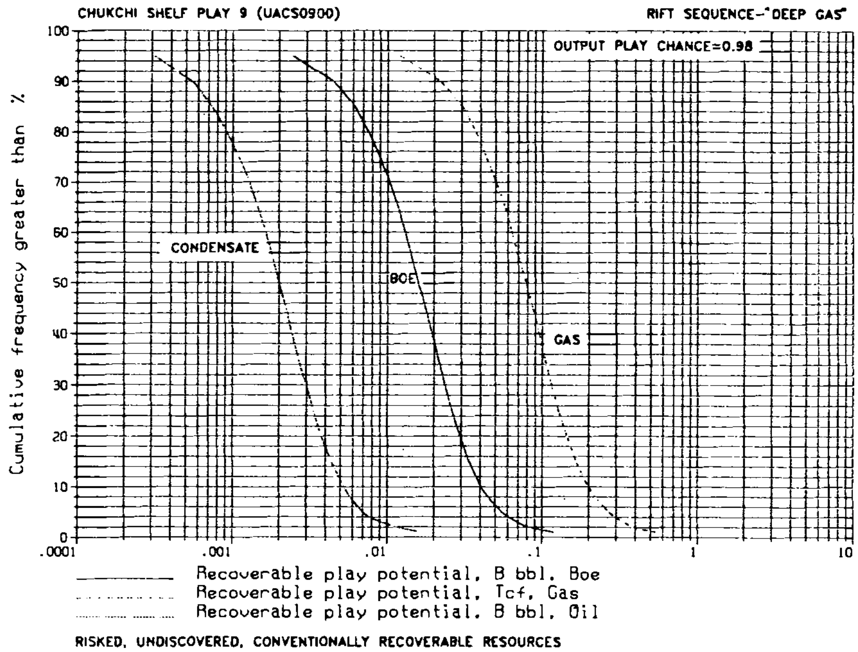
CHUKCHI SHELF PLAY 7 (UACS0700)			
FRACTILES	**F95**	**MEAN**	**F05**
GAS (TCFG)	**5.314**	**8.547**	**14.204**
OIL (BBO)	**2.385**	**4.136**	**7.770**
BOE (BBO)	**3.410**	**5.656**	**9.968**



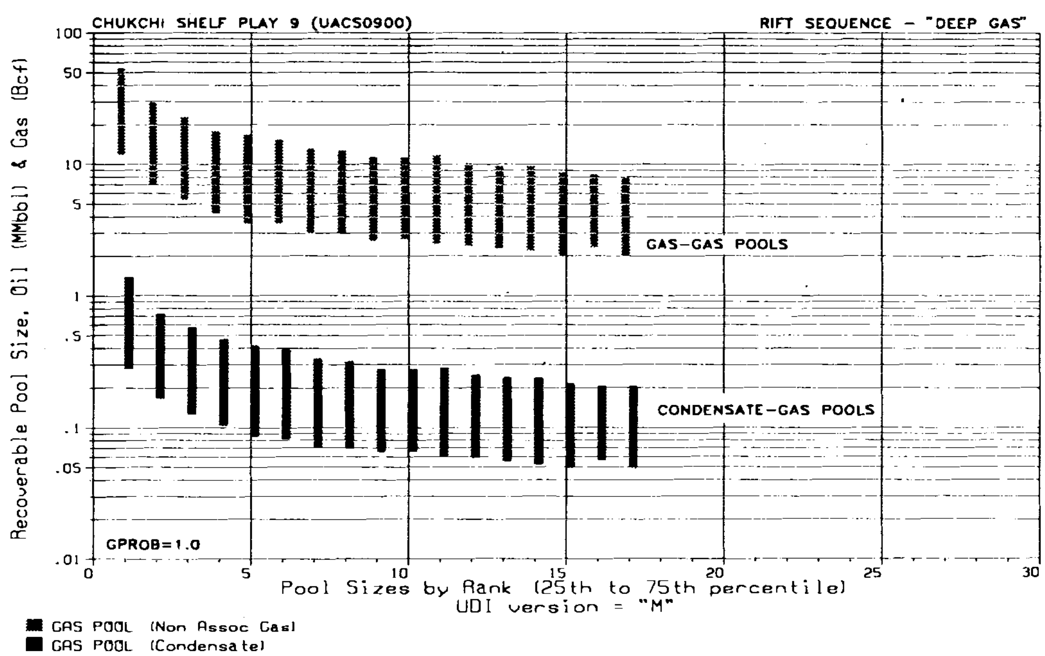


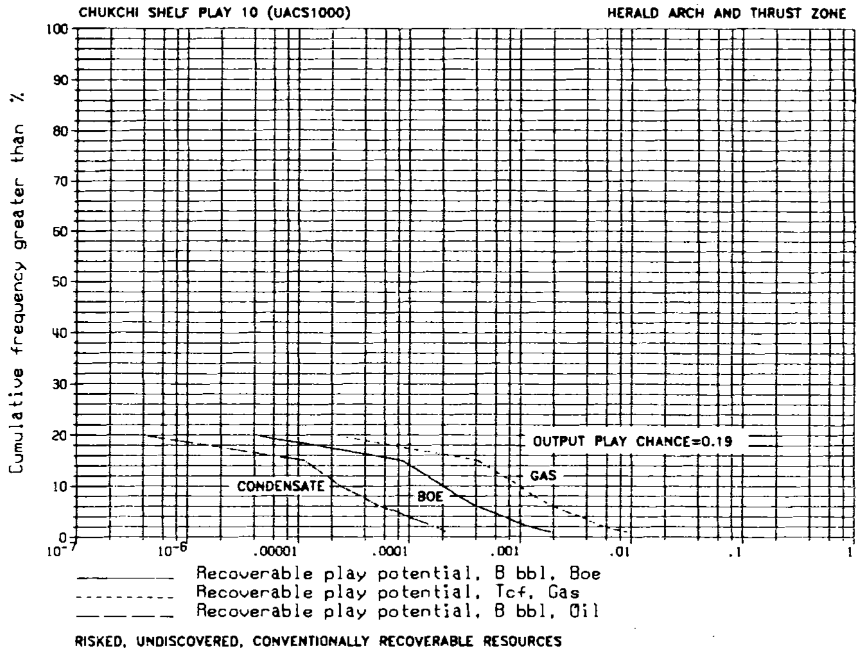
CHUKCHI SHELF PLAY 8 (UACS0800)			
FRACTILES	**F95**	**MEAN**	**F05**
GAS (TCFG)	**3.118**	**5.026**	**8.193**
OIL (BBO)	**0.910**	**1.645**	**3.121**
BOE (BBO)	**1.492**	**2.539**	**4.487**



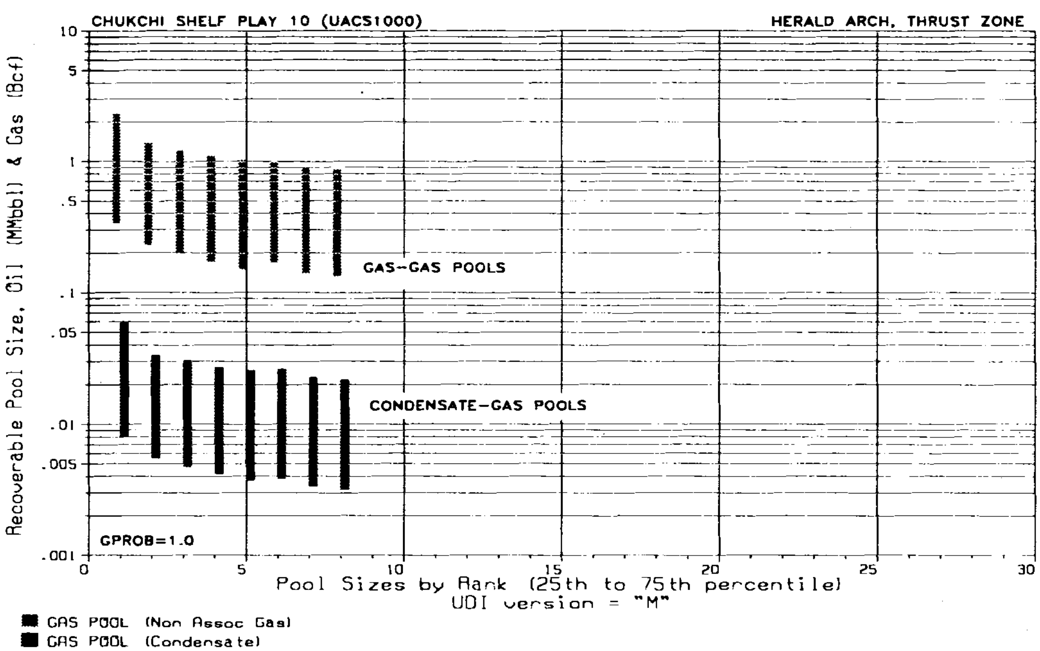


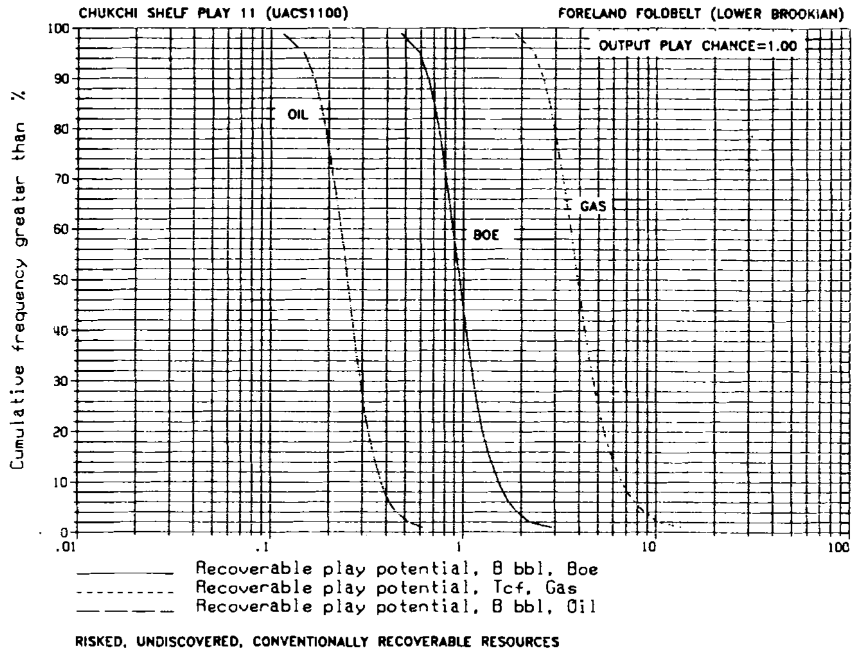
CHUKCHI SHELF PLAY 9 (UACS0900)			
FRACTILES	**F95**	**MEAN**	**F05**
GAS (TCFG)	**0.012**	**0.108**	**0.269**
OIL (BBO)	**0.0003**	**0.003**	**0.007**
BOE (BBO)	**0.002**	**0.022**	**0.055**



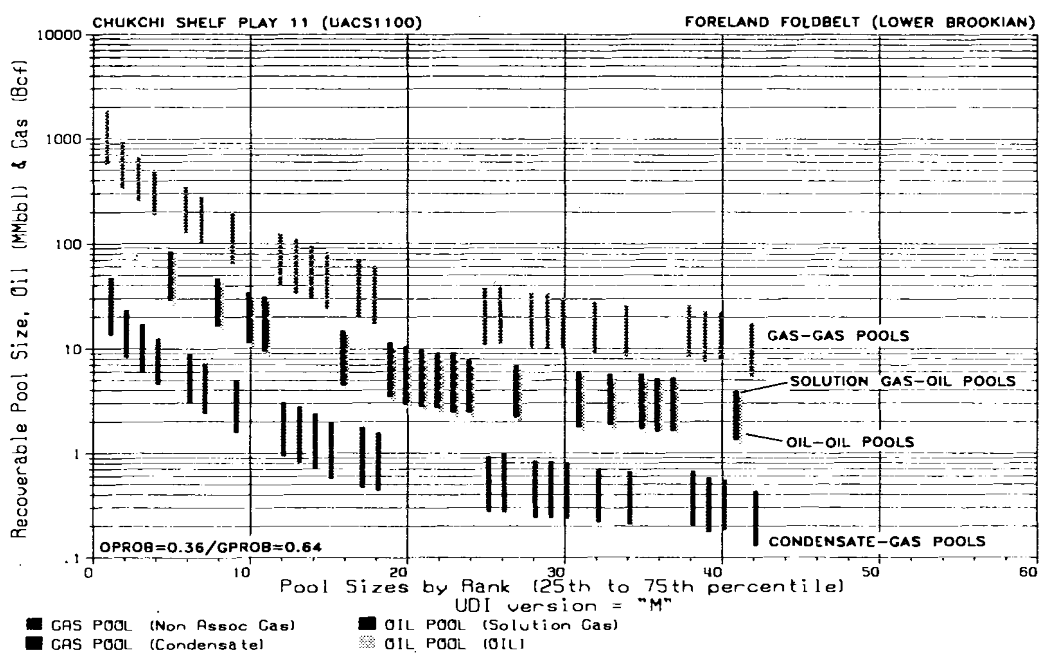


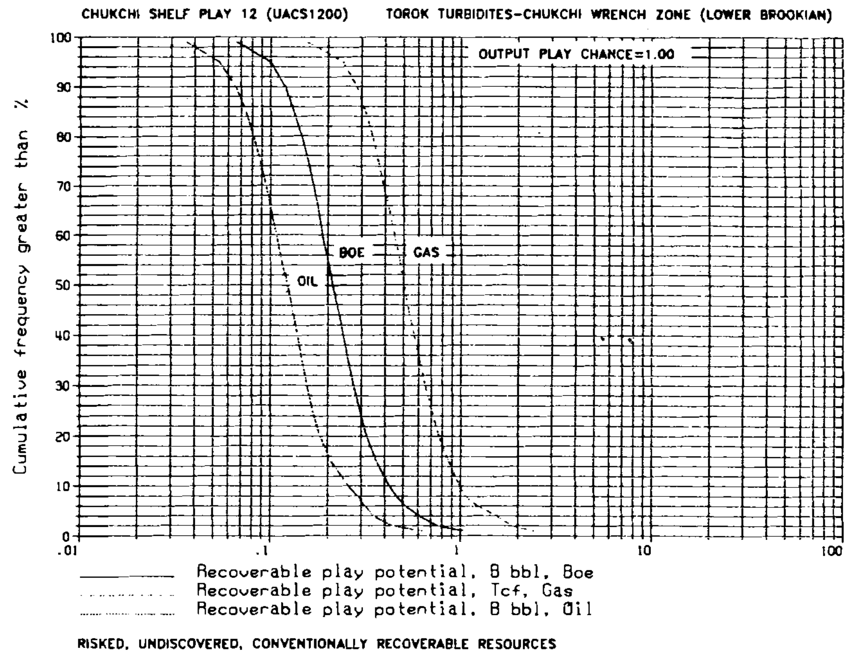
CHUKCHI SHELF PLAY 10 (UACS1000)			
FRACTILES	F95	MEAN	F05
GAS (TCFG)	0.000	0.0006	0.003
OIL (BBO)	0.000	0.00002	0.00008
BOE (BBO)	0.000	0.0001	0.0005



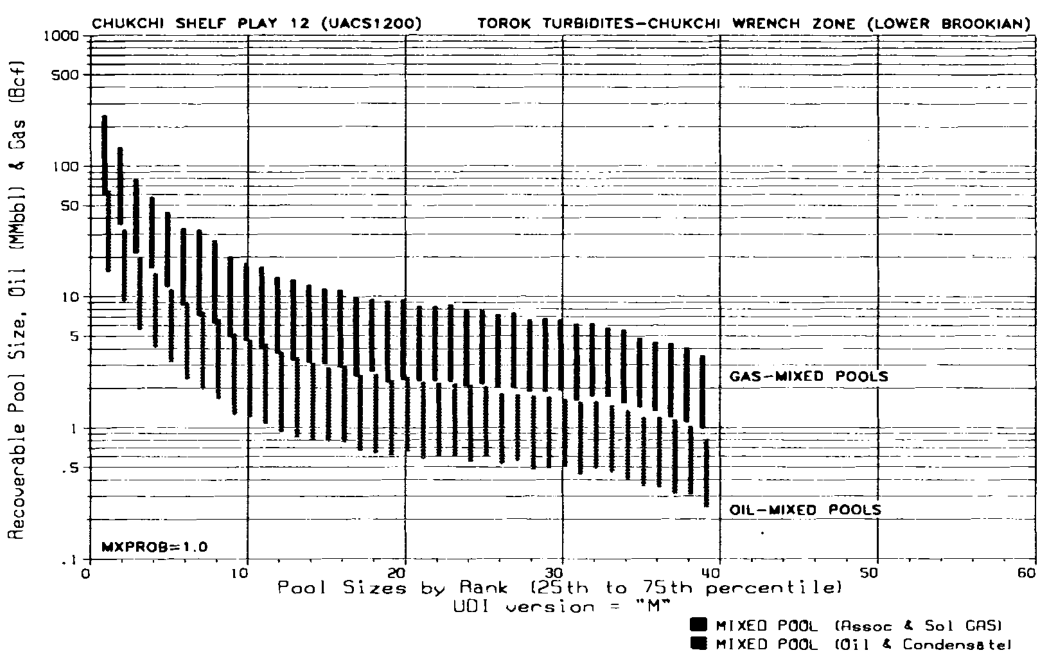


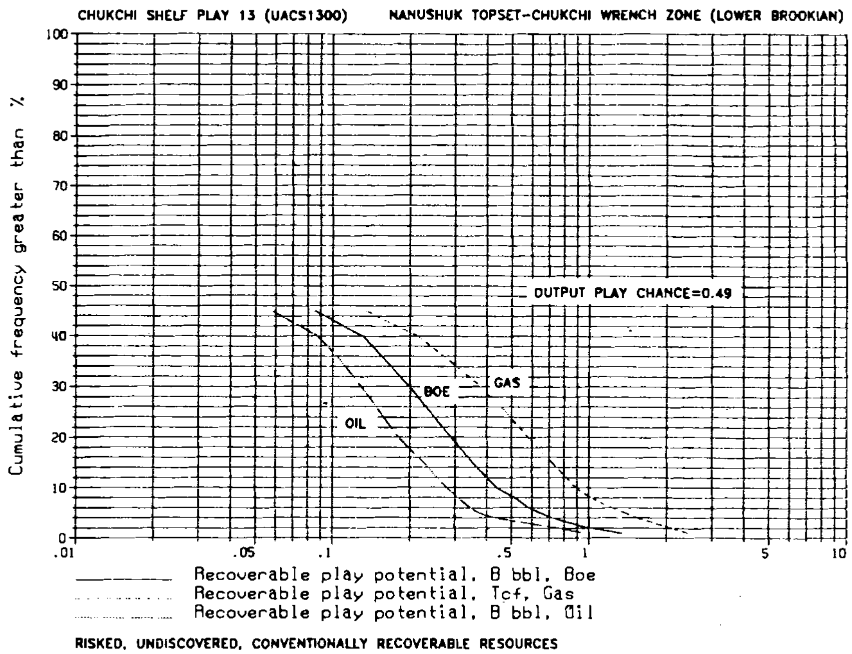
CHUKCHI SHELF PLAY 11 (UACS1100)			
FRACTILES	**F95**	**MEAN**	**F05**
GAS (TCFG)	**2.328**	**4.491**	**8.225**
OIL (BBO)	**0.149**	**0.265**	**0.430**
BOE (BBO)	**0.590**	**1.065**	**1.821**



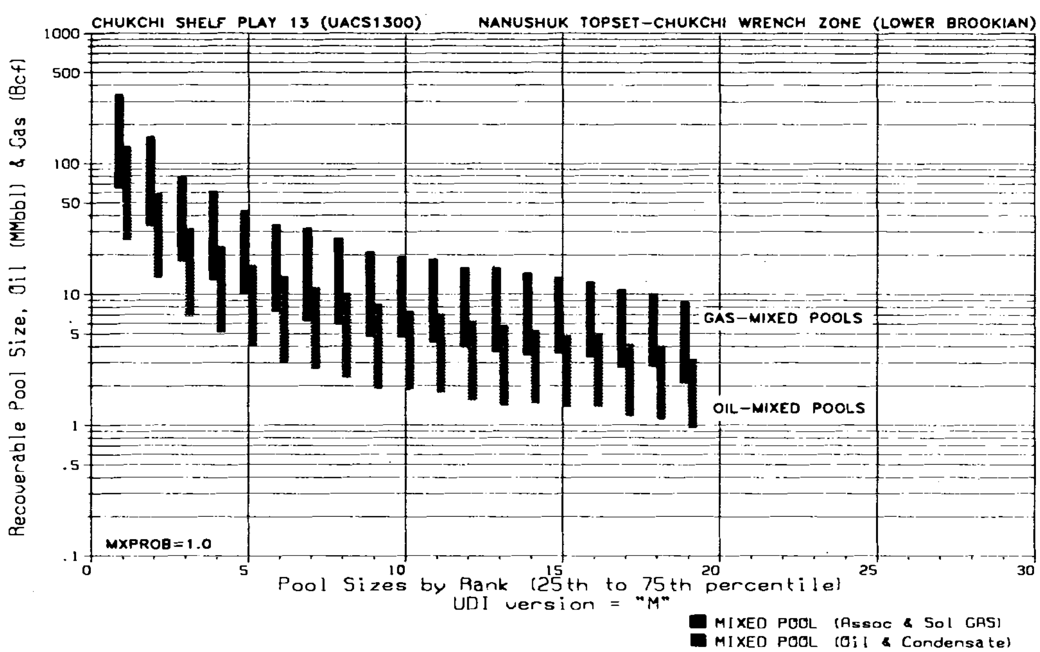


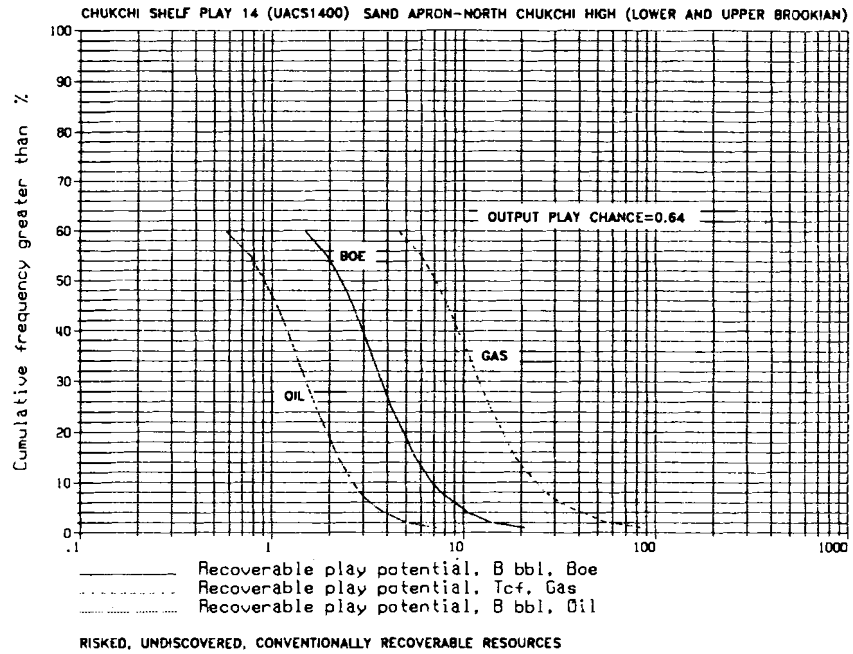
CHUKCHI SHELF PLAY 12 (UACS1200)			
FRACTILES	**F95**	**MEAN**	**F05**
GAS (TCFG)	**0.240**	**0.635**	**1.384**
OIL (BBO)	**0.054**	**0.147**	**0.331**
BOE (BBO)	**0.100**	**0.261**	**0.556**



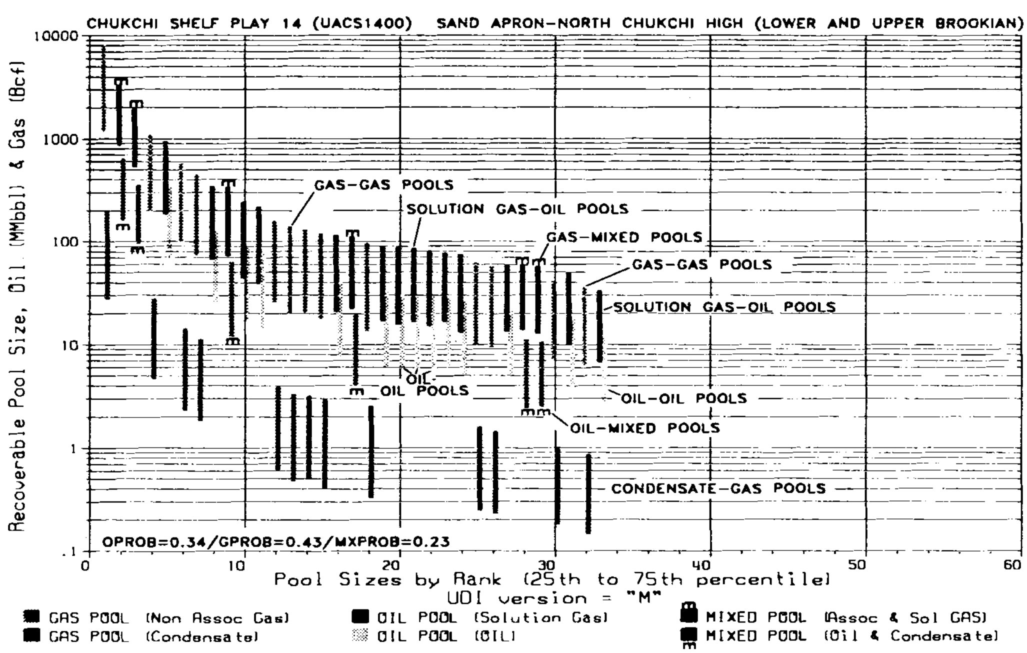


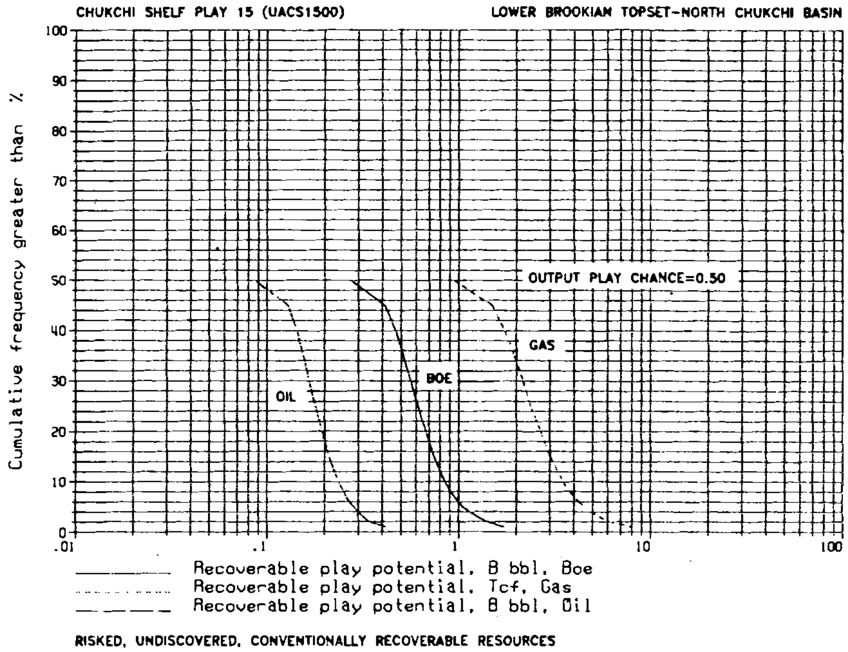
CHUKCHI SHELF PLAY 13 (UACS1300)			
FRACTILES	**F95**	**MEAN**	**F05**
GAS (TCFG)	**0.000**	**0.326**	**1.376**
OIL (BBO)	**0.000**	**0.110**	**0.371**
BOE (BBO)	**0.000**	**0.168**	**0.642**



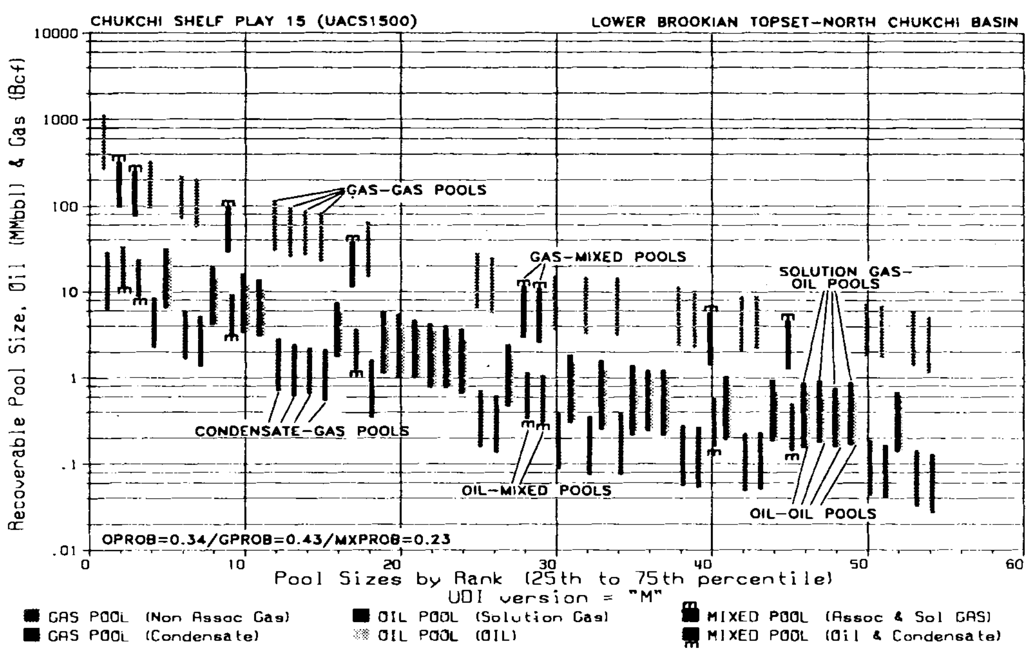


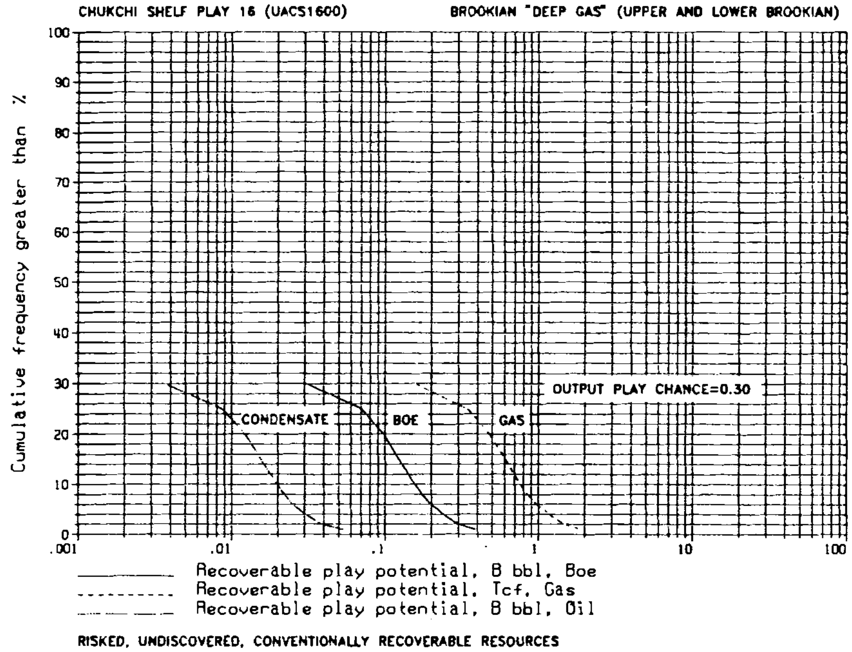
CHUKCHI SHELF PLAY 14 (UACS1400)			
FRACTILES	F95	MEAN	F05
GAS (TCFG)	0.000	13.082	36.046
OIL (BBO)	0.000	1.182	3.497
BOE (BBO)	0.000	3.510	9.761



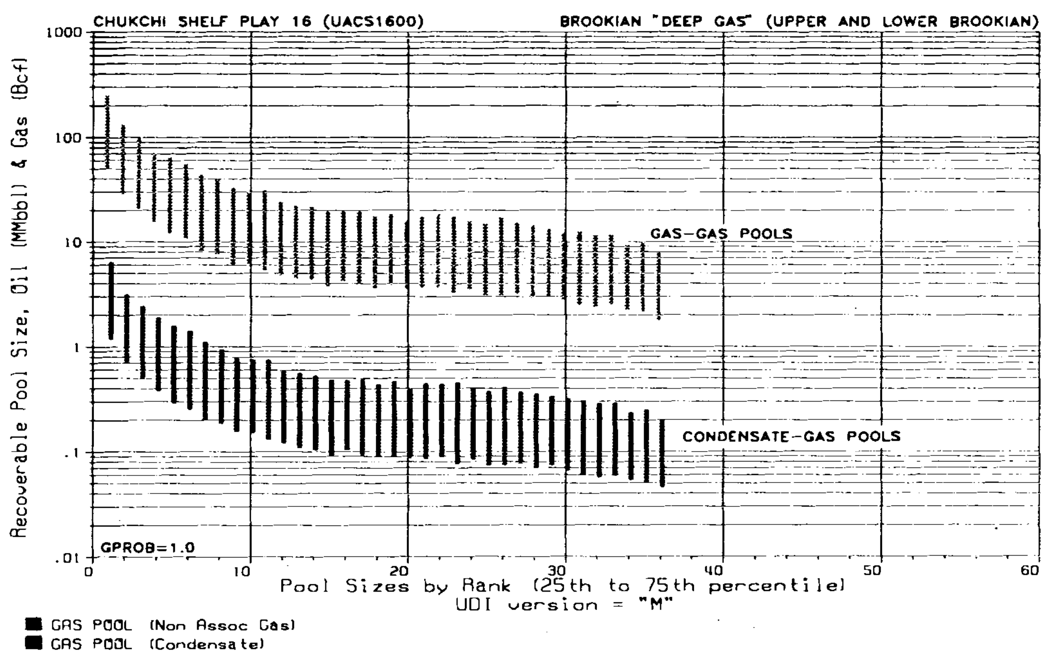


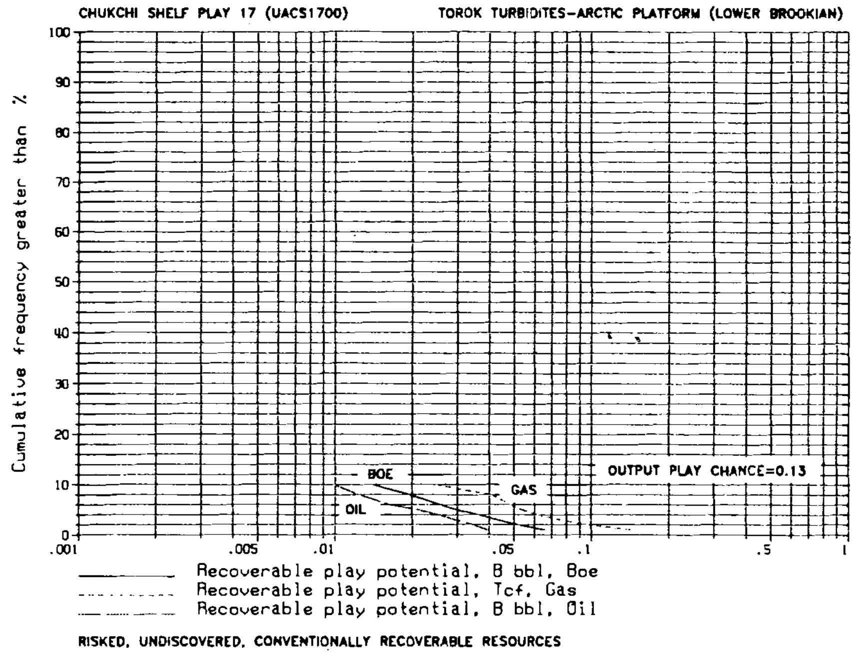
CHUKCHI SHELF PLAY 15 (UACS1500)			
FRACTILES	**F95**	**MEAN**	**F05**
GAS (TCFG)	**0.000**	**1.491**	**4.564**
OIL (BBO)	**0.000**	**0.099**	**0.283**
BOE (BBO)	**0.000**	**0.365**	**1.051**



