DEPARTMENT OF THE INTERIOR

GEOLOGICAL SURVEY

MINERALS MANAGEMENT SERVICE

National Assessment of Undiscovered Conventional Oil and Gas Resources

USGS-MMS Working Paper

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PREFACE

These working papers describe the methodologies, assumptions, and data being used by the Minerals Management Service (MMS) and the United States Geological Survey (USGS) in an assessment of undiscovered, conventionally recoverable, oil and natural gas resources of the United States. Making forecasts of resources yet undiscovered clearly is problematical and potentially subject to substantial error. Although there is a relatively finite amount of conventionally recoverable oil and gas in the United States which, if discovered, could be produced at roughly current prices, no one truly knows how much oil and gas exists or where it is located. This reissued version of the report contains textual clarifications, corrections of typographical errors, and a few corrections of tabulated province estimates where errors were discovered in transcription, input, or calculation.

It clearly would be useful to know the answers to "how much" and "where" because this information would aid in national energy planning and would reduce significantly the cost of oil and gas exploration. For example, there would be no unsuccessful exploratory wells. But, in the absence of such definitive knowledge, both industry and government must make educated guesses, about "how much" and "where." Oil companies spend substantial amounts trying to answer these questions so they can better direct exploratory investments. Although industry has become increasingly sophisticated in directing its exploration activities, many uncertainties remain. There have been many successes, some spectacular, but also many failures, some no less spectacular.

Government similarly prepares estimates which are used, in combination with expressions of interest from industry, for national energy planning, preparing lease sale Environmental Impact Statements (EIS), and for land use decision making. Indeed, for the Outer Continental Shelf (OCS), the law requires that estimates be prepared biennially. The MMS also uses these estimates in tract-specific analyses for helping determine whether to accept bids from OCS lease sales.

The likely validity and credibility of such estimates depends on the appropriateness of the methodology used and the level of understanding of the underlying geologic and economic parameters. The level of methodological sophistication has increased significantly over time for both industry and the Government. Particularly for the onshore estimates, the methodology used in this assessment is much more sophisticated than the one used for making such an assessment in 1981.

In the case of OCS resources, a number of improvements have been made to the methodology used in the most recent offshore assessment of economically recoverable resources in 1985. Some of these improvements were suggested by a National Research Council peer-review of the MMS approach. Additionally, MMS has developed a new methodology for estimating the "economics free" undiscovered resource base. This methodology is based on the previously reviewed economically recoverable procedures but it has not yet been subjected to a wide review by the resource assessment community.

In both cases, it is important to have further peer review of these methodologies and their application before publishing a final set of resource estimates. A peer review of the underlying geologic and economic assumptions is called for as well to assure that information of significance is not overlooked and is most appropriately interpreted, allowing for disagreement among different reviewers looking at the same data. At the conclusion of the peer review, the results will be examined by USGS and MMS resource evaluation personnel, appropriately incorporated into a final narrative and set of estimates, and published for broad distribution.

Because the methodology, assumptions, and data are being subjected to extensive peer review, it would be inappropriate to use figures in these working papers to project national estimates at this time. The agencies will summarize the estimates for national totals only after determining what adjustments should be made in the assessment process following the peer review.

In recognition of the great uncertainties associated with estimating quantities of undiscovered resources, estimates in these working papers for each onshore and offshore geologic province are presented at three levels of possible occurrence: a low case with a 95 percent probability of that amount or more occurring; a high case with a 5 percent probability of that amount or more occurring; and an averge case representing the arithmetic average of all of the probabilities of possible resource occurrences.

I. OVERVIEW

A. BACKGROUND

In 1981, the U.S. Geological Survey (USGS) published the results of a 1980 national assessment of undiscovered oil and natural gas resources for the United States, including the Outer Continental Shelf (OCS). The publication, USGS Circular 860, was entitled "Estimates of Undiscovered Recoverable Conventional Resources of Oil and Gas in the United States" (hereafter referred to as Circular 860). The assessment provided an update to the previous USGS estimates for the Nation (published in 1975 as Circular 725).

In 1982, the Minerals Management Service (MMS) was formed from a portion of USGS and other Department of the Interior (DOI) organizations for resource management of Federal offshore areas and for management of revenues collected from onshore and offshore Federal mineral leases. The MMS published estimates of undiscovered oil and natural gas resources for the OCS in 1985 in a report entitled "Estimates of Undiscovered, Economically Recoverable Oil and Gas Resources for the Outer Continental Shelf as of July 1984" (OCS Report MMS 85-0012).

The agencies, both part of DOI, agreed in 1985 to conduct a cooperative assessment of the entire United States to estimate undiscovered oil and natural gas based upon a common date. These working papers provide estimates for the onshore and offshore geologic provinces of the Nation and summarize the methodologies, assumptions, and data utilized in the development of those estimates. (Figs. I.5 and I.6 are index maps showing the geologic provinces.) The methodologies, assumptions, and data differ from those used in the previous assessments, thereby making direct comparisons between estimates of this and previous assessments difficult to interpret. Therefore, these working papers have been prepared as a means of eliciting comments from peer scientific, academic, and industry experts in the estimation of oil and natural gas resources.

B. SCOPE

These working papers present estimates of undiscovered, conventionally recoverable oil and natural gas resources and known reserves as of January 1, 1987. The estimates are based upon a coordinated assessment of the known and possible petroleum bearing onshore and offshore geologic provinces of the United States by two Agencies of DOI, the USGS and MMS. Estimates for the onshore geologic provinces and the State offshore areas were developed by USGS. Estimates for the Federal offshore areas of the United States were developed by MMS.

The estimates presented in Appendices C and D are a "snap-shot" viewpoint of the geologic and engineering conditions as of January 1, 1987, and should be viewed as indicators of the relative petroleum potential of the geologic provinces and regions rather than exact assessments of the absolute quantities of oil and natural gas to be found in these provinces.

The assessment incorporates additional geologic, engineering, and economic information resulting from petroleum exploration and development activities carried out in these geologic provinces since the most recent assessment publications by the two Agencies: USGS Circular 860 and MMS 85-0012.

For the purposes of this assessment, the United States was divided into nine onshore regions comprising 80 geologic provinces and four offshore regions comprising 35 geologic provinces. The regions correspond, in general, to those addressed by USGS Circular 860 and those addressed by MMS OCS Report MMS 85-0012. The offshore areas include the OCS Exclusive Economic Zone (EEZ) adjacent to the Lower 48 States and Alaska. Hawaii was not included because its volcanic terrain is not considered prospective for hydrocarbons.

The information presented herein regarding known reserves of discovered oil and natural gas was derived from separate sources for the onshore and offshore provinces. The reserve estimates for the onshore and State offshore provinces were derived from data published by the Energy Information Administration (EIA) of the U.S. Department of Energy, specifically EIA's publication entitled "U.S. Crude Oil, Natural Gas, and Natural Gas Liquids Reserves - 1986 Annual Report." The reserve estimates for the Federal offshore areas are based upon data published by MMS in two reports: "Estimated Oil and Gas Reserves, Gulf of Mexico, December 31, 1986" (OCS Report MMS 87-0070) and "Estimated Oil and Gas Reserves, Pacific Outer Continental Shelf, December 31, 1986" (OCS Report MMS 87-0045). Published MMS reserves estimates were supplemented, in some instances, to include estimates for fields lacking estimates at the time the publications were prepared or, in the case of Alaska offshore areas, supplemental information from published reports is presented in view of the proprietary nature of MMS reserve estimates.

C. COMMODITIES ASSESSED

The present assessment appraised undiscovered conventional sources of recoverable crude oil, natural gas, and natural gas liquids. Crude oil is a natural mixture of hydrocarbons occurring underground in a liquid state in reservoir rock and remaining in a liquid state as it is produced from wells. Natural gas is a mixture of gaseous hydrocarbons occurring underground in reservoir rock, either in association with crude oil as free gas or dissolved gas, or as nonassociated gas in a free state not associated with crude oil. Natural gas liquids (NGL) are those portions of reservoir gas that are liquefied at the surface in lease separators, other field facilities, or in gas processing plants. Included are propane, ethane, butane, pentane, natural gasoline, and condensate.

The estimates in this report do not include resources from heavy oil deposits, resources in tar deposits, oil shales, gas from low permeability tight sandstone reservoirs, gas from fractured shale reservoirs with in-situ permeabilities to gas less than 0.1 millidarcy, coal bed methane, gas in geopressured shales and brines or gas hydrates. However, these working papers do contain a limited discussion pertaining to several of these resource categories with estimates provided where studies are available to support such estimates. Although considered "unconventional" for the purposes of this joint assessment, this information is presented in recognition of the existence of these resources. Additionally, some portion of these types of accumulations is often included in oil and natural gas resource estimates and reserves estimates by some experts who differ regarding the demarcation between the conventional and unconventional classification. Estimates of undiscovered resources also do not include volumes that may yet be found in new pay zones in known fields or extensions to known fields. These are reported as inferred reserves and schematically shown on figure I.1.

D. TERMINOLOGY

The terminology utilized in these working papers is intended to be representative of the standard definitions and usage practiced by the oil and natural gas industry and the resource estimation community. No attempt has been made to include a detailed listing of common industry definitions; however, several definitions that are essential to the proper understanding of the materials in these working papers are presented. These definitions should be viewed as general explanatory wording rather than strict technical definitions of the term being addressed.

<u>Undiscovered Resources</u>

Resources estimated to exist from broad geologic knowledge and theory outside of known fields. Also included are resources from undiscovered pools that occur as unrelated accumulations controlled by distinctly separate structural features or stratigraphic conditions within areas of known fields.

<u>Undiscovered Recoverable Resources</u> (also termed Undiscovered Resource Base)

Resource estimates which include resources in undiscovered accumulations analogous to those in existing fields producible with current recovery technology and efficiency, but without reference to economic viability. Nevertheless, these accumulations are generally considered to be of sufficient size to be amenable to conventional recovery technology. These resources occupy the area of the heavily framed box in figure I.1.

<u>Undiscovered Economically Recoverable Resources</u>

Resources assessed in the undiscovered recoverable resources category that are economically recoverable under conditions of current technology and imposed economic assumptions. The estimates of the undiscovered economically recoverable resources were predicated upon a 1987 oil price of $18 per barrel and a gas price of $1.80 per MCF, with annual adjustments over future years for predictions of price and cost progression and other economic factors influencing industry's development effort in the United States. Exploration costs were not included. Undiscovered accumulations were determined to be economically recoverable if projected cash flows were sufficient to pay operating costs and provide an after-tax rate of return averaging 8 percent. The impact of this is to eliminate from the economic category all estimated accumulations smaller than the minimum economic field size (MEFS), being most significant in high cost operating environments such as the Arctic and offshore. The economically recoverable resources occupy the hachured area on the resources classification chart (fig. I.1).

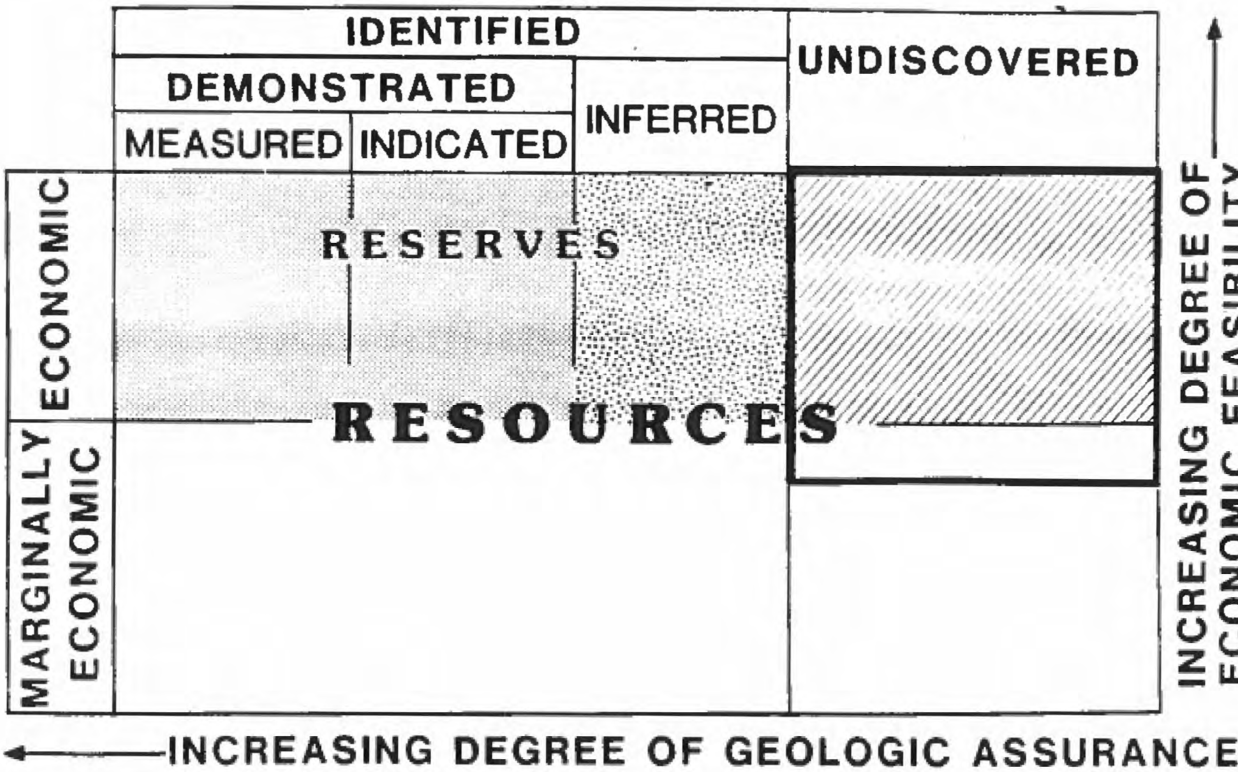

Figure I.1. Diagrammatic representation of petroleum resource classification. The total graph represents conventional oil and gas resources. The area within the heavy frame on the upper right represents the undiscovered recoverable resources estimated in the report. The hachured area within the heavy frame indicates the quantities of undiscovered resources that are estimated to be economically recoverable. (U.S. Bureau of Mines and the U.S. Geological Survey, 1980 (modified).