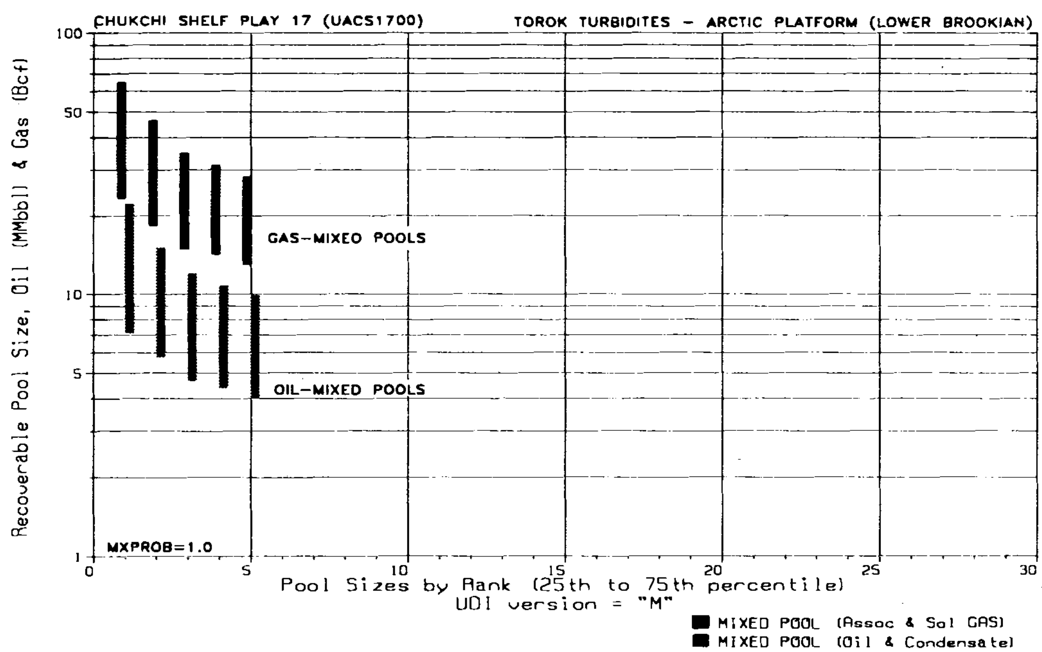


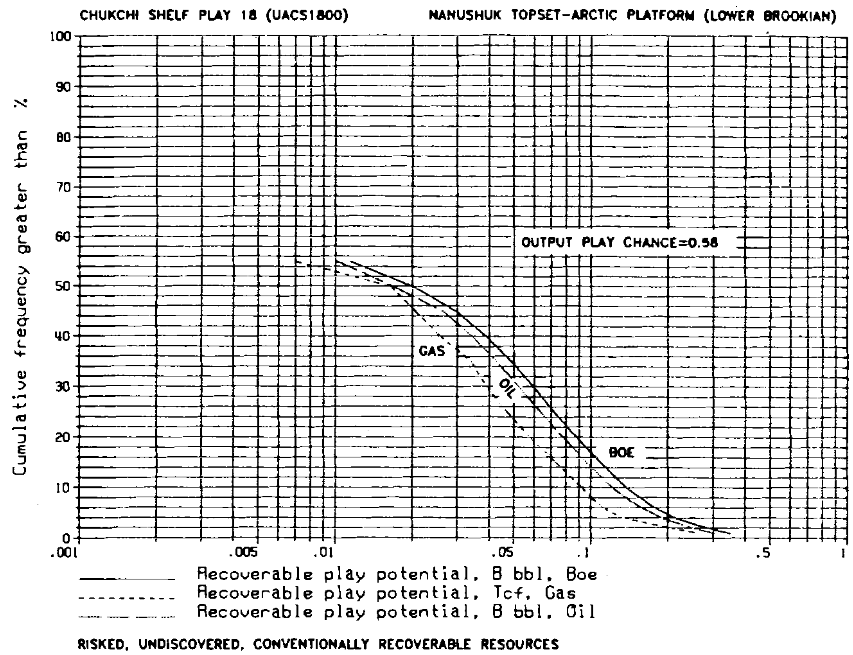
CHUKCHI SHELF PLAY 16 (UACS1600)			
FRACTILES	F95	MEAN	F05
GAS (TCFG)	0.000	0.237	1.076
OIL (BBO)	0.000	0.006	0.028
BOE (BBO)	0.000	0.048	0.220



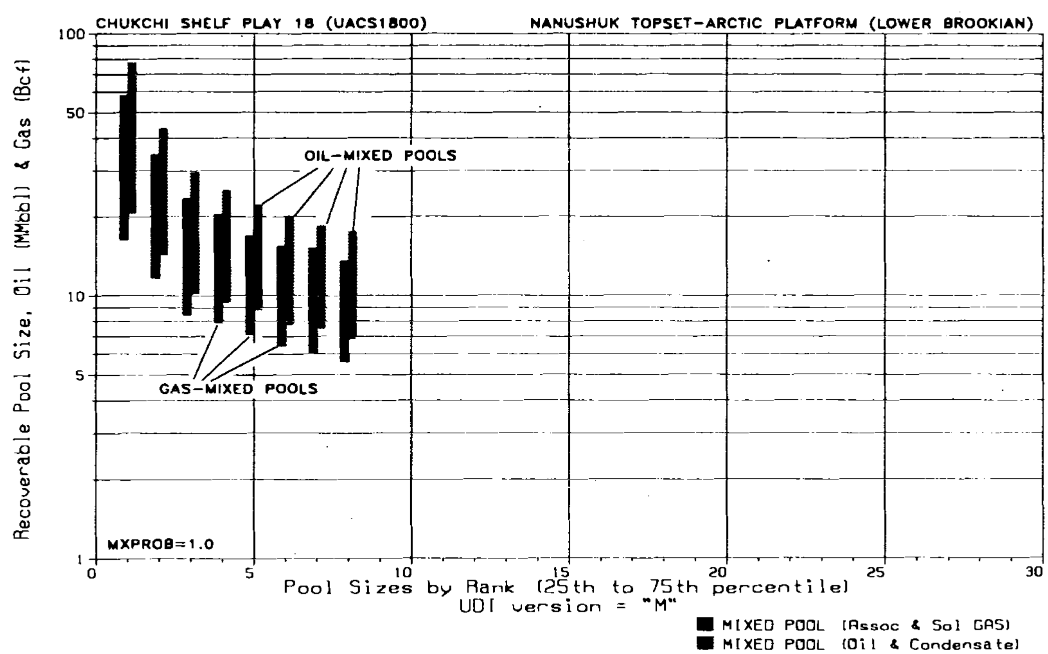


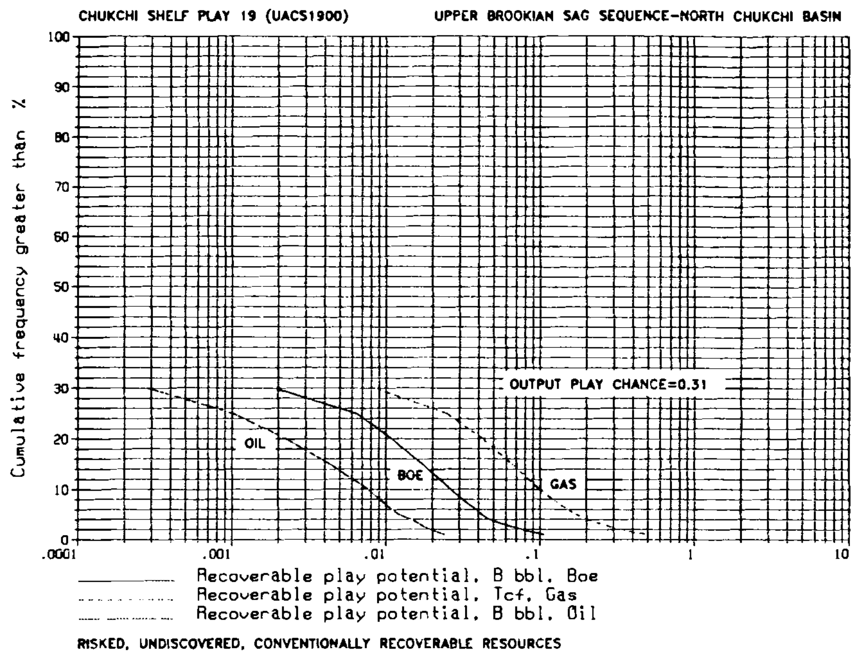
CHUKCHI SHELF PLAY 17 (UACS1700)			
FRACTILES	**F95**	**MEAN**	**F05**
GAS (TCFG)	**0.000**	**0.008**	**0.053**
OIL (BBO)	**0.000**	**0.003**	**0.021**
BOE (BBO)	**0.000**	**0.004**	**0.030**



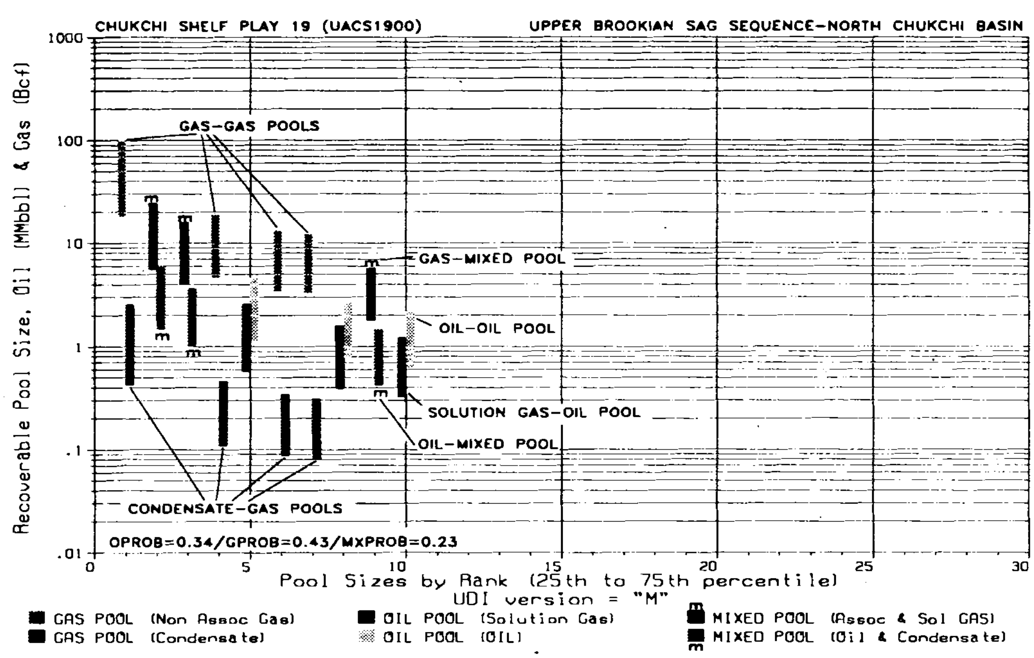


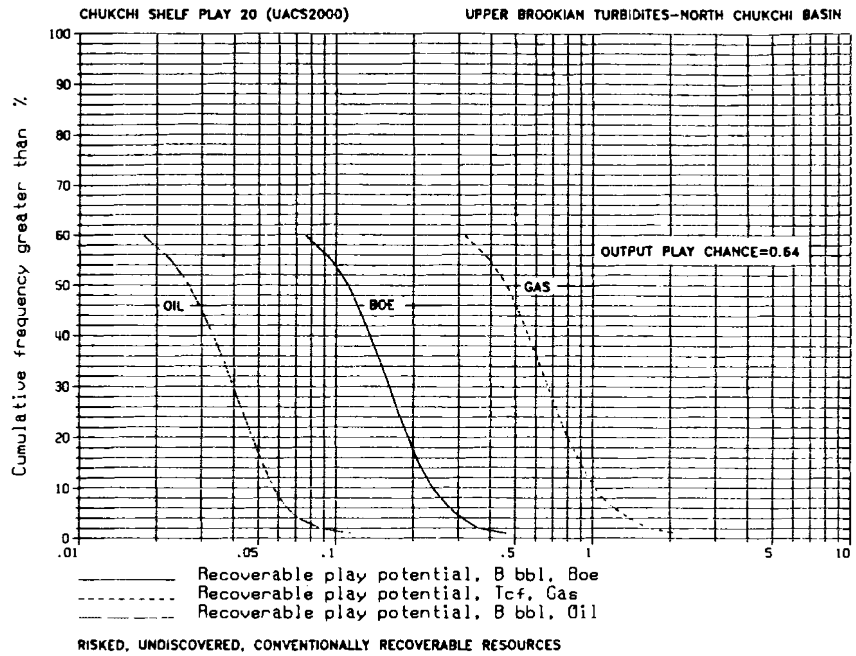
CHUKCHI SHELF PLAY 18 (UACS1800)			
FRACTILES	**F95**	**MEAN**	**F05**
GAS (TCFG)	**0.000**	**0.034**	**0.121**
OIL (BBO)	**0.000**	**0.045**	**0.173**
BOE (BBO)	**0.000**	**0.051**	**0.194**



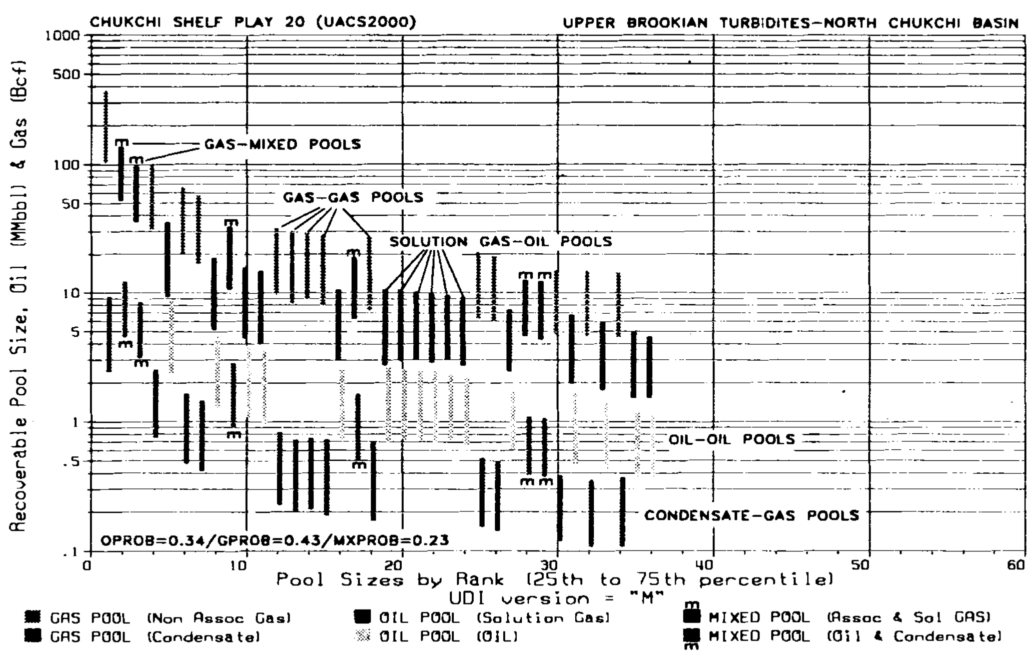


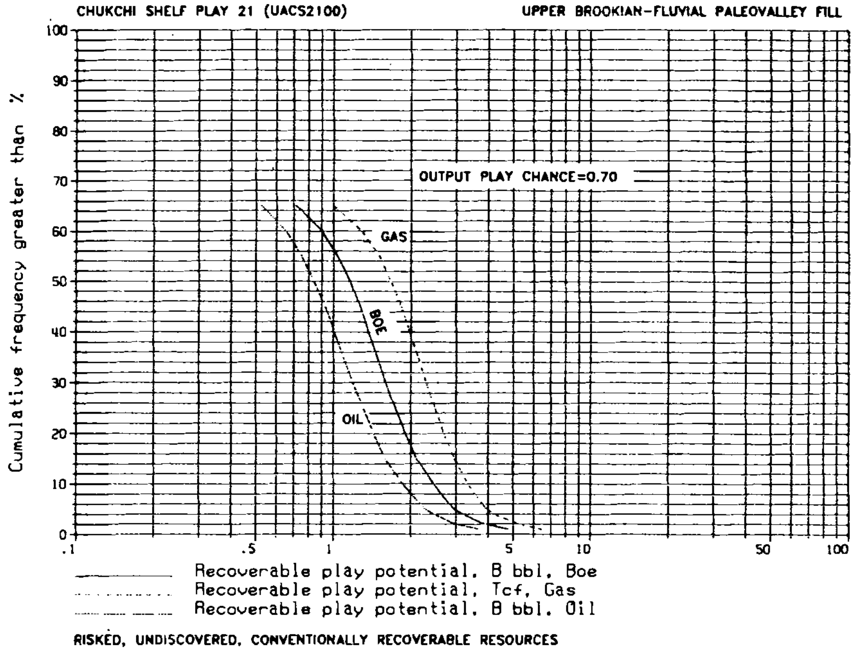
CHUKCHI SHELF PLAY 19 (UACS1900)			
FRACTILES	**F95**	**MEAN**	**F05**
GAS (TCFG)	**0.000**	**0.038**	**0.171**
OIL (BBO)	**0.000**	**0.002**	**0.012**
BOE (BBO)	**0.000**	**0.009**	**0.042**



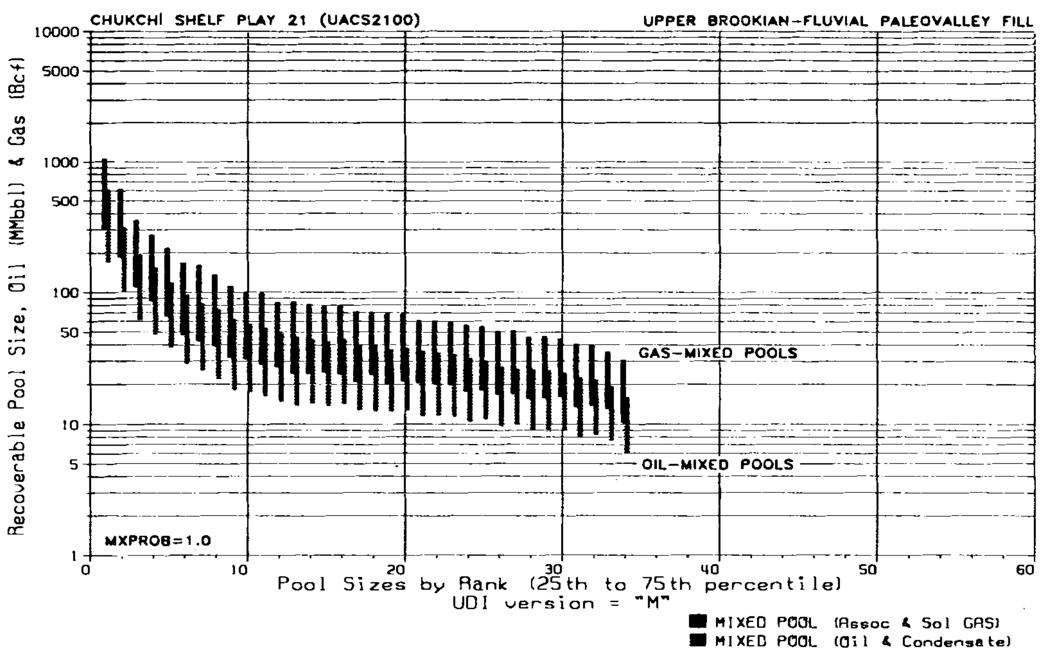


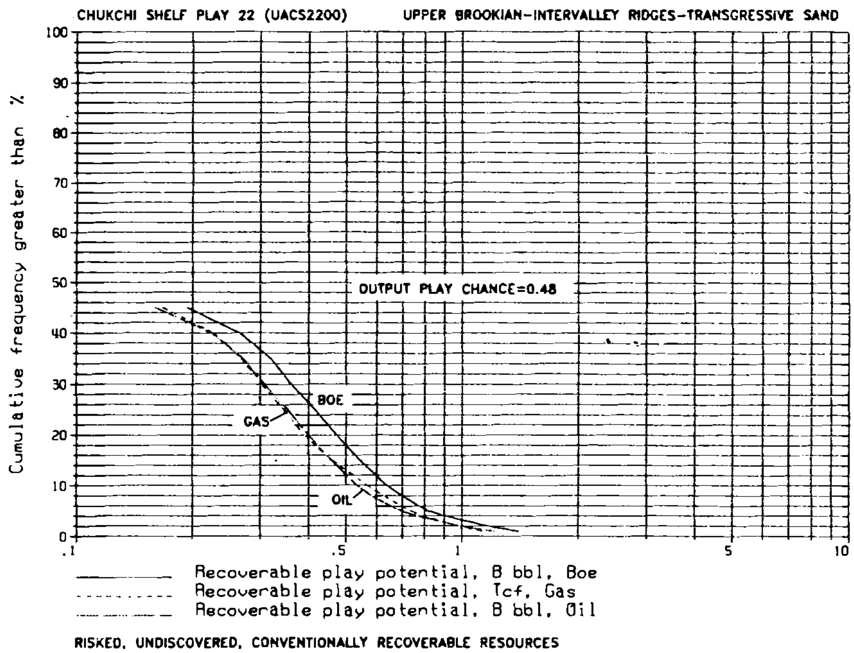
CHUKCHI SHELF PLAY 20 (UACS2000)			
FRACTILES	**F95**	**MEAN**	**F05**
GAS (TCFG)	**0.000**	**0.484**	**1.306**
OIL (BBO)	**0.000**	**0.027**	**0.068**
BOE (BBO)	**0.000**	**0.113**	**0.293**



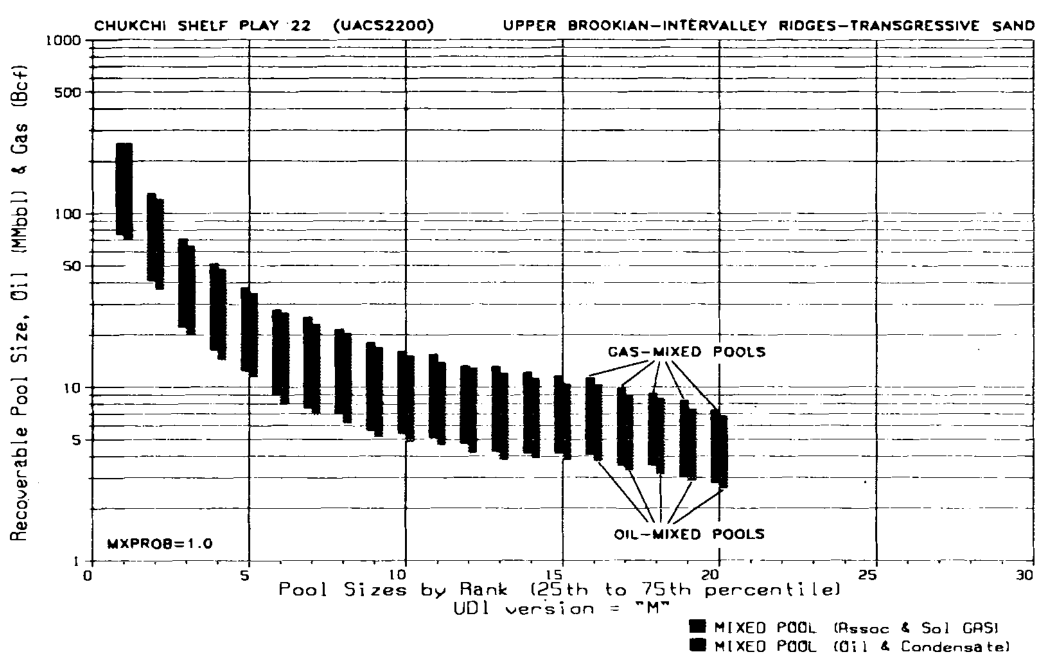


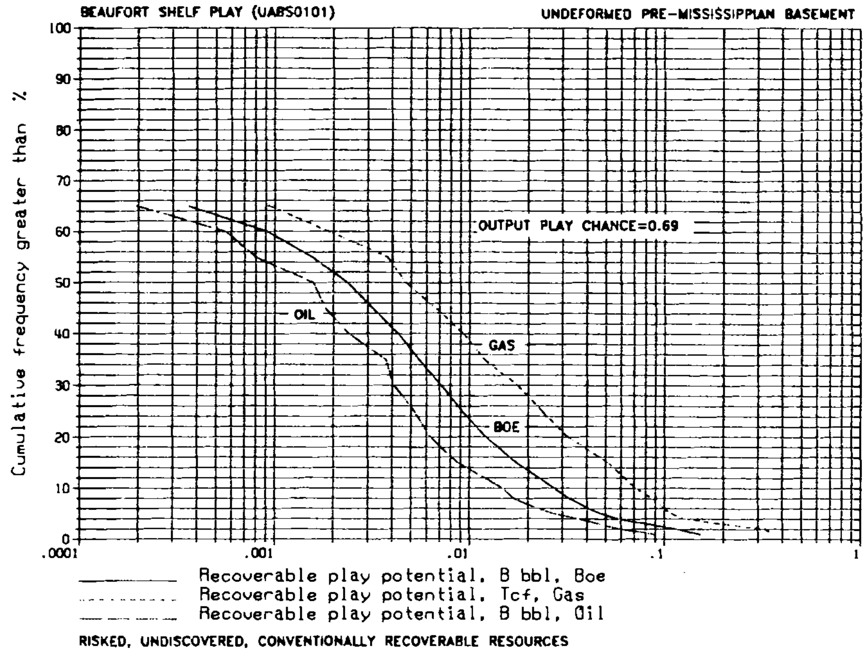
CHUKCHI SHELF PLAY 21 (UACS2100)			
FRACTILES	**F95**	**MEAN**	**F05**
GAS (TCFG)	**0.000**	**1.637**	**3.961**
OIL (BBO)	**0.000**	**0.886**	**2.283**
BOE (BBO)	**0.000**	**1.177**	**2.953**



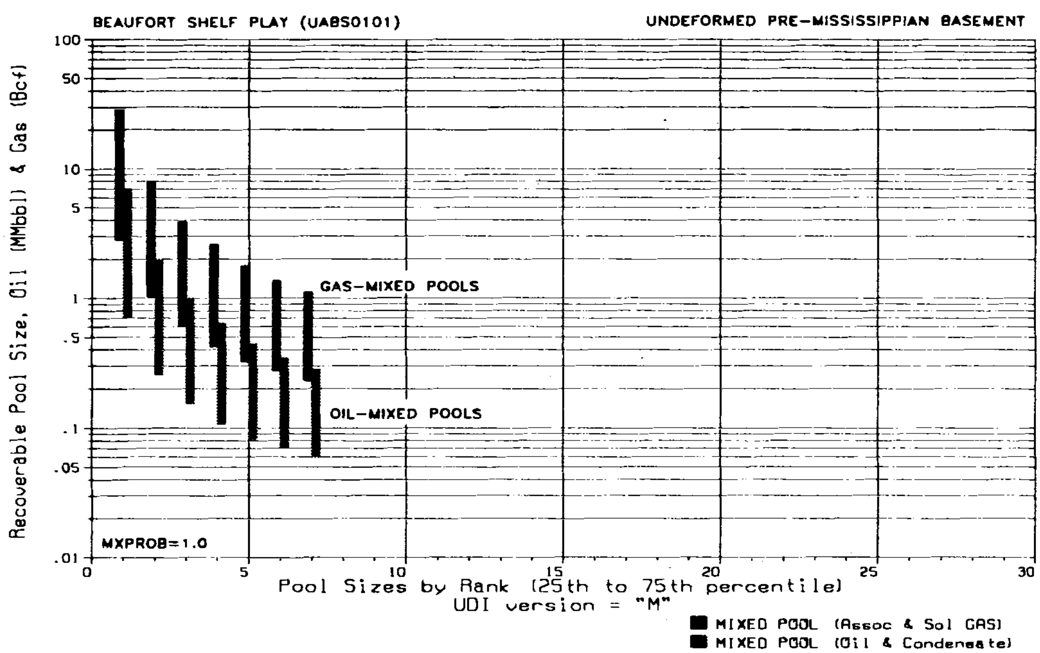


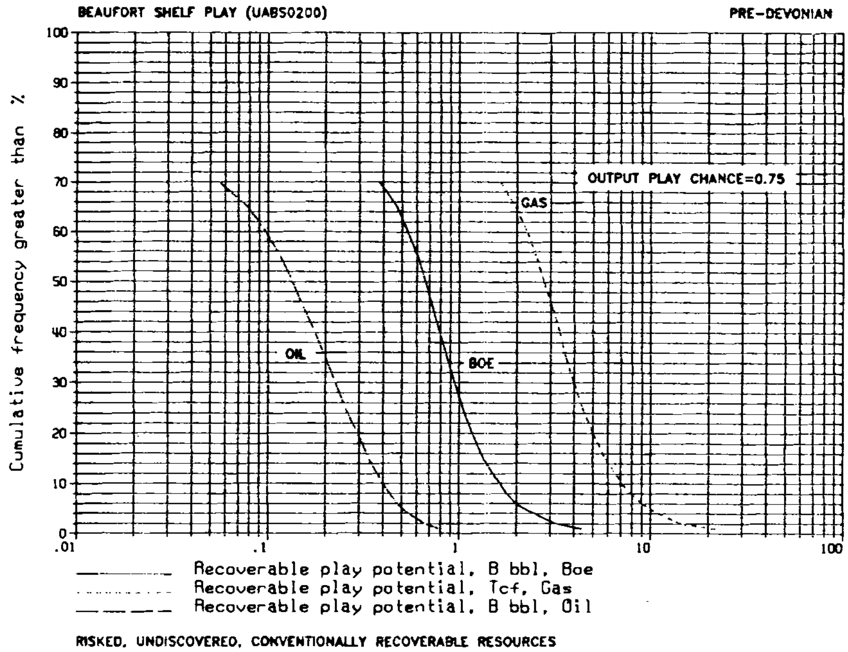
CHUKCHI SHELF PLAY 22 (UACS2200)			
FRACTILES	**F95**	**MEAN**	**F05**
GAS (TCFG)	**0.000**	**0.203**	**0.740**
OIL (BBO)	**0.000**	**0.204**	**0.697**
BOE (BBO)	**0.000**	**0.240**	**0.816**



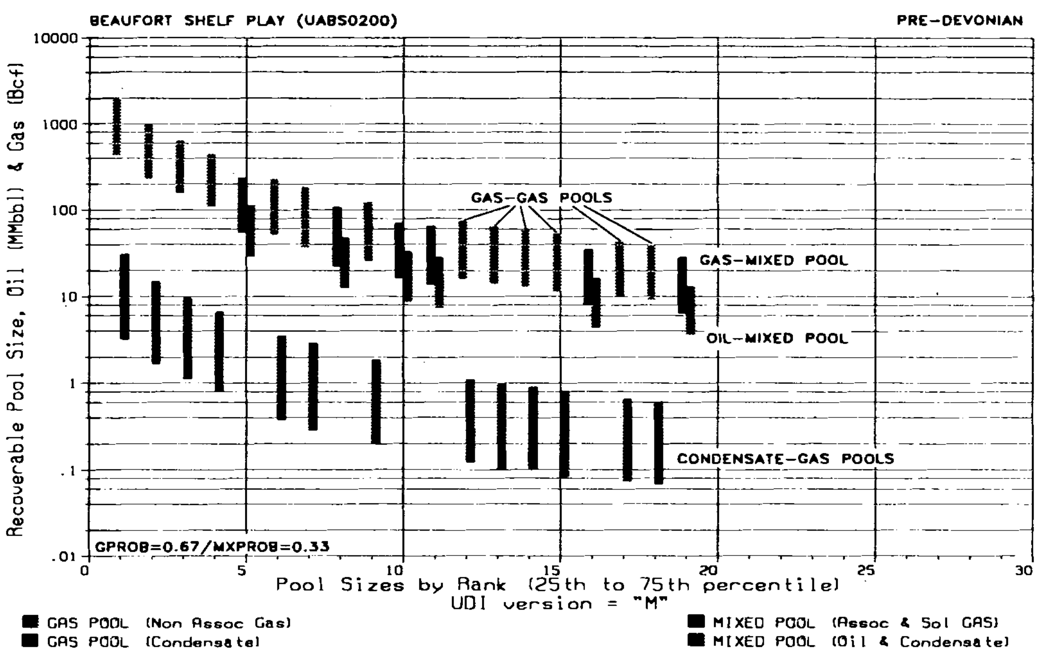


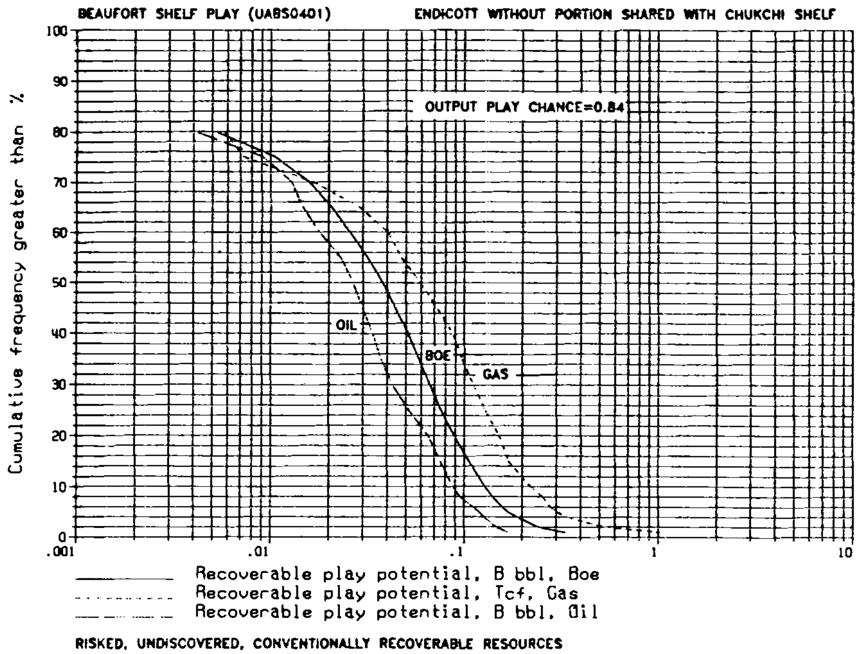
BEAUFORT SHELF PLAY (UABS0101)			
FRACTILES	**F95**	**MEAN**	**F05**
GAS (TCFG)	**0.000**	**0.028**	**0.109**
OIL (BBO)	**0.000**	**0.006**	**0.027**
BOE (BBO)	**0.000**	**0.011**	**0.047**



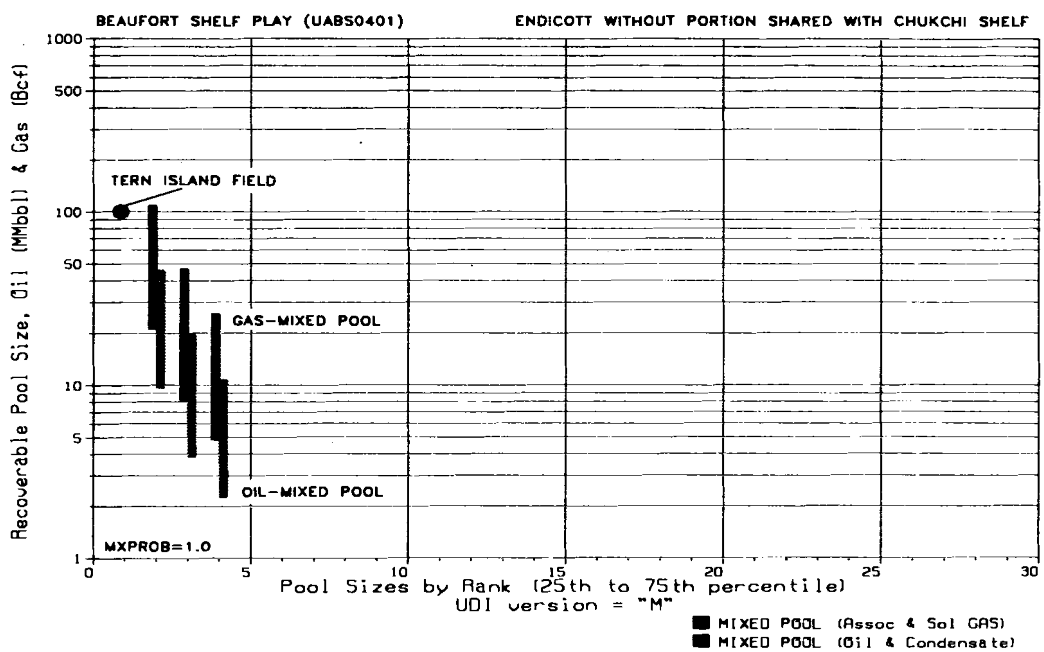


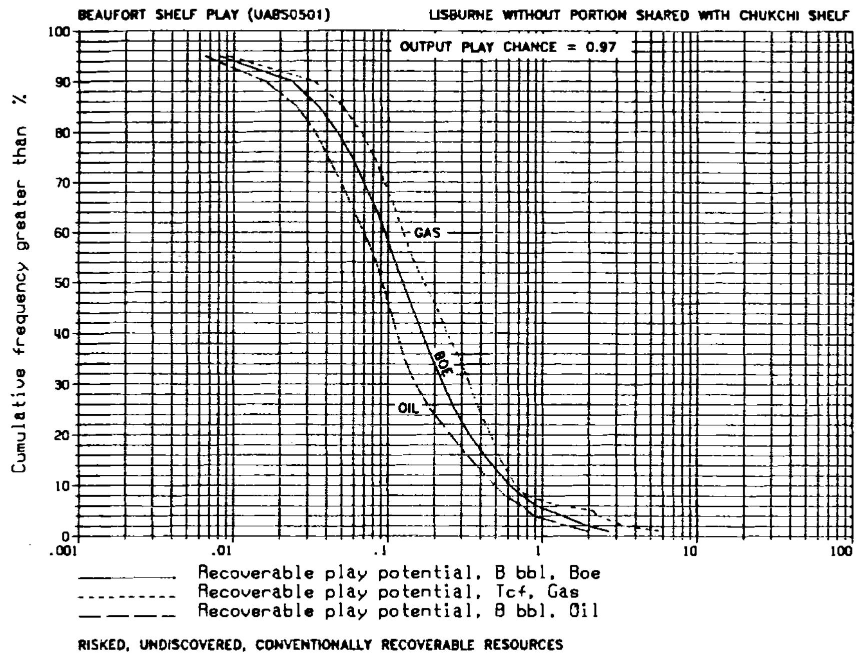
BEAUFORT SHELF PLAY (UABS0200)			
FRACTILES	**F95**	**MEAN**	**F05**
GAS (TCFG)	**0.000**	**3.534**	**9.958**
OIL (BBO)	**0.000**	**0.173**	**0.505**
BOE (BBO)	**0.000**	**0.802**	**2.191**



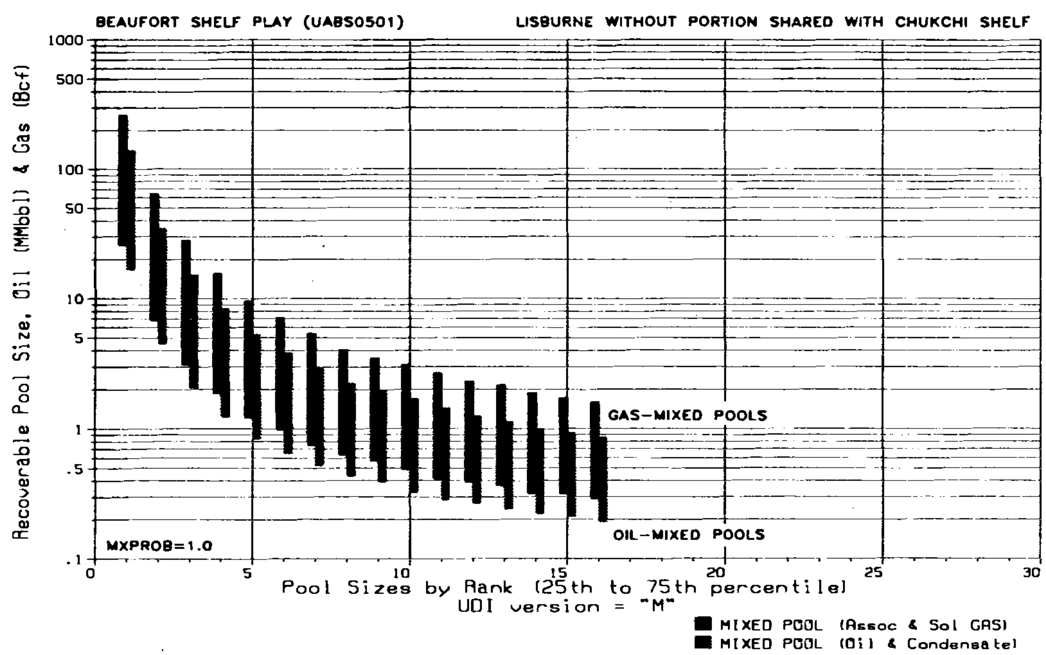


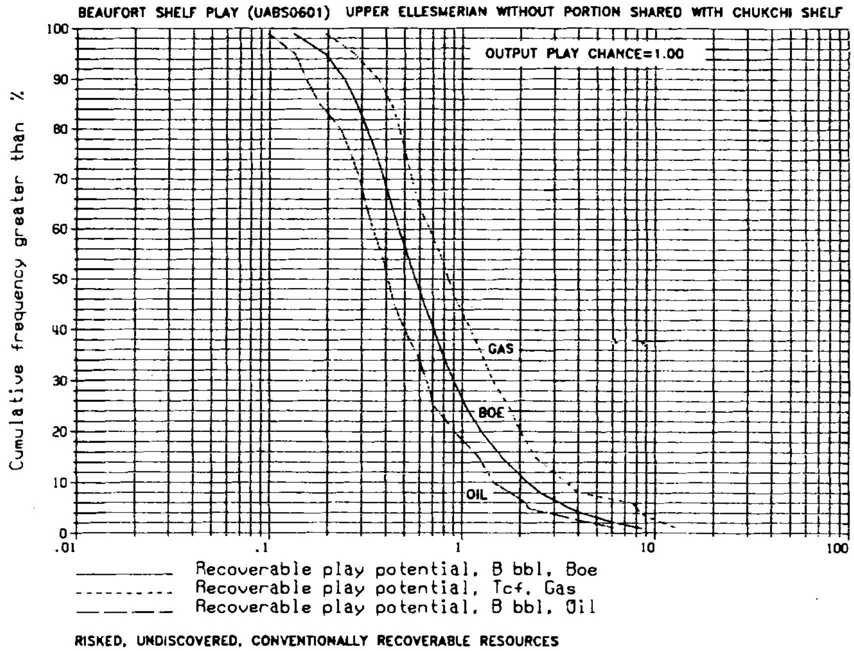
BEAUFORT SHELF PLAY (UABS0401)			
FRACTILES	**F95**	**MEAN**	**F05**
GAS (TCFG)	**0.000**	**0.109**	**0.303**
OIL (BBO)	**0.000**	**0.037**	**0.120**
BOE (BBO)	**0.000**	**0.056**	**0.169**



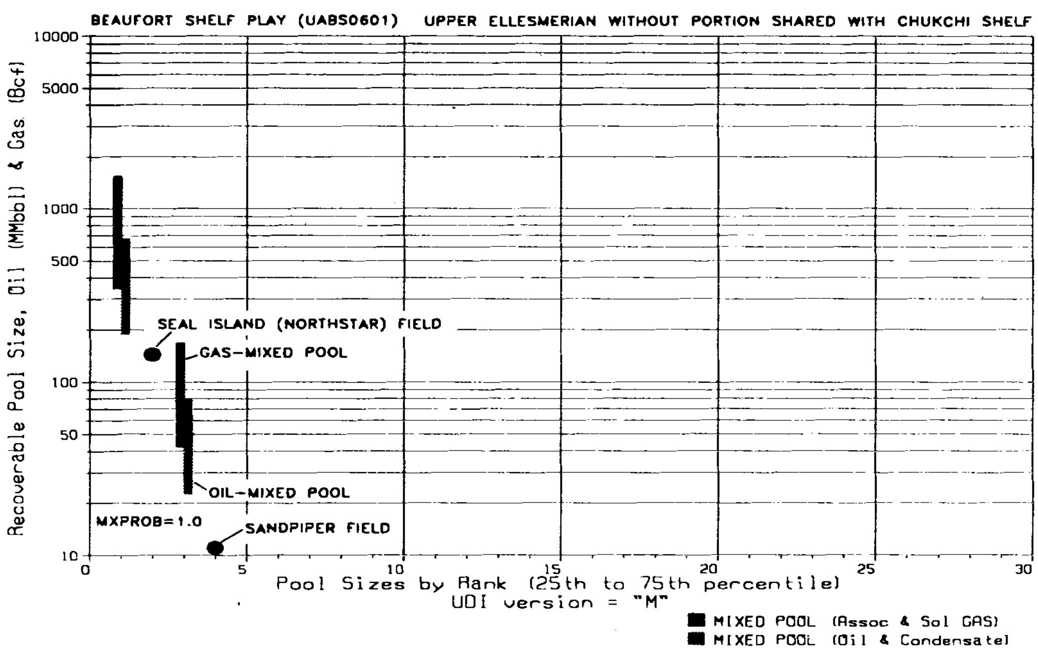


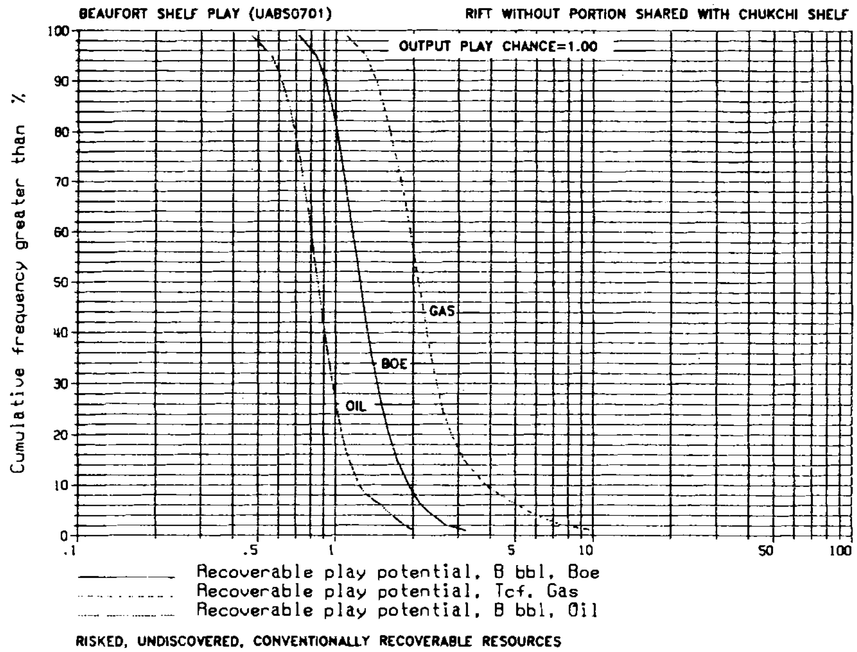
BEAUFORT SHELF PLAY (UABS0501)			
FRACTILES	**F95**	**MEAN**	**F05**
GAS (TCFG)	**0.009**	**0.452**	**2.117**
OIL (BBO)	**0.006**	**0.208**	**0.805**
BOE (BBO)	**0.008**	**0.288**	**1.122**





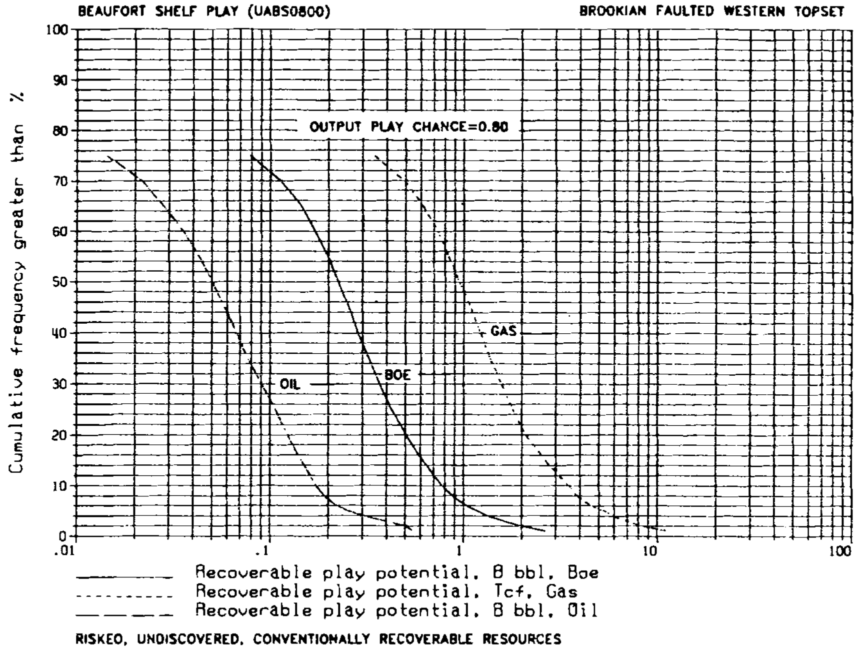
BEAUFORT SHELF PLAY (UABS0601)			
FRACTILES	**F95**	**MEAN**	**F05**
GAS (TCFG)	**0.273**	**1.834**	**8.057**
OIL (BBO)	**0.135**	**0.763**	**2.200**
BOE (BBO)	**0.193**	**1.090**	**3.581**



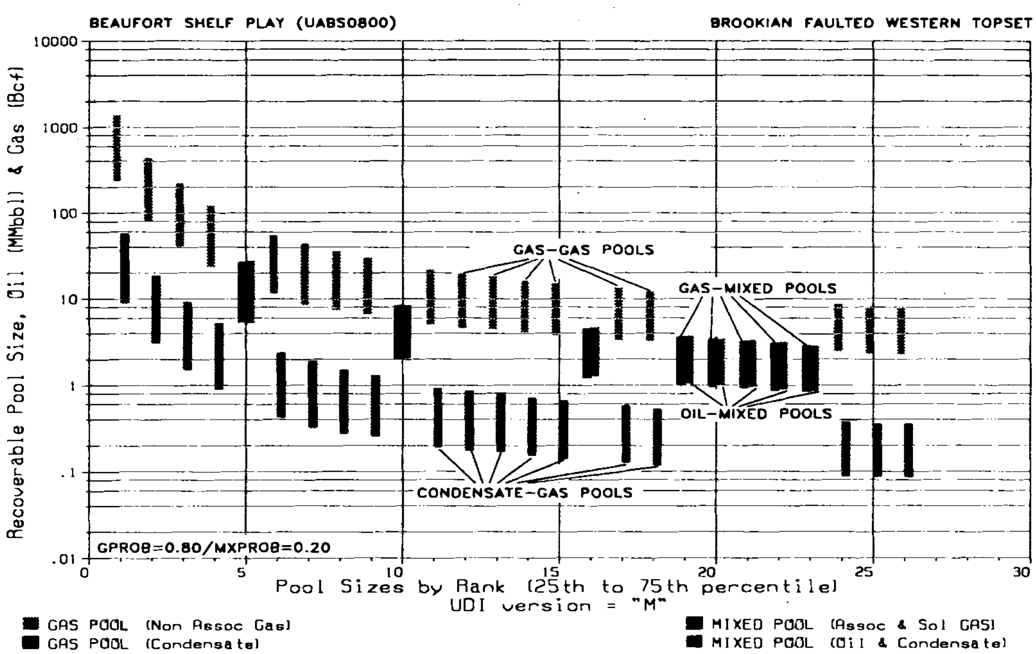


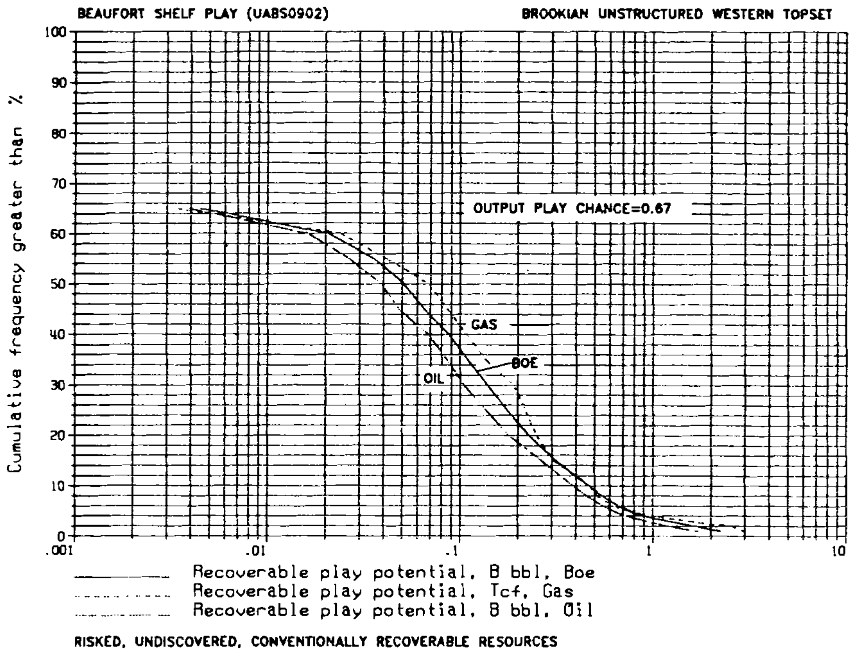
BEAUFORT SHELF PLAY (UABS0701)			
FRACTILES	**F95**	**MEAN**	**F05**
GAS (TCFG)	**1.302**	**2.559**	**5.512**
OIL (BBO)	**0.564**	**0.910**	**1.570**
BOE (BBO)	**0.837**	**1.365**	**2.256**

POOL RANK PLOT NOT AVAILABLE

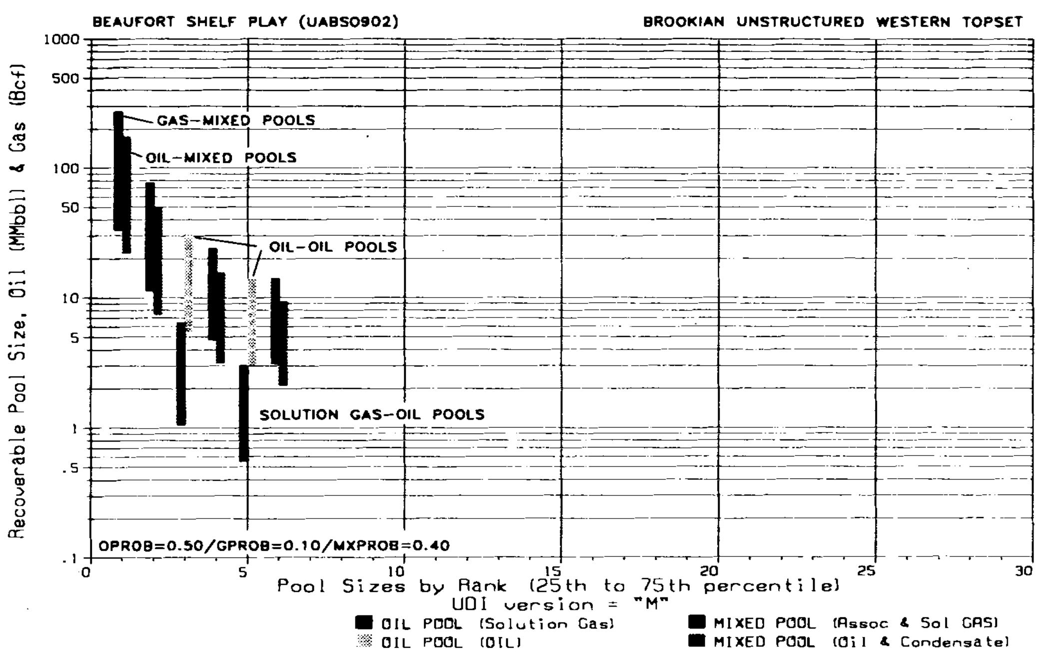


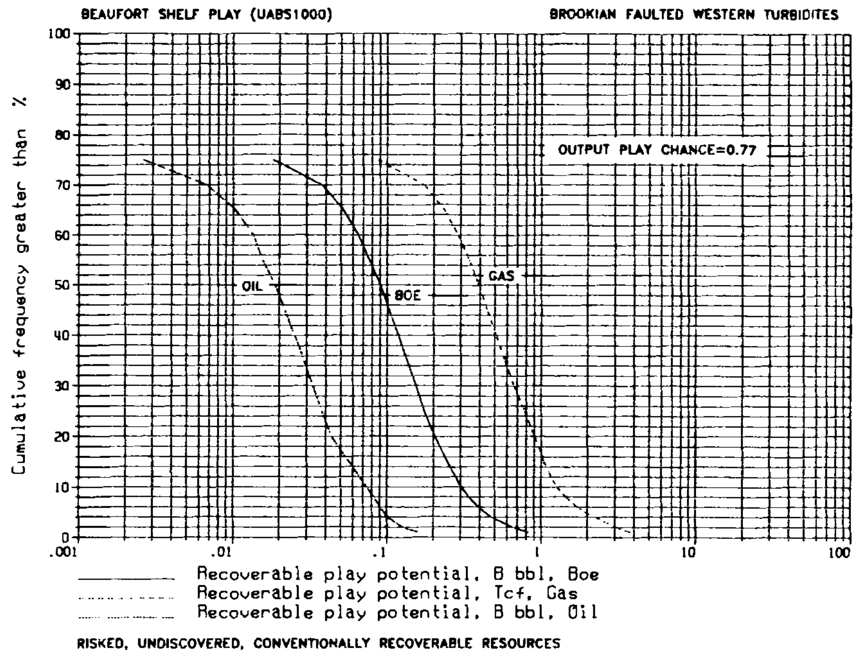
BEAUFORT SHELF PLAY (UABS0800)			
FRACTILES	**F95**	**MEAN**	**F05**
GAS (TCFG)	**0.000**	**1.570**	**5.372**
OIL (BBO)	**0.000**	**0.082**	**0.254**
BOE (BBO)	**0.000**	**0.361**	**1.176**



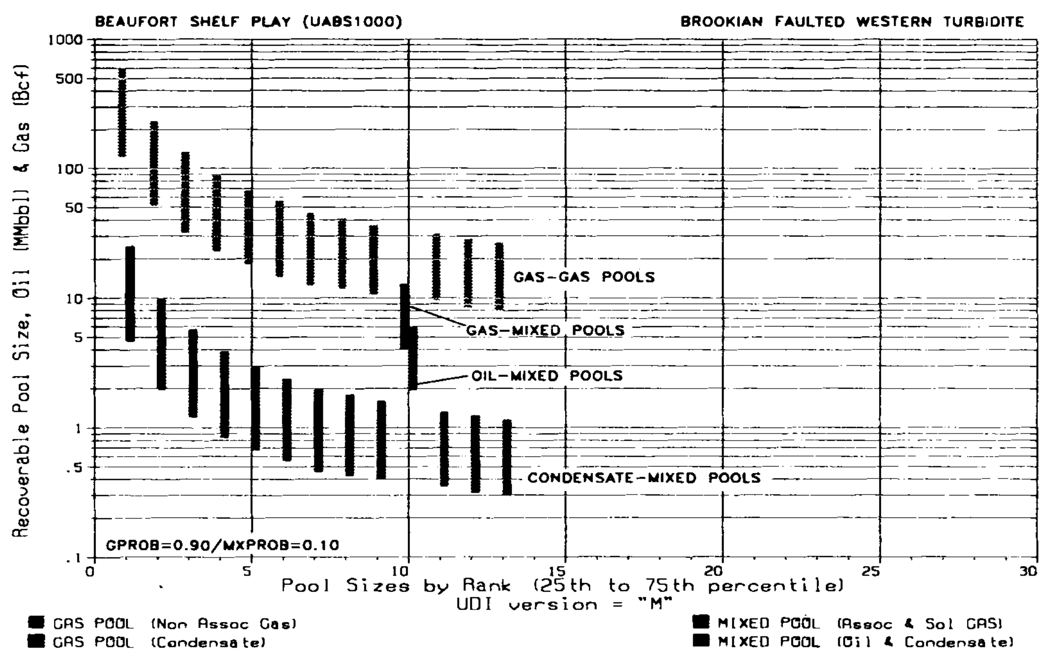


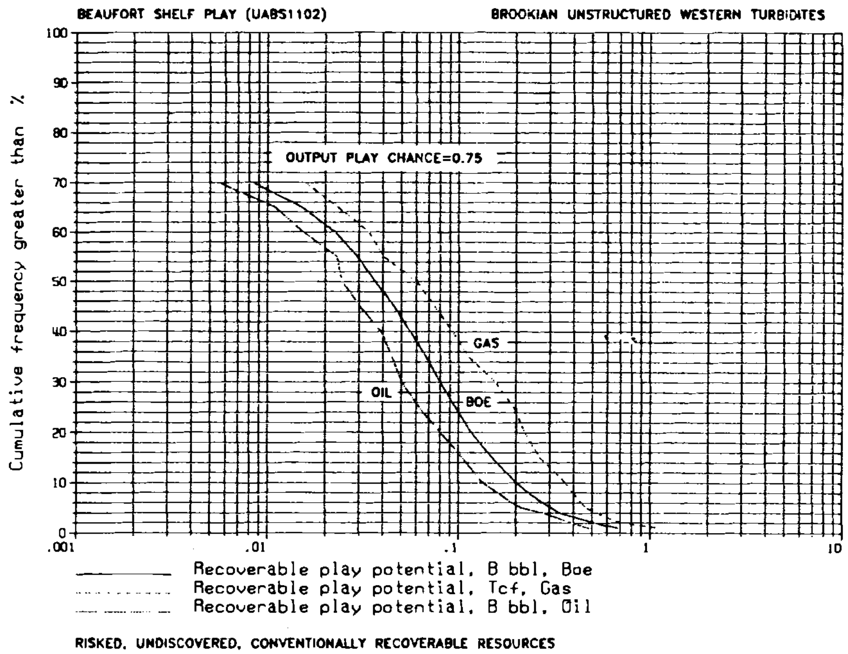
BEAUFORT SHELF PLAY (UABS0902)			
FRACTILES	**F95**	**MEAN**	**F05**
GAS (TCFG)	**0.000**	**0.211**	**0.748**
OIL (BBO)	**0.000**	**0.146**	**0.631**
BOE (BBO)	**0.000**	**0.184**	**0.763**



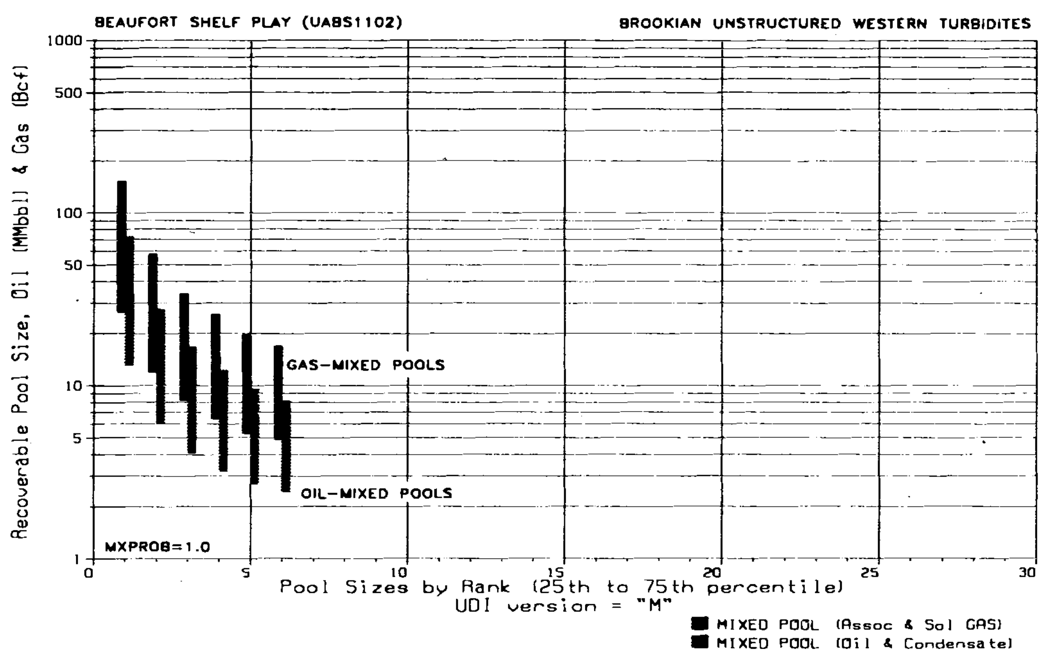


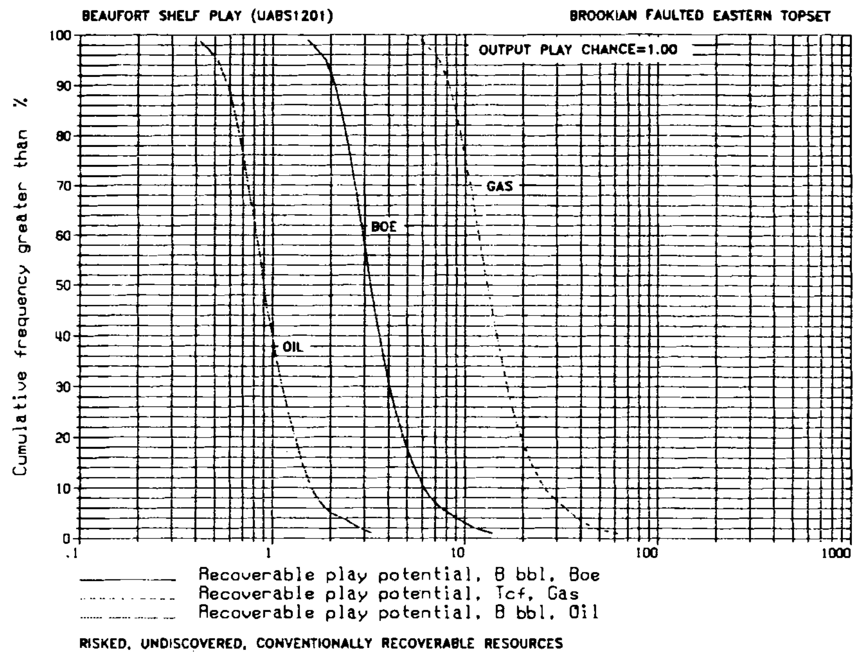
BEAUFORT SHELF PLAY (UABS1000)			
FRACTILES	**F95**	**MEAN**	**F05**
GAS (TCFG)	**0.000**	**0.601**	**1.923**
OIL (BBO)	**0.000**	**0.029**	**0.095**
BOE (BBO)	**0.000**	**0.136**	**0.428**



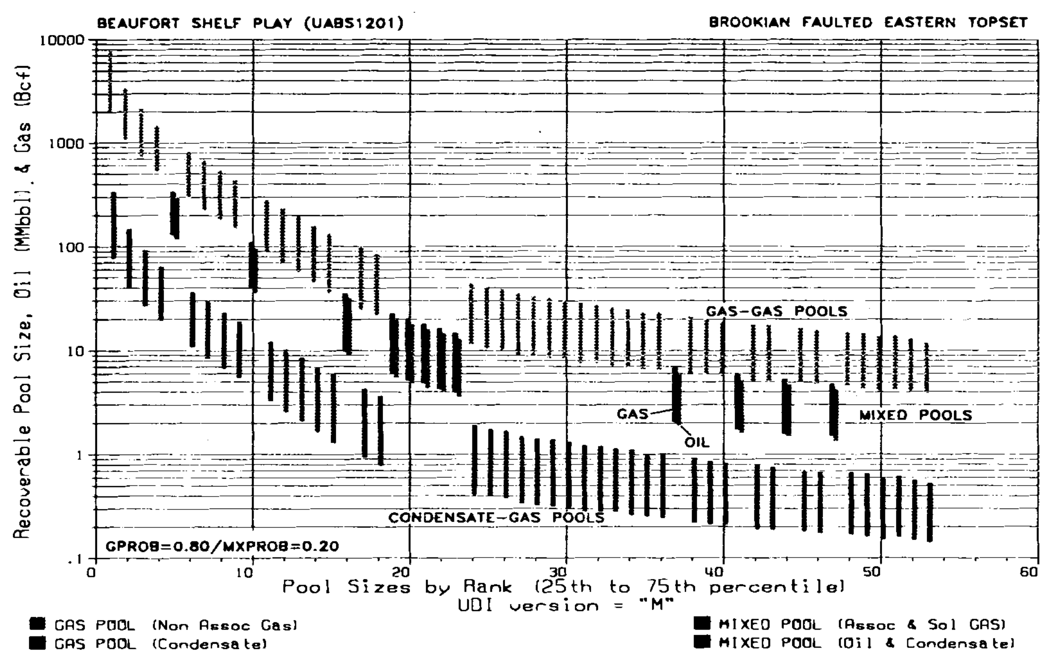


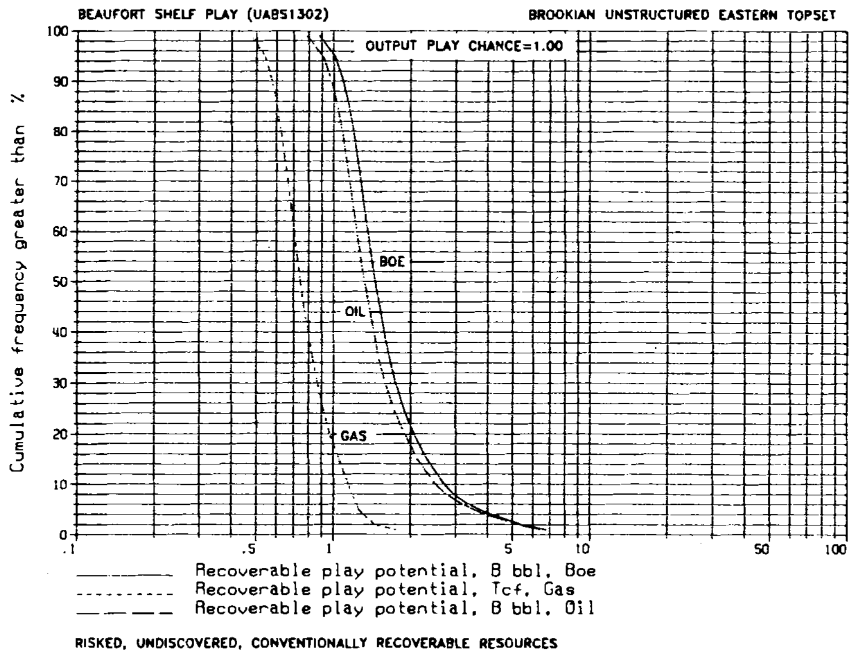
BEAUFORT SHELF PLAY (UABS1102)			
FRACTILES	**F95**	**MEAN**	**F05**
GAS (TCFG)	**0.000**	**0.133**	**0.468**
OIL (BBO)	**0.000**	**0.057**	**0.214**
BOE (BBO)	**0.000**	**0.081**	**0.307**



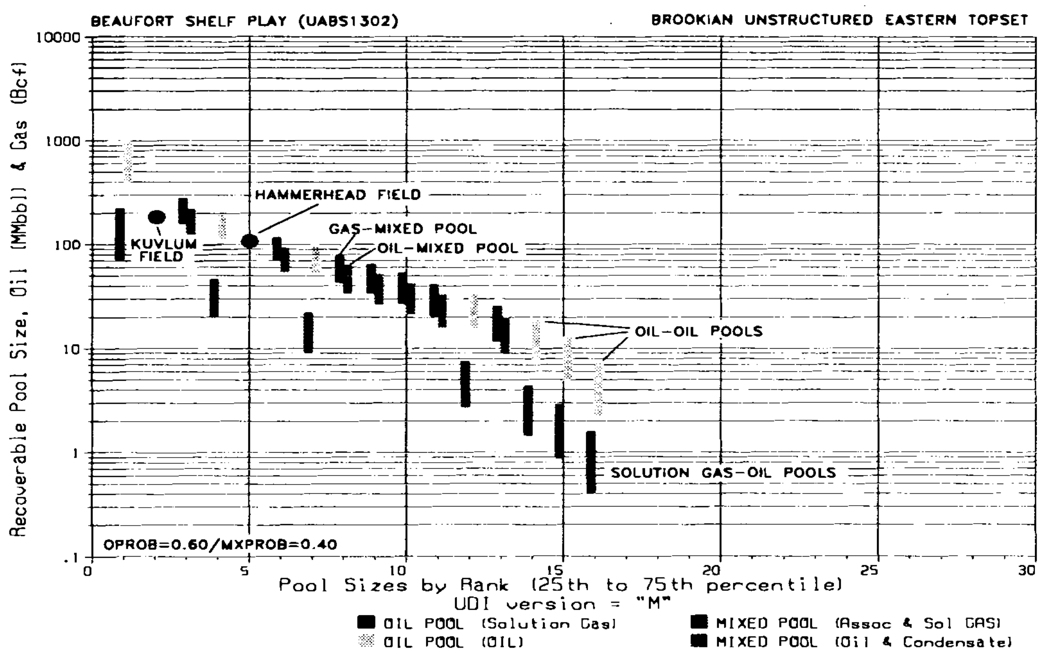


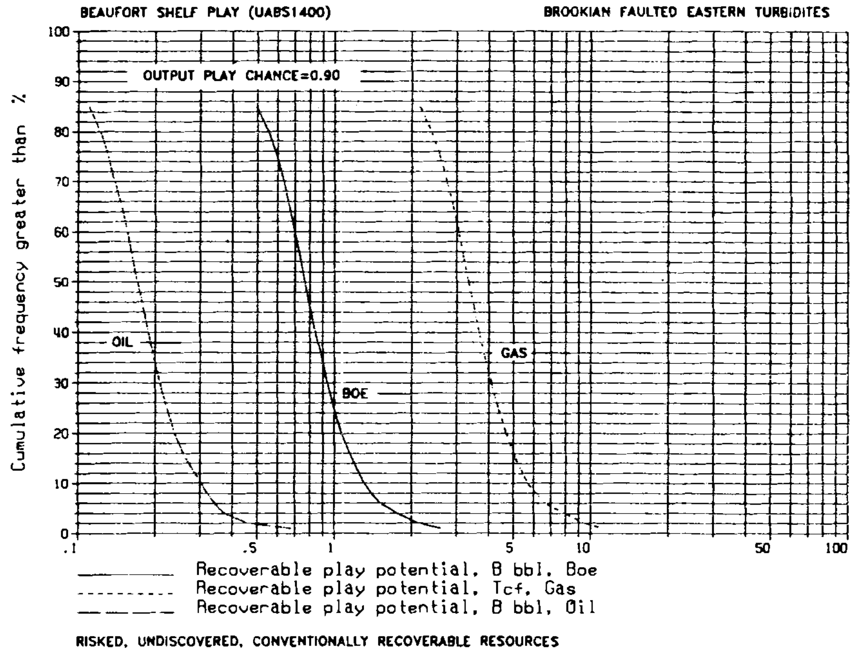
BEAUFORT SHELF PLAY (UABS1201)			
FRACTILES	**F95**	**MEAN**	**F05**
GAS (TCFG)	**7.323**	**16.074**	**35.665**
OIL (BBO)	**0.518**	**1.046**	**2.042**
BOE (BBO)	**1.890**	**3.908**	**8.187**