Conventionally Recoverable Resources

Oil and natural gas resources which may be produced at the surface from a well-bore as a consequence of natural pressure within the subsurface reservoir; artificial lifting of oil from the reservoir to the surface, where economically applicable; and the maintenance of reservoir pressure by means of water or gas injection. (Definition modified from National Petroleum Council.)

Measured Reserves

That part of the identified economic resource that is estimated from geologic evidence supported directly by engineering data. They are demonstrated with reasonable certainty to be recoverable in future years from known reservoirs under existing economic and operating conditions (fig. I.1).

Indicated Reserves

Reserves that are in known productive reservoirs in existing fields in addition to measured reserves and are expected to respond to improved recovery techniques such as fluid injection where (a) an improved recovery technique has been installed but its effects are not yet known or (b) where an improved technique has been installed in another similar reservoir and the results of that installation can be used to estimate the additional indicated resources (fig. I.1).

Inferred Reserves

That part of the identified economic resources over and above measured and indicated reserves that will be added through extension, revisions, and the addition of new pay zones (fig. I.1).

Oil-Equivalent Gas

Gas volume that is expressed in terms of its energy equivalent in barrels of oil, approximately 6,000 cubic feet of gas per barrel of oil equivalent.

Field

A single pool or multiple pools of hydrocarbon accumulations grouped on, or related to, a single structural or stratigraphic feature.

Play

A group of geologically-related prospects with similar hydrocarbon sources, reservoirs, and traps.

Marginal Probability of Hydrocarbons

An estimate, expressed as a decimal fraction, of the chance that oil or natural gas exist in an area. For economically recoverable resources, the marginal probability represents the probability that commercial quantities of oil or natural gas exist in at least one accumulation in the area being assessed under the economic parameters and price scenario applicable to the assessment.

Conditional Estimate

Estimates of the volumes of oil or natural gas which may exist in an area under the condition that recoverable oil or natural gas exist in the area. Conditional estimates do not incorporate the risk that the area may be devoid of any recoverable oil or natural gas.

Risked Estimates

Estimates of the volumes of oil or natural gas which may exist in an area including the possibility that the area may be devoid of oil or natural gas. Statistically, the risked mean may be determined through multiplication of the mean of a conditional distribution by the related marginal probability. However, other points of the risked distribution must be determined mathematically. Estimates presented in this report are risked estimates.

Cumulative Distribution of Resources

A graphical depiction of possible resource volumes presented with associated cumulative probabilities of occurrence for specific volumes. This distribution is used to derive the 95 percent, 5 percent, and mean resource levels reported in this publication; a low case, with a 95 percent probability of that amount or more occurring, a high case, with a 5 percent probability of that amount or more occurring, and an average case representing an arithmetic or weighted average of all of the possible resource occurrences weighted by their probabilities (fig. I.2).

E. DATA BASE

The development of resource estimates for the undiscovered oil and natural gas resources for this assessment required the compilation and analyses of geologic, geophysical, engineering, and economic data from published and private sources throughout Government and industry. Since the estimates for the onshore and State waters provinces developed by USGS and those estimates for Federal offshore provinces developed by MMS used different methodologies, a separate description of the applicable data bases is provided.

MMS

The MMS resource estimates are generally based upon data from industry exploration and development operations carried out under permits or mineral leases issued for the offshore areas of the United States. Since 1954, nearly 10,000 permits have been issued for conducting geophysical or geological studies in the Federal offshore lands. Additionally, more than 9,000 leases have been issued to private companies for exploration, development, and production of oil and natural gas from Federal offshore lands. These permits and leases have resulted in approximately 4 million miles of common depth point (CDP) seismic data and more than 25,000 wells. The MMS has acquired more than 1 million miles of this CSP data and has extensive geological information, including well logs, from offshore wells. This data base is utilized by MMS to identify and map specific prospects within offshore petroleum plays as well as to determine important parameters for the geological and engineering factors which may be associated with these prospects. The data may also be used for representing potential prospects which are not identifiable seismic interpretation or whose size

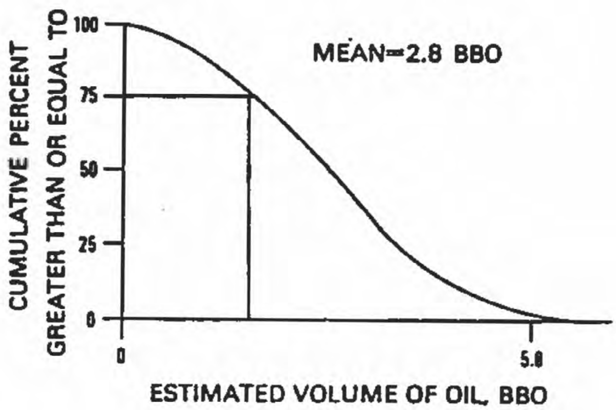

Figure I.2. Graph of an example of estimated resource volumes with associated cumulative probabilities of occurrence for specific volumes.

may prevent identification because of data gaps or mapping techniques. In those cases where little or no activity has occurred in offshore provinces which would provide sufficient detailed data for resource assessment by geologic plays or individual prospects, analogous data from geologically similar petroleum provinces from the United States and foreign provinces were incorporated into the MMS resource assessment methodology. These analogs were identified and developed by MMS experts and, pertinent data were based upon information contained in commercial data bases pertaining to oil and natural gas fields maintained on a national and worldwide basis. Data were also obtained from similar petroleum plays in the onshore or State waters through consultation and coordination with USGS resource assessment personnel, particularly in those cases where geologic provinces and potential petroleum plays extended across the boundaries of the Agencies' assessments.

USGS

The onshore and State offshore analysis is based on nonproprietary data that is either published or otherwise available from commercial sources. Some USGS data are from studies in progress that have not been published. Province geologists utilized data from previous assessment work, published data and interpretations of geologic, geochemical, and geophysical data from all available sources to develop the play framework for the assessments. Open-file reports now being prepared by the province geologists for each basin describe the petroleum geology of the basins or provinces and describe the plays.

Computerized drilling and completion data came from the Well History Control System (Petroleum Information, Denver, Colorado) which contains data on more than 1.8 million oil and gas exploratory and development wells. These data were incorporated into exploration and development maps which showed dry hole penetrations and the areal size of oil and gas pools in a play. In addition, annual and cumulative drilling statistics were developed from this data. For the majority of the basins assessed, the December 1985 version of the Well History Control System was available. For many of the provinces assessed, the system contains essentially all wells drilled. However, in some provinces, parts of the historical record are missing. This is particularly true of the Eastern Interior Region and California.

Computerized oil field data were available in both the Petroleum Data System (Petroleum Information, Denver, Colorado) and the significant oil and gas fields in the United States file (R. G. Nehring and Associates, Colorado Springs, Colorado). Reserves and cumulative production data of fields were previously available from the significant oil and gas fields file. Other published sources, particularly State data, were used to develop data for missing fields. This was done primarily in Oklahoma. Data for sizes of fields in the Appalachian Basin were not available.

F. ECONOMIC PARAMETERS

The estimates of economically recoverable undiscovered oil and gas resources were based upon several assumptions pertaining to future oil and gas prices as well as future costs of development activities and transportation scenarios. These assumptions include: inflation rates, discount factors, acceptable investment rate of return, development activity timing, and other factors which could significantly affect the magnitude of the estimates. In recognition of the uncertainties associated with such assumptions and the different Agency methodologies employing such data, the economic scenario employed for this assessment was generated around a range of possible occurrences. To be consistent with the January 1, 1987, date of the estimates, future oil and gas prices were projected using a starting price of $18 as a base landed price per barrel of oil and $1.80 as a landed base price for natural gas. Real prices were forecast to decrease slightly during the period 1987-1989, followed by increases in real oil and gas prices in 1990 and beyond. Using the maximum and minimum values for the forecast price changes, "envelopes" were constructed for such changes as shown in figures I.3 and I.4. Estimates for undiscovered, economically recoverable oil and gas resources were based, in part, upon price assumptions within these envelopes.

The future costs of development activities and transportation facilities were based upon costs reported during the 1985-1986 period. For the purposes of this assessment, such costs were forecast to remain relatively stale for future activities when viewed in terms of constant (noninflated) dollars. Assumptions pertaining to the timing of development activities and transportation costs were developed specifically for each geologic province based upon past experience and current conditions pertaining to each province. Leasehold and exploration costs were assumed to be previously expended. Hence, estimates pertain to accumulations deemed to be "discovered" on January 1, 1987, and do not incorporate future discoveries.

The economic parameters developed for this assessment were utilized to determine a minimum accumulation size which would be commercially viable, that is, the minimum economic field size (MEFS) which would yield an acceptable after-tax return on investment once discounted future revenues and developments and transportation costs were determined. Although the MEFS is determined in slightly different ways by MMS and USGS because of their different resource assessment methodologies and data bases, the estimates of undiscovered, economically recoverable resources for onshore and offshore geologic provinces are compatible.

Detailed descriptions of the specific economic assumptions used by USGS and MMS in estimating economically recoverable resource are in the chapters describing Agency methodologies.

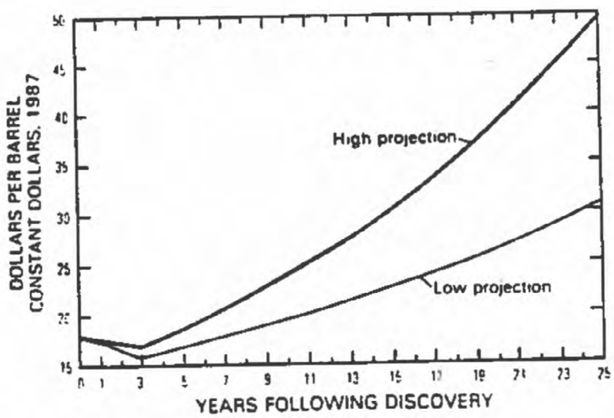

Figure I.3. Graph of price assumptions, both low and high, on which estimates of undiscovered economically recoverable crude oil volumes were based. In constant 1987 dollars.

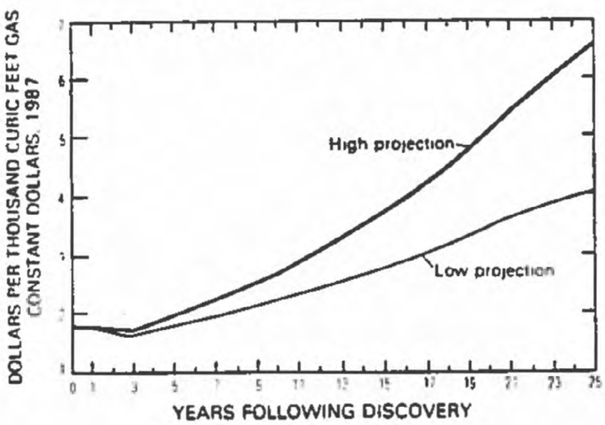

Figure I.4. Graph of price assumptions, both low and high, on which estimates of undiscovered economically recoverable natural gas volumes were based. In constant 1987 dollars.

G. GENERAL METHODOLOGY

The assessment of undiscovered oil and natural gas resources for geologic provinces of the United States required that MMS and USGS develop a work plan which would accommodate the differences in the Agencies' resource assessment methodologies and data availability, yet provide comparable estimates by province. This was accomplished through the Agencies reaching preliminary agreements, standardizing important procedural aspects of the assessment such as economic assumptions and geologic definitions, while developing clear objectives for the format of the results. Additionally, the Agencies maintained close coordination through discussions of geologic and economic factors applicable to those petroleum provinces extending across agreed upon assessment boundaries as well as providing technical support and reviews of the province estimates. Hence, although the individual Agency assessment methodologies differed in procedural approach and the type and level of detailed data, the estimates presented in this report for the various resource categories are compatible.

The Onshore and State Offshore Assessment

The assessment of the onshore and offshore State waters was performed by the USGS and included 80 petroleum provinces (figs. I.5 and I.6). In these areas, a play analysis method was used to estimate resources in accumulations greater than 1 million barrels of oil or 6 billion cubic feet of gas. Risk was assigned to the geologic factors controlling the occurrence of oil or gas, and estimates were made of the size and number of the undiscovered accumulations.

In this method, geologic settings of oil and gas occurrence are modeled. The play is treated as a collection of accumulations conceived as having similar geologic risks and sharing common geologic elements, such as a known or suspected trapping condition, which may be structural, stratigraphic, or combination of both. Geologists make judgments as to the probability of occurrence of the geologic factors necessary for the formation of oil or gas deposits and quantitatively assess accumulation sizes and numbers as probability distributions. The computer program FASPFS (Fast Appraisal System for Petroleum - Field Size) then performs the resource calculation on the basis of this information, employing an analytical method based on probability theory rather than Monte Carlo simulation (Crovelli, 1987). This procedure incorporates the geologist's expertise with geologic factors and the computer's facility in manipulation of numbers within the appraisal model. The method provides for a systematic integration and analysis of the geologic factors essential for the occurrence of oil or gas, a thorough documentation of the analysis, and an assessment that provides information on the size distribution and number of hydrocarbon accumulations and the quantity of estimated resources.