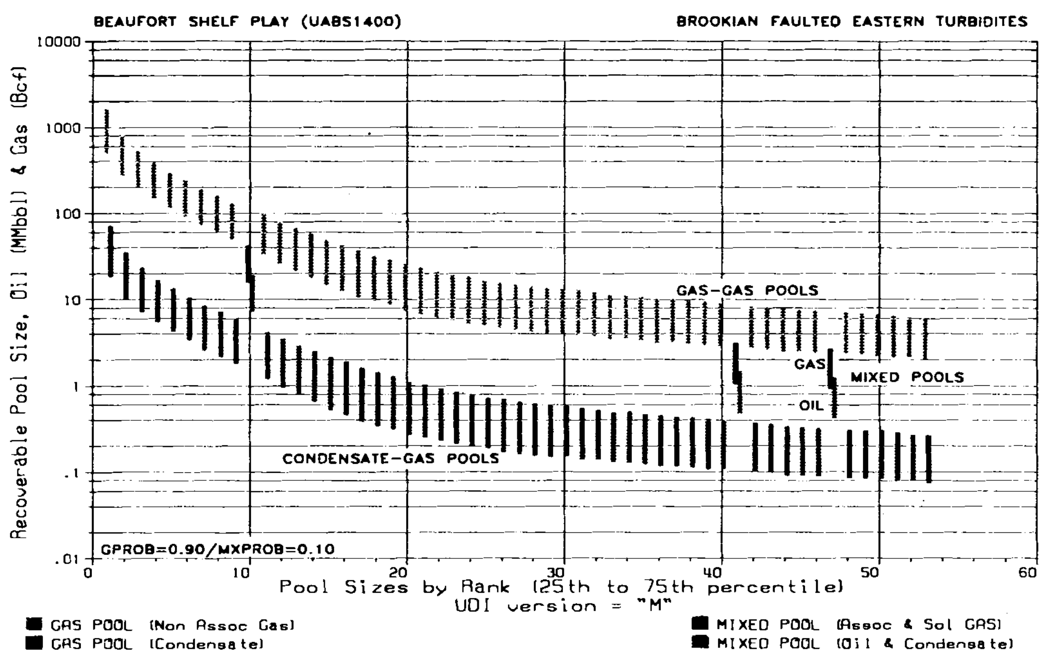


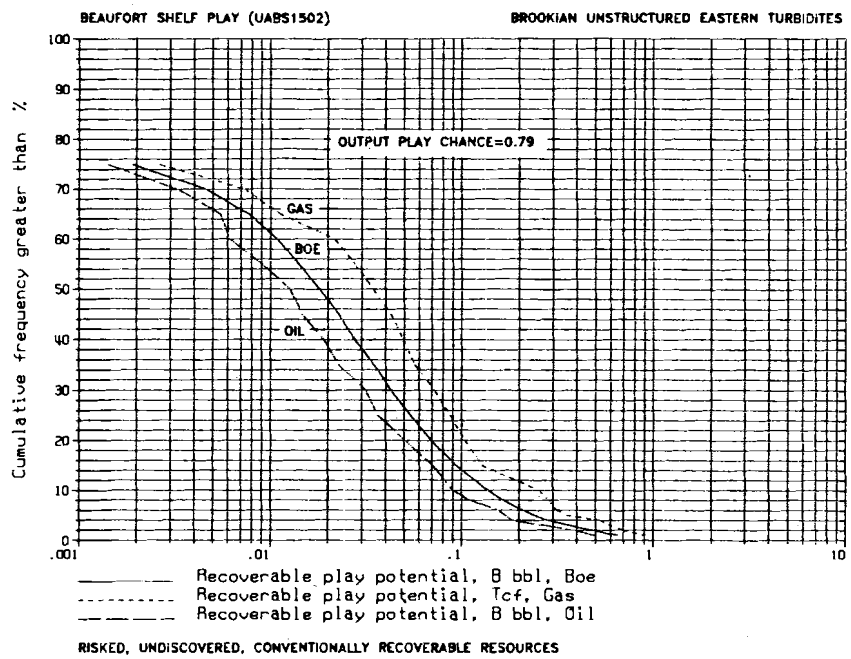
BEAUFORT SHELF PLAY (UABS1302)			
FRACTILES	**F95**	**MEAN**	**F05**
GAS (TCFG)	**0.539**	**0.813**	**1.258**
OIL (BBO)	**0.907**	**1.648**	**3.497**
BOE (BBO)	**1.011**	**1.793**	**3.695**



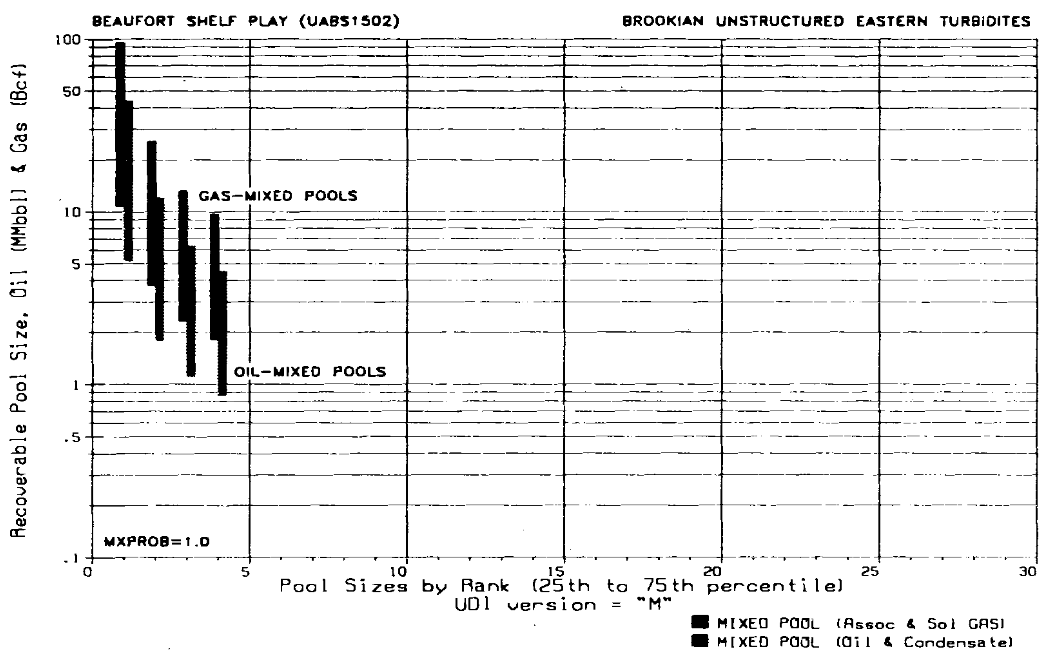


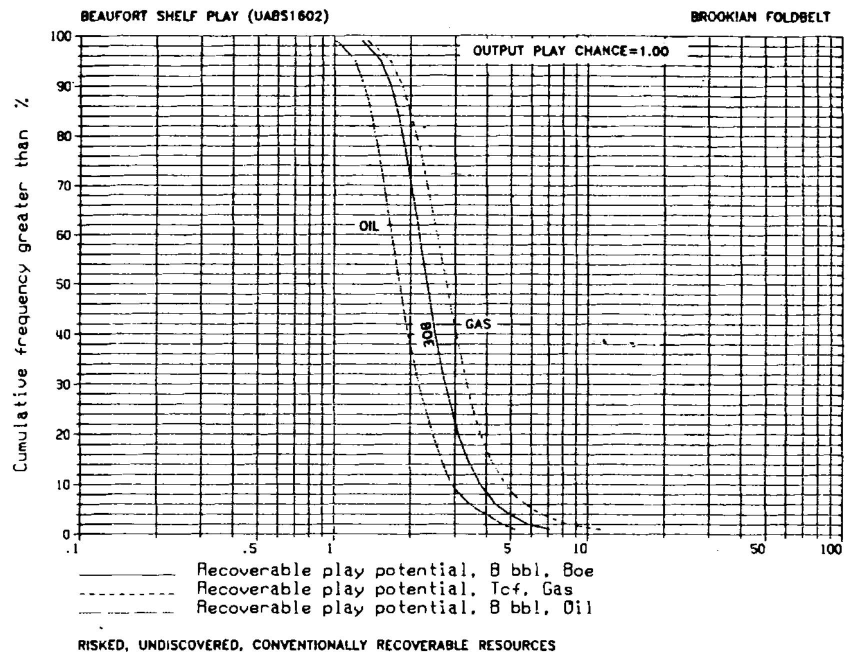
BEAUFORT SHELF PLAY (UABS1400)			
FRACTILES	**F95**	**MEAN**	**F05**
GAS (TCFG)	**0.000**	**3.585**	**7.252**
OIL (BBO)	**0.000**	**0.183**	**0.355**
BOE (BBO)	**0.000**	**0.821**	**1.643**



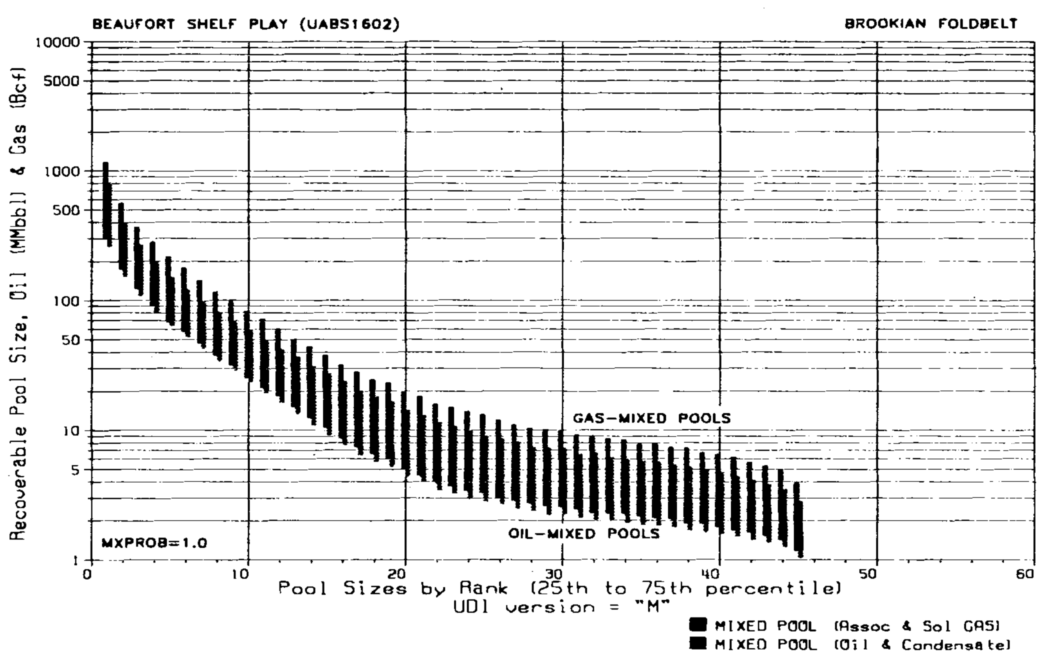


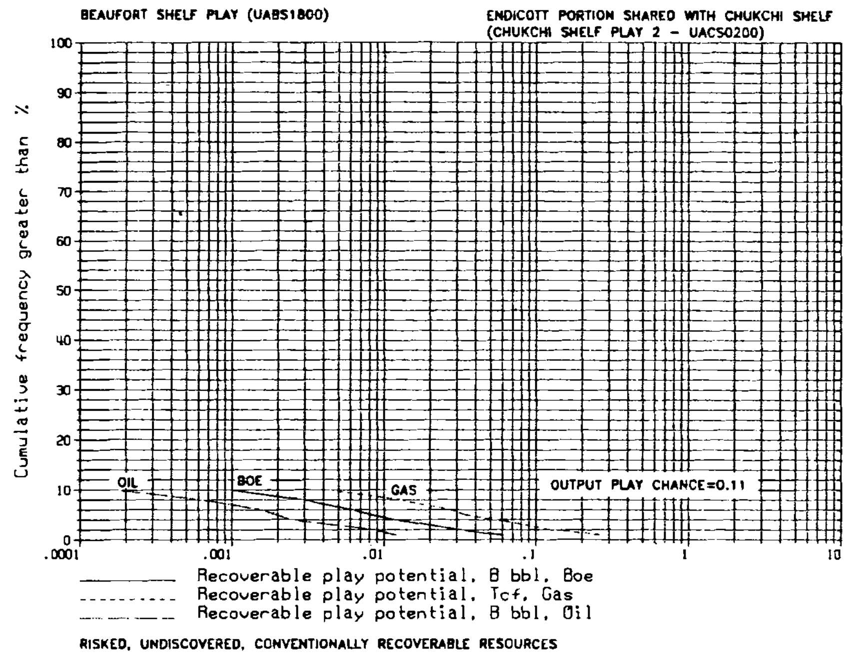
BEAUFORT SHELF PLAY (UABS1502)			
FRACTILES	**F95**	**MEAN**	**F05**
GAS (TCFG)	**0.000**	**0.090**	**0.349**
OIL (BBO)	**0.000**	**0.042**	**0.169**
BOE (BBO)	**0.000**	**0.059**	**0.241**



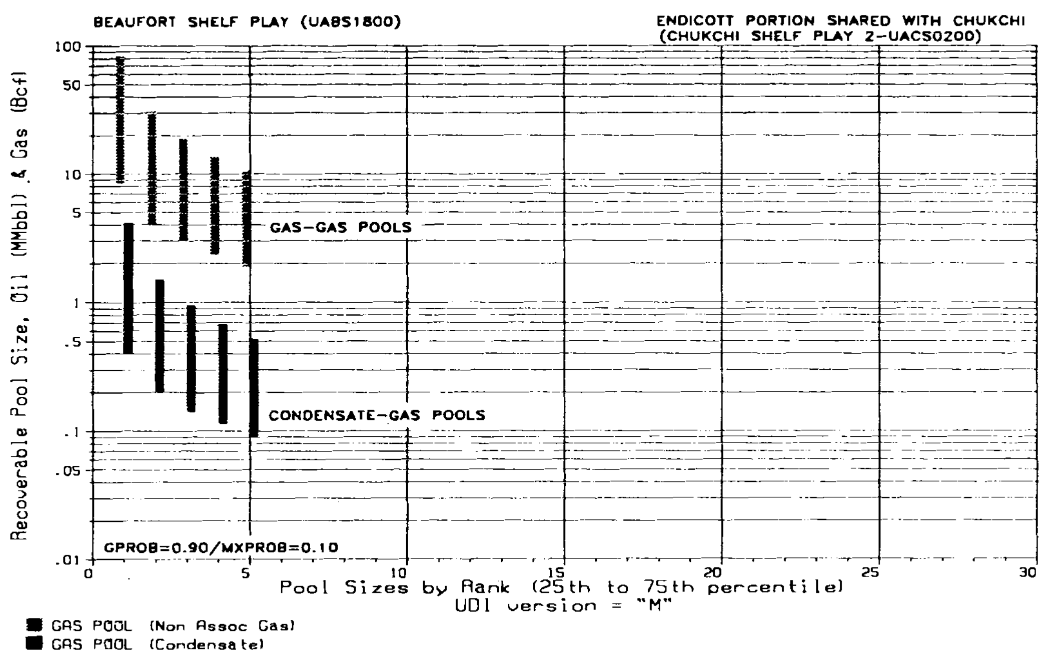


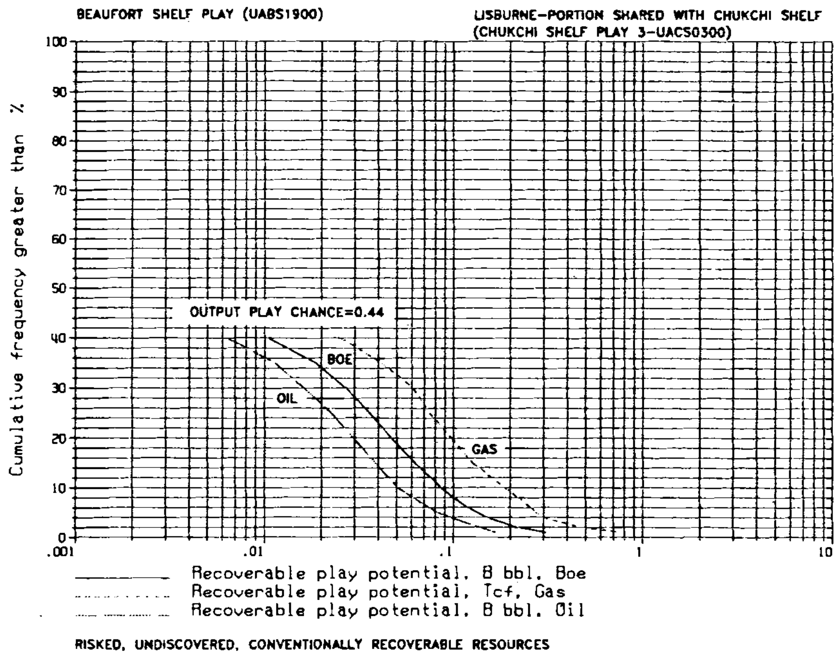
BEAUFORT SHELF PLAY (UABS1602)			
FRACTILES	**F95**	**MEAN**	**F05**
GAS (TCFG)	**1.662**	**3.188**	**6.108**
OIL (BBO)	**1.205**	**2.038**	**3.680**
BOE (BBO)	**1.521**	**2.606**	**4.644**



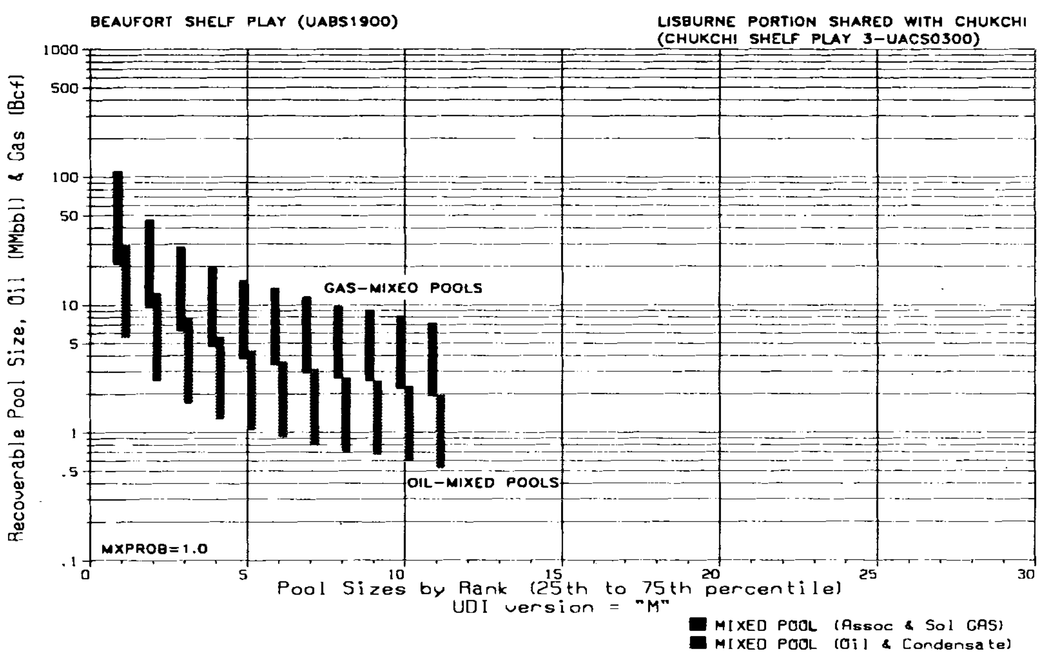


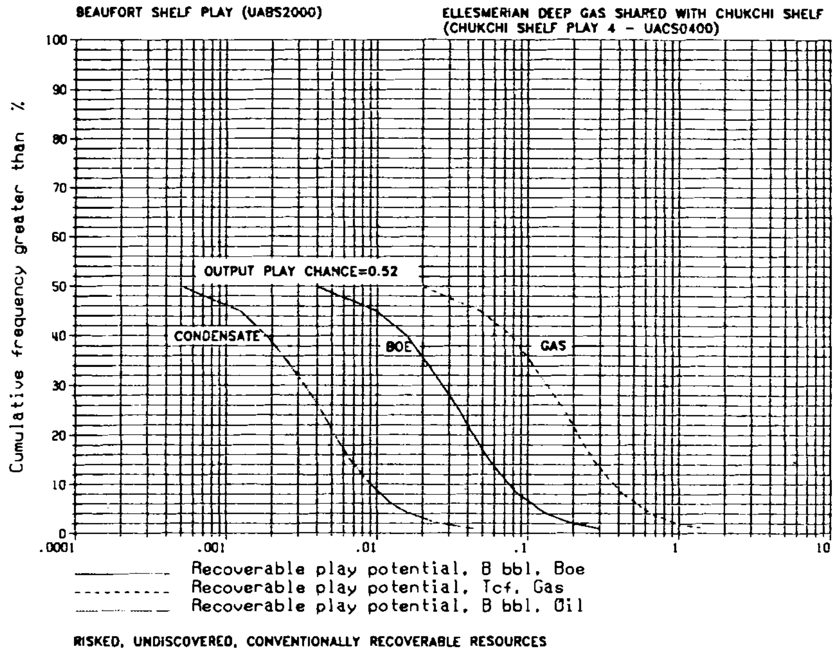
BEAUFORT SHELF PLAY (UABS1800)			
FRACTILES	**F95**	**MEAN**	**F05**
GAS (TCFG)	**0.000**	**0.012**	**0.034**
OIL (BBO)	**0.000**	**0.0006**	**0.002**
BOE (BBO)	**0.000**	**0.003**	**0.008**



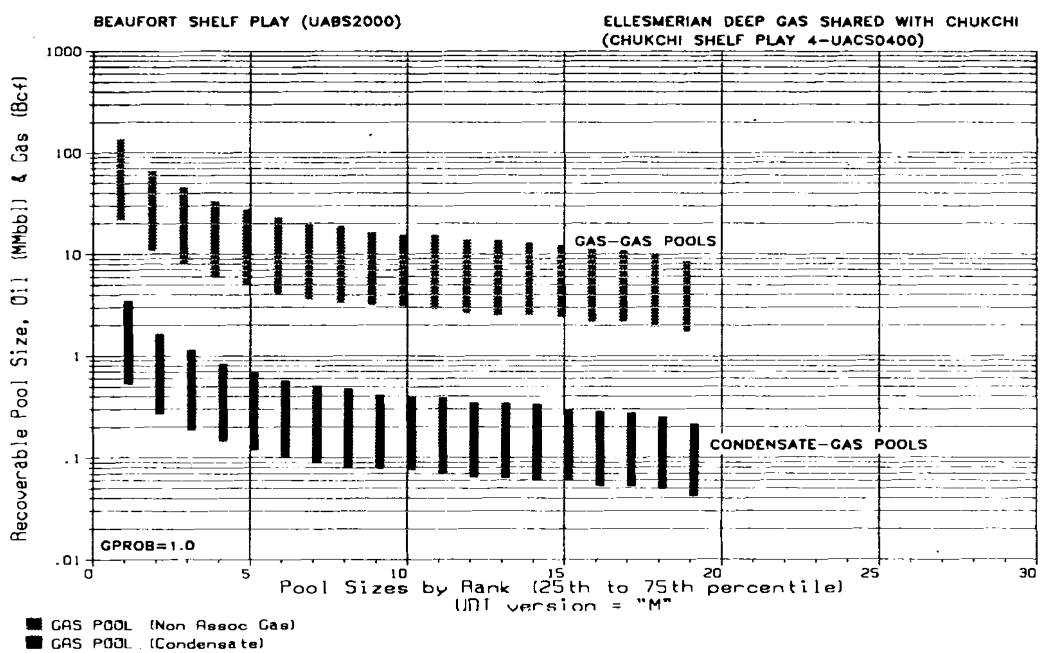


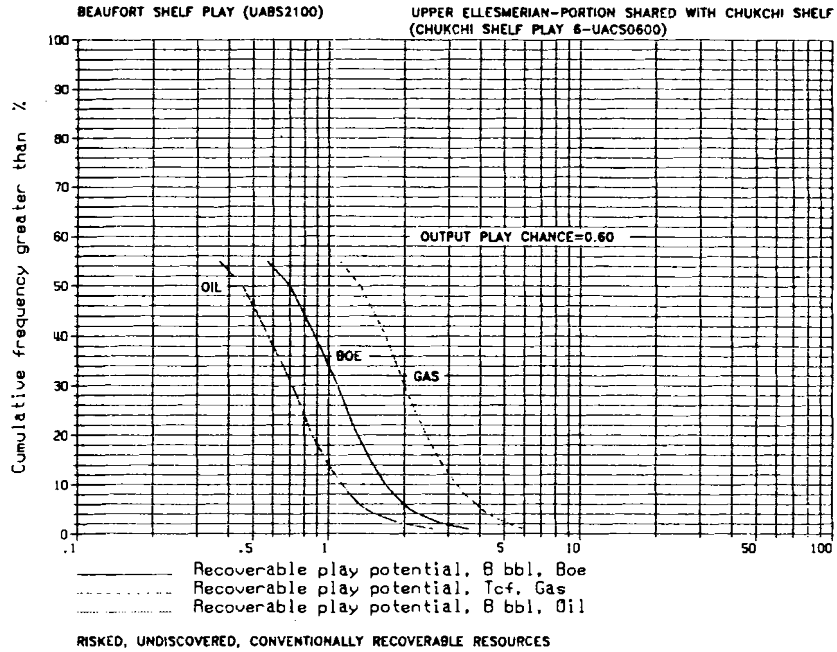
BEAUFORT SHELF PLAY (UABS1900)			
FRACTILES	**F95**	**MEAN**	**F05**
GAS (TCFG)	**0.000**	**0.065**	**0.273**
OIL (BBO)	**0.000**	**0.018**	**0.083**
BOE (BBO)	**0.000**	**0.030**	**0.132**



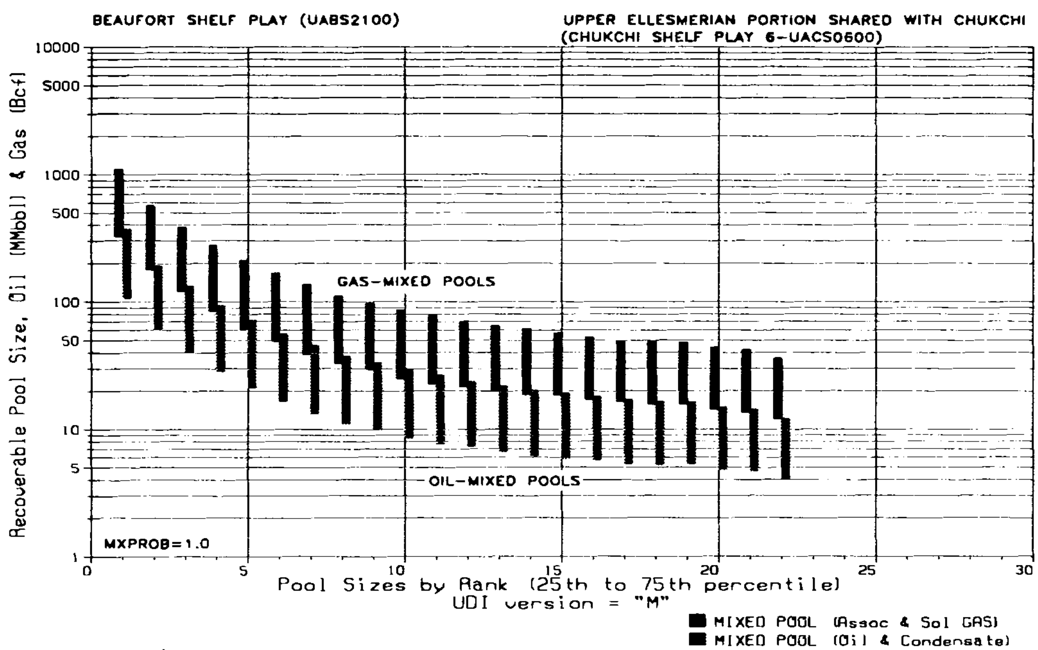


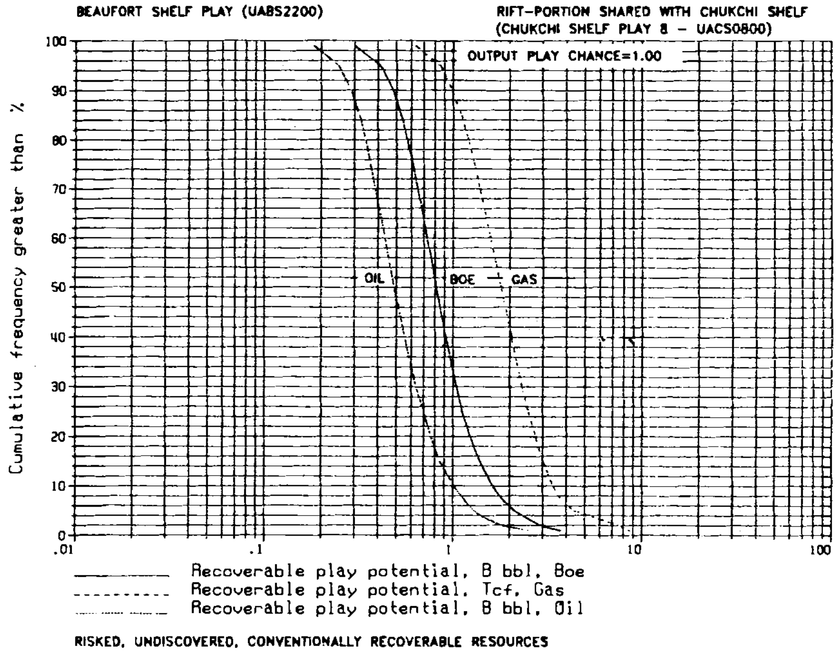
BEAUFORT SHELF PLAY (UABS2000)			
FRACTILES	**F95**	**MEAN**	**F05**
GAS (TCFG)	**0.000**	**0.150**	**0.583**
OIL (BBO)	**0.000**	**0.004**	**0.014**
BOE (BBO)	**0.000**	**0.031**	**0.118**



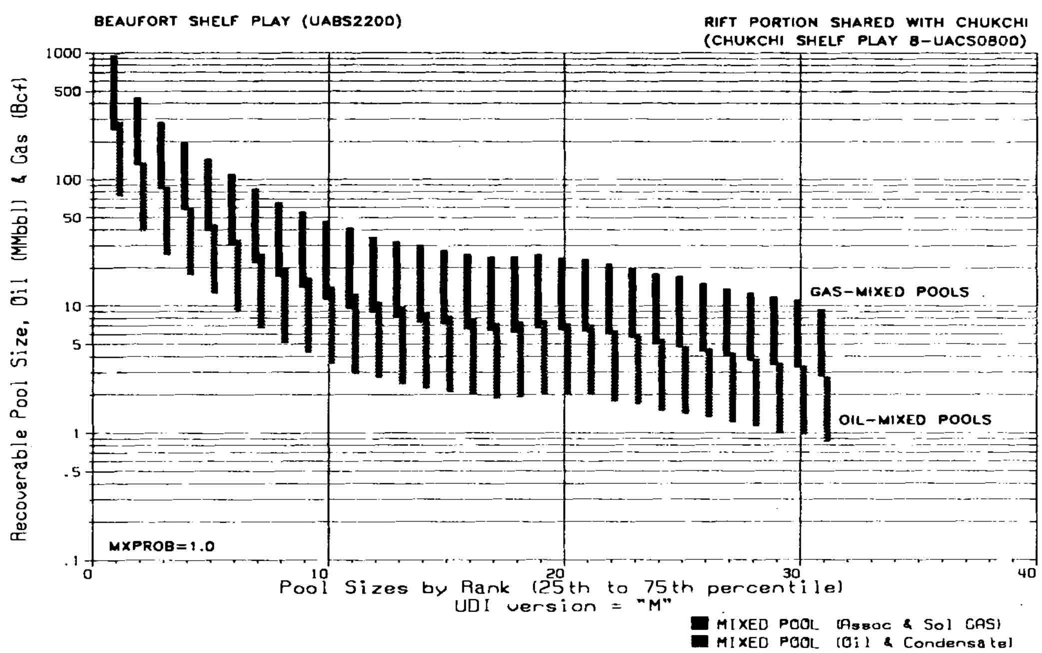


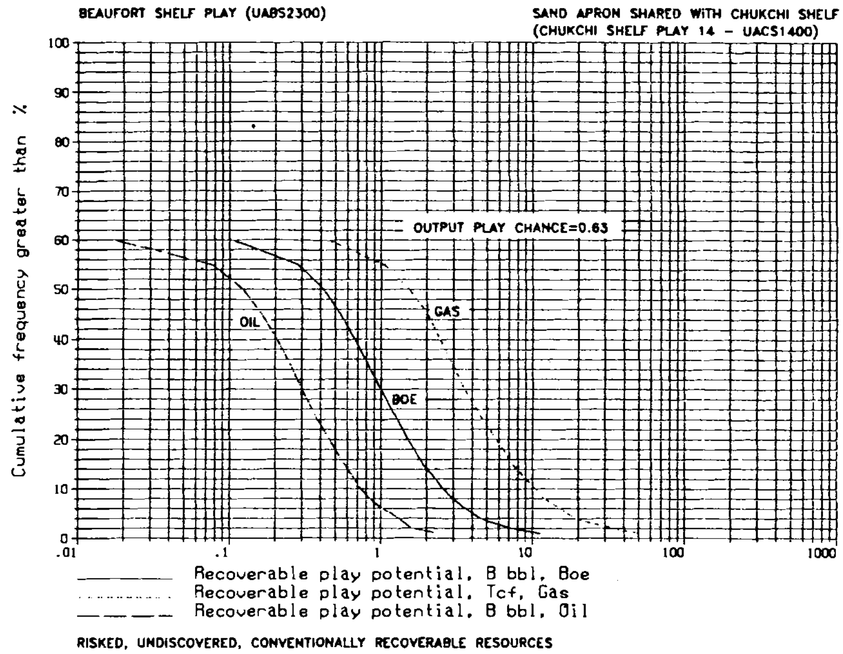
BEAUFORT SHELF PLAY (UABS2100)			
FRACTILES	**F95**	**MEAN**	**F05**
GAS (TCFG)	**0.000**	**1.391**	**4.075**
OIL (BBO)	**0.000**	**0.497**	**1.407**
BOE (BBO)	**0.000**	**0.744**	**2.093**



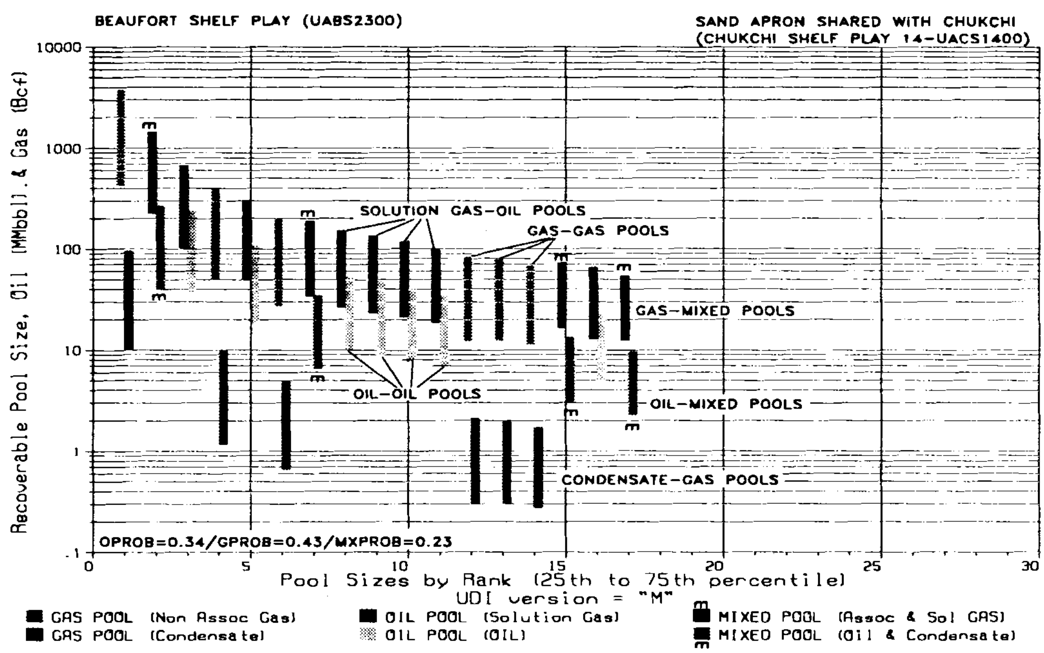


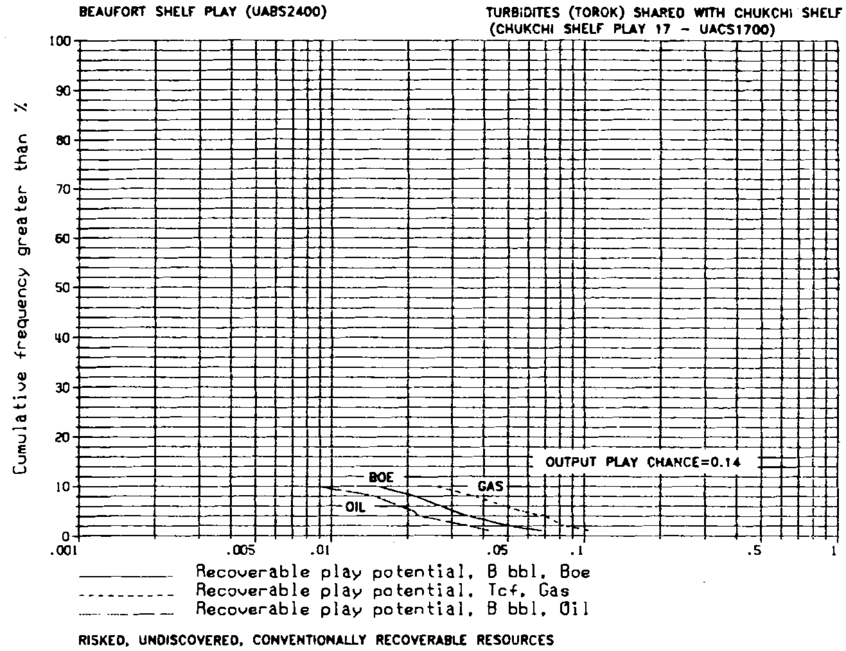
BEAUFORT SHELF PLAY (UABS2200)			
FRACTILES	**F95**	**MEAN**	**F05**
GAS (TCFG)	**0.855**	**2.166**	**4.404**
OIL (BBO)	**0.248**	**0.606**	**1.300**
BOE (BBO)	**0.410**	**0.991**	**2.121**



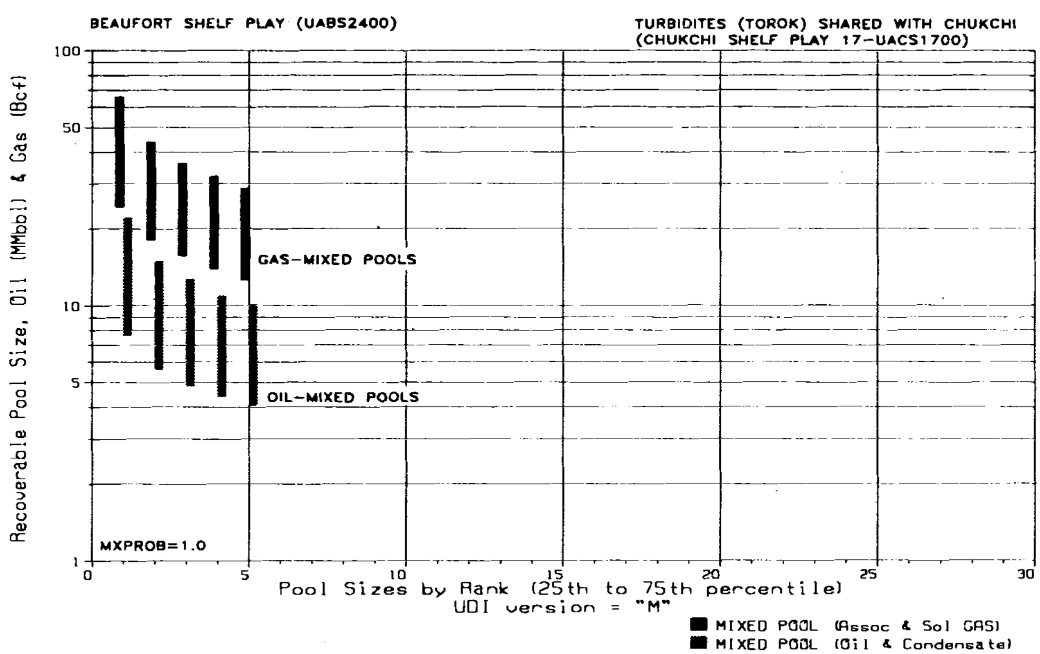


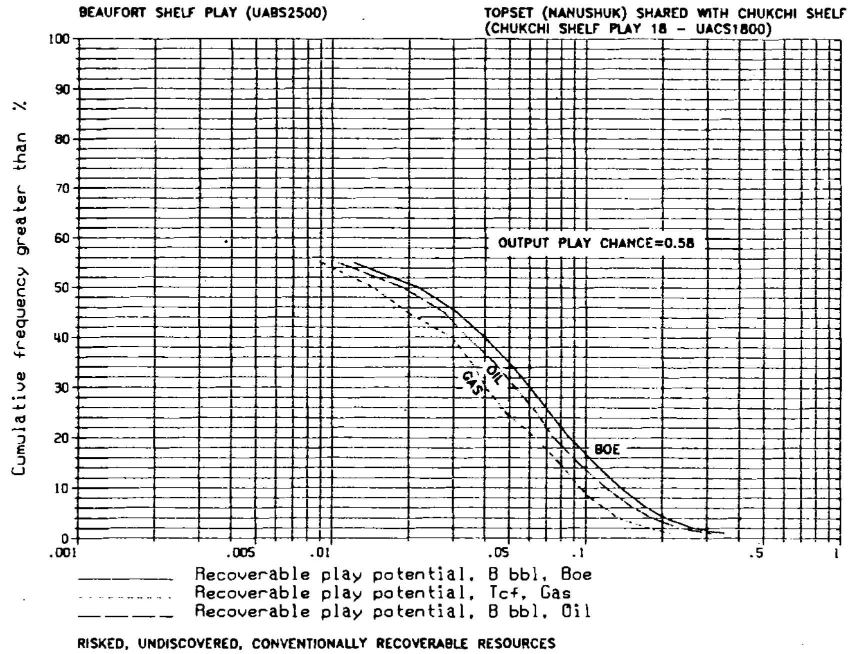
BEAUFORT SHELF PLAY (UABS2300)			
FRACTILES	**F95**	**MEAN**	**F05**
GAS (TCFG)	**0.000**	**4.895**	**17.000**
OIL (BBO)	**0.000**	**0.291**	**1.173**
BOE (BBO)	**0.000**	**1.162**	**4.029**



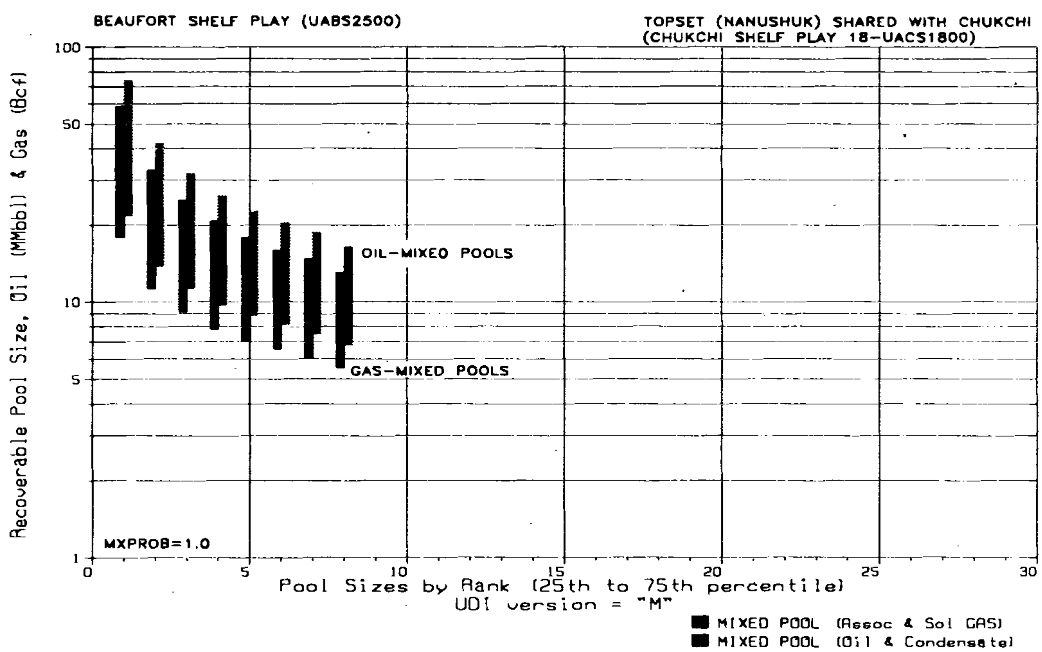


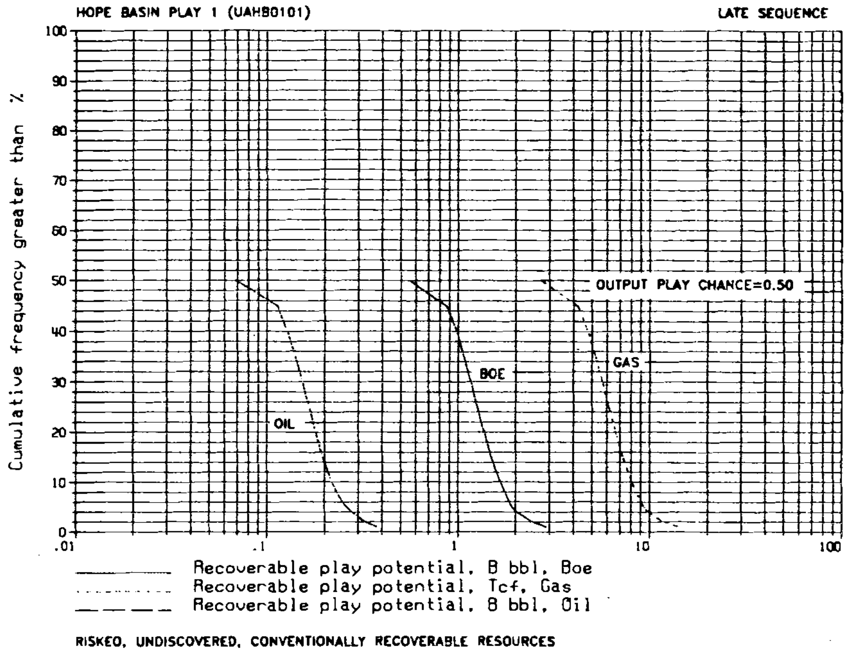
BEAUFORT SHELF PLAY (UABS2400)			
FRACTILES	**F95**	**MEAN**	**F05**
GAS (TCFG)	**0.000**	**0.008**	**0.057**
OIL (BBO)	**0.000**	**0.003**	**0.021**
BOE (BBO)	**0.000**	**0.004**	**0.030**



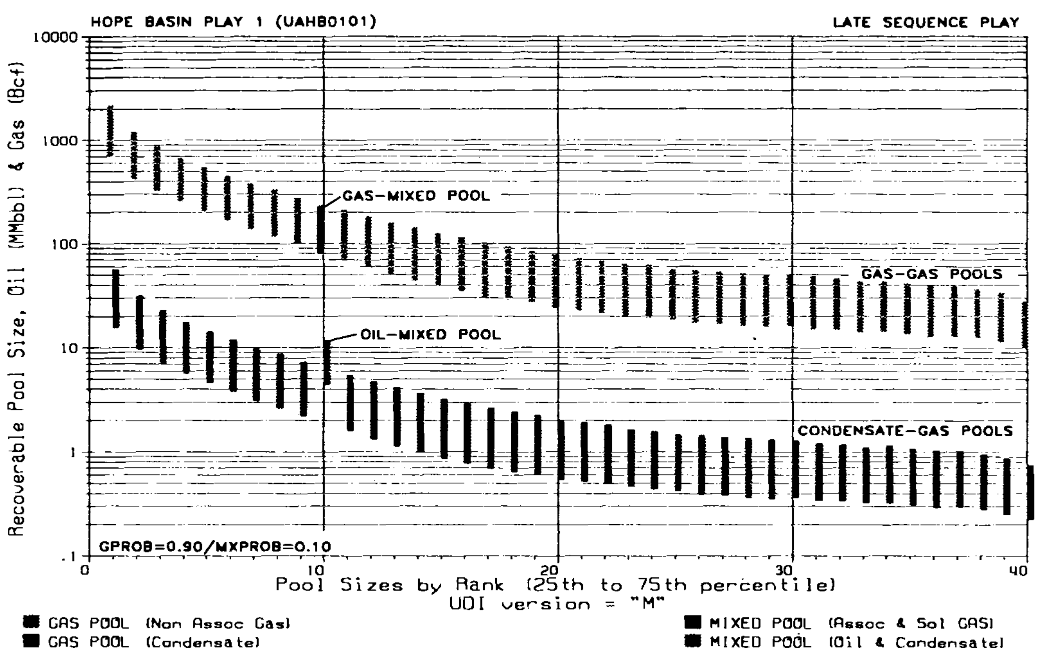


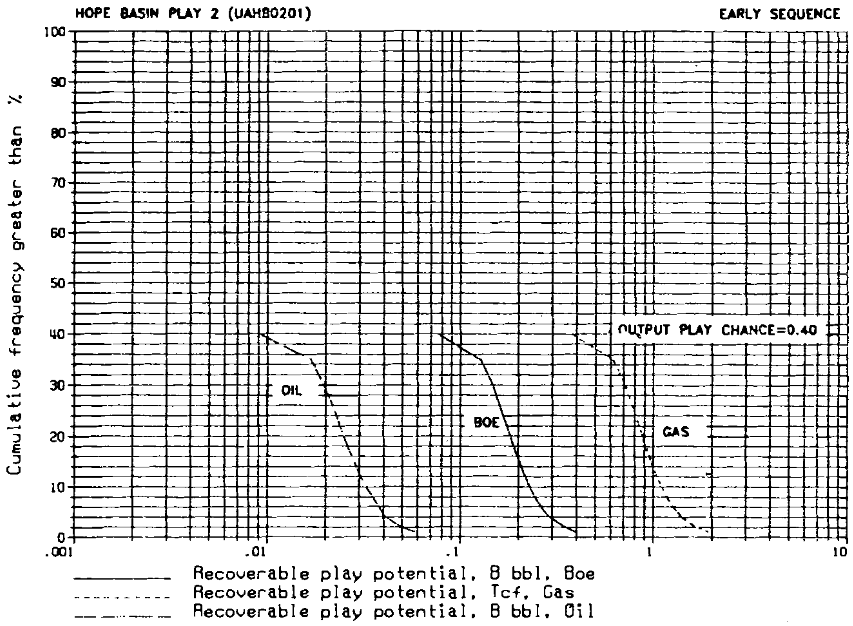
BEAUFORT SHELF PLAY (UABS2500)			
FRACTILES	**F95**	**MEAN**	**F05**
GAS (TCFG)	**0.000**	**0.034**	**0.127**
OIL (BBO)	**0.000**	**0.044**	**0.167**
BOE (BBO)	**0.000**	**0.050**	**0.189**



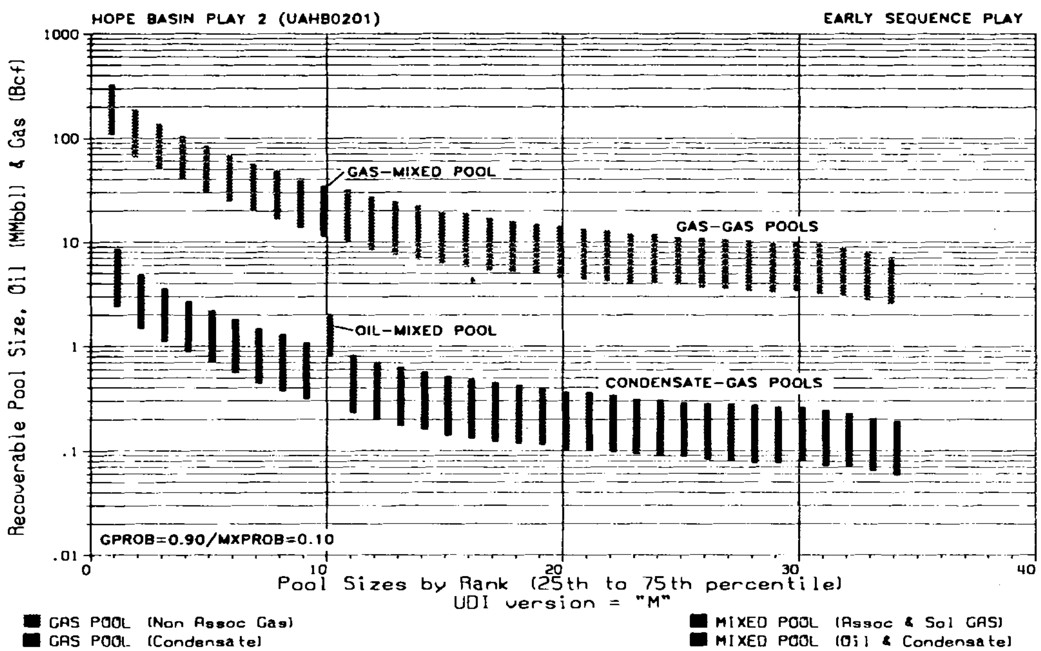


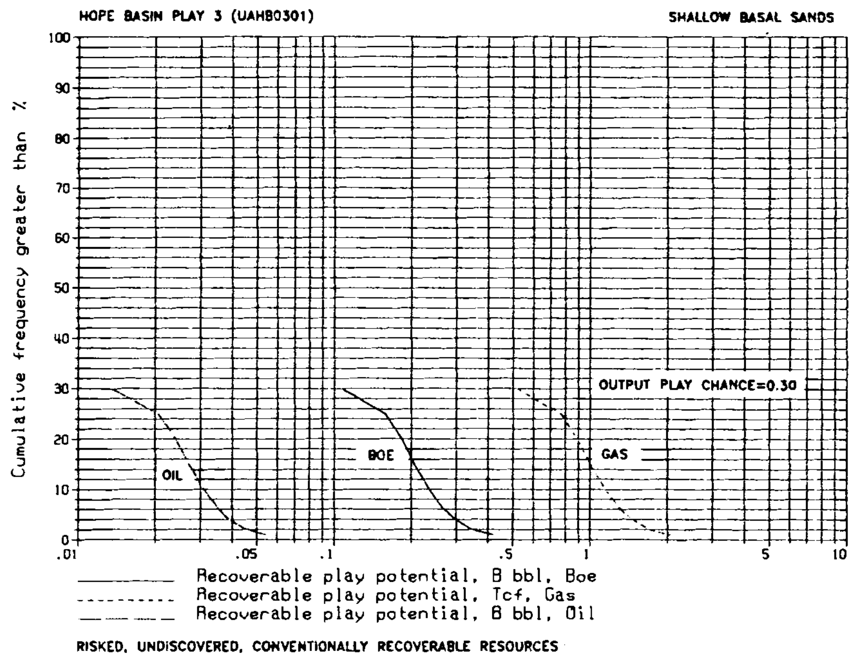
HOPE BASIN PLAY 1 (UAHB0101)			
FRACTILES	**F95**	**MEAN**	**F05**
GAS (TCFG)	**0.000**	**3.341**	**9.368**
OIL (BBO)	**0.000**	**0.090**	**0.262**
BOE (BBO)	**0.000**	**0.685**	**1.912**



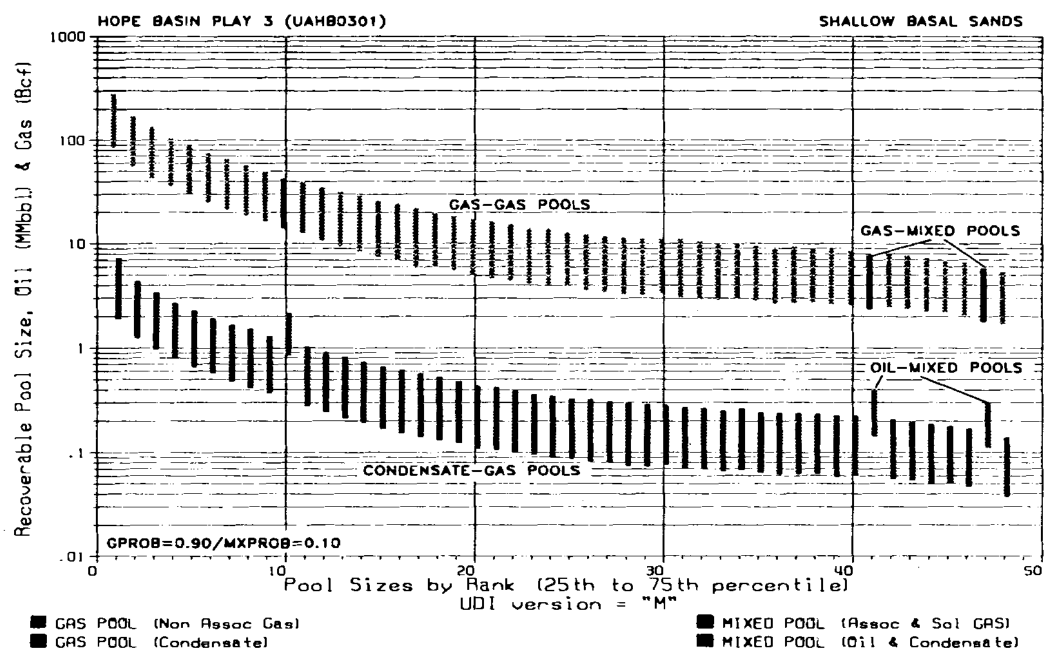


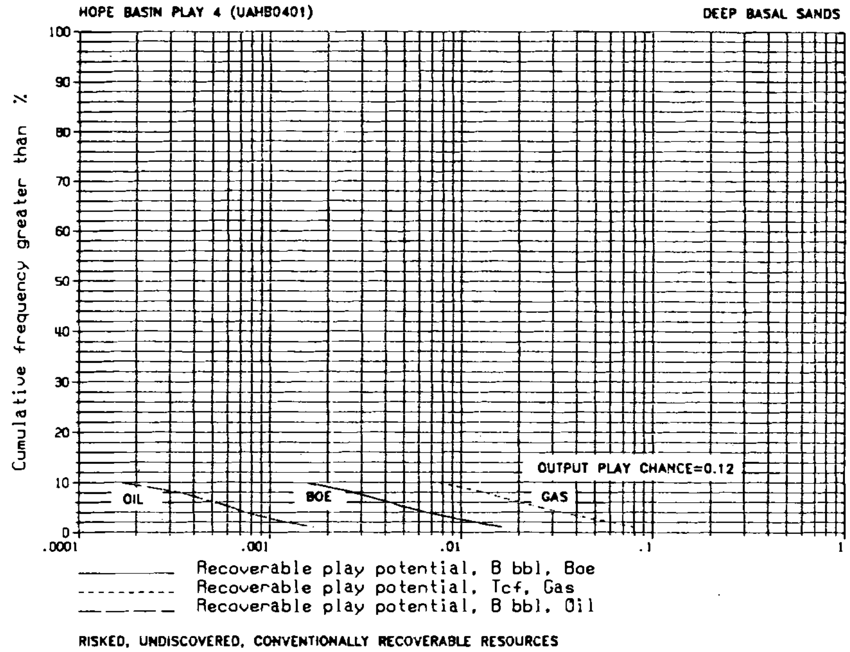
HOPE BASIN PLAY 2 (UAHB0201)			
FRACTILES	**F95**	**MEAN**	**F05**
GAS (TCFG)	**0.000**	**0.387**	**1.331**
OIL (BBO)	**0.000**	**0.011**	**0.039**
BOE (BBO)	**0.000**	**0.080**	**0.273**



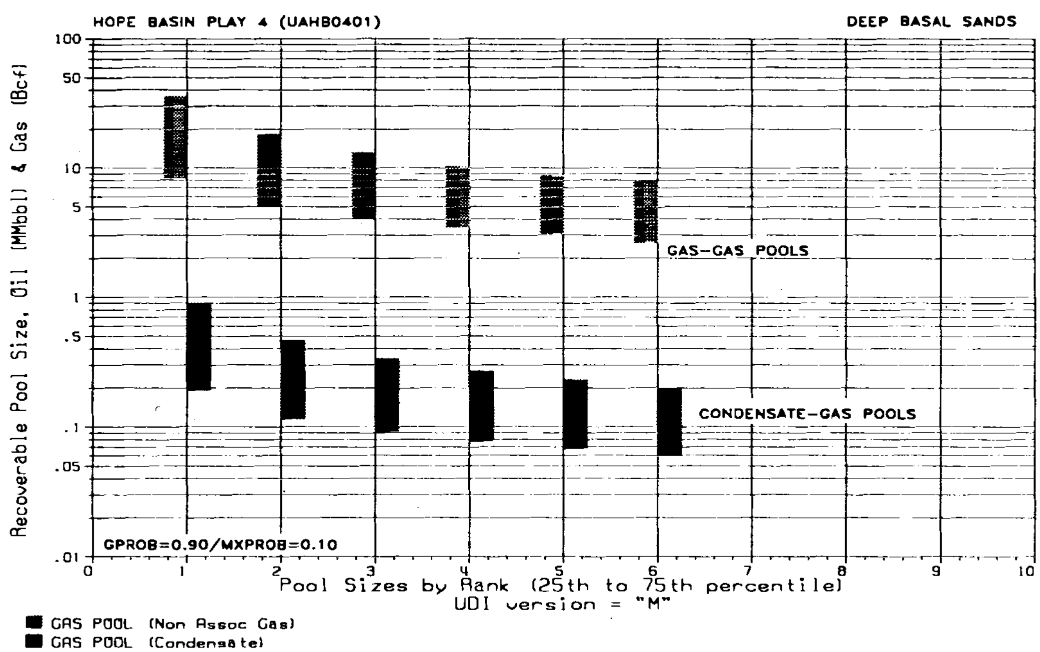


HOPE BASIN PLAY 3 (UAHB0301)			
FRACTILES	**F95**	**MEAN**	**F05**
GAS (TCFG)	**0.000**	**0.333**	**1.387**
OIL (BBO)	**0.000**	**0.009**	**0.037**
BOE (BBO)	**0.000**	**0.068**	**0.282**





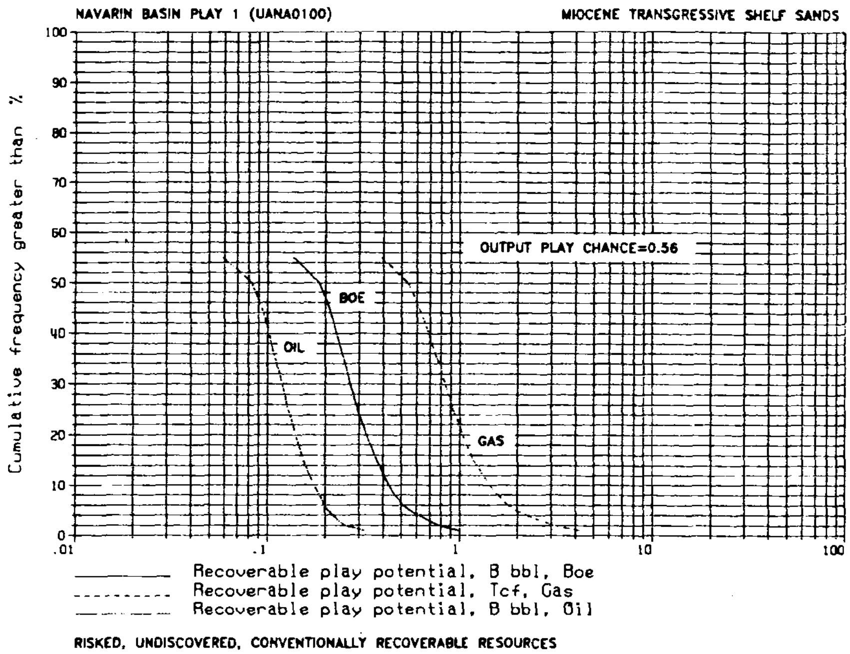
HOPE BASIN PLAY 4 (UAHB0401)			
FRACTILES	**F95**	**MEAN**	**F05**
GAS (TCFG)	**0.000**	**0.004**	**0.026**
OIL (BBO)	**0.000**	**0.00009**	**0.0006**
BOE (BBO)	**0.000**	**0.0008**	**0.005**



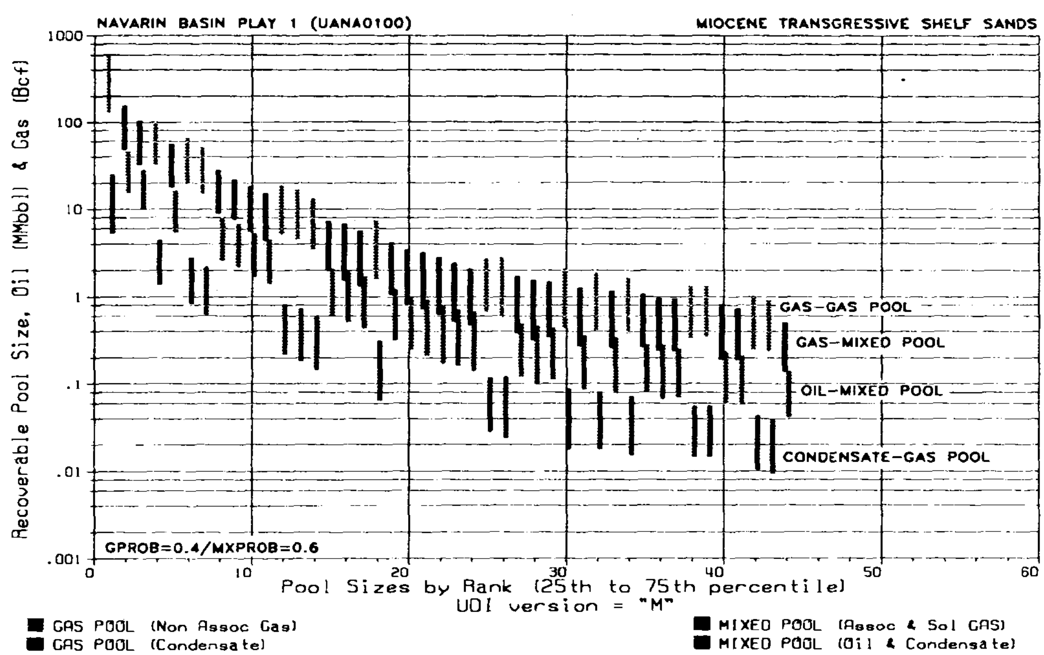
APPENDIX B

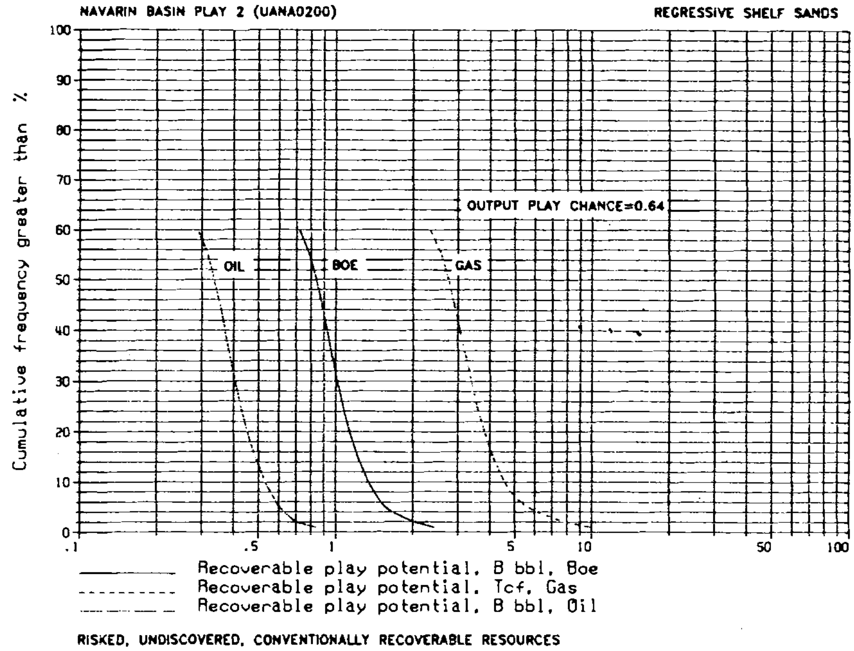
BERING SHELF SUBREGION PLAY SUMMARIES

NAVARIN BASIN
NORTH ALEUTIAN BASIN
ST. GEORGE BASIN
NORTON BASIN
ST. MATTHEW-HALL BASIN

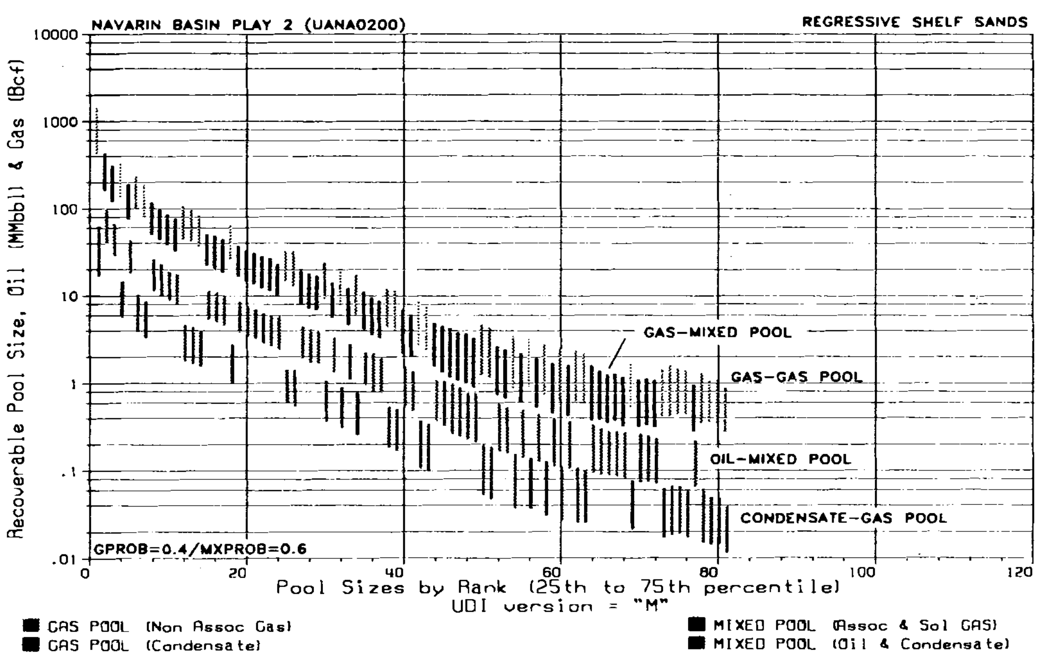


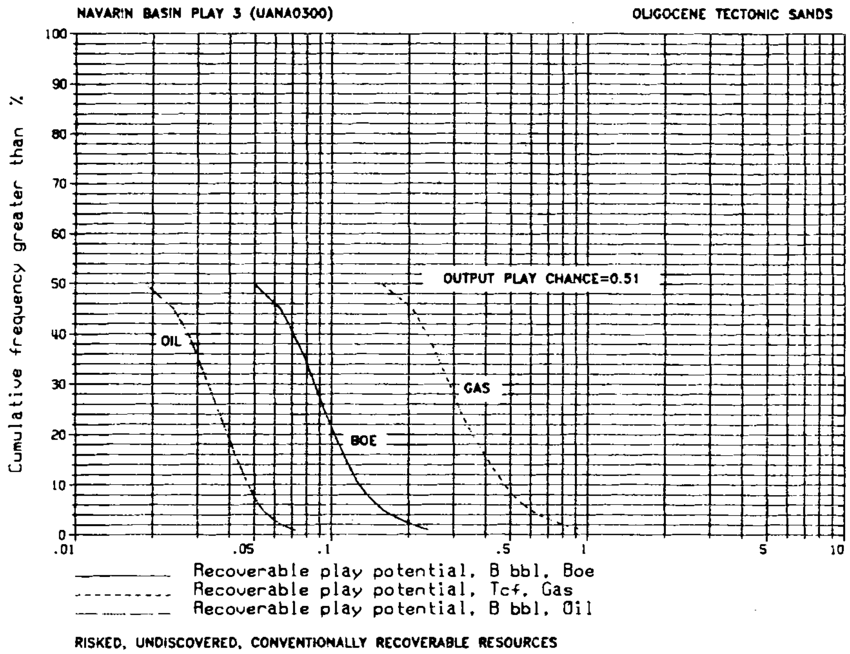
NAVARIN BASIN PLAY 1 (UANA0100)			
FRACTILES	**F95**	**MEAN**	**F05**
GAS (TCFG)	**0.000**	**0.666**	**1.951**
OIL (BBO)	**0.000**	**0.078**	**0.206**
BOE (BBO)	**0.000**	**0.196**	**0.550**