In this assessment, 250 plays were identified, and for each play oil and gas resources were estimated. In turn, the estimates for each of the plays were aggregated, using probability theory, to produce the estimates of total resources for the provinces.

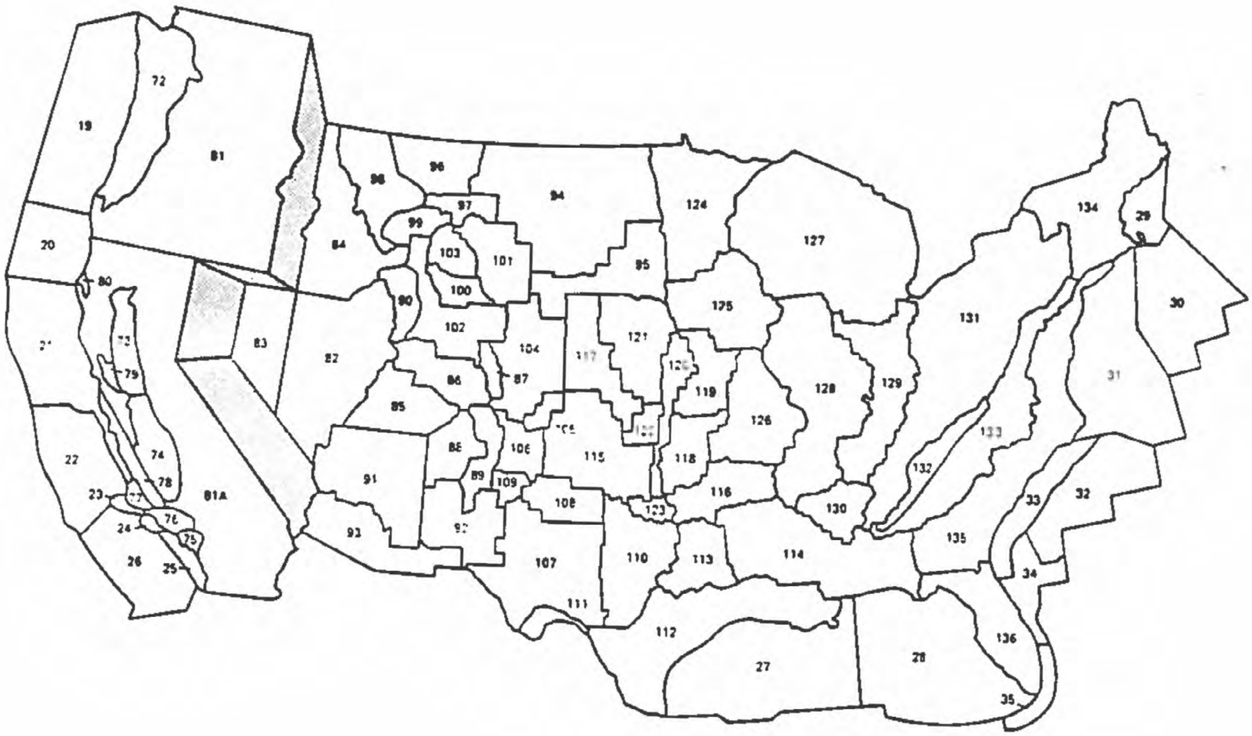

Figure I.5. Index map of Lower 48 States showing provinces assessed. Numbers refer to names of provinces listed by number in tables I.1 and I.2.

Figure I.6. Index map of Alaska showing provinces assessed. Numbers refer to names of provinces listed by number in tables I.1 and I.2.

The play analysis method provided estimates of undiscovered resources in recoverable accumulations equal to or greater than 1 million barrels of oil or 6 billion cubic feet of gas. Probabilistic estimates of recoverable oil and gas in accumulations smaller than the above cutoffs were made separately. These latter estimates were based, in part, on log-geometric extrapolations of numbers of fields into field-size classes smaller than the play analysis cutoffs. Undiscovered resource estimates for these small fields were made for each province as a whole.

The Federal Offshore Assessment

The MMS resource estimates for the Federal offshore provinces are based, in part, upon data from industry exploratory and development operations carried out under permits or mineral leases issued for the Federal OCS. These data were used by the MMS to identify and map specific prospects within offshore petroleum plays and to determine important parameters for the geologic and engineering factors that may be associated with these prospects. These data were also used for extrapolating potential prospects that are not currently identifiable through seismic interpretation or whose size may be masked by data gaps or mapping techniques. Economic parameters were developed for incorporating oil and natural gas prices, development, production, and transportation costs, and future predictions for these and other economic factors that may influence industry's development activities.

The MMS developed estimates of undiscovered economically recoverable oil and gas resources by employing a computer mathematical simulation model termed "PRESTO" (an acronym for Probabilistic Resource ESTimates-Offshore). The model performs multiple simulations of industry exploration efforts for potential prospects and ranks possible outcomes of such efforts that prove economically successful in terms of resources "discovered" and probabilities of occurrence. For estimates of the undiscovered recoverable resources, the MMD modified the data base to eliminate the economic constraints imposed upon potential resource "discoveries" and employed statistical techniques to extrapolate the size and number of all potential fields within the areas being modeled. For this assessment, the MMS defined this category of resources to include potential fields of 1 million barrels of oil equivalent or larger, unless accumulations of smaller sizes are presently considered economically recoverable under the economic scenarios imposed.

Detailed descriptions of the resource assessment methodologies of USGS and MMS are provided in subsequent chapters of the working papers.

B. ESTIMATES AS DISTRIBUTIONS

The USGS and MMS methods provide estimates of resources as a range of values corresponding to probabilities of occurrence in order to express the inherent uncertainty involved in assessment of unknowns. The underlying complementary cumulative probability distribution, as shown in figure I.2, represents the quantity of undiscovered resource. These distributions summarize the range of estimates as a single probability curve in a "greater than" format. Because of the uncertainty attached to the many geologic variables, no single answer is possible to the question of how much oil and gas are present; instead, an infinite number of answers are possible, each with its own confidence level. In nature only one real value exists, and the curve is an expression of the uncertainty about the size of that value. Larger quantities correspond to lower probabilities; that is, there is less confidence that those quantities are present. The degree of uncertainty is expressed in the "spread" of variance of the distribution.

Estimates are reported at the mean and at the 95th and 5th fractiles; the 95th and 5th fractiles are considered to be reasonable minimum and maximum values. Values exist beyond this nominal range, but estimates in these extreme parts of the probability distribution are highly sensitive to assumptions about the form of the statistical distribution and assumptions and dependencies in the underlying assessment. Mean values, although useful for comparative purposes, do not necessarily represent the actual value of resource, which is expected to lie, with 90 percent confidence, somewhere within the reported range.

Table I.1.--Estimates of undiscovered recoverable conventional oil, gas and natural gas liquids in onshore provinces and adjacent state waters of the United States.

		Crude Oil (Billion Barrels)			Total Gas (Trillion Cubic Feet)			NGL (Billion Barrels)		
		F95	F5	Mean	F95	F5	Mean	F95	F5	Mean
Region 1 - Alaska										
058	Arctic Coastal Plain	1.50	14.80	6.00	4.66	58.24	22.11	0.13	1.41	0.56
059	Northern Foothills	0.67	5.12	2.24	4.03	24.31	11.49	0.07	0.44	0.21
060	Southern Foothills	0.58	13.18	4.35	2.85	61.56	20.49	0.04	0.87	0.29
061	Kandik	0.00	0.49	0.11	0.00	0.49	0.11	0.00	0.00	0.00
062	Alaska Interior	0.00	0.00	0.00	0.45	2.85	1.33	0.00	Negl.	Negl.
063	Interior Lowlands (Incl. in 62)									
064	Bristol basin	0.00	0.00	0.00	0.11	0.67	0.32	0.00	0.00	0.00
065	Hope Basin	-	-	-	-	-	-	-	-	-
066	Copper River (Incl. in 62)									
067	Cook Inlet	0.09	0.64	0.29	0.35	3.91	1.53	0.00	Negl.	Negl.
068	Alaska Peninsula (Incl. in 62)									
069	Gulf of Alaska	0.03	0.58	0.19	0.03	2.00	0.56	Negl.	0.01	Negl.
070	Kodiak	-	-	-	-	-	-	-	-	-
071	SE Alaska	-	-	-	-	-	-	-	-	-
Region 2 - Pacific Coast										
072	W. Oregon-Washington	0.00	0.00	0.00	0.87	4.29	2.18	0.00	0.00	0.00
073	Sacramento basin	0.00	0.00	0.00	0.76	3.37	1.78	Negl.	Negl.	Negl.
074	San Joaquin basin	0.55	3.22	1.53	1.23	6.69	3.27	0.08	0.53	0.24
075	Los Angeles basin	0.24	1.42	0.68	0.29	1.69	0.81	0.02	0.09	0.04
076	Ventura basin	0.20	1.63	0.70	0.40	2.93	1.30	0.02	0.12	0.05
077	Santa Maria basin	0.13	0.49	0.27	0.11	0.44	0.24	0.01	0.02	0.01
078	Central Coastal	0.05	0.72	0.27	0.04	0.58	0.21	Negl.	0.02	0.01
079	Sonoma-Livermore basin	0.00	0.01	0.01	0.00	0.01	0.01	0.00	0.00	0.00
080	Humboldt basin	0.00	0.00	0.00	0.01	0.10	0.04	0.00	0.00	0.00
081	E. Oregon-Washington	0.00	0.00	0.00	0.43	2.39	1.16	Negl.	Negl.	Negl.
81A	Eastern California	-	-	-	-	-	-	-	-	-

Table I.1.--continued.

		Crude Oil (Billion Barrels)			Total Gas (Trillion Cubic Feet)			NGL (Billion Barrels)		
		F95	F5	Mean	F95	F5	Mean	F95	F5	Mean
Region 3 - Colorado Plateau and Basin & Range										
082	E. Basin & Range	0.09	0.65	0.29	0.03	0.47	0.17	Negl.	0.01	Negl.
083	W. Basin & Range	Negl.	0.06	0.02	Negl.	0.14	0.04	Negl.	Negl.	Negl.
084	Idaho-Snake River	0.00	0.00	0.00	0.01	0.10	0.04	0.00	0.00	0.00
085	Paradox basin	0.01	0.72	0.20	0.04	1.26	0.38	Negl.	0.01	Negl.
086	Uinta-Piceance	0.04	0.55	0.20	1.11	3.76	2.19	0.01	0.03	0.02
087	Park basin	Negl.	0.03	0.01	0.01	0.05	0.02	0.00	0.00	0.00
088	San Juan basin	0.04	0.16	0.09	1.40	2.73	2.00	Negl.	Negl.	Negl.
089	Albuquerque-Santa Fe rift	Negl.	0.07	0.02	0.06	0.63	0.25	0.00	0.00	0.00
090	Wyoming Thrust Belt	0.21	1.19	0.58	6.29	31.31	15.81	0.20	1.34	0.61
091	Northern Arizona	0.02	0.27	0.10	0.01	0.07	0.03	0.00	0.00	0.00
092	So. Central New Mexico	Negl.	0.05	0.02	0.05	0.70	0.26	0.00	0.00	0.00
093	So. Ariz.-SW New Mexico	Negl.	0.02	0.01	0.02	0.23	0.09	0.00	0.00	0.00
Region 4 - Rocky Mountains and Northern Great Plains										
094	Williston basin	0.49	1.15	0.78	0.49	1.07	0.74	0.03	0.06	0.04
095	Sioux Arch (Incl. in 094)									
096	Sweetgrass Arch	0.05	0.18	0.10	0.31	0.95	0.57	Negl.	Negl.	Negl.
097	Central Montana	0.01	0.06	0.03	0.01	0.02	0.01	0.00	0.00	0.00
098	Montana Overthrust	Negl.	0.04	0.01	0.42	8.72	2.92	0.01	0.19	0.07
099	SW Montana	Negl.	0.06	0.02	0.07	1.07	0.38	Negl.	0.02	0.01
100	Wind River basin	0.09	0.37	0.20	0.82	3.55	1.89	0.01	0.02	0.01
101	Powder River basin	1.16	3.82	2.25	1.38	4.78	2.76	0.03	0.12	0.06
102	SW Wyoming	0.06	0.47	0.21	1.32	6.76	3.38	0.02	0.09	0.05
103	Bighorn basin	0.10	0.48	0.25	0.18	1.59	0.66	Negl.	0.02	0.01
104	Denver basin	0.37	0.87	0.59	0.96	2.76	1.71	0.04	0.08	0.06
105	Las Animas arch	0.02	0.07	0.04	0.04	0.15	0.09	0.00	0.00	0.00
106	Raton-Sierra Grande	Negl.	0.02	0.01	0.02	0.36	0.13	Negl.	Negl.	Negl.

Table I.1.--continued.