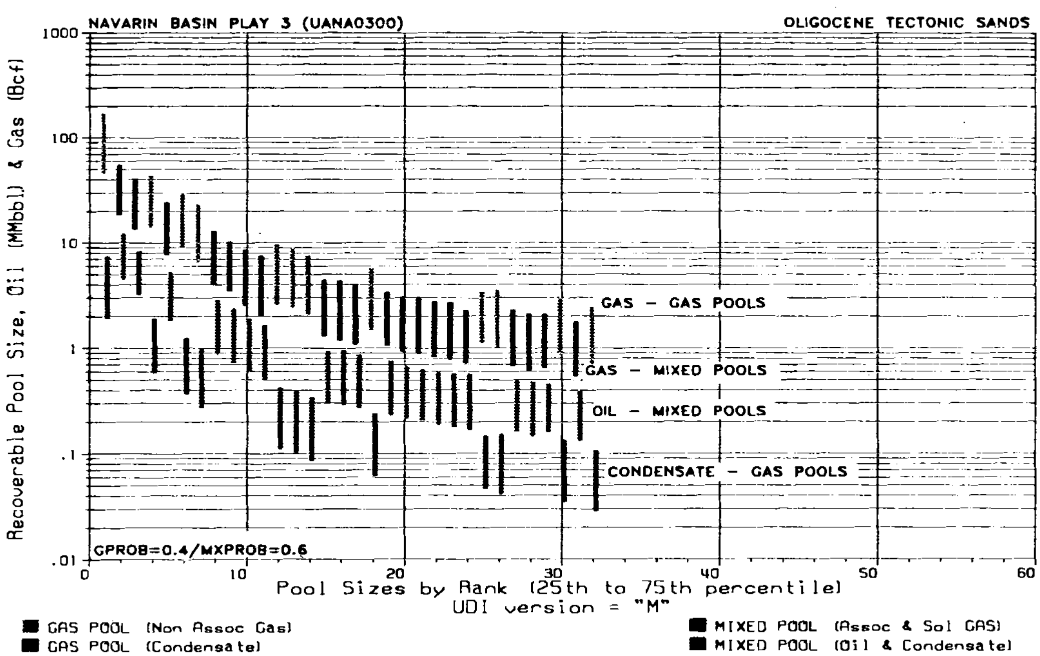


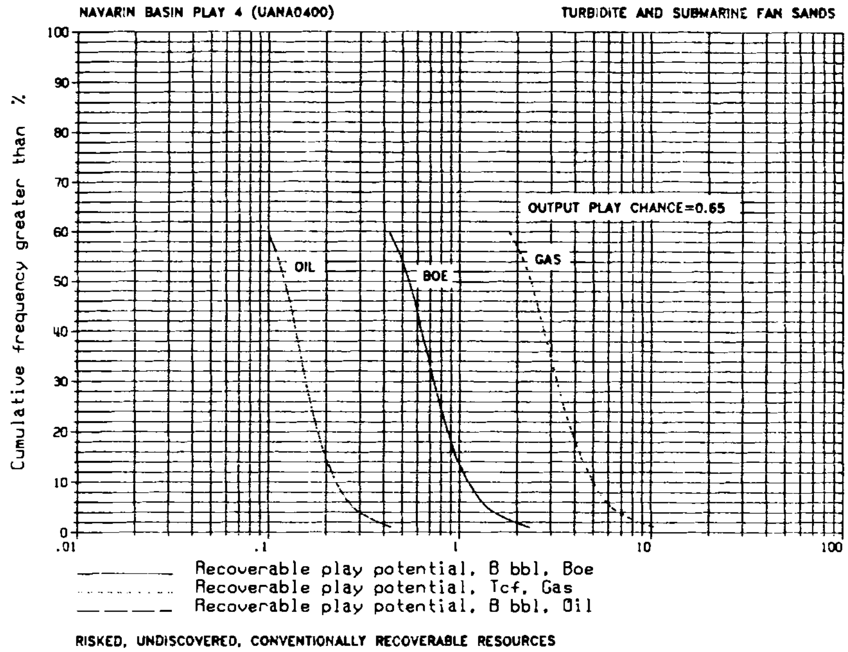
NAVARIN BASIN PLAY 2 (UANA0200)			
FRACTILES	**F95**	**MEAN**	**F05**
GAS (TCFG)	**0.000**	**2.432**	**5.655**
OIL (BBO)	**0.000**	**0.272**	**0.605**
BOE (BBO)	**0.000**	**0.705**	**1.566**



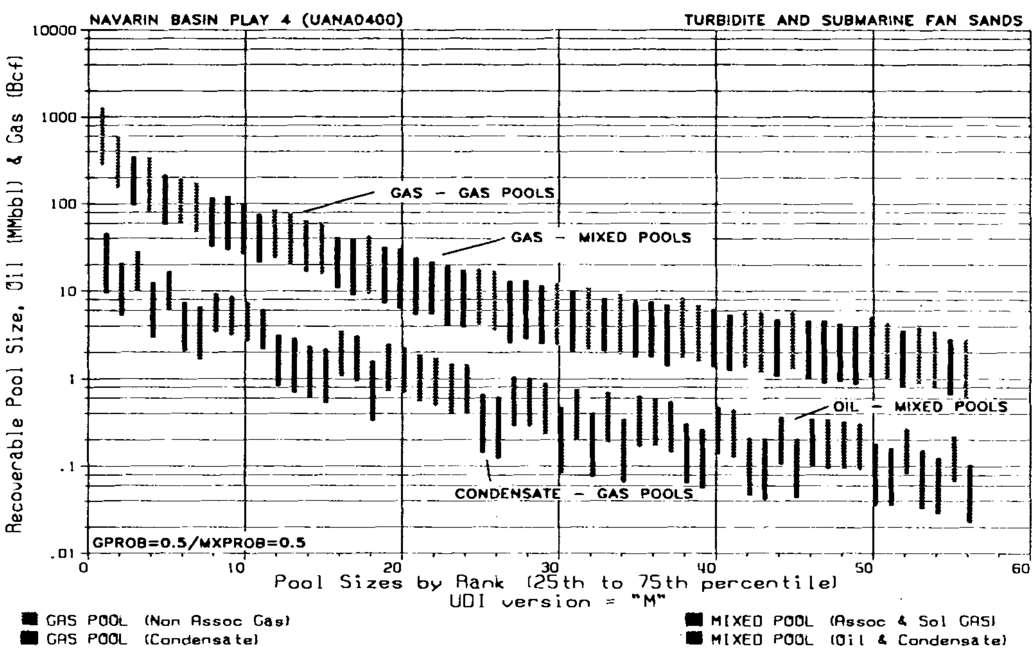


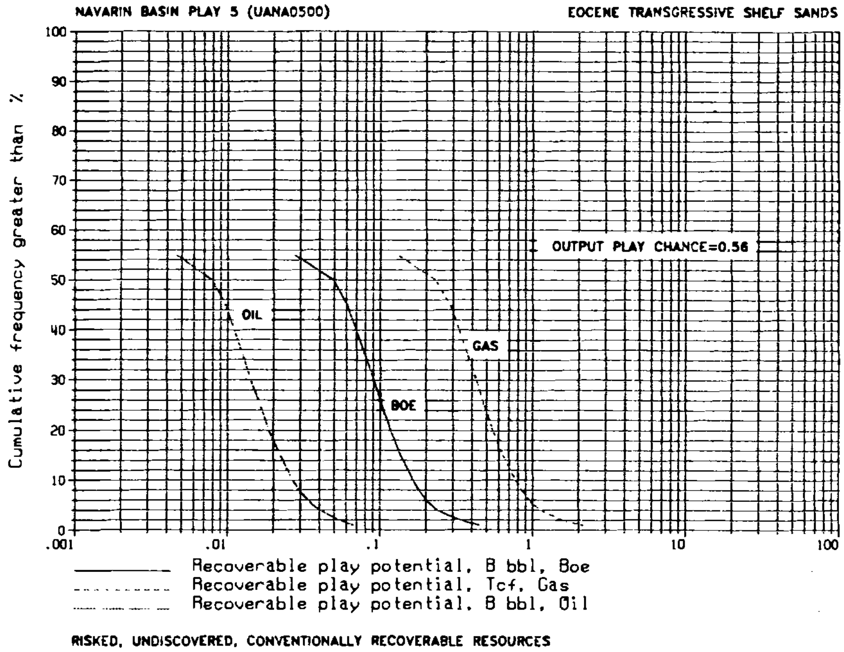
NAVARIN BASIN PLAY 3 (UANA0300)			
FRACTILES	**F95**	**MEAN**	**F05**
GAS (TCFG)	**0.000**	**0.196**	**0.599**
OIL (BBO)	**0.000**	**0.020**	**0.054**
BOE (BBO)	**0.000**	**0.054**	**0.158**



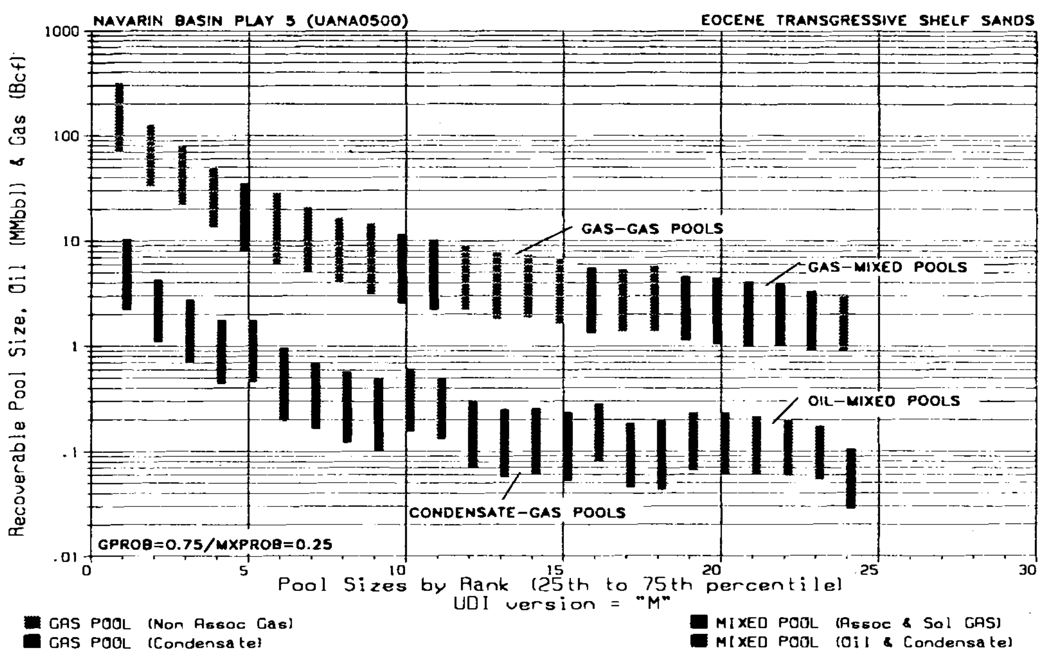


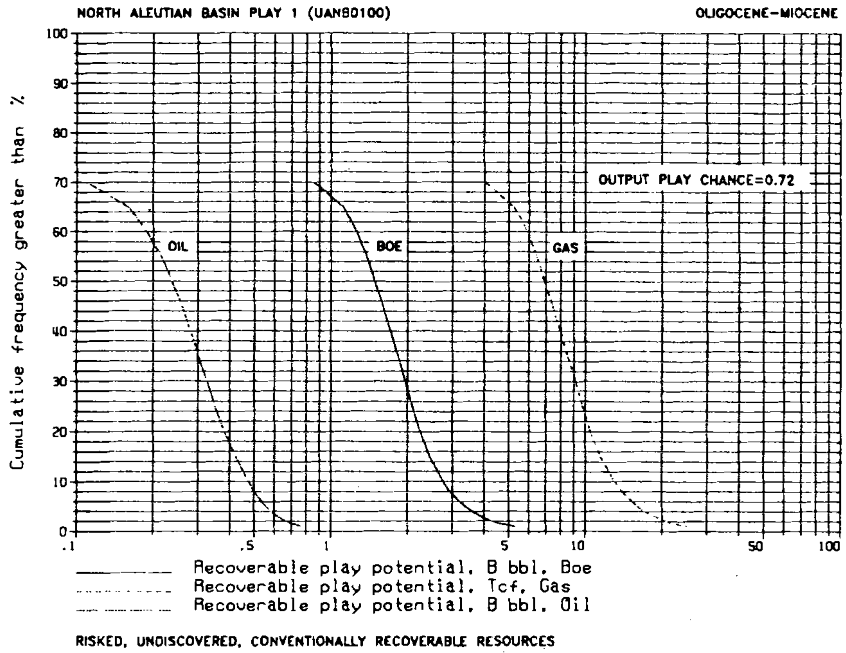
NAVARIN BASIN PLAY 4 (UANA0400)			
FRACTILES	**F95**	**MEAN**	**F05**
GAS (TCFG)	**0.000**	**2.518**	**6.236**
OIL (BBO)	**0.000**	**0.116**	**0.275**
BOE (BBO)	**0.000**	**0.564**	**1.388**



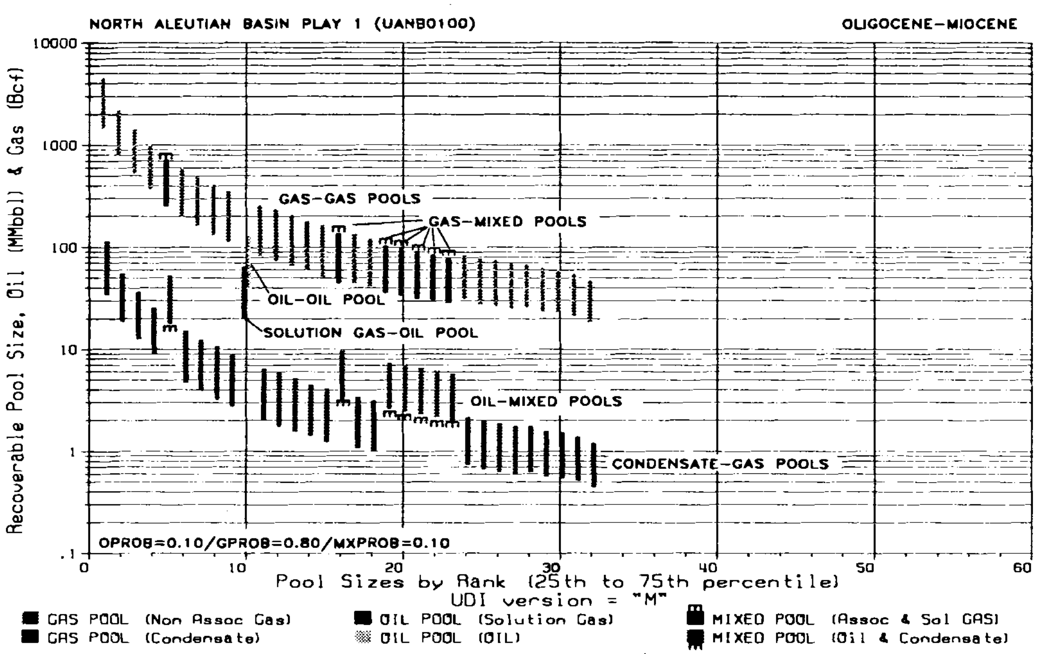


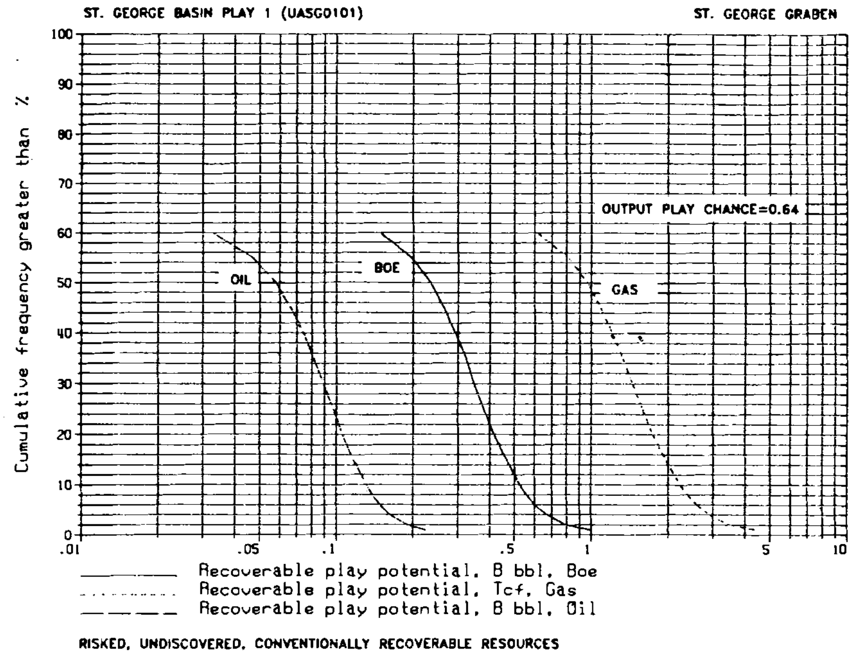
NAVARIN BASIN PLAY 5 (UANA0500)			
FRACTILES	**F95**	**MEAN**	**F05**
GAS (TCFG)	**0.000**	**0.335**	**1.024**
OIL (BBO)	**0.000**	**0.011**	**0.036**
BOE (BBO)	**0.000**	**0.071**	**0.218**



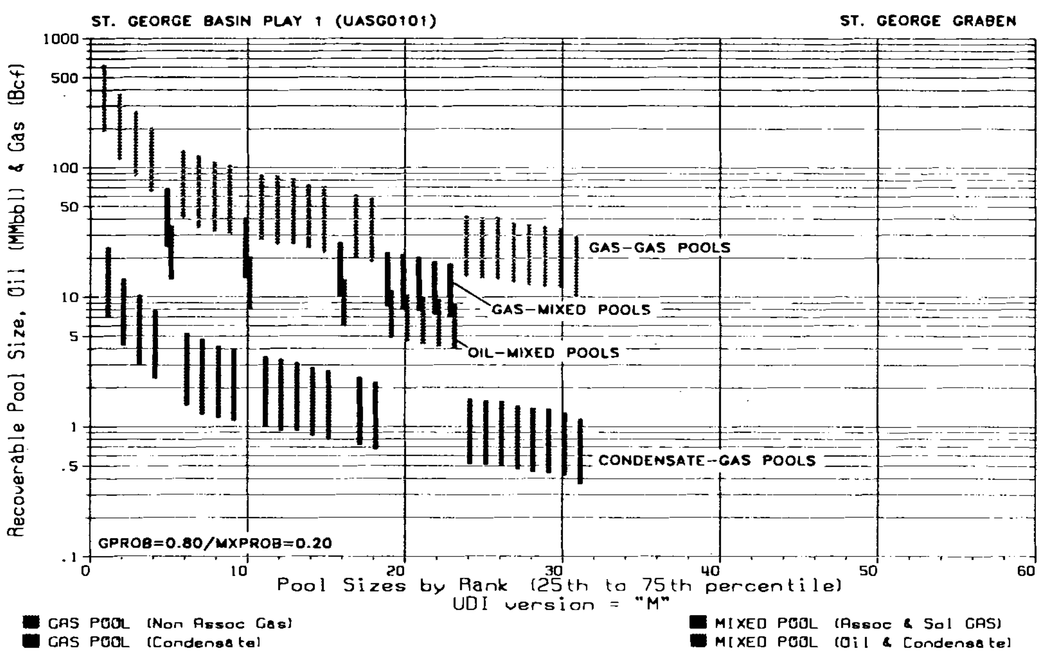


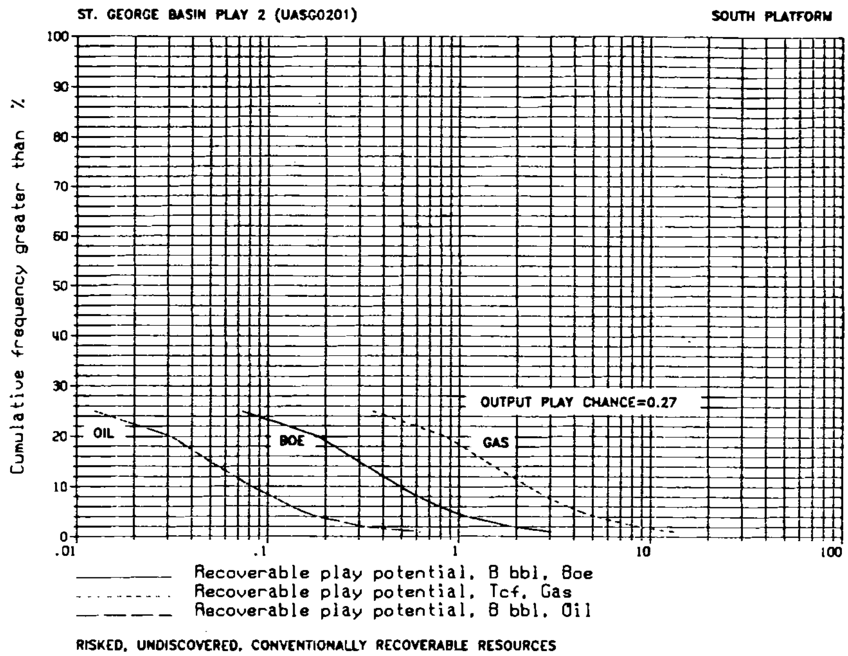
NORTH ALEUTIAN BASIN PLAY 1 (UANB0100)			
FRACTILES	**F95**	**MEAN**	**F05**
GAS (TCFG)	**0.000**	**6.791**	**16.031**
OIL (BBO)	**0.000**	**0.233**	**0.555**
BOE (BBO)	**0.000**	**1.441**	**3.379**



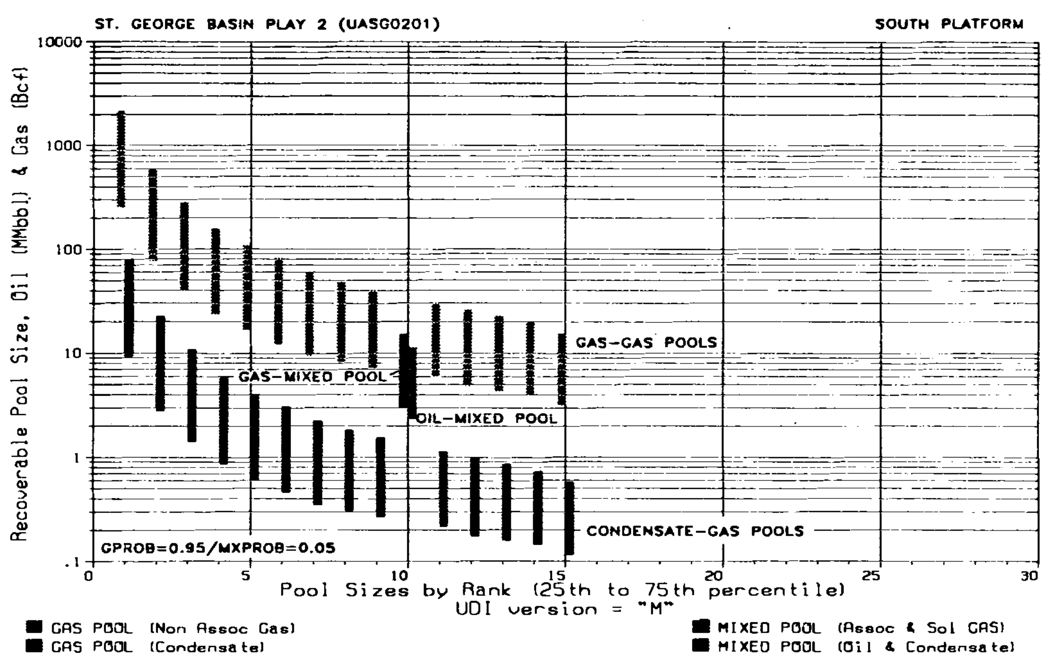


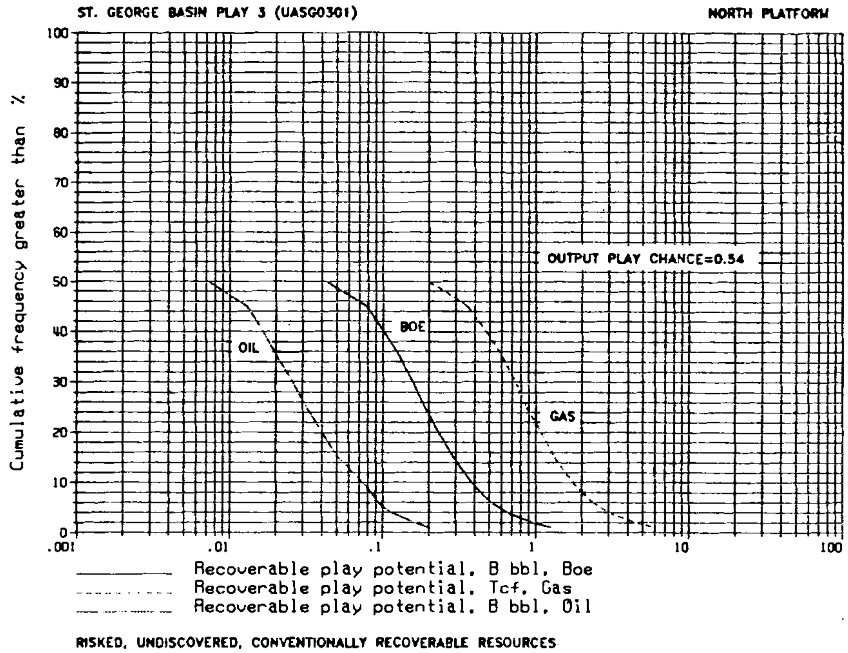
ST. GEORGE BASIN PLAY 1 (UASG0101)			
FRACTILES	**F95**	**MEAN**	**F05**
GAS (TCFG)	**0.000**	**1.007**	**2.743**
OIL (BBO)	**0.000**	**0.059**	**0.155**
BOE (BBO)	**0.000**	**0.238**	**0.633**



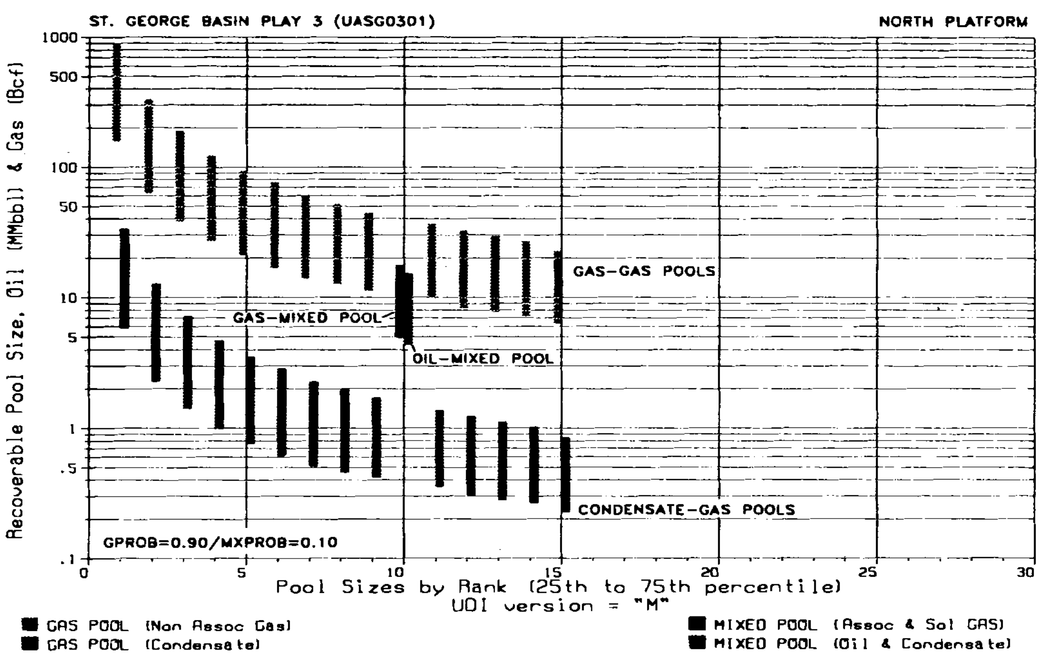


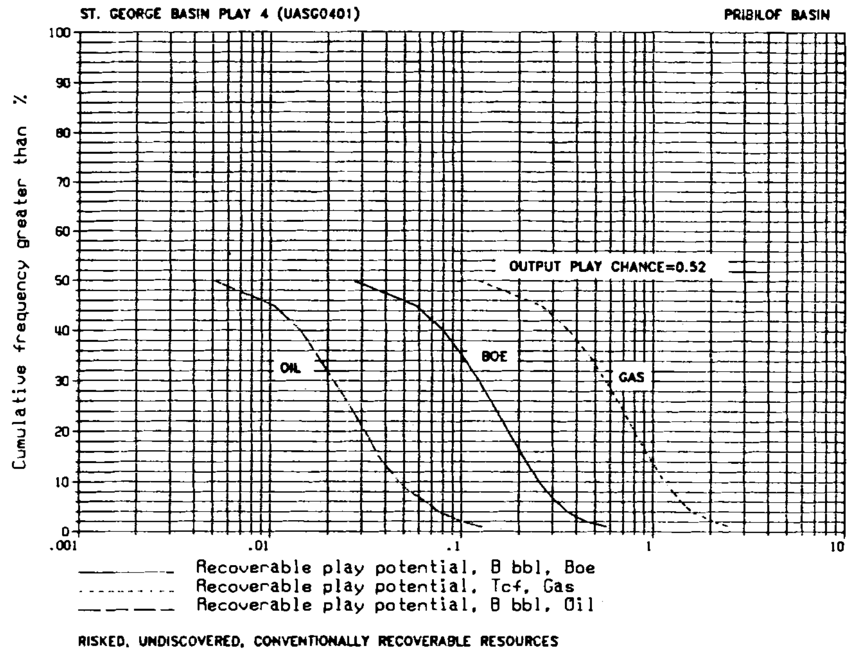
ST. GEORGE BASIN PLAY 2 (UASG0201)			
FRACTILES	**F95**	**MEAN**	**F05**
GAS (TCFG)	**0.000**	**0.898**	**4.325**
OIL (BBO)	**0.000**	**0.034**	**0.152**
BOE (BBO)	**0.000**	**0.193**	**0.922**



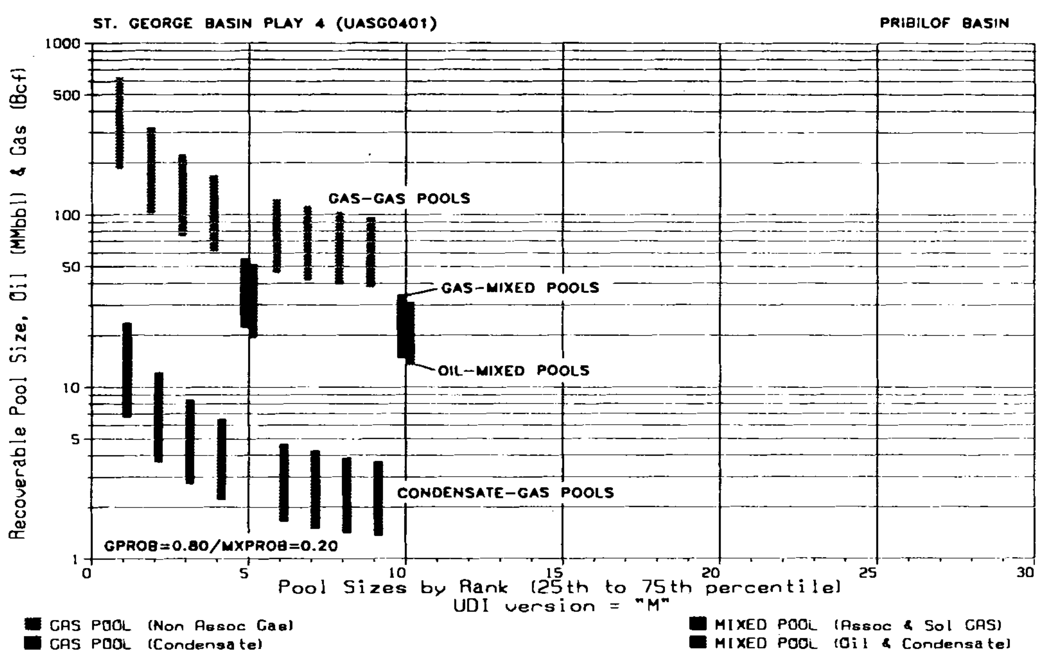


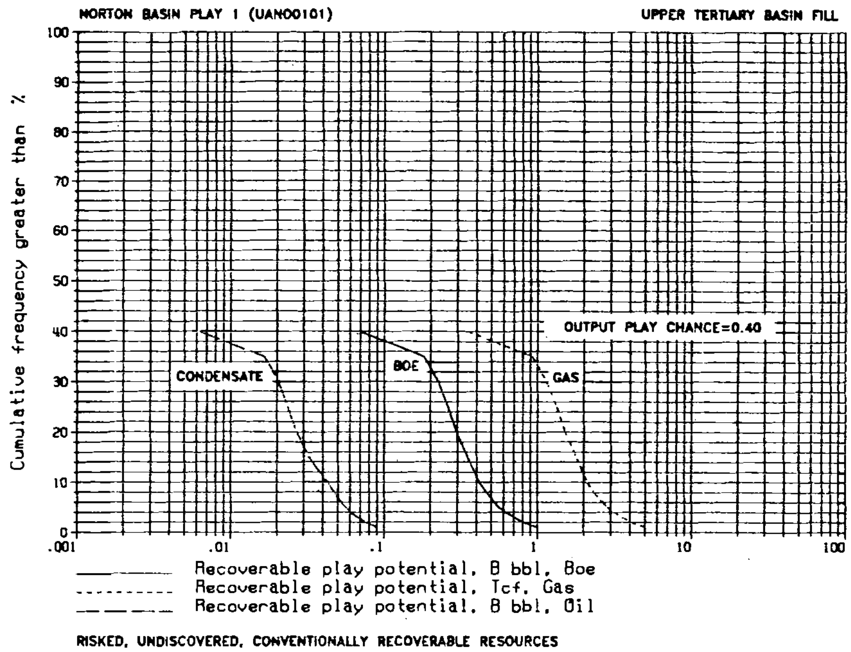
ST. GEORGE BASIN PLAY 3 (UASG0301)			
FRACTILES	**F95**	**MEAN**	**F05**
GAS (TCFG)	**0.000**	**0.676**	**2.674**
OIL (BBO)	**0.000**	**0.025**	**0.101**
BOE (BBO)	**0.000**	**0.146**	**0.579**



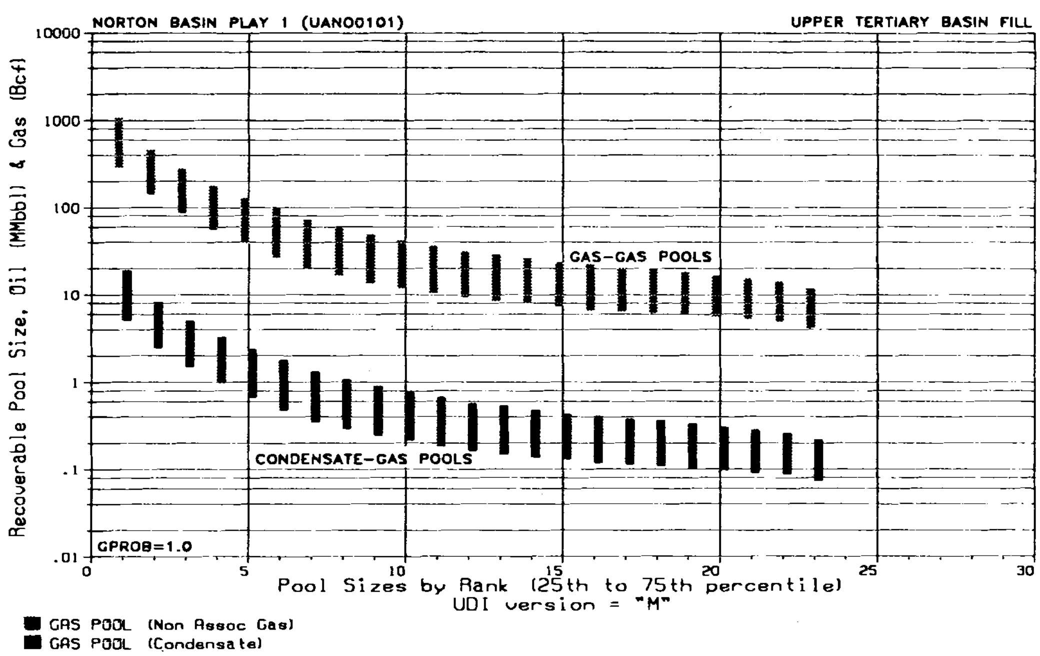


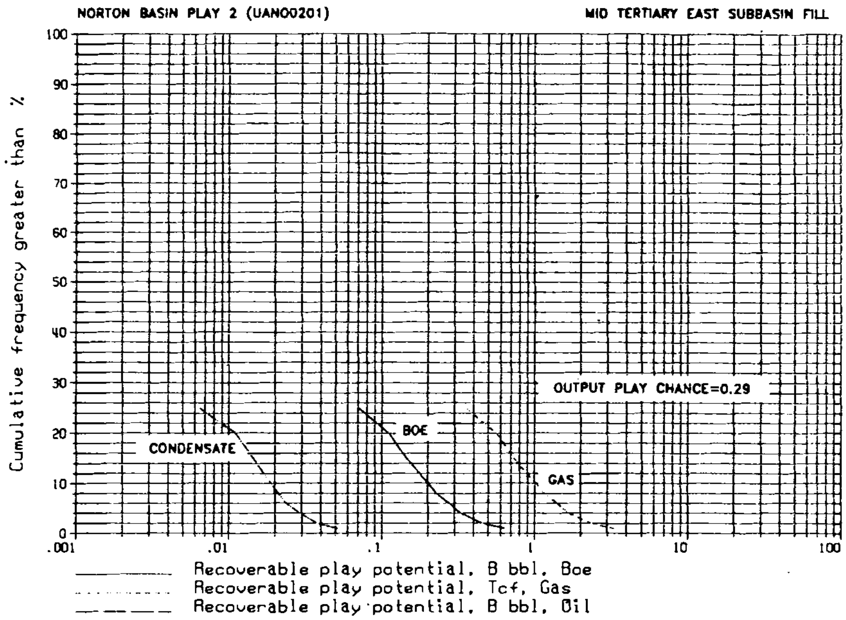
ST. GEORGE BASIN PLAY 4 (UASG0401)			
FRACTILES	**F95**	**MEAN**	**F05**
GAS (TCFG)	**0.000**	**0.414**	**1.502**
OIL (BBO)	**0.000**	**0.017**	**0.070**
BOE (BBO)	**0.000**	**0.091**	**0.337**



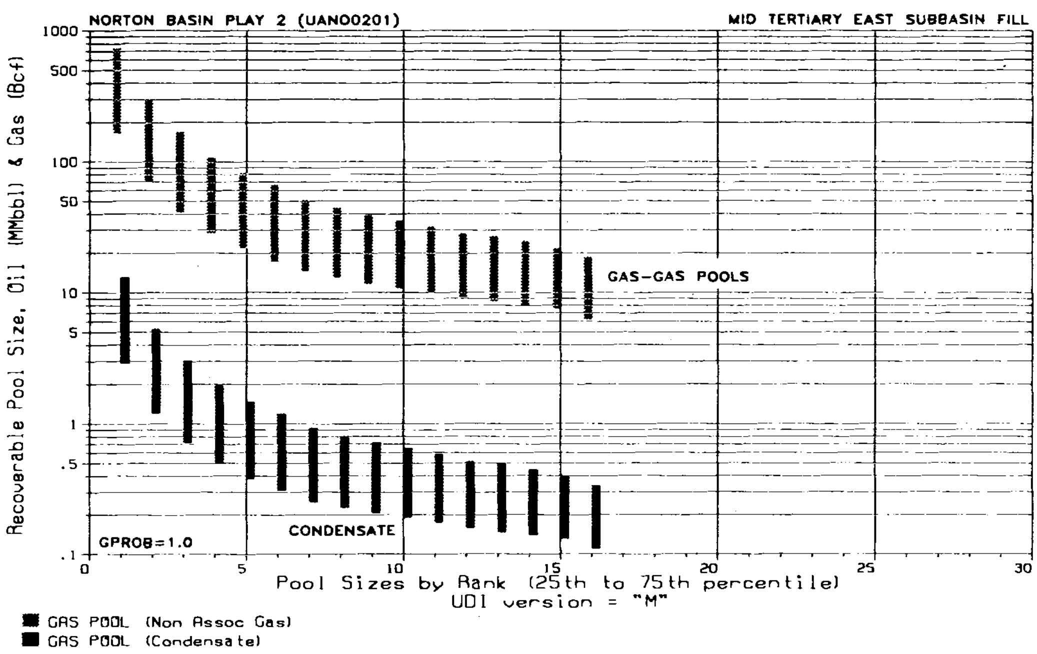


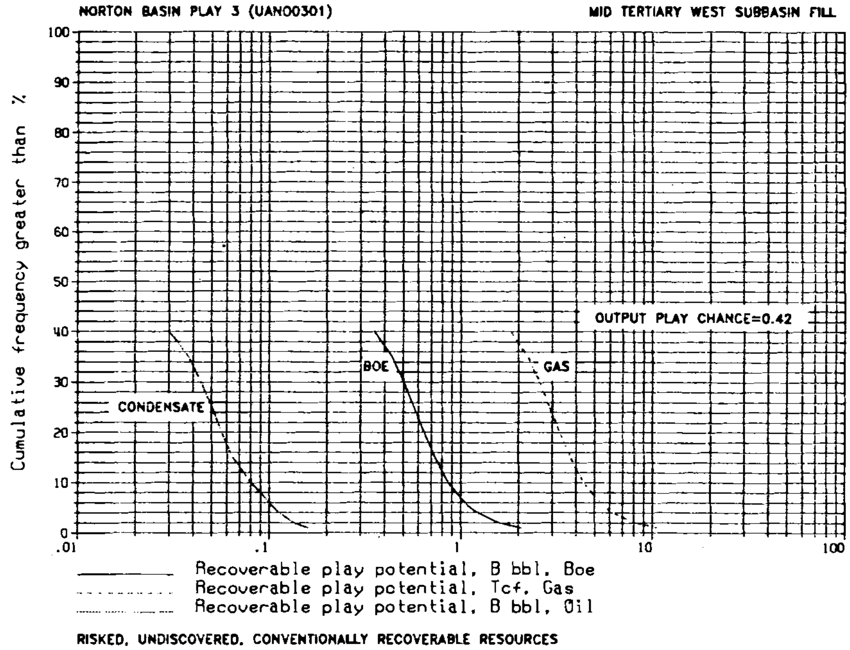
NORTON BASIN PLAY 1 (UANO0101)			
FRACTILES	F95	MEAN	F05
GAS (TCFG)	0.000	0.745	2.848
OIL (BBO)	0.000	0.014	0.056
BOE (BBO)	0.000	0.146	0.561



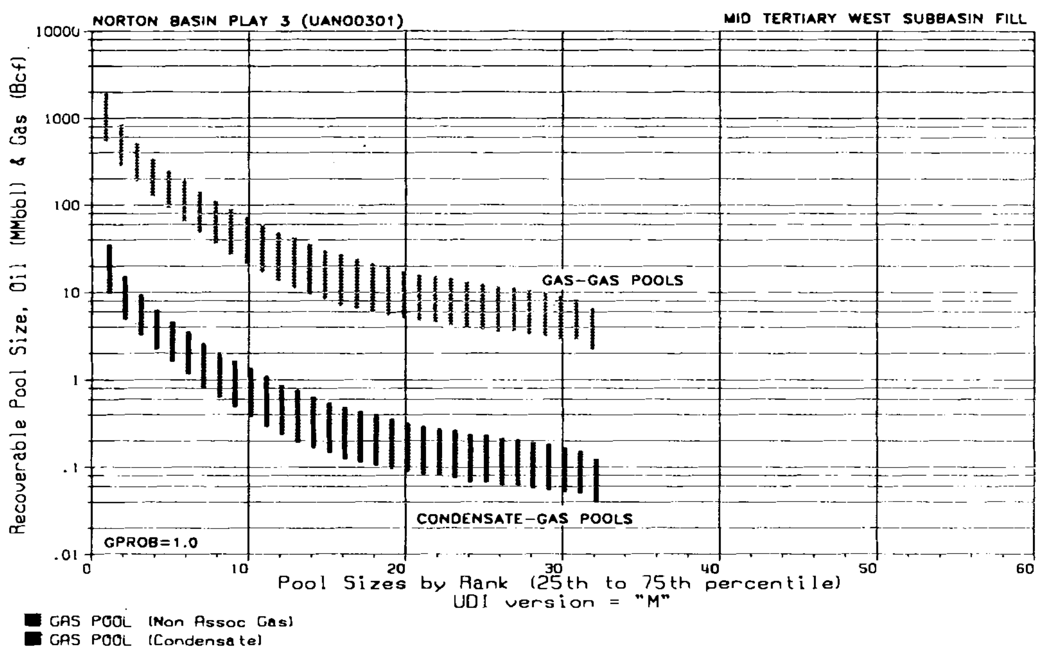


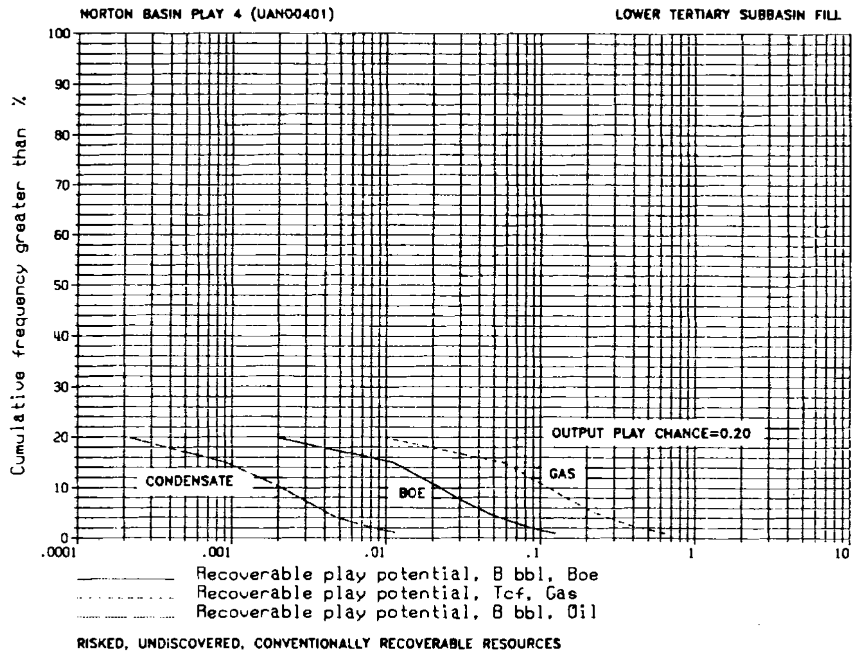
NORTON BASIN PLAY 2 (UANO0201)			
FRACTILES	F95	MEAN	F05
GAS (TCFG)	0.000	0.306	1.533
OIL (BBO)	0.000	0.005	0.026
BOE (BBO)	0.000	0.060	0.300



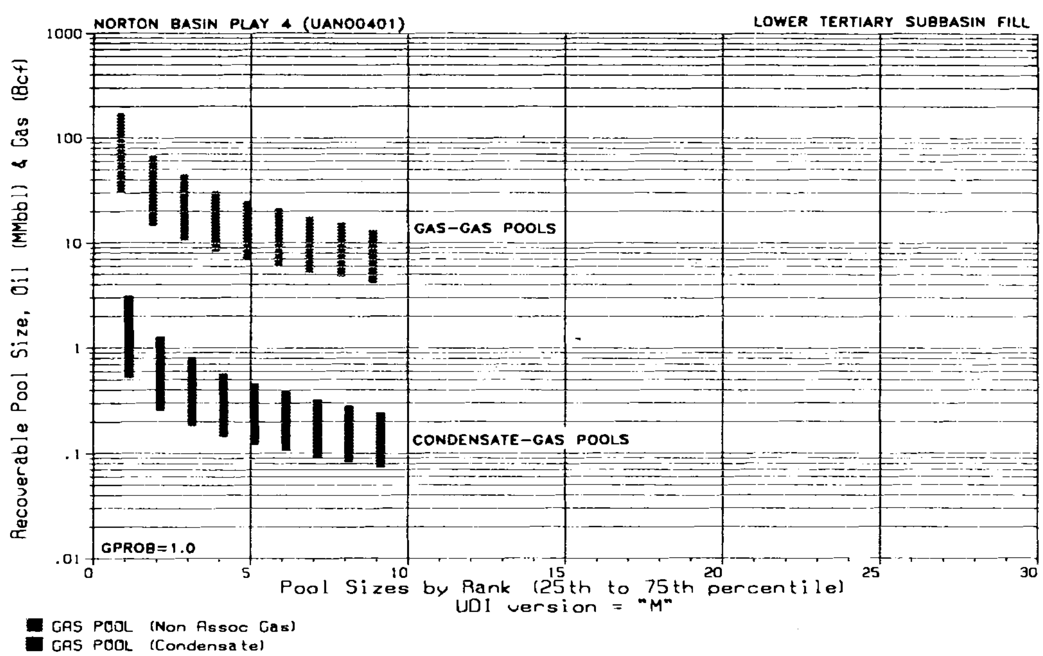


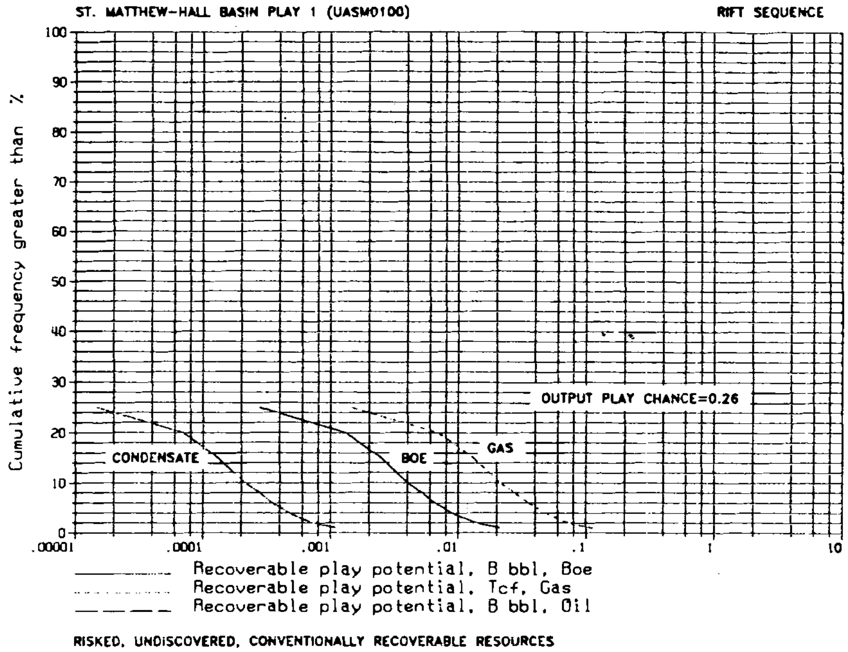
NORTON BASIN PLAY 3 (UANO0301)			
FRACTILES	F95	MEAN	F05
GAS (TCFG)	0.000	1.617	5.680
OIL (BBO)	0.000	0.028	0.105
BOE (BBO)	0.000	0.316	1.114



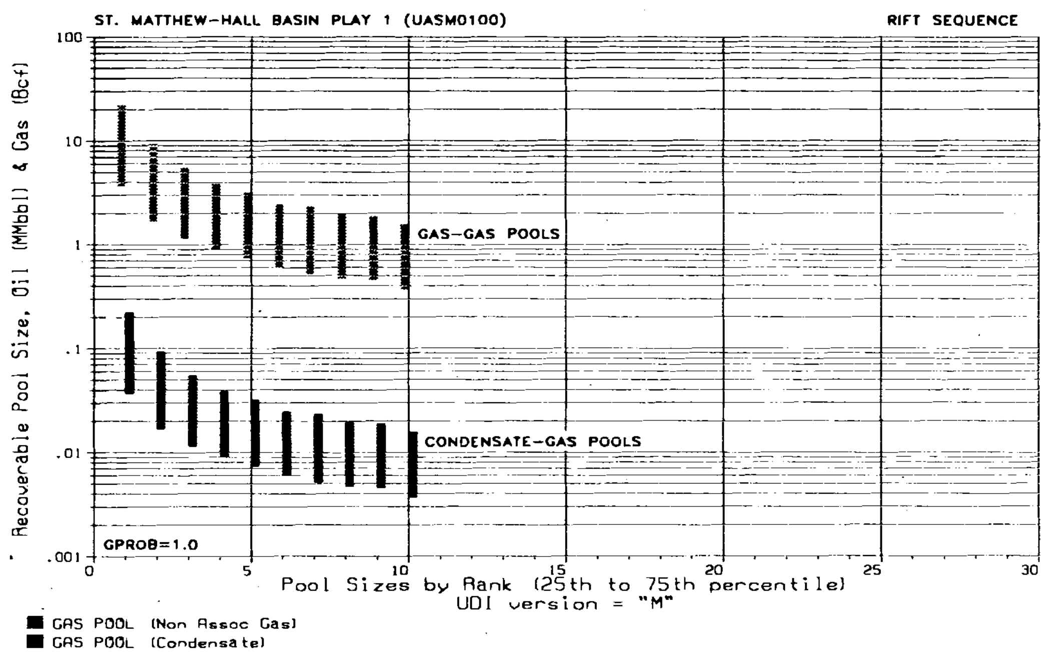


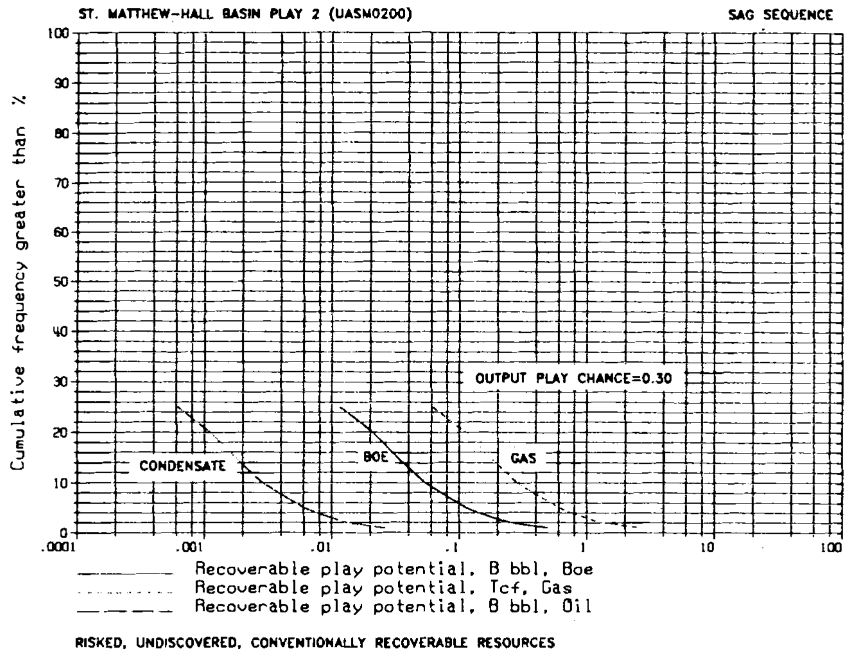
NORTON BASIN PLAY 4 (UANO0401)			
FRACTILES	**F95**	**MEAN**	**F05**
GAS (TCFG)	**0.000**	**0.040**	**0.231**
OIL (BBO)	**0.000**	**0.0007**	**0.004**
BOE (BBO)	**0.000**	**0.008**	**0.046**



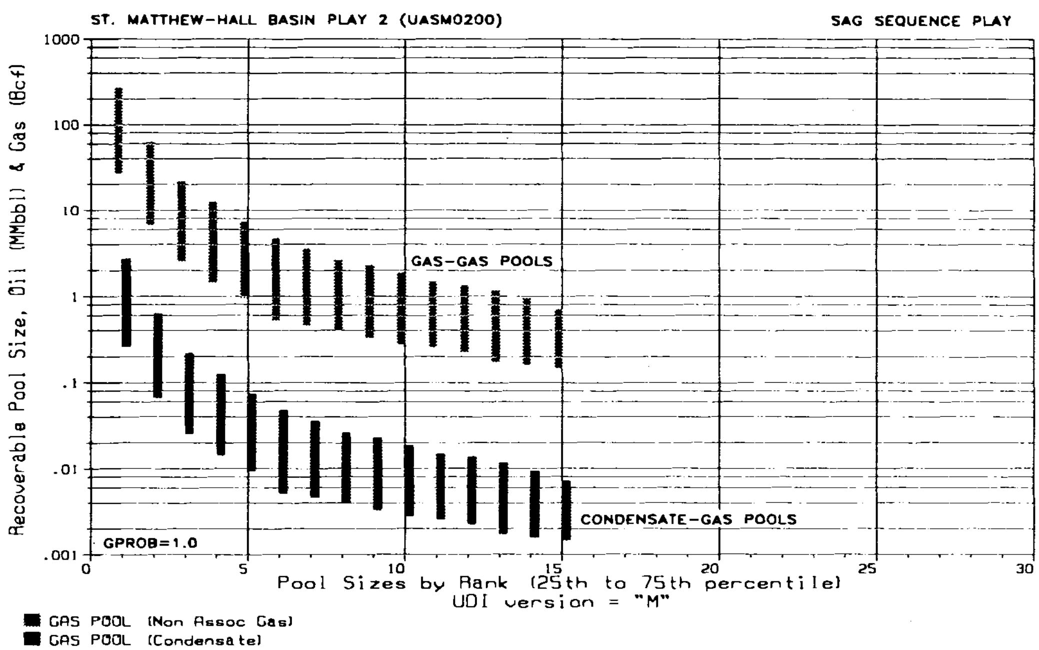


ST. MATTHEW-HALL BASIN PLAY 1 (UASM0100)			
FRACTILES	**F95**	**MEAN**	**F05**
GAS (TCFG)	**0.000**	**0.008**	**0.041**
OIL (BBO)	**0.000**	**0.00008**	**0.0004**
BOE (BBO)	**0.000**	**0.002**	**0.008**





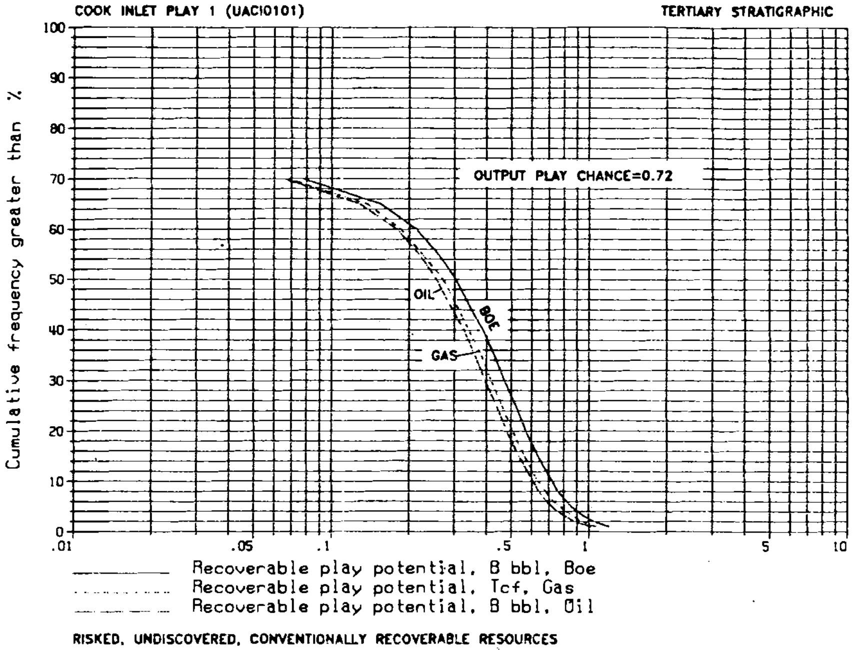
ST. MATTHEW-HALL BASIN PLAY 2 (UASM0200)			
FRACTILES	**F95**	**MEAN**	**F05**
GAS (TCFG)	**0.000**	**0.147**	**0.606**
OIL (BBO)	**0.000**	**0.001**	**0.006**
BOE (BBO)	**0.000**	**0.028**	**0.114**



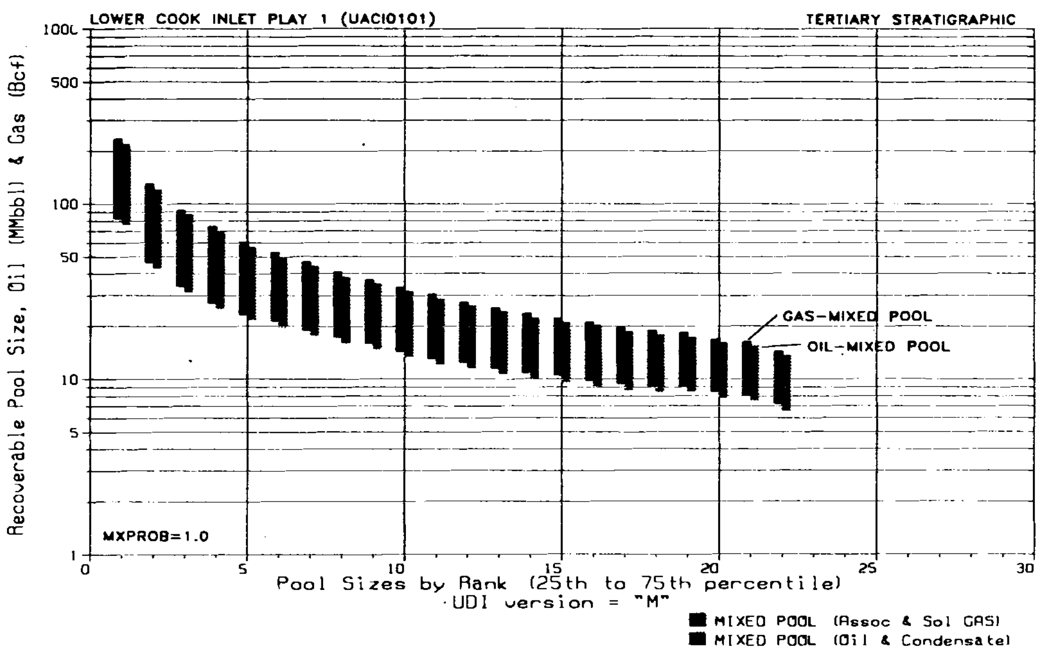
APPENDIX B

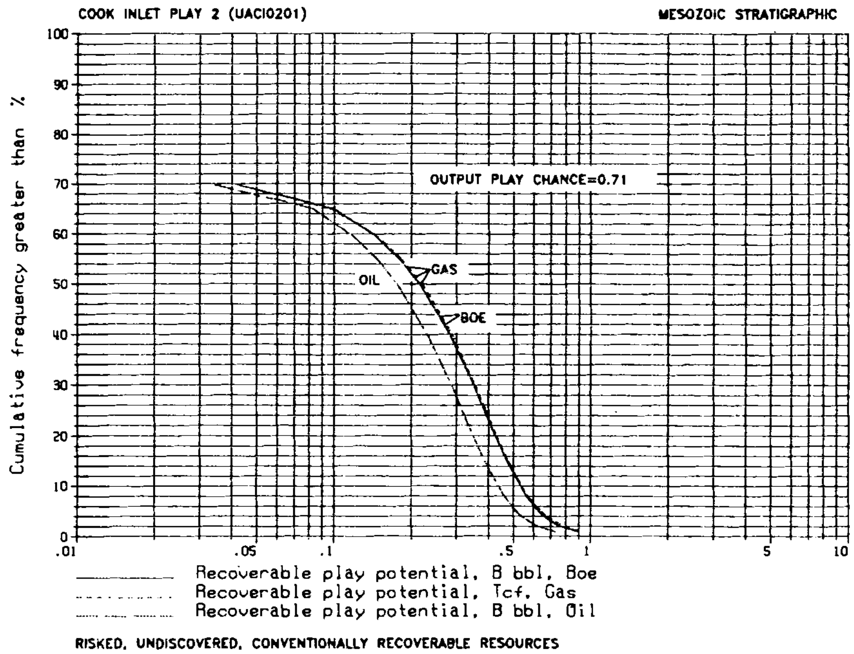
PACIFIC MARGIN SUBREGION PLAY SUMMARIES

COOK INLET
GULF OF ALASKA SHELF
SHUMAGIN-KODIAK SHELF

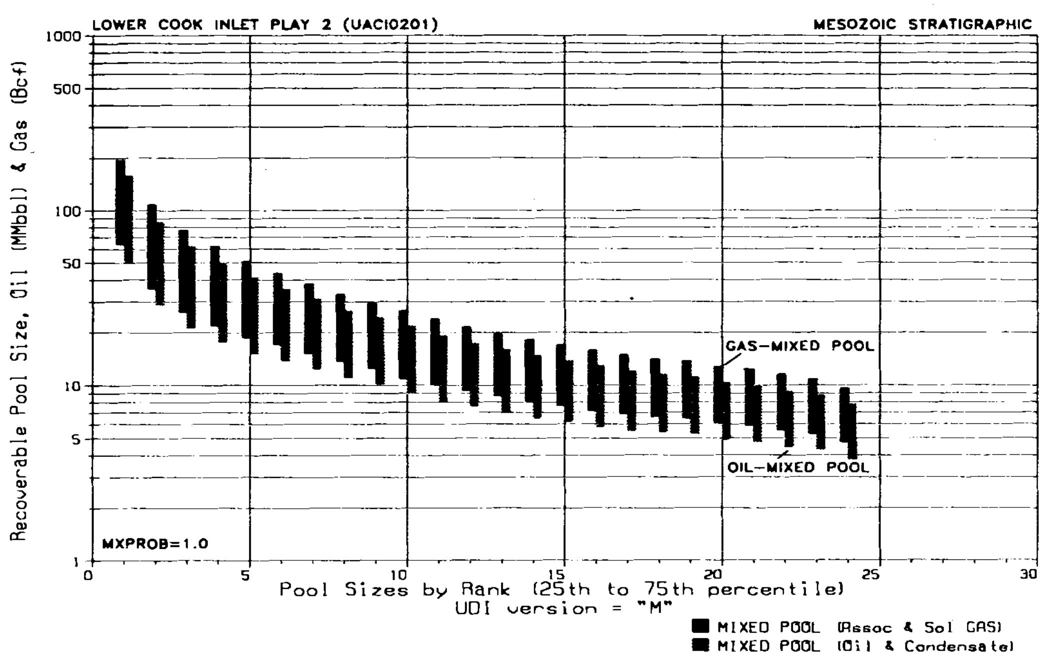


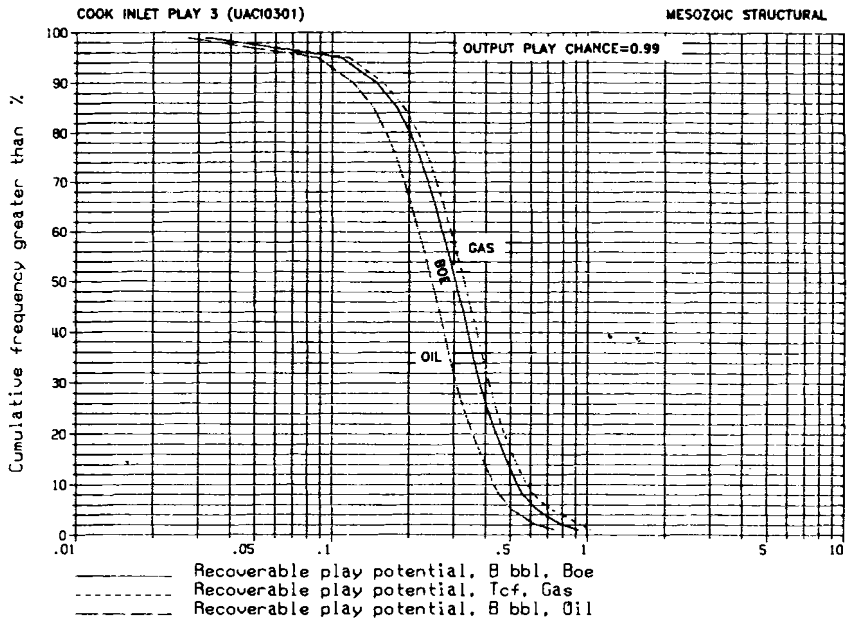
COOK INLET PLAY 1 (UACI0101)			
FRACTILES	**F95**	**MEAN**	**F05**
GAS (TCFG)	**0.000**	**0.291**	**0.776**
OIL (BBO)	**0.000**	**0.276**	**0.723**
BOE (BBO)	**0.000**	**0.328**	**0.860**





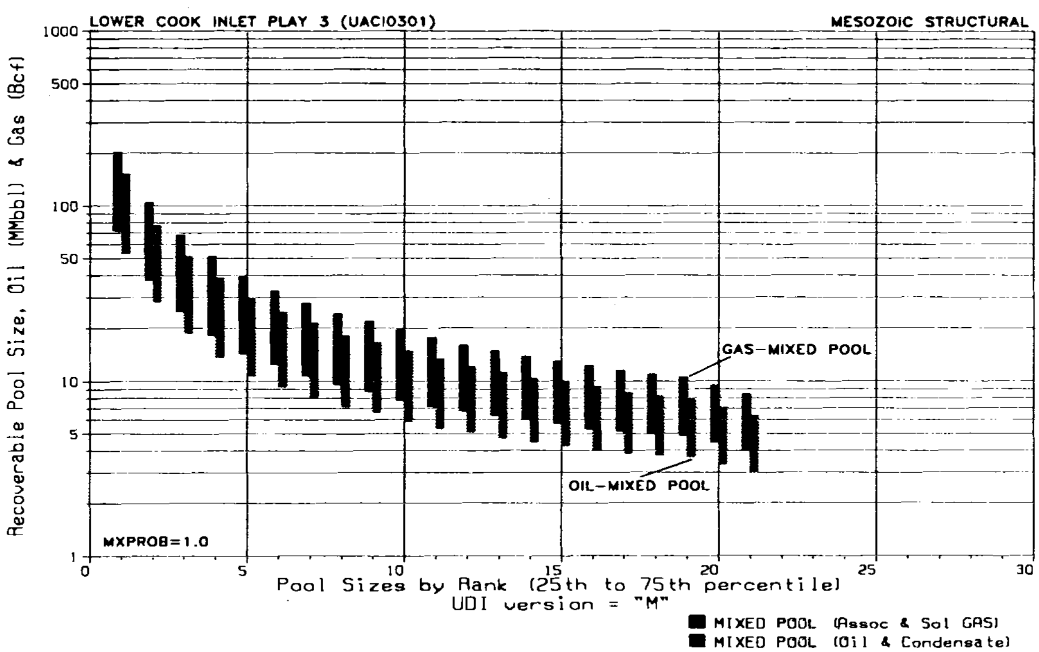
COOK INLET PLAY 2 (UACI0201)			
FRACTILES	**F95**	**MEAN**	**F05**
GAS (TCFG)	**0.000**	**0.242**	**0.642**
OIL (BBO)	**0.000**	**0.195**	**0.515**
BOE (BBO)	**0.000**	**0.238**	**0.632**

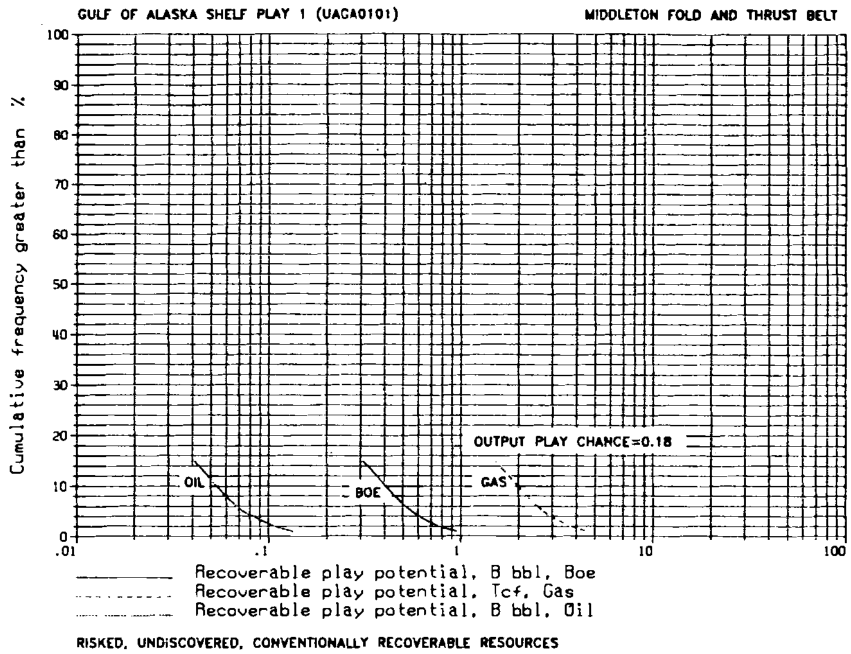




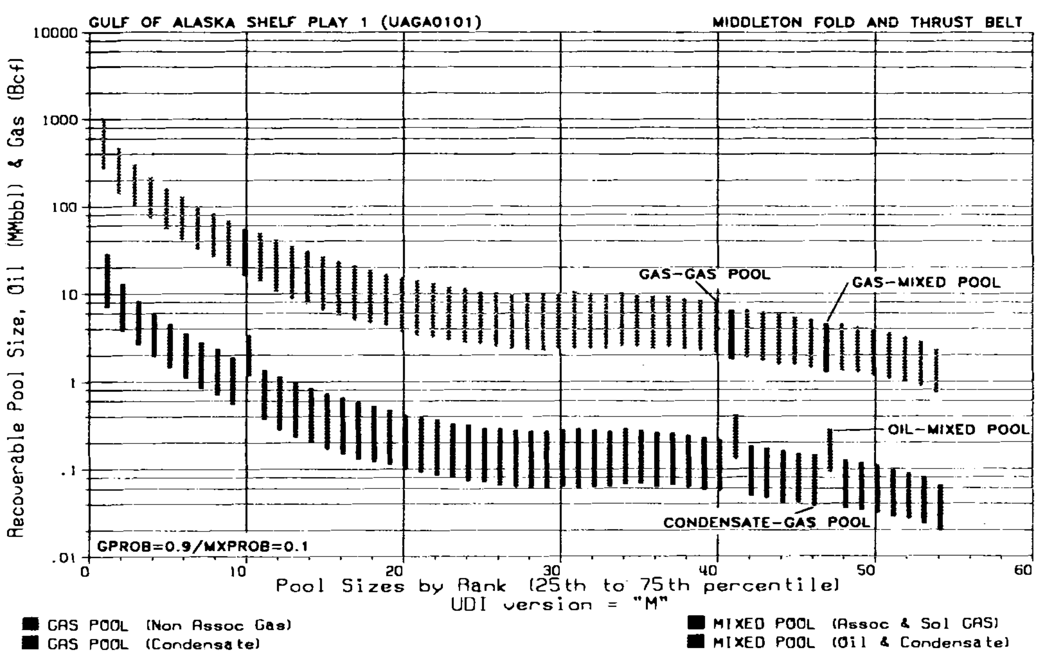
RISKED, UNDISCOVERED, CONVENTIONALLY RECOVERABLE RESOURCES

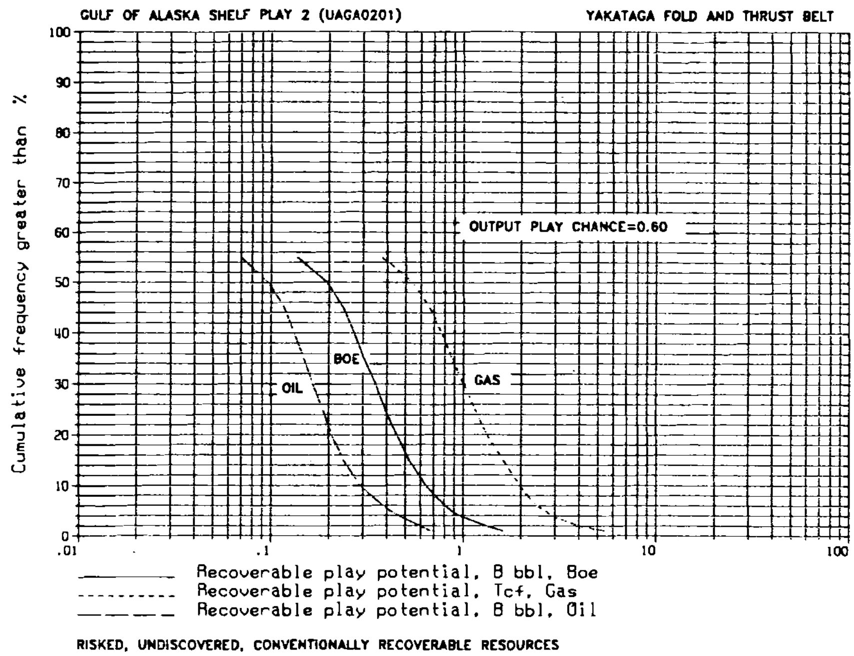
COOK INLET PLAY 3 (UACI0301)			
FRACTILES	**F95**	**MEAN**	**F05**
GAS (TCFG)	**0.116**	**0.360**	**0.727**
OIL (BBO)	**0.088**	**0.266**	**0.508**
BOE (BBO)	**0.109**	**0.330**	**0.643**