		Crude Oil (Billion Barrels)			Total Gas (Trillion Cubic Feet)			NGL (Billion Barrels)		
		F95	F5	Mean	F95	F5	Mean	F95	F5	Mean
Region 5 - West Texas and Eastern New Mexico										
107	Permian basin	0.99	3.18	1.89	10.17	28.11	17.74	0.25	0.75	0.46
108	Palo Duro basin	0.05	0.24	0.13	0.02	0.11	0.05	0.00	Negl.	Negl.
109	Pedernal uplift	-	-	-	-	-	-	-	-	-
110	Bend arch	0.37	0.76	0.54	1.00	2.31	1.57	0.05	0.10	0.07
111	Marathon fold belt	0.00	0.00	0.00	0.28	1.63	0.78	Negl.	0.01	Negl.
Region 6 - Gulf Coast										
112	Western Gulf basin	1.59	5.16	3.05	38.71	99.79	64.78	1.02	2.78	1.76
113	East Texas basin	0.18	0.80	0.42	1.51	4.59	2.78	0.06	0.18	0.11
114	La.-Miss. Salt basins	0.48	1.16	0.77	8.06	24.59	14.91	0.57	1.80	1.07
Region 7 - Mid-Continent										
115	Anadarko basin	0.49	1.53	0.92	13.77	41.04	25.12	0.33	0.90	0.57
116	Arkoma basin	Negl.	0.07	0.03	1.01	3.24	1.93	0.00	0.00	0.00
117	Central Kansas Uplift	0.23	0.46	0.34	0.08	0.17	0.12	Negl.	Negl.	Negl.
118	Cherokee Platform	0.18	0.37	0.27	0.36	0.74	0.53	0.01	0.02	0.01
119	Forest City basin	Negl.	Negl.	Negl.	0.01	0.02	0.01	0.00	0.00	0.00
120	Nemaha Uplift	0.07	0.18	0.12	0.12	0.28	0.19	Negl.	0.01	Negl.
121	Salina basin	0.01	0.02	0.02	Negl.	0.01	Negl.	0.00	Negl.	Negl.
122	Sedgwick basin	0.06	0.11	0.08	0.32	0.66	0.47	0.01	0.01	0.01
123	So. Oklahoma	0.05	0.21	0.11	0.15	0.52	0.30	0.01	0.02	0.01
124	Sioux Uplift (Incl. in 125)									
125	Iowa Shelf	0.00	0.00	0.00	0.00	0.31	0.06	0.00	Negl.	Negl.
126	Ozark Uplift	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00

Table I.1.--continued.

	Crude Oil (Billion Barrels)			Total Gas (Trillion Cubic Feet)			NGL (Billion Barrels)		
	F95	F5	Mean	F95	F5	Mean	F95	F5	Mean
<u>Region 8 - Eastern Interior</u>									
127 Michigan basin	0.63	1.62	1.05	3.92	13.40	7.78	0.10	0.30	0.19
128 Illinois Basin	0.30	0.67	0.46	0.16	1.63	0.66	0.01	0.02	0.01
129 Cincinnati arch	0.05	0.18	0.10	0.07	0.22	0.13	Negl.	Negl.	Negl.
130 Black Warrior basin	Negl.	0.01	0.01	0.73	1.98	1.26	Negl.	0.01	0.01
131 Appalachian basin	0.08	0.25	0.15	2.77	12.29	6.46	0.07	0.31	0.16
132 Blue Ridge Overthrust	0.00	0.00	0.00	0.22	1.93	0.81	0.00	0.00	0.00
133 Piedmont	0.01	0.09	0.04	0.05	0.27	0.13	0.00	0.00	0.00
134 New England-Adirondack (Incl. in 132)									
<u>Region 9 - Atlantic Coast</u>									
135 Atlantic Coastal Plain (Incl. in 133)									
136 So. Florida	0.06	0.50	0.21	0.01	0.04	0.02	0.00	0.00	0.00

Table I.2.--Estimates of undiscovered recoverable oil and gas in Federal offshore areas of the United States.**

	Crude Oil (BBO)**			Gas (TCF)		
	F95	F5	Mean	F95	F5	Mean
Region 1A - Alaska						
Beaufort Shelf	0.49	3.74	1.27	2.14	12.81	8.26
Beaufort Basin	Negl.	Negl.	Negl.	Negl.	Negl.	Negl.
Chukchi Sea	0.00	7.19	2.22	0.00	16.87	6.33
Chukchi Borderland	Negl.	Negl.	Negl.	Negl.	Negl.	Negl.
Hope Basin	0.00	0.04	0.02	0.00	0.94	0.26
Norton Basin	0.00	0.05	0.01	0.00	1.79	0.19
St. Matthew-Hall	Negl.	Negl.	Negl.	Negl.	Negl.	Negl.
Navarin Basin	0.00	0.12	0.07	0.00	0.10*	0.23
St. George Basin	0.00	0.05	0.03	0.00	1.46	0.37
N. Aleutian Basin	0.00	0.02*	0.03	0.00	0.70	0.16
Bering Basin	Negl.	Negl.	Negl.	Negl.	Negl.	Negl.
Aleutian Arc	Negl.	Negl.	Negl.	Negl.	Negl.	Negl.
Aleutian Trench	Negl.	Negl.	Negl.	Negl.	Negl.	Negl.
Shumagin Shelf	0.00	0.00	0.01	0.00	0.00	0.04
Cook Inlet	0.00	0.30	0.03	0.00	0.67	0.05
Kodiak Shelf	0.00	0.18	0.04	0.00	0.39	0.20
GOA Shelf	0.00	1.39	0.12	0.00	4.59	0.67
GOA Basin	Negl.	Negl.	Negl.	Negl.	Negl.	Negl.
Region 2A - Pacific						
Oregon/Washington	0.00	0.24	0.06	0.00	2.57	0.57
Northern Cal.	0.00	0.40	0.13	0.00	5.04	1.61
Central California	0.68	2.45	1.55	0.83	3.63	1.93
Santa Maria	0.10	1.03	0.59	0.06	0.71	0.54
Santa Barbara	0.18	0.49	0.32	0.48	1.35	0.90
Los Angeles Basin	0.00	0.42	0.09	0.00	0.73	0.13
Inner Banks	0.07	0.83	0.45	0.06	1.84	0.78
Outer Banks	0.00	0.89	0.33	0.00	4.40	1.55
Region 6A - Gulf of Mexico						
Cenozoic	5.07	14.60	9.27	58.36	154.91	100.34
Mesozoic	0.12	0.52	0.30	0.55	7.84	3.00
Region 9A - Atlantic						
Gulf of Maine	0.00	0.00	Negl.	0.00	0.00	0.02
Georges Bank	0.00	0.38	0.10	0.00	6.75	1.94
Baltimore Canyon	0.05	1.16	0.48	1.34	22.46	9.72
Carolina Trough	0.00	0.71	0.20	0.00	13.37	3.57
SE Ga. Embayment	0.00	0.00	Negl.	0.00	0.00	0.02
Blake Plateau	0.00	0.56	0.08	0.00	7.66	1.38
Florida Straits	0.00	0.45	0.08	0.00	1.86	0.38

* In these cases, the low marginal probability causes the risked mean to be located at a percentile below the 5th percentile, resulting in the risked mean being greater than the risked 5% estimate.

** Includes natural gas liquids.

Table I.3.--Estimates of undiscovered economically recoverable conventional oil, gas and natural gas liquids in onshore provinces and adjacent state waters of the United States.

	Crude Oil (Billion Barrels)			Total Gas (Trillion Cubic Feet)			NGL (Billion Barrels)		
	F95	F5	Mean	F95	F5	Mean	F95	F5	Mean
Region 1 - Alaska									
058 Arctic Coastal Plain	0.00	10.93	3.36	0.00	0.00	0.00	0.00	0.00	0.00
059 Northern Foothills	0.00	2.64	0.72	0.00	0.00	0.00	0.00	0.00	0.00
060 Southern Foothills	0.00	12.64	3.59	0.00	0.00	0.00	0.00	0.00	0.00
061 Kandik	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
062 Alaska Interior	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
063 Interior Lowlands (Incl. in 062)									
064 Bristol basin	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
065 Hope basin	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
066 Copper River (Incl. in 062)									
067 Cook Inlet	0.05	0.60	0.24	0.15	3.69	1.20	0.00	Negl.	Negl.
068 Alaska Peninsula (Incl. in 062)									
069 Gulf of Alaska	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
070 Kodiak	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
071 SE Alaska	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
Region 2 - Pacific Coast									
072 W. Oregon-Washington	0.00	0.00	0.00	0.80	4.28	2.06	0.00	0.00	0.00
073 Sacramento basin	0.00	0.00	0.00	0.72	3.25	1.70	Negl.	Negl.	Negl.
074 San Joaquin basin	0.55	3.21	1.53	1.22	6.68	3.26	0.08	0.53	0.24
075 Los Angeles basin	0.20	1.50	0.66	0.25	1.60	0.78	0.01	0.08	0.04
076 Ventura basin	0.16	1.65	0.66	0.34	2.80	1.21	0.01	0.12	0.05
077 Santa Maria basin	0.11	0.50	0.26	0.10	0.43	0.23	0.01	0.02	0.01
078 Central Coastal	0.05	0.71	0.26	0.04	0.57	0.21	Negl.	0.02	0.01
079 Sonoma-Livermore basin	0.00	0.01	Negl.	0.00	0.01	Negl.	0.00	0.00	0.00
080 Humboldt basin	0.00	0.00	0.00	Negl.	0.08	0.02	0.00	0.00	0.00
081 E. Oregon-Washington	0.00	0.00	0.00	0.41	2.32	1.12	0.00	Negl.	Negl.
081A E. California	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00

Table I.3.--continued.

		Crude Oil (Billion Barrels)			Total Gas (Trillion Cubic Feet)			NGL (Billion Barrels)		
		F95	F5	Mean	F95	F5	Mean	F95	F5	Mean
Region 3 - Colorado Plateau and Basin & Range										
082	E. Basin & Range	0.08	0.62	0.26	0.03	0.44	0.16	0.00	0.01	Negl.
083	W. Basin & Range	Negl.	0.04	0.01	Negl.	0.13	0.04	0.00	Negl.	Negl.
084	Idaho-Snake River	0.00	0.00	0.00	0.00	0.10	0.03	0.00	0.00	0.00
085	Paradox basin	0.01	0.68	0.18	0.03	1.20	0.35	Negl.	0.01	Negl.
086	Uinta Piceance basin	0.03	0.54	0.19	1.08	3.70	2.15	0.01	0.03	0.02
087	Park basin	Negl.	0.03	0.01	0.01	0.05	0.02	0.00	0.00	0.00
088	San Juan Basin	0.04	0.15	0.08	1.39	2.70	1.97	0.00	Negl.	Negl.
089	Albuquerque-Santa Fe rift	Negl.	0.07	0.02	0.05	0.59	0.22	0.00	0.00	0.00
090	Wyoming Thrust Belt	0.21	1.17	0.56	6.22	31.15	15.70	0.20	1.33	0.61
091	Northern Arizona	0.02	0.27	0.10	0.01	0.07	0.03	0.00	0.00	0.00
092	So. Central New Mexico	Negl.	0.05	0.02	0.05	0.67	0.24	0.00	0.00	0.00
093	So. Ariz.-SW New Mexico	Negl.	0.01	0.01	0.02	0.21	0.08	0.00	0.00	0.00
Region 4 - Rocky Mountains and Northern Great Plains										
094	Williston basin	0.29	0.80	0.51	0.33	0.78	0.52	0.02	0.04	0.03
095	Sioux Arch (Incl. in 094)									
096	Sweetgrass Arch	0.04	0.17	0.09	0.30	0.93	0.56	Negl.	Negl.	Negl.
097	Central Montana	0.01	0.06	0.03	0.01	0.02	0.01	0.00	0.00	0.00
098	Montana Overthrust	Negl.	0.04	0.01	0.41	8.65	2.89	0.01	0.19	0.07
099	SW Montana	Negl.	0.05	0.01	0.06	1.04	0.36	Negl.	0.02	0.01
100	Wind River basin	0.09	0.36	0.19	0.79	3.49	1.84	0.01	0.02	0.01
101	Powder River basin	1.02	3.55	2.04	1.21	4.45	2.51	0.03	0.12	0.06
102	SW Wyoming	0.06	0.46	0.20	1.19	6.51	3.19	0.02	0.08	0.04
103	Bighorn basin	0.09	0.47	0.24	0.17	1.55	0.64	Negl.	0.02	0.01
104	Denver basin	0.26	0.67	0.43	0.77	2.44	1.46	0.03	0.06	0.04
105	Las Animas arch	0.02	0.06	0.03	0.04	0.15	0.08	0.00	0.00	0.00
106	Raton-Sierra Grande	Negl.	0.02	0.01	0.02	0.34	0.12	Negl.	Negl.	Negl.

Table I.3.--continued

	Crude Oil (Billion Barrels)			Total Gas (Trillion Cubic Feet)			NGL (Billion Barrels)		
	F95	F5	Mean	F95	F5	Mean	F95	F5	Mean
Region 5 - West Texas and Eastern New Mexico									
107 Permian basin	0.94	3.11	1.82	9.68	27.32	17.09	0.24	0.73	0.44
108 Palo Duro basin	0.05	0.23	0.12	0.02	0.10	0.05	Negl.	Negl.	Negl.
109 Pedernal	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
110 Bend arch	0.30	0.63	0.44	0.91	2.14	1.44	0.04	0.10	0.06
111 Marathon fold belt	0.00	0.00	0.00	0.26	1.58	0.74	Negl.	0.01	Negl.
Region 6 - Gulf Coast									
112 Western Gulf basin	1.51	5.14	2.99	36.30	97.84	62.36	0.96	2.74	1.71
113 East Texas basin	0.17	0.77	0.40	1.34	4.29	2.55	0.05	0.16	0.10
114 La.-Miss. Salt basins	0.36	0.96	0.62	7.09	23.90	14.41	0.49	1.90	1.05
Region 7 - Mid-Continent									
115 Anadarko basin	0.44	1.38	0.83	12.71	38.49	23.41	0.30	0.84	0.53
116 Arkoma basin	Negl.	0.07	0.02	0.90	3.05	1.77	0.00	0.00	0.00
117 Central Kansas Uplift	0.23	0.46	0.34	0.08	0.17	0.12	Negl.	Negl.	Negl.
118 Cherokee Platform	0.18	0.37	0.26	0.36	0.73	0.53	0.01	0.02	0.01
119 Forest City basin	Negl.	Negl.	Negl.	0.01	0.02	0.01	0.00	0.00	0.00
120 Nemaha Uplift	0.07	0.18	0.11	0.12	0.27	0.19	Negl.	0.01	Negl.
121 Salina basin	0.01	0.02	0.01	Negl.	0.01	Negl.	0.00	0.00	0.00
122 Sedgwick basin	0.05	0.10	0.08	0.31	0.64	0.46	0.01	0.01	0.01
123 So. Oklahoma	0.04	0.17	0.09	0.11	0.45	0.24	Negl.	0.02	0.01
124 Sioux Uplift (Incl. in 125)									
125 Iowa Shelf	0.00	0.00	0.00	0.00	0.22	0.05	0.00	Negl.	Negl.
126 Ozark Uplift	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00

Table I.3.--continued.

		Crude Oil (Billion Barrels)			Total Gas (Trillion Cubic Feet)			NGL (Billion Barrels)		
		F95	F5	Mean	F95	F5	Mean	F95	F5	Mean
Region 8 - Eastern Interior										
127	Michigan basin	0.61	1.59	1.03	3.70	13.03	7.47	0.10	0.29	0.18
128	Illinois basin	0.30	0.67	0.46	0.16	1.63	0.66	0.01	0.02	0.01
129	Cincinnati arch	0.05	0.18	0.10	0.07	0.22	0.13	Negl.	Negl.	Negl.
130	Black Warrior basin	Negl.	0.01	0.01	0.68	1.90	1.19	Negl.	0.01	0.01
131	Appalachian basin	0.07	0.22	0.13	2.55	11.44	5.99	0.07	0.28	0.15
132	Blue Ridge Overthrust	0.00	0.00	0.00	0.18	1.93	0.76	0.00	0.00	0.00
133	Piedmont	0.01	0.08	0.04	0.04	0.23	0.11	0.00	0.00	0.00
134	New England-Adironack (Incl. in 132)									
Region 9 - Atlantic Coast										
135	Atlantic Coastal Plain (Incl. in 133)									
136	So. Florida	0.05	0.50	0.21	Negl.	0.04	0.02	0.00	0.00	0.00

Table I.4.-- Estimates of undiscovered economically recoverable oil* and gas in Federal offshore areas of the United States.

	Crude Oil (BBO)*			Gas (TCF)		
	F95	F5	Mean	F95	F5	Mean
Region 1A - Alaska						
Beaufort Shelf	0.00	1.74	0.21	0.00	0.00	0.00
Beaufort Basin	Negl.	Negl.	Negl.	Negl.	Negl.	Negl.
Chukchi Sea	0.00	3.59	0.59	0.00	0.00	0.00
Chukchi Borderland	Negl.	Negl.	Negl.	Negl.	Negl.	Negl.
Hope Basin	0.00	0.00	Negl.	0.00	0.00	0.00
Norton Basin	0.00	0.00	Negl.	0.00	0.00	0.00
St. Matthew-Hall	Negl.	Negl.	Negl.	Negl.	Negl.	Negl.
Navarin Basin	0.00	0.00	0.03	0.00	0.00	0.00
St. George Basin	0.00	0.00	0.01	0.00	0.00	0.00
N. Aleutian Basin	0.00	0.00	0.01	0.00	0.00	0.00
Bering Basin	Negl.	Negl.	Negl.	Negl.	Negl.	Negl.
Aleutian Arc	Negl.	Negl.	Negl.	Negl.	Negl.	Negl.
Aleutian Trench	Negl.	Negl.	Negl.	Negl.	Negl.	Negl.
Shumagin Shelf	0.00	0.00	Negl.	0.00	0.00	0.00
Cook Inlet	0.00	0.00	Negl.	0.00	0.00	0.00
Kodiak Shelf	0.00	0.00	0.02	0.00	0.00	0.00
GOA Shelf	0.00	0.00	0.03	0.00	0.00	0.00
GOA Basin	Negl.	Negl.	Negl.	Negl.	Negl.	Negl.
Region 2A - Pacific						
Oregon/Washington	0.00	0.23	0.04	0.00	2.44	0.46
Northern Cal.	0.00	0.14	0.04	0.00	2.42	0.69
Central California	0.13	1.33	0.74	0.21	1.80	1.05
Santa Maria	0.02	0.61	0.26	0.02	0.53	0.25
Santa Barbara	0.13	0.48	0.29	0.41	1.25	0.79
Los Angeles Basin	0.00	0.43	0.09	0.00	0.76	0.13
Inner Banks	0.04	0.82	0.40	0.05	1.52	0.69
Outer Banks	0.00	0.90	0.23	0.00	4.22	1.11
Region 6A - Gulf of Mexico						
Cenozoic	2.24	9.04	5.36	28.24	102.33	62.10
Mesozoic	0.05	0.58	0.27	0.01	6.77	2.22
Region 9A - Atlantic						
Gulf of Maine	0.00	0.00	Negl.	0.00	0.00	0.02
Georges Bank	0.00	0.19	0.04	0.00	4.16	0.98
Baltimore Canyon	0.00	0.40	0.10	0.00	9.44	2.36
Carolina Trough	0.00	0.21	0.03	0.00	5.02	0.77
SE Ga. Embayment	Negl.	Negl.	Negl.	Negl.	Negl.	Negl.
Blake Plateau	0.00	0.16	0.02	0.00	2.51	0.30
Florida Straits	0.00	0.42	0.06	0.00	0.54	0.08

* Includes natural gas liquids.

II. USGS METHODOLOGY

A. ASSESSMENT PROCESS

The USGS assessment of oil and gas resources was accomplished in several stages. Approximately 70 USGS geologists provided basic geologic data for the province(s) in their respective areas of expertise. The assessment was organized into three segments: (1) review of the geologic and geophysical data and identification of the plays and subplays (the units of assessment); (2) assessment of the geologic input parameters and computer generation of initial oil and gas resource estimates; and (3) review of the entire assessment. The general scheme is shown in figure II.A.1.

Following initial studies by province geologists, and using data from previous assessment investigations and a broad range of available geologic information and analyses from other sources, petroleum plays were tentatively defined and characterized. A review of geologic and geophysical data and interpretation was done by an assessment panel in order to further refine, identify, or combine plays for later assessment. Approximately 250 plays were thus developed for individual assessment.

After play definition, the province geologists conducted studies to carefully analyze and describe the geology of the plays to be assessed. These studies incorporated geologic information, as well as production and other exploration data.

These data and analyses were presented by each province geologist to an assessment committee that consisted of from 3 to 6 geologists. The assessment team reviewed and synthesized extensive data summaries and interpretations for each play. A typical data summary for a play consists of several types of maps, cross sections, charts, and graphs. These comprehensive data summaries are essential for an efficient and reliable assessment and are based upon data derived largely from subsurface and surface geological, geochemical, and other related studies in the play area, as well as from contiguous or analog areas. In a few areas, geophysical data were available. Judgments were elicited by consensus and entered on appraisal data forms. These judgments included assignment of risk to the geologic attributes in each play and estimation of probability distributions using seven fractiles for hydrocarbon reservoir size and number.

As data for each play were completed, the information was entered into a computer and processed by the play-analysis program FASPFS (Fast Appraisal System for Petroleum - Field Size), which for each play resulted in initial resource estimates of oil and gas and pool sizes.

Following completion of this cycle of assessment, initial play estimates were reviewed by the province geologists and the assessment panel to insure validity of geologic input and to analyze the assessed plays to make sure they properly represent the geologic understanding of the area being assessed, including the relative value or ranking of plays as well as their absolute values. In many instances, several reviews were made.

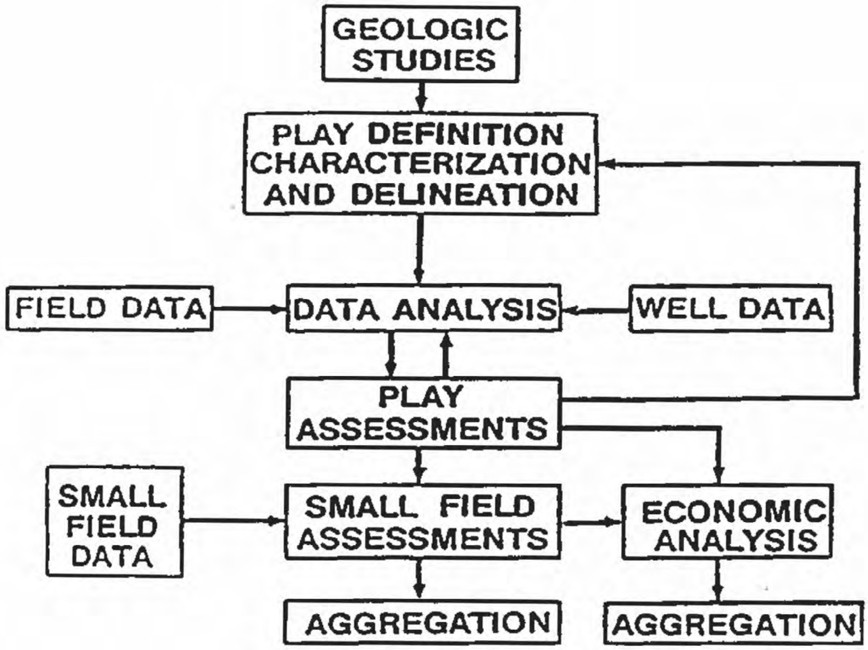

Figure II.A.1. Flow chart for estimation of undiscovered resources.

After play assessment and review, the panel completed assessment of resources in small fields (<1 million barrels of oil or 6 billion cubic feet of gas in each province as described in section IIF.)

Final estimates were aggregated into reporting units of provinces, regions, and national totals. Aggregation used analytical methods based on probability theory (Crovelli and Balay, 1986) (see section II.D, this report).

B. GENERAL ASSESSMENT METHODS

The onshore and coastal State water assessment of undiscovered recoverable conventional resources was accomplished by the USGS in petroleum provinces, three principal appraisal techniques were employed: 1) play analysis, including the computer program FASPFS; 2) small field assessment based on extrapolation of log geometric models; and 3) direct volumetric assessment of a few plays where data did not permit a play analysis approach. The assessment was supported by a number of analytical procedures. The assessment of economically recoverable resources was derived from the above through methods described in section II.I, and the assessment results were aggregated into the reporting units by utilizing analytical procedures rather than Monte Carlo simulation (Crovelli, 1986).

The play analysis technique was primary to the assessment and was employed for all resources in accumulations greater than 1 million barrels of oil or 6 billion cubic feet of gas. Risk was assigned to the geologic factors controlling the occurrence of oil or gas, and estimates were made of the size and number of the undiscovered accumulations. The method is a modification of a play analysis technique developed by the U.S. Geological Survey from a Geological Survey of Canada appraisal program (Canada Department of Energy, Mines and Resources, 1977). In its earlier form, the method had been used in the assessment of the National Petroleum Reserve in Alaska and the Arctic National Wildlife Refuge (U.S. Department of the Interior, Office of Minerals Policy and Research Analysis, 1979; Mast and others, 1980; White, 1981; Miller, 1981; Bird, 1986; Dolton and others, 1987).

The play is treated as a collection of accumulations conceived as having similar geologic risks and sharing common geologic elements, such as a known or suspected trapping condition, which may be structural, stratigraphic, or a combination of both. In the play analysis assessment method, geologic settings of oil and gas occurrence are modeled. Geologists make judgments as to the probability of occurrence of the geologic factors necessary for the formation of oil or gas deposits and quantitatively assess accumulation sizes and numbers as probability distributions. The computer program FASPFS then performs the resource calculation on the basis of this information (see section II.D).

Probabilistic estimates of oil and gas resources in deposits smaller than 1 million barrels of oil and 6 billion cubic feet of gas were made separately. These estimates were based on log-geometric extrapolations of numbers of fields and associated resources into field-size classes smaller than the play analysis cutoffs. Estimates for these small field resources were made for each province as a whole.

Resources in plays for which adequate historic or analog field data were lacking were assessed through a direct subjective estimate, expressed as a probability distribution, rather than estimation by field size and number. This modified Delphi method was employed in the Appalachian basin, Eastern Oregon and Washington, and for the collective assessment of other plays of small or poorly defined potential outside of the principal plays assessed in maturely explored areas.

C. PLAY ASSESSMENT MODEL

The play analysis method attempts to describe and model the natural occurrence of oil and gas. The assessment model divides the geologic characteristics of a play into two classes: play and accumulation attributes, which determine the presence of hydrocarbons; and characteristics relating to amount of resources contained, that is, the number and sizes of accumulations. The geologist's judgments and quantifications of these characteristics are recorded on a data form. An example of this form is shown in figure II.C.1 to show how the method addresses the two fundamental questions asked in any assessment: (1) are there oil or gas accumulations in the area, and (2) if so, how much oil and gas is present?