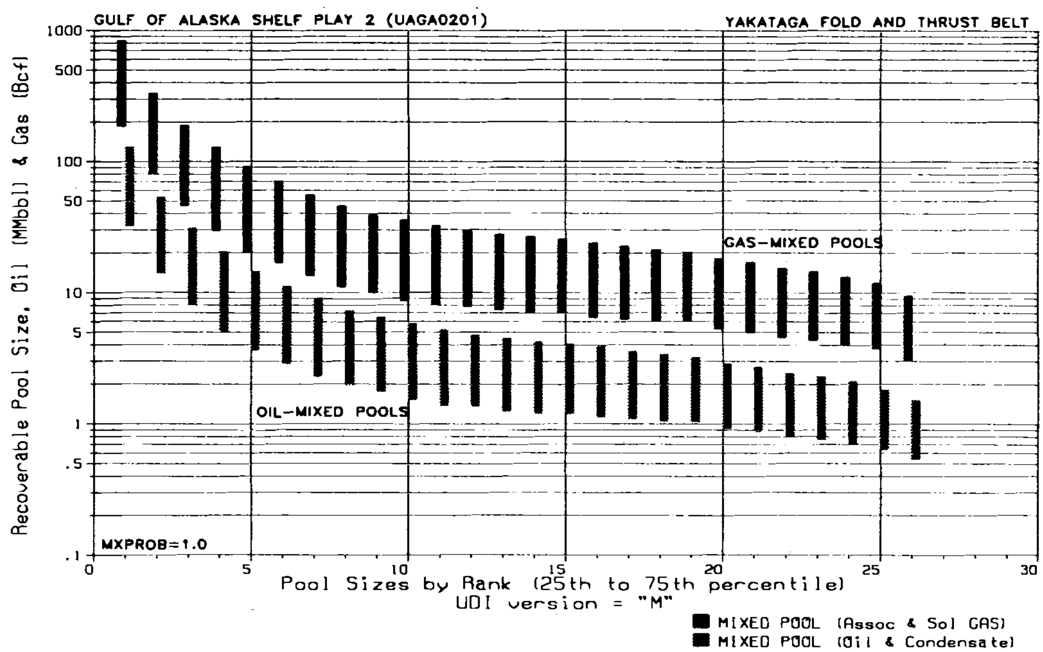


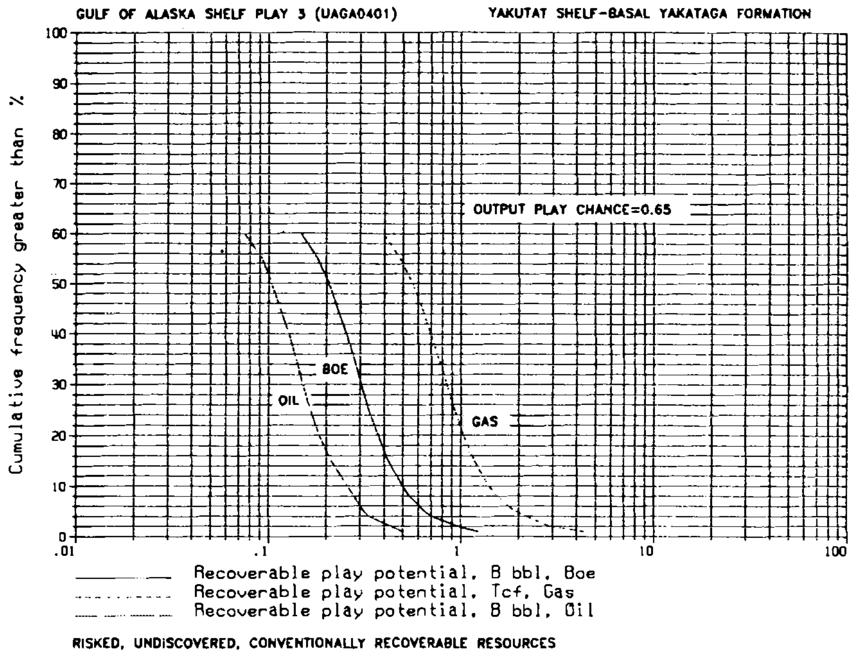
GULF OF ALASKA SHELF PLAY 1 (UAGA0101)			
FRACTILES	**F95**	**MEAN**	**F05**
GAS (TCFG)	**0.000**	**0.456**	**2.700**
OIL (BBO)	**0.000**	**0.013**	**0.074**
BOE (BBO)	**0.000**	**0.094**	**0.557**



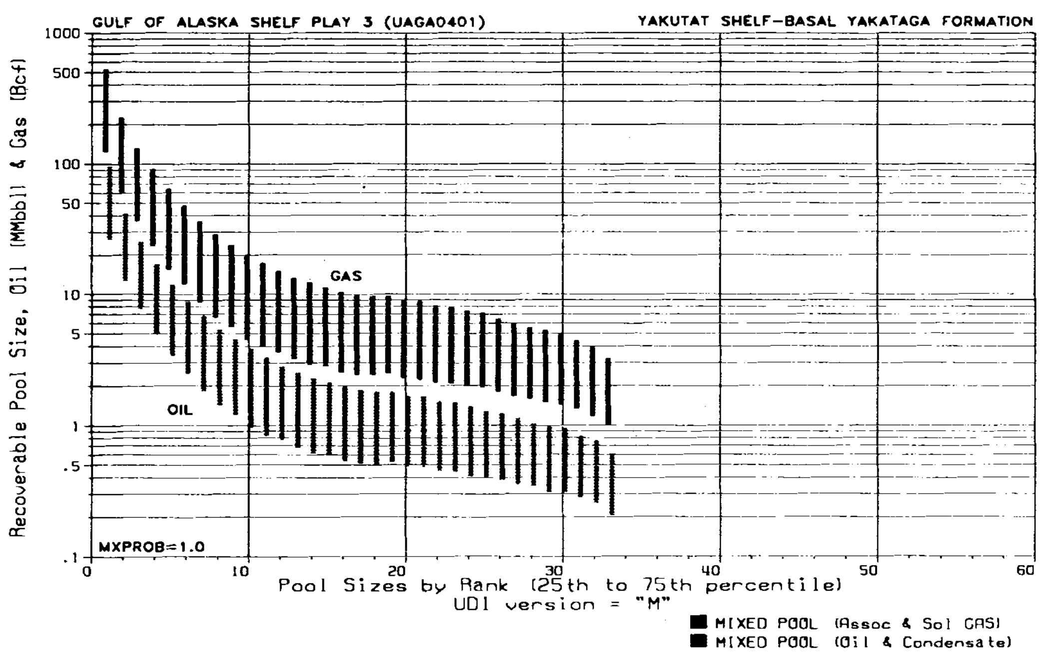


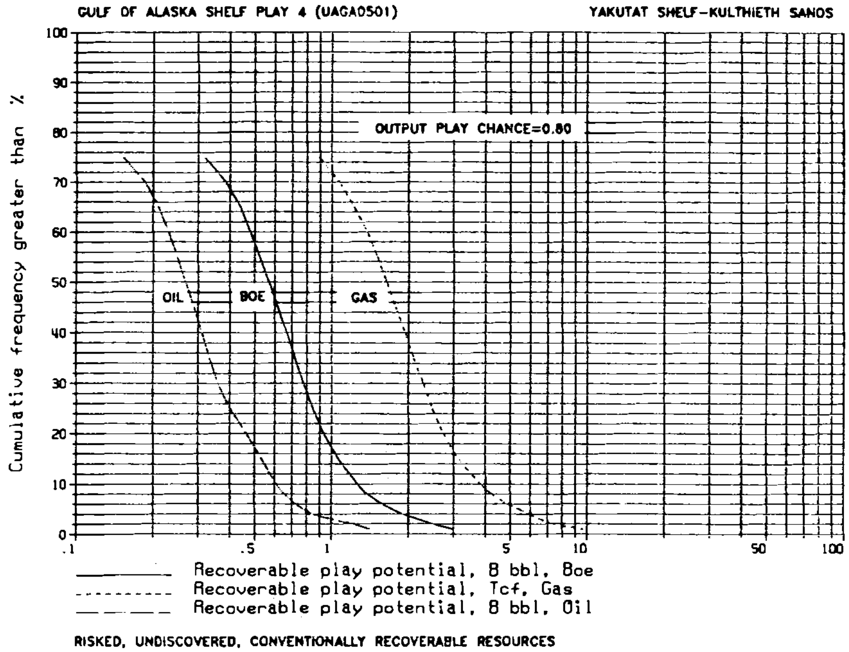
GULF OF ALASKA SHELF PLAY 2 (UAGA0201)			
FRACTILES	**F95**	**MEAN**	**F05**
GAS (TCFG)	**0.000**	**0.805**	**2.677**
OIL (BBO)	**0.000**	**0.122**	**0.415**
BOE (BBO)	**0.000**	**0.265**	**0.866**



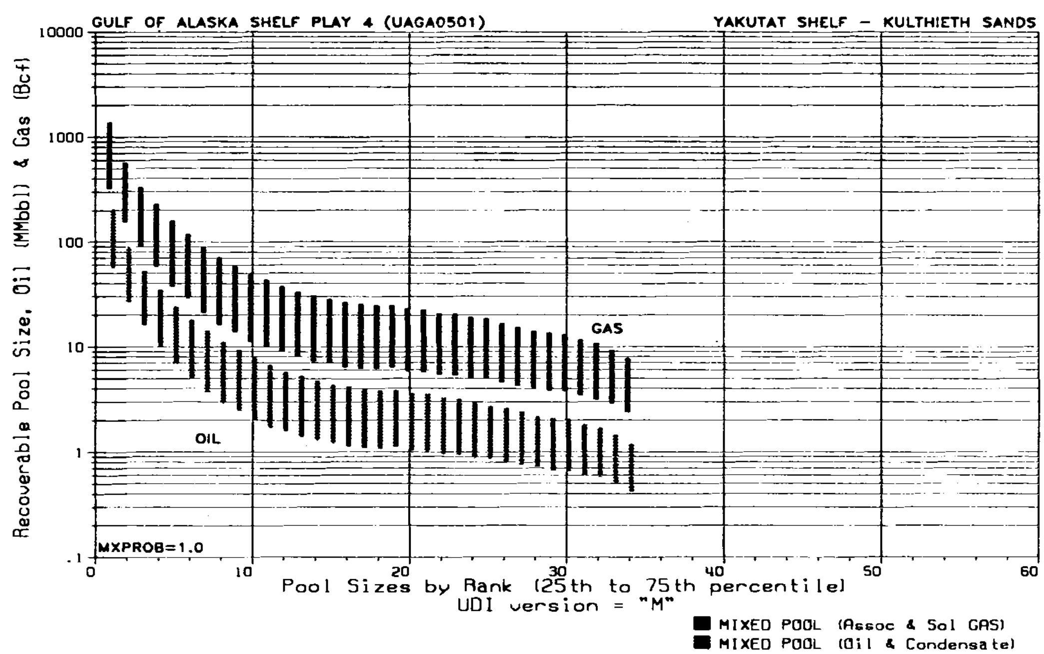


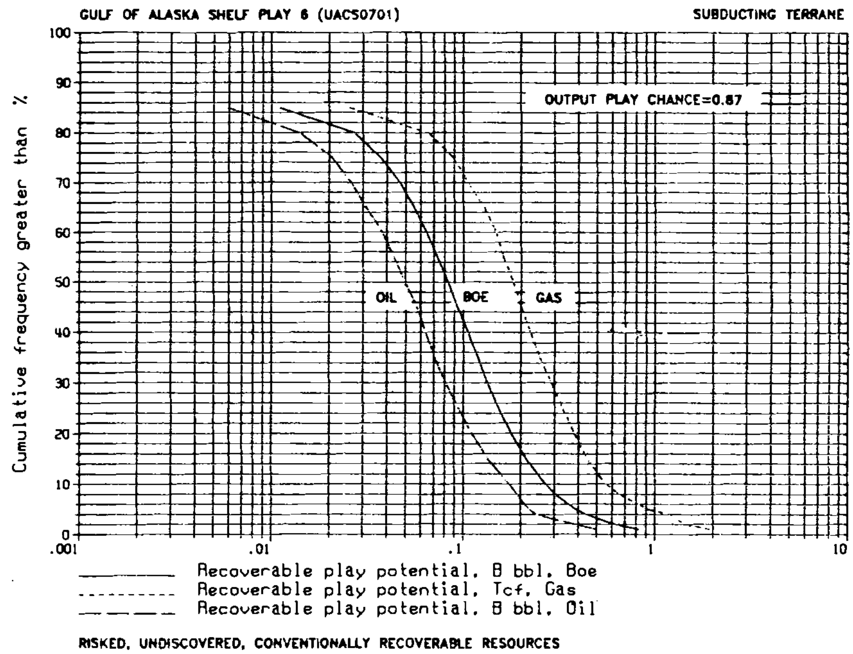
GULF OF ALASKA SHELF PLAY 3 (UAGA0401)			
FRACTILES	**F95**	**MEAN**	**F05**
GAS (TCFG)	**0.000**	**0.669**	**1.937**
OIL (BBO)	**0.000**	**0.111**	**0.313**
BOE (BBO)	**0.000**	**0.230**	**2.036**



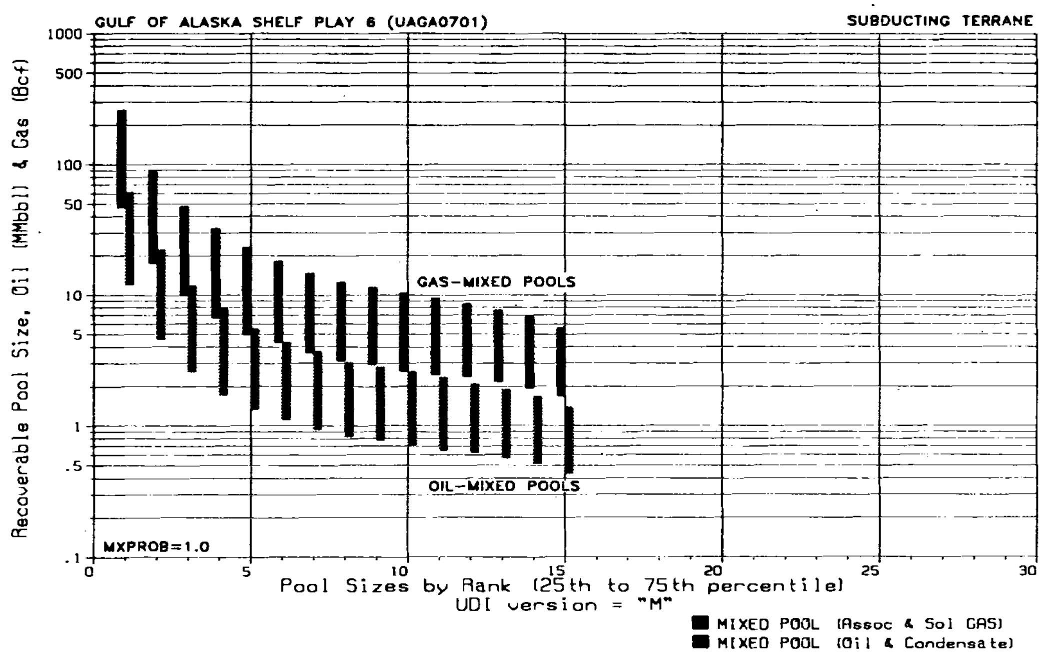


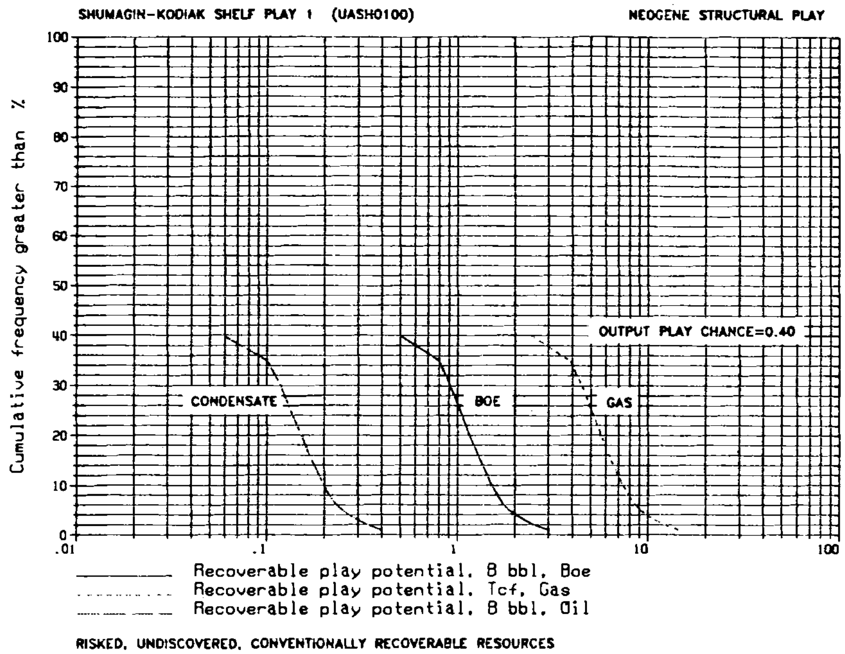
GULF OF ALASKA SHELF PLAY 4 (UAGA0501)			
FRACTILES	**F95**	**MEAN**	**F05**
GAS (TCFG)	**0.000**	**1.967**	**5.397**
OIL (BBO)	**0.000**	**0.308**	**0.778**
BOE (BBO)	**0.000**	**0.658**	**1.711**



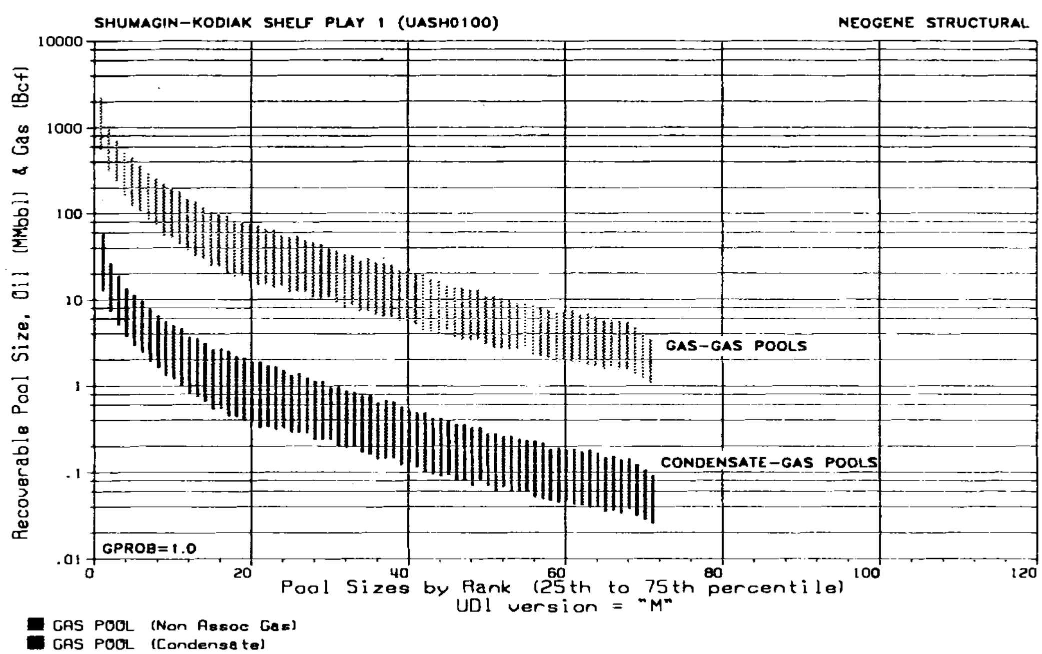


GULF OF ALASKA SHELF PLAY 6 (UAGA0701)			
FRACTILES	**F95**	**MEAN**	**F05**
GAS (TCFG)	**0.000**	**0.282**	**0.926**
OIL (BBO)	**0.000**	**0.076**	**0.222**
BOE (BBO)	**0.000**	**0.126**	**0.387**





SHUMAGIN-KODIAK SHELF PLAY 1 (UASH0100)			
FRACTILES	**F95**	**MEAN**	**F05**
GAS (TCFG)	**0.000**	**2.650**	**9.089**
OIL (BBO)	**0.000**	**0.070**	**0.250**
BOE (BBO)	**0.000**	**0.541**	**1.858**



Suggested Reference Style

Chapter Author(s), 1998, Chapter Title: in: *Undiscovered Oil and Gas Resources, Alaska Federal Offshore (As of January 1995)*, Sherwood, K.W. (ed.), U.S. Minerals Management Service, OCS Monograph MMS 98-0054, 531 p. (or p. ___-___.)

Plate 1.1: Assessment Provinces of the Alaska Federal Offshore
1995 National Resource Assessment, OCS Monograph MMS 98-0054

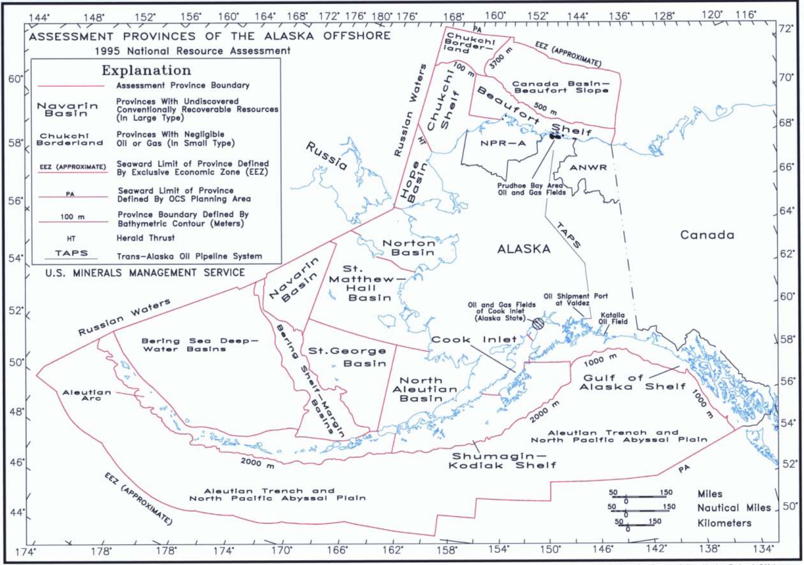
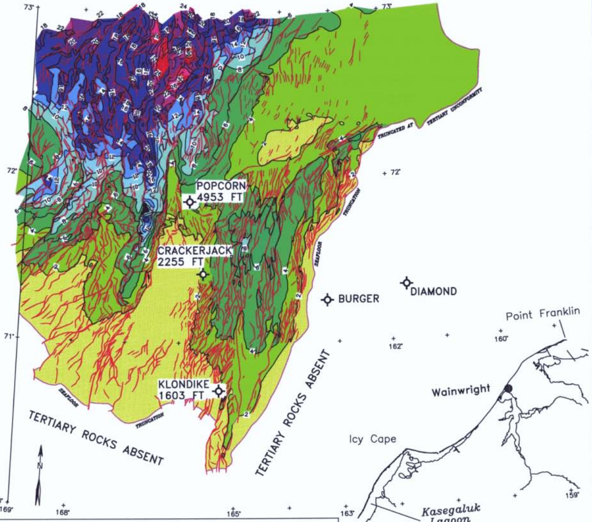


Plate 13.3: Structure at Base of Tertiary Rocks, Chukchi Shelf
1995 National Resource Assessment, Alaska Federal Offshore
OCS Monograph MMS 98-0054

STRUCTURE AT BASE OF TERTIARY ROCKS
(MAP DATUM: MID-BROOKIAN UNCONFORMITY, OR "MBU")



EXPLANATION

PLUGGED AND ABANDONED WELL

2255 FT — SUBSEA DEPTH TO MAP DATUM AT WELL

CONTOURS FOR DEPTH IN 1,000 FEET SUBSEA

TRUNCATION OF MID-BROOKIAN UNCONFORMITY (PALEOCENE) AT YOUNGER UNCONFORMITIES OR SEAFLOOR

FAULTS

DIAPIRS

0-2,000 ft
2,000-4,000 ft
4,000-6,000 ft
6,000-8,000 ft
8,000-10,000 ft
10,000-12,000 ft
12,000-14,000 ft
14,000-16,000 ft
16,000-18,000 ft
18,000-20,000 ft
20,000-22,000 ft
22,000-24,000 ft
24,000-26,000 ft
26,000-28,000 ft
28,000-30,000 ft
>30,000 ft

0 30 Nautical Miles
0 30 Statute Miles
0 30 Kilometers

COMPILED BY PETER P. JOHNSON FROM MMS SEISMIC MAPPING

U.S. MINERALS MANAGEMENT SERVICE

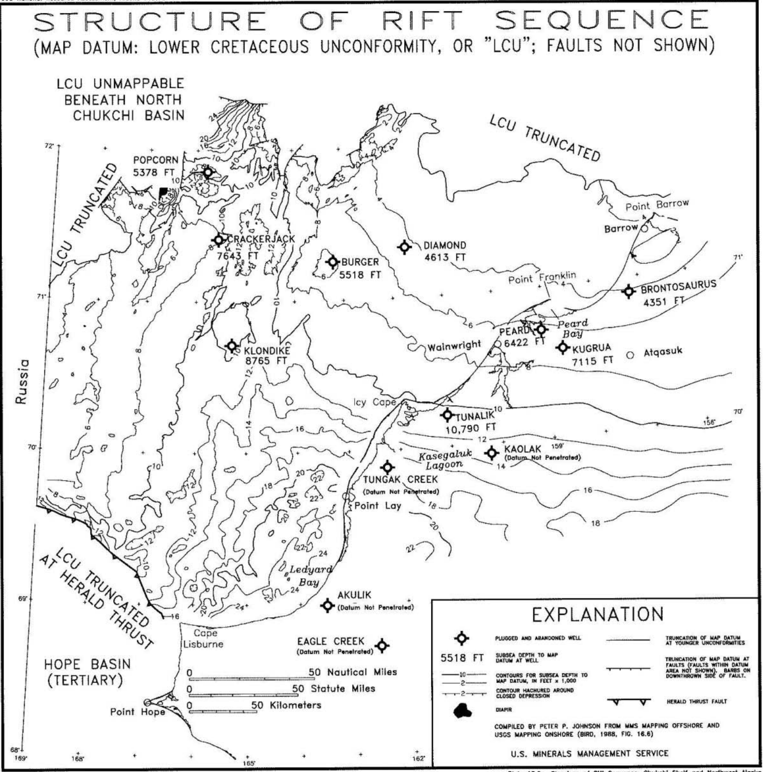
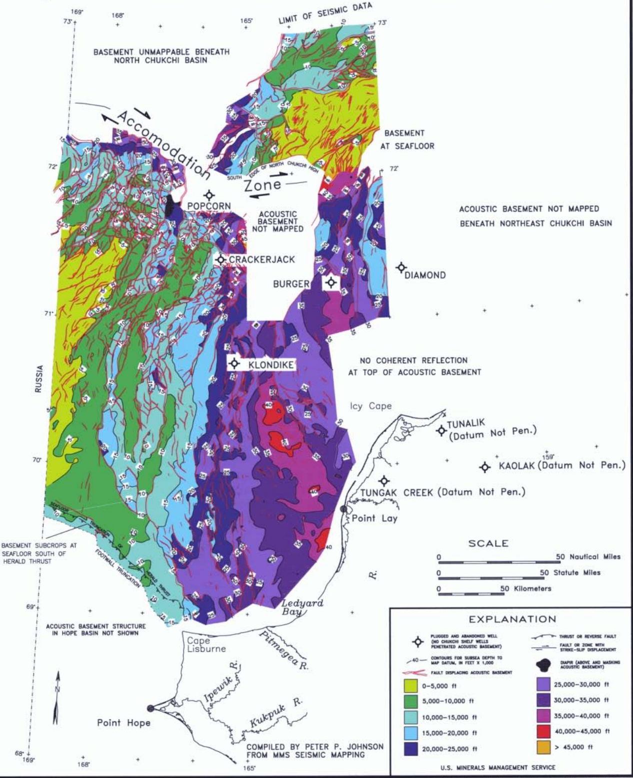

STRUCTURE OF RIFT SEQUENCE
(MAP DATUM: LOWER CRETACEOUS UNCONFORMITY, OR "LCU"; FAULTS NOT SHOWN)
LCU UNMAPPABLE BENEATH NORTH CHUKCHI BASIN
LCU TRUNCATED
LCU TRUNCATED
LCU TRUNCATED AT HERALD THRUST
POPCORN 5378 FT
CRACKERJACK 7643 FT
BURGER 5518 FT
DIAMOND 4613 FT
KLONDIKE 8765 FT
Point Barrow
Barrow
Point Franklin
BRONTOSAURUS 4351 FT
PEARD 6422 FT
Peard Bay
Wainwright
KUGRUA 7115 FT
Atqasuk
Russia
Icy Cape
TUNALIK 10,790 FT
KAOLAK (Datum Not Penetrated)
Kasegaluk Lagoon
TUNGAK CREEK (Datum Not Penetrated)
Point Lay
Ledyard Bay
AKULIK (Datum Not Penetrated)
EAGLE CREEK (Datum Not Penetrated)
Cape Lisburne
HOPE BASIN (TERTIARY)
Point Hope
0 50 Nautical Miles
0 50 Statute Miles
0 50 Kilometers
72°
71°
70°
69°
68°
169°
168°
165°
162°
159°
156°
EXPLANATION
PLUGGED AND ABANDONED WELL
5518 FT SUBSEA DEPTH TO MAP DATUM AT WELL
CONTOURS FOR SUBSEA DEPTH TO MAP DATUM, IN FEET x 1,000
CONTOUR HACHURED AROUND CLOSED DEPRESSION
DIAPIR
TRUNCATION OF MAP DATUM AT YOUNGER UNCONFORMITIES
TRUNCATION OF MAP DATUM AT FAULTS (FAULTS WITHIN DATUM AREA NOT SHOWN). BARBS ON DOWNTHROWN SIDE OF FAULT.
HERALD THRUST FAULT
COMPILED BY PETER P. JOHNSON FROM MMS MAPPING OFFSHORE AND USGS MAPPING ONSHORE (BIRD, 1988, FIG. 16.6)
U.S. MINERALS MANAGEMENT SERVICE

Plate 13.1: Structure of Ellesmerian Rocks, Chukchi Shelf
1995 National Resource Assessment, Alaska Federal Offshore
OCS Monograph MMS 98-0054

STRUCTURE ON ACOUSTIC BASEMENT
(MAP DATUM: BASE OF STRATIFIED ROCKS)



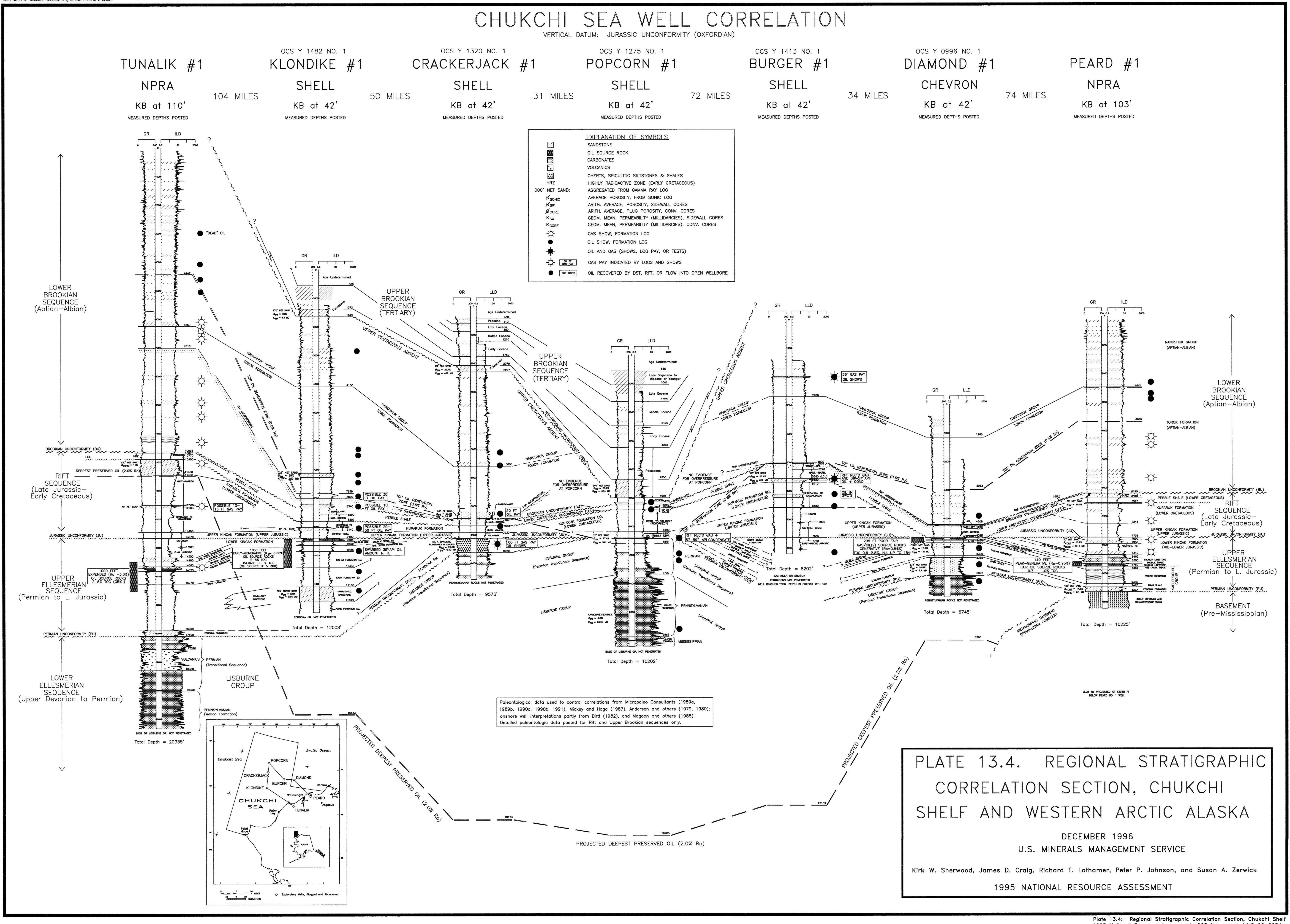


PLATE 13.4. REGIONAL STRATIGRAPHIC CORRELATION SECTION, CHUKCHI SHELF AND WESTERN ARCTIC ALASKA

DECEMBER 1996

U.S. MINERALS MANAGEMENT SERVICE

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