To answer the first question, it is necessary to assess the play and accumulation attributes. Play attributes are the geologic conditions or regional characteristics that apply to the play as a whole. They include hydrocarbon source, timing, migration, and potential reservoir-rock facies adequate to allow accumulations of the minimum size being assessed. Jointly, they determine favorability in the play for the occurrence of oil or gas. They are assessed as to probability of occurrence, taken to be independent, and their product is the marginal play probability.

The presence of favorable play attributes is a necessary but not sufficient condition for the existence of accumulated hydrocarbons, since favorable conditions at the prospect level are also required. The accumulation attribute embodies those additional geologic conditions that further determine hydrocarbon occurrence, and include the occurrence of trap, effective porosity and seal, and availability of hydrocarbons to one or more prospects within the play with proper timing relative to trap formation so that an accumulation may somewhere be present, given that the play attributes are favorable. The conditional accumulation probability is directly estimated. Most mature plays have little or no risk for another hydrocarbon accumulation unless they are approaching exhaustion. The probability that a hydrocarbon accumulation exists in the play is the product of the marginal play probability and the conditional accumulation probability.

	Attribute	Probability Favorable or Present
Play Attributes	Hydrocarbon Source (S)	
	Timing (T)	
	Migration (M)	
	Potential Reservoir Facies (R)	
	Marginal Play Probability SxTxMxR=MP	
Accumulation Attribute	Conditional Probability of at least one undisc. accumulation in play Minimum accumulation size assessed: ___x10 ^{6} BBL; ______x10 ^{9} CF.	

RISK

ARE THERE ANY OIL & GAS ACCUMULATIONS PRESENT?

Hydrocarbon Accumulation Parameters (Undisc. accum's)									
Reservoir Lithology	Sandstone								
	Carbonate								
	Other								
Hydrocarbon mix	Gas								
	Oil								
Attribute \ Fractiles		100	95	75	50	25	5	0
Accumulation Size	Oil (10^6 BBL)							
	NA Gas (10^9CF)							
Reservoir Depth ($x10^3$ Ft)	Oil							
	NA Gas							
Conditional No. of accumulations								

VOLUME

IF PRESENT, HOW MUCH OIL OR GAS?

Average ratio of associated-dissolved gas to oil:________CF/barrel

Average ratio of NGL to gas: NA GAS______BBL/10 ^{6} CFG; Assoc-Dis Gas______BBL/10 ^{6} CFG.

Figure II.C.1. Oil and gas appraisal data form used in the National assessment.

To answer the second question of how much oil and gas is present, it is necessary to assess the number and size of accumulations. This is done on a conditional basis; that is, presuming their occurrence and assessing their probable values. Identification of prospects within a play is generally impossible because of limitations on data availability and because specific success rates are poorly known. Estimates of both size and number of accumulations deal with great uncertainty and are therefore made as cumulative probability distributions expressed by the assessors with 7 fractiles.

The distribution of the number of accumulations derived from an understanding of the geologic framework and exploration history and from analysis of existing or analog field data for the play and computer-generated play exploration and development maps and other subsurface geologic maps. These data and their analysis allow estimation of unseen but suspected accumulations.

The estimates of sizes of undiscovered oil or gas deposits are expressed as probability distributions, represented on the form as fractiles of "accumulation size", that show the probability of occurrence of various sizes within the undiscovered population, or, viewed another way, describe the size of a randomly selected accumulation within that population. In reaching this assessment, the estimators considered the areal size and geologic requirements for such accumulations, including reservoir development, play location relative to source rocks, migration paths, seal effectiveness, probability of requisite traps, and the exploration history. Analytical information bearing on accumulation sizes and numbers is obtained from historic and analog data sets. Separate size distributions are assessed for oil accumulations and for nonassociated gas accumulations. The proportion of the undiscovered accumulations that are oil or nonassociated gas is assessed as the hydrocarbon mix.

The distributions of number and size are conditional, and, as such, they must be risked by the probability of occurrence derived from the marginal play and accumulation probabilities to determine resource estimates.

The amount of gas dissolved with the oil and other associated gases is calculated using estimated gas-oil ratios. Natural gas liquids (NGL's) are calculated using estimated liquid to gas ratios. Although the play analysis method is robust and flexible in its handling of uncertain events, it requires that all plays be identified and properly modeled when it is used as a method to assess total resource. In the exploration process, unanticipated discoveries and failures occur often enough to warrant cautioning users that as new data become available and play concepts are modified or revised, resource estimates are subject to change. The method, nevertheless, provides a systematic analysis and integration of the geologic factors essential for the occurrence of oil and gas, a thorough documentation of the analysis and an assessment that provides information on the size, distribution, and number of hydrocarbon accumulations as well as their resources.

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D. ASSESSMENT METHODOLOGY FOR ESTIMATION OF UNDISCOVERED PETROLEUM RESOURCES IN PLAY ANALYSIS OF THE UNITED STATES AND AGGREGATION METHODS

by

R.A. Crovelli, R.F. Mast, G.L. Dolton, and R.H. Balay

Abstract

A geostochastic system called FASPF was developed for the assessment of undiscovered petroleum resources in the United States. It is a fast appraisal system for petroleum play analysis that uses a field-size geologic model and an analytic probabilistic methodology. The geologic model is a particular type of probability model in which the volumes of oil and gas accumulations are modeled as statistical distributions in the form of probability histograms and the risk structure is bilevel (play and accumulation) in terms of conditional probability. The probabilistic methodology is an analytic method derived from probability theory as opposed to Monte Carlo simulation. Resource estimates of crude oil and natural gas are calculated and expressed in terms of probability distributions.

The analytic system comprises a package of 11 computer programs for play analysis, subplay analysis, economic analysis, and aggregation analysis. Subplay analysis includes the estimation of petroleum resources on non-Federal offshore areas. Economic analysis involves the truncation of field size using a minimum economic cut-off value. Aggregation analysis aggregates individual play and subplay estimates of oil and gas, respectively, at the provincial, regional, and national levels. The FASPF computer package is a large complex system that is very flexible and efficient.

Introduction

During the past few years, the USGS has made major progress in the design and development of petroleum resource appraisal studies involving play analysis and analytic probabilistic methodology using a variety of geologic models. Play analysis is a general approach that uses various geologic models and probabilistic methods to analyze a geologic play. In applying play analysis, a petroleum assessment area is first partitioned into geologic plays and the individual plays are analyzed. The individual play estimates of oil and gas are aggregated, respectively, in order to estimate the petroleum potential of the entire assessment area. A geologic model for the quantity of undiscovered petroleum resources in a play involves uncertainty because of incomplete or fragmentary geologic information generally available.

Some recent petroleum resource appraisal studies by the USGS involved play analysis. The Arctic National Wildlife Refuge (ANWR) study of 1987 assessed geologic plays in the North Slope of Alaska using a reservoir-engineering model. The assessment methodology is explained in Crovelli (1988); an early version of the computer source code is in Crovelli and Balay (1986). The Hungarian Oil and Gas Trust (OKGT) study required generalizing the reservoir-engineering and aggregation models used in the ANWR study. The resulting system consisted of a universal-site geologic model with metric units for IBM-PC/XT/AT (and compatible) microcomputers and is available in Crovelli and Balay (1987). The Western Tight Gas Sands study (Johnson et al., 1987) was a play-analysis assessment of low-permeability gas resources of the Upper Cretaceous Mesaverde Group in the Piceance basin of western Colorado.

Geologic Probability Model

In play analysis, a petroleum assessment area is partitioned into geologic plays and the individual plays are analyzed. In this study, a play is considered to consist of a collection of hydrocarbon accumulations having a relatively homogeneous geologic setting. A hydrocarbon accumulation is a discrete oil or gas deposit that may consist of one or more pools depending upon the specific play concept. An accumulation is modeled by separately considering the uncertainty of the occurrence of the assessed hydrocarbon exceeding a specific amount and the quantity of the hydrocarbon, if present. An accumulation of hydrocarbon is modeled as either crude oil and its associated dissolved gas or solely as nonassociated gas. The amount of associated dissolved gas in an accumulation of oil is calculated using a gas-oil ratio. Because gas refers to either nonassociated gas or associated-dissolved gas, the amount of gas in a play is the sum of the two types of gas from the accumulations. Three sets of geologic attributes or random variables are involved in this play-analysis approach; those for the play, for the caccumulation occurrence, and for the accumulation sizes. The play and accumulation occurrence attributes are concerned with the presence or absence of certain geologic characteristics at the play and accumulation levels, respectively. The hydrocarbon accumulation parameters are concerned with the size of the hydrocarbon accumulation.

The play attributes are: (1) existence of a hydrocarbon source, (2) favorable timing for migration of hydrocarbons from source to trap, (3) potential migration paths, and (4) existence of potential reservoir facies. The presence of all four play attributes (in which case the play is said to be favorable) is a necessary, but not sufficient, condition for the existence of oil or gas deposits in the play. Thus, if one or more of these attributes is not present, all the accumulations within the play are dry. Subjective judgments are made by experts for estimating the probability of the presence of each play attribute. The product of these four probabilities is the probability that the play is favorable for the existence of hydrocarbon accumulations and is called the marginal play probability.

A conditional probability of at least one undiscovered accumulation in the play exceeding specified minimum amounts for oil and gas is assigned; the condition being that the play is favorable. The hydrocarbon-type probabilities, that is, the respective probabilities of a given accumulation being either oil or nonassociated gas, are also estimated.

The hydrocarbon accumulation parameters include the oil and nonassociated gas accumulation sizes, both of which are treated as continuous independent random variables. The probability distribution for an accumulation size is determined from subjective judgments made by experts, usually geologists, based on actual geological and geophysical data when available and/or the experience and knowledge of the experts using analog data and geologic extrapolations. The probability distribution for each accumulation size is described by a complementary cumulative distribution function determined from seven estimated fractiles (100th, 95th, 75th, 50th, 25th, 5th, 0th). (The 5th fractile, for example, is an accumulation-size value such that there is a 5 percent chance of at least that value.) In each play analyzed, the seven fractiles are estimated for the oil and nonassociated gas accumulation sizes.

The conditional number of accumulations in the play is treated as a discrete random variable, and seven fractiles are estimated. The condition is that there is at least one undiscovered accumulation in the play.

The average ratio of NGL to nonassociated gas and the average ratio of NGL to associated-dissolved gas are estimated. The percentages of the play's resources on Federal land, Indian (native) land, and non-Federal offshore are also estimated.

Probability judgments concerning the play and accumulation attributes are developed by experts familiar with the geology of the area of interest. The experts review all available data relevant to the appraisal, identify the major plays within the assessment area (e.g., basin or province), and then assess each identified play. All of the geologic data required by this model for a play is entered on an oil and gas appraisal data form (fig. II.D.1). Information from the data form is entered into computer data files as the input for a computer program based upon an analytic method.

This assessment study also included several other geologic models, some of which were quite complex. A probability histogram model was designed to aid in the modeling of the input distributions for the hydrocarbon accumulation parameters. A subplay model was developed to estimate resources in a fraction of the play from estimates of the entire play. An economic model truncates distributions of the field sizes using a minimum economic cut-off value. An aggregation model was needed to aggregate individual play and subplay estimates of oil and gas, respectively, in order to estimate the petroleum potential of assessment areas and sets of subplays.

Analytic Method of Play Analysis

An analytic method using probability theory was developed as a more efficient alternative to the costly and time-consuming Monte Carlo simulation method for petroleum play analysis.

The analytic method was developed by the application of many laws of expectation and variance in probability theory. It systematically tracks through the geologic probability model, computes all of the means and variances of the appropriate random variables, and calculates all of the probabilities of occurrence. In order to arrive at probability fractiles, the lognormal distribution is used as a model for an unknown distribution (Crovelli, 1984). Oil, nonassociated gas, associated-dissolved gas, gas, NGL in nonassociated gas, NGL in associated-dissolved gas, and NGL in gas resources are each assessed in turn. Separate methodologies were developed for analyzing individual plays and for aggregating the plays.

The basic steps of the analytic method of play analysis (field-size model) are:

1. Select the play.
2. Select oil as the first resource to be assessed.

CODE: ____________

NATIONAL ASSESSMENT
OIL AND GAS APPRAISAL DATA FORM
(FASPFS)

Evaluator ____________ Play Name: ____________
Date Evaluated ____________ Province ____________ No. ____

	Attrribute		Probability Favorable or Present	Comments
Play Attributes	Hydrocarbon Source (S)			
	Timing (T)			
	Migration (M)			
	Potential Reservoir Facies (R)			
	Marginal Play Probability SxTxMxR=MP			
Accumulation Attribute	Conditional Probability of at least one undisc. accumulation in play Minimum accumulation size assessed: ___x10 ^{6} BBL; _____x10 ^{9} CF.			

Hydrocarbon Accumulation Parameters (Undisc. accum's)									
Reservoir Lithology	Sandstone								
	Carbonate								
	Other								
Hydrocarbon type	Gas								
	Oil								
Attribute \ Fractiles		100	95	75	50	25	5	0	
Accumulation Size	Oil (10^6 BBL)								
	Gas (10^9 CF)								
Reservoir Depth ($x10^3$ Ft.)	Oil								
	NA Gas								
Conditional No. of accumulations									

Average ratio of associated-dissolved gas to oil:_______CF/barrel

Average ratio of NGL to gas: NA GAS_____BBL/10^6CFG; Assoc-Dis Gas_____BBL/10^6CFG.

Est. % resource on: Federal land___%; Indian (native) land___%; Non-Federal offshore___%

Play area_____mi^2

Discovered resources:

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

Figure II.D.1. Oil and gas appraisal data form used in the National assessment.

3. Compute the mean and variance of the accumulation size of oil using the estimated seven fractiles and assuming a uniform distribution between fractiles, that is, a piecewise uniform probability density function (as is done in the case of a simulation method).
4. Compute the mean and variance of the conditional number of accumulations from the estimated seven fractiles, assuming a uniform distribution between fractiles (as is also the case in a simulation method).
5. Compute the mean and variance of the conditional number of oil accumulations by applying the hydrocarbon-type probability of oil to the mean and variance of the conditional number of accumulations.
6. Compute the mean and variance of the conditional (A) play potential for oil--the quantity of oil in the play--given the play is favorable and there is at least one undiscovered accumulation within the play. These values are determined from the probability theory of the expectation and variance of a random number (conditional number of oil accumulations) of random variables (oil accumulation size).
7. Compute the conditional play probability of oil--that is, the probability that a favorable play with at least one undiscovered accumulation in the play has at least one oil accumulation. This probability is a function of the hydrocarbon-type probability of oil and the conditional number-of-accumulations distribution.
8. Compute the mean and variance of the conditional (B) play potential for oil--the quantity of oil in the play--given the play is favorable and there is at least one oil accumulation within the play. These values are determined by applying the conditional play probability of oil to the mean and variance of the conditional (A) play potential for oil.
9. Compute the unconditional play probability of oil--the probability that the play has at least one oil accumulation. This probability is the product of the conditional play probability of oil, the conditional probability of at least one undiscovered accumulation in the play, and the marginal play probability.
10. Compute the mean and variance of the unconditional play potential for oil--the quantity of oil in the play. These values are determined by applying the unconditional play probability of oil to the mean and variance of the conditional (B) play potential for oil.
11. Model the probability distribution of the conditional (B) play potential for oil by using the lognormal distribution with mean and variance from step 8. Calculate various lognormal fractiles.
12. Compute various fractiles of the conditional (A) play potential for oil by a transformation to appropriate lognormal fractiles of the conditional (B) play potential for oil using the conditional play probability of oil.
13. Compute various fractiles of the unconditional play potential for oil by a transformation to appropriate lognormal fractiles of the conditional (B) play potential for oil using the unconditional play probability of oil.
14. Select nonassociated gas as the second resource to be assessed. Repeat steps 3 through 13, substituting nonassociated gas for oil and using the accumulation size of nonassociated gas and the hydrocarbon-type probability of nonassociated gas.

15. Select associated-dissolved gas as the third resource to be assessed. Repeat steps 3 through 13, substituting associated-dissolved gas for oil, with two basic modifications as follows. The accumulation size of oil is multiplied by a gas-oil ratio. The hydrocarbon-type probability of associated-dissolved gas is the same as the hydrocarbon-type probability of oil.
16. Select gas as the fourth resource to be assessed. Repeat steps 3 through 13, substituting gas for oil, with two basic modifications as follows. Replace step 3 to compute the mean and variance of the accumulation size of gas by using conditional probability theory and conditioning on the two types of gas. The hydrocarbon-type probability of gas is 1.0.
17. Select NGL in nonassociated gas as the fifth resource to be assessed. Repeat steps 3 through 13, substituting NGL in nonassociated gas for oil, with two basic modifications as follows. The accumulation size of nonassociated gas is multiplied by the average ratio of NGL to nonassociated gas. The hydrocarbon-type probability of NGL in nonassociated gas is the same as the hydrocarbon-type probability of nonassociated gas or zero if the NGL ratio is zero.
18. Select NGL in associated-dissolved gas as the sixth resource to be assessed. Repeat steps 3 through 13, substituting NGL in associated-dissolved gas for oil, with two basic modifications as follows. The accumulation size of associated-dissolved gas is multiplied by the average ratio of NGL to associated-dissolved gas. The hydrocarbon-type probability of NGL in associated-dissolved gas is the same as the hydrocarbon-type probability of associated-dissolved gas or zero if the NGL ratio is zero.
19. Select NGL in gas as the seventh resource to be assessed. Repeat steps 3 through 13, substituting NGL in gas for oil, with two basic modifications as follows. Replace step 3 to compute the mean and variance of the accumulation size of NGL in gas by using conditional probability theory and conditioning on the two types of NGL. The hydrocarbon-type probability of NGL in gas depends on whether or not the two NGL ratios are equal to zero.

A simplified flowchart of the analytic method of play analysis (field-size model) is presented in figure II.D.2.

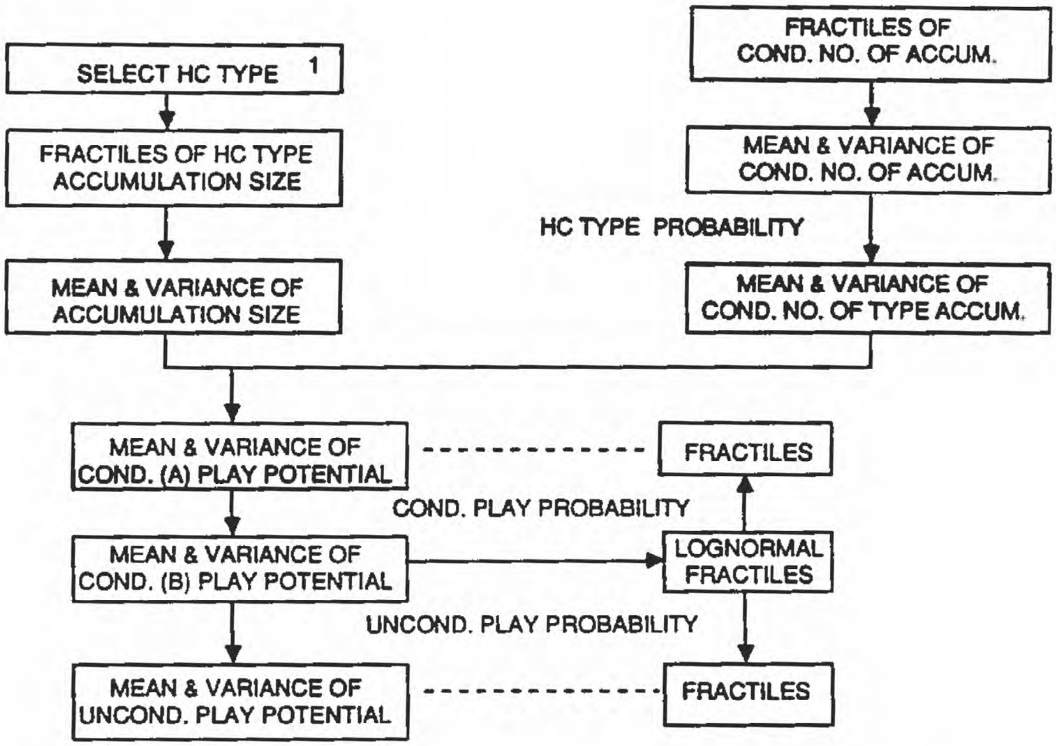
On the basis of the analytic method, a computer program was designed and called the Fast Appraisal System for Petroleum--Field Size (FASPFS). Because both cost and running time are negligible, FASPFS allows for quick feedback evaluation of geologic input data.

<u>Analytic Method of Play Aggregation</u>

A separate methodology was developed to estimate the aggregation of a set of plays. In this method, the resource estimates of the individual plays from the analytic method of play analysis using the FASPFS program are aggregated by means of probability theory. Oil, nonassociated gas, associated-dissolved gas, gas, NGL in nonassociated gas, NGL in associated-dissolved gas, and NGL in gas resources are each aggregated in turn.

The basic steps of the analytic method of play aggregation are:

1. Select plays to aggregate.
2. Select oil as the first resource to be aggregated.



[1] OIL, NONASSOCIATED GAS, ASSOCIATED-DISSOLVED GAS, GAS, NGL IN NONASSOCIATED GAS,NGL IN ASSOCIATED-DISSOLVED GAS, AND NGL IN GAS RESOURCES ARE EACH ASSESSED IN TURN.

Figure II.D.2. Flowchart of analytic method of play analysis (field-size model). Computer programs were also written on the basis of the analytic methodologies that were mathematically derived from the other geologic probability models established in this study. A number of variations of FASPFS and FASPAG were designed for the other geologic probability models.

3. Compute the mean and variance of the unconditional aggregate potential for oil--the quantity of oil in the assessment area of the aggregated plays. These are determined by adding all of the individual play means and variances of the unconditional play potential for oil, respectively, assuming independence among the plays. Under the assumption of perfect positive correlation, all of the individual play standard deviations (instead of the variances) of the unconditional play potential for oil are added together. In terms of the standard deviation of the unconditional aggregate potential, any degree of dependency is possible between 0 and 1, where 0 corresponds to independence and 1 denotes perfect positive correlation.
4. Compute the unconditional aggregate probability of oil--the probability that the assessment area has at least one play with oil. This probability is a function of the individual unconditional play probabilities of oil. It is calculated under the assumption of independence and also under the assumption of complete dependence of step 3.
5. Compute the mean and variance of the conditional aggregate potential for oil--the quantity of oil in the assessment area, given the assessment area has at least one play with oil. These are determined by applying the unconditional aggregate probability of oil to the mean and variance of the unconditional aggregate potential for oil.
6. Model the probability distribution of the conditional aggregate potential for oil by using the lognormal distribution with mean and variance from step 5. Calculate various lognormal fractiles.
7. Compute various fractiles of the unconditional aggregate potential for oil by a transformation to appropriate lognormal fractiles of the conditional aggregate potential for oil by using the unconditional aggregate probability of oil.
8. Select nonassociated gas as the second resource to be aggregated. Repeat steps 3 through 7 using play-analysis estimates of nonassociated gas--namely, the individual play means and variances of the unconditional play potential for nonassociated gas--as well as the individual unconditional play probabilities of nonassociated gas.
9. Select associated-dissolved gas as the third resource to be aggregated. Repeat steps 3 through 7 using play-analysis estimates of associated-dissolved gas--namely, the individual play means and variances of the unconditional play potential for associated-dissolved gas--as well as the individual unconditional play probabilities of associated-dissolved gas.
10. Select gas as the fourth resource to be aggregated. Repeat steps 3 through 7 using play-analysis estimates of gas--namely, the individual play means and variances of the unconditional play potential for gas--as well as the individual unconditional play probabilities of gas.
11. Select NGL in nonassociated gas as the fifth resource to be aggregated. Repeat steps 3 through 7 using play-analysis estimates of NGL in nonassociated gas--namely, the individual play means and variances of the unconditional play potential for NGL in nonassociated gas--as well as the individual unconditional play probabilities of NGL in nonassociated gas.

12. Select NGL in associated-dissolved gas as the sixth resource to be aggregated. Repeat steps 3 through 7 using play-analysis estimates of NGL in associated-dissolved gas--namely, the individual play means and variances of the unconditional play potential for NGL in associated-dissolved gas--as well as the individual unconditional play probabilities of NGL in associated-dissolved gas.
13. Select NGL in gas as the seventh resource to be aggregated. Repeat steps 3 through 7 using play-analysis estimates of NGL in gas--namely, the individual play means and variances of the unconditional play potential for NGL in gas--as well as the individual unconditional play probabilities of NGL in gas.

A simplified flowchart of the analytic method of play aggregation is presented in figure II.D.3.

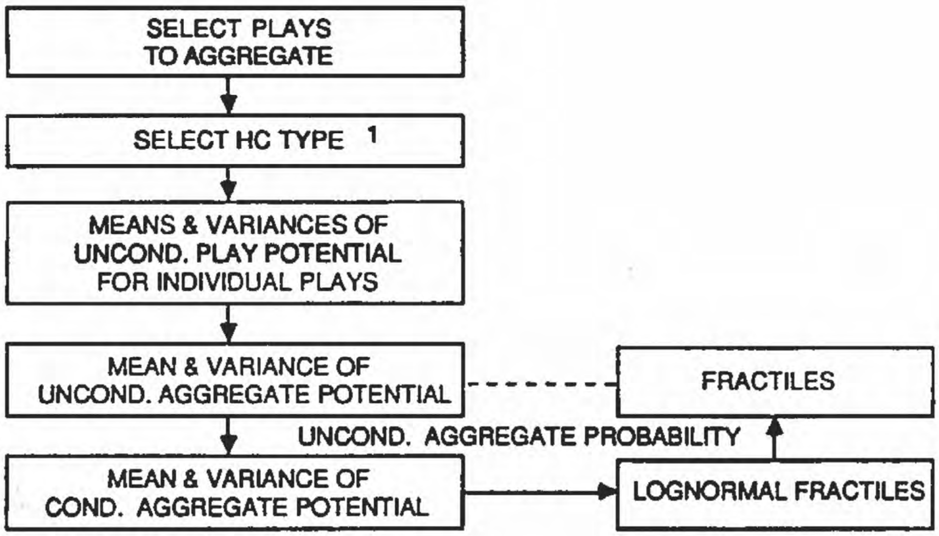
A computer program was designed on the basis of the analytic method for the aggregation of plays and called the Fast Appraisal System for Petroleum Aggregation (FASPAG). FASPAG interfaces with FASPFS as follows. FASPFS not only generates a file of resource estimates for an individual play but also outputs a second file of results that consists of the mean and standard deviation of the unconditional play potential for each of the resources and the corresponding unconditional play probabilities. The second file is needed for an aggregation of plays and forms an input file for FASPAG. Therefore, after FASPFS is run on each play in a set of plays, any subset of plays can be aggregated by running FASPAG on the corresponding subset of aggregation input files. FASPAG not only generates a file of resource estimates for an aggregation of plays but also outputs a second file of results needed for an aggregation of aggregations, which forms yet another input file for FASPAG. Hence, after FASPAG is run on each aggregation in a set of aggregations, any subset of aggregations can be aggregated at once. Compared to the simulation method, the application of FASPAG can result in tremendous savings of time and cost, especially when analyzing many aggregations involving hundreds of plays. FASPAG also possesses the capacity of aggregating a set of plays under a dependency assumption.

A computer package called FASPF was created and includes the following computer programs:

FASPPH--A program for developing probability histograms.

FASPFS--A program for play analysis of undiscovered recoverable petroleum resources onshore and non-Federal offshore.

FASPFSS--A program for subplay analysis of undiscovered recoverable petroleum resources onshore and non-Federal offshore, separately assessed. The onshore and non-Federal offshore percentages are applied to the number of accumulations (mean, variance, fractiles) for each of the seven resources.



[1] OIL, NONASSOCIATED GAS, ASSOCIATED-DISSOLVED GAS, GAS, NGL IN NONASSOCIATED GAS, NGL IN ASSOCIATED-DISSOLVED GAS, AND NGL IN GAS RESOURCES ARE EACH AGGREGATED IN TURN.

Figure II.D.3. Flowchart of analytic method of play aggregation.

FASPFSP--A program for subplay analysis of undiscovered recoverable petroleum resources onshore and non-Federal offshore, separately assessed small-field plays. The onshore and non-Federal offshore percentages are applied to the oil and nonassociated gas accumulation size fractiles because a small-field play consists of a single accumulation.

FASPFST--A program for play analysis of undiscovered economically recoverable petroleum resources onshore plus non-Federal offshore. The oil and nonassociated gas accumulation size distributions are truncated using minimum economic cut-off values. The hydrocarbon-type probabilities of oil and nonassociated gas are multiplied by the corresponding probability of the accumulation size exceeding the cut-off value. The number of hydrocarbon-type accumulations for each resource is reduced accordingly.

FASPFSF--A program for play analysis of undiscovered economically recoverable petroleum resources onshore plus non-Federal offshore in small-field plays. Economically recoverable percentages are applied to the oil and nonassociated gas accumulation size fractiles because a small-field play consists of a single accumulation.

FASPFSTS--A program for subplay analysis of undiscovered economically recoverable petroleum resources onshore and non-Federal offshore separately assessed. The oil and nonassociated gas accumulation size distributions are truncated using minimum economic cut-off values. The hydrocarbon-type probabilities of oil and nonassociated gas are multiplied by the corresponding probability of the accumulation size exceeding the cut-off value. The number of hydrocarbon-type accumulations for each resource is reduced accordingly. The onshore and non-Federal offshore percentages are applied to the number of accumulations (mean, variance, fractiles) for each of the seven resources.

FASPFSFP--A program for subplay analysis of undiscovered economically recoverable petroleum resources onshore and non-Federal offshore separately assessed small-field plays. Economically recoverable percentages and also the onshore and non-Federal offshore percentages are applied to the oil and nonassociated gas accumulation size fractiles because a small-field play consists of a single accumulation.

FASPAG--A program for aggregation of play and subplay estimates of onshore and non-Federal offshore undiscovered recoverable and economically recoverable petroleum resources, respectively. Play and subplay estimates within provinces are aggregated with a degree of dependency equal to 1 in order to obtain provincial estimates. Provincial estimates within regions are aggregated with a dependency of 0.5 in order to obtain regional estimates. Regional estimates within the entire United States are aggregated with a dependency of 0 in order to obtain national estimates.

FASPAGPC--A variation of FASPAG modified especially for Minerals Management Service (MMS) to be used on an IBM-PC. The MMS resource assessment computer program PRESTO produces provincial estimates. PRESTO was modified by MMS to generate aggregation files compatible with FASPAGPC. FASPAGPC was used by MMS to aggregate Federal offshore provincial estimates in order to obtain Federal offshore regional estimates.

FASPAG5--A variation of FASPAG for aggregating the USGS aggregation files of onshore and non-Federal offshore regional estimates and the MMS aggregation files of Federal offshore regional estimates in order to obtain national estimates.

The relationships among the programs comprising the FASPF computer package are summarized as follows.

	Play	Subplay	Aggregation
Recoverable	FASPPH	FASPFSS	FASPAG
Resource	FASPFS	FASPFSP	FASPAGPC
			FASPAG5
Economically	FASPFST	FASPFSTS	FASPAG
Recoverable	FASPFSF	FASPFSFP	FASPAGPC
Resource			FASPAG5

Conclusions

The analytic method using probability theory is a practical alternative to the simulation method for petroleum play analysis. The computer package FASPF based on the analytic method operates thousands of times faster than a corresponding computer program based on the simulation method. Because the cost and running time are negligible, FASPF allows for quick feedback evaluation of the estimated geologic data, a feature which is invaluable during actual resource assessment meetings. Moreover, FASPF can be adapted to most microcomputers; it needs no system-dependent subroutines or unusual library functions. The analytic method produces not only numerical estimates of petroleum resources, but also mathematical equations of probabilistic relationships involving these resources, whereas, the simulation method produces no such equations.

A tremendous savings of time and cost can result using FASPF, especially when analyzing hundreds of individual plays. However, the greater advantage of the analytic method might lie in the aggregation of a set of plays, especially if the set is large and there are many combinations of aggregations required. The computer program FASPAG based on the analytic method can aggregate any subset of plays almost instantly, and it can aggregate aggregations. FASPAG has considerable flexibility, in that it can even aggregate under a dependency assumption.

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E. GLOSSARY FOR OIL AND GAS APPRAISAL DATA FORM

This section consists of a glossary of terms used in the Oil and Gas Appraisal Data Form, which was developed for the appraisal of the undiscovered hydrocarbon resources. The terms are arranged according to their order in the form. Terms printed in capitals indicate that their definitions are included in this section.

OIL AND GAS APPRAISAL DATA FORM: A form designed for systematic recording of geologic judgments pertaining to the occurrence of oil and gas. The form is organized by three main categories: (1) PLAY ATTRIBUTES, (2) ACCUMULATION ATTRIBUTE AND (3) HYDROCARBON RESERVOIR PARAMETERS. Judgments recorded on this form are used to quantitatively model the petroleum geology of the PLAY under consideration and to drive a computer program that yields a probabilistic resource appraisal.

PLAY: An area consisting of one or more known or suspected accumulations in a common or relatively homogeneous geologic setting with respect to source, reservoir type, and trapping conditions.

PLAY AREA: The area over which a PLAY is considered to have potential for undiscovered accumulation.

PLAY ATTRIBUTES: Four regional characteristics that describe a given PLAY: 1) HYDROCARBON SOURCE (S), 2) TIMING (T), 3) MIGRATION (M), and 4) POTENTIAL RESERVOIR FACIES (R). These attributes determine if conditions underlying the play are favorable for occurrence of oil or gas.

HYDROCARBON SOURCE (S): This PLAY ATTRIBUTE estimates the probability of occurrence of a rock unit that has generated and expelled oil or gas. Evaluation of this attribute is accomplished by recording a single value between 0 (total certainty that the attribute is absent) and 1 (total certainty that the attribute is present) for the probability that oil or gas has been generated and expelled from source rocks in sufficient quantity to form an accumulation within the PLAY. The evaluation of this parameter is based on a set of minimum source rock criteria which includes organic richness, kerogen type, and thermal maturity. Kerogen types favorable for oil are amorphous and herbaceous; for gas, herbaceous and coaly. If known hydrocarbon accumulations occur in the play area, this play attribute probability is 1.

TIMING (T): This PLAY ATTRIBUTE estimates the probability of occurrence of a suitable relationship between the time of trap formation and the time of hydrocarbon movement into or through the PLAY area. Evaluation of this attribute is accomplished by recording a single value between 0 (total certainty that the attribute is absent) and 1 (total certainty that the attribute is present) for the probability that favorable timing occurred somewhere in the play area. Evaluation of this attribute is based on knowledge of the time of trap formation and on estimates of the time of maturity of source rocks. If known hydrocarbon accumulations occur in the play area, this play attribute probability is 1.

MIGRATION (M): This PLAY ATTRIBUTE estimates the probability of effective movement of hydrocarbons through a conduit, which may be a permeable clastic or carbonate rock, a joint, or a fault. Evaluation of this attribute is accomplished by recording a single value between 0 (total certainty that the attribute is absent) and 1 (total certainty that the attribute is present) for the probability that oil or gas has migrated in sufficient quantity to form an accumulation somewhere in the PLAY area. Evaluation of this parameter is based on structural and stratigraphic information from which inferences can be drawn concerning the presence of a geologically favorable conduit. If known hydrocarbon accumulations occur in the play area, this play attribute probability is 1.

POTENTIAL RESERVOIR FACIES (R): This PLAY ATTRIBUTE estimates the probability of occurrence of a rock that may contain porosity and permeability capable of containing producible hydrocarbons. Evaluation of this attribute is accomplished by recording a single value between 0 (total certainty that the attribute is absent) and 1 (total certainty that the attribute is present) for the probability that favorable reservoir rocks occur somewhere in the PLAY area. Data used in the evaluation of this attribute may include reservoir data from the play area, projections from adjacent areas, or analog comparisons. If known hydrocarbon accumulations occur in the play area, this play attribute probability is 1.

MARGINAL PLAY PROBABILITY (MP): This term expresses the probability that all of the first four PLAY ATTRIBUTES are concurrently favorable somewhere in the PLAY. Because each play attribute is assumed to be statistically independent of the others, this probability is the product of the four separate play attribute probabilities (MP=S x T x M x R), where S=HYDROCARBON SOURCE, T=TIMING, M=MIGRATION, and R=POTENTIAL RESERVOIR FACIES. A discovered oil or natural gas deposit in the play is an indication that all four play attributes are concurrently favorable, and therefore the marginal play probability is 1.

ACCUMULATION ATTRIBUTE (conditional probability of accumulation): This term expresses the probability that one or more undiscovered accumulations above the threshold size exist in the play, given that the PLAY ATTRIBUTES are favorable. In other words, this judgment assesses the probability of occurrence of trap(s) in proper setting to accumulate hydrocarbons, given the play attributes are favorable. The product of the MARGINAL PLAY PROBABILITY and CONDITIONAL PROBABILITY OF ACCUMULATION describes probability of success in the play for accumulations of the minimum size.

MINIMUM ACCUMULATION SIZE: These minimum values apply to the smallest accumulation size considered in the assessment, that is, one million barrels of oil or six billion cubic feet of nonassociated gas, unless otherwise specified. All conditions of the play are assessed in terms of sufficiency to meet this minimum size or larger and describe such accumulations.

HYDROCARBON VOLUME PARAMETERS: These parameters include: 1) RESERVOIR LITHOLOGY, 2) HYDROCARBON MIX, 3) ACCUMULATION SIZE, 4) RESERVOIR DEPTH and 5) NUMBER OF ACCUMULATIONS. They describe character of the reservoir and fluids and the range of possible sizes and numbers of accumulations within the play. Evaluation of the latter parameters is accomplished by recording judgmental values at seven probability levels (fractiles) ranging from 100 percent (total certainty that at least the estimated value will be attained) to 0 percent (total certainty that the estimated value will not be exceeded); when being assessed, it is assumed that both the MARGINAL PLAY PROBABILITY and the CONDITIONAL PROBABILITY OF ACCUMULATION are 1. Thus, the HYDROCARBON VOLUME PARAMETER judgments are conditional on these attributes being favorable.

RESERVOIR LITHOLOGY: This hydrocarbon volume parameter describes the characteristic reservoir rock type expected in the play. Evaluation of this attribute is accomplished by selecting sandstone, carbonate, or other appropriate lithology and, where mixed, indicating decimal proportions.

HYDROCARBON MIX OR HYDROCARBON TYPE: This hydrocarbon volume parameter describes the tendency of accumulations in the play to be either oil or nonassociated gas. The computer program employed in this method is set to consider hydrocarbon accumulations to be either oil (with dissolved and associated gas) or nonassociated gas (with NGL). Evaluation of this attribute is accomplished by estimating two values that sum to one (gas + oil = 1.0). For example: a mix of 0.8 gas and 0.2 oil would indicate an 80 percent chance that a randomly selected accumulation in the play would be nonassociated gas and a 20 percent chance that the accumulation would be oil. Data used in the evaluation of this parameter are based on concepts of thermal maturity, the type of organic material in the source rock, and the type of hydrocarbon observed in wells and seeps or known fields.

ACCUMULATION SIZE: This HYDROCARBON VOLUME PARAMETER estimates the possible range for the size of accumulations in the play (see MINIMUM ACCUMULATION SIZE). Sizes of oil accumulations and nonassociated gas accumulations are separately assessed. Evaluation of this parameter is accomplished by entering estimates for size at seven probability levels (fractiles) ranging from 100 percent (total certainty that at least this value will be attained) to 0 percent (total certainty that this value will not be exceeded). Intermediate fractiles indicate the relative confidence that the size is at least as large as the recorded fractile value. The F_{100} is generally the MINIMUM ACCUMULATION SIZE. Data used in the evaluation of this parameter may include accumulations discovered to date, seismic or surface geologic mapping, analog comparison, and an assessment of hydrocarbon charge and trap efficiency.

RESERVOIR DEPTH (x 10^3 ft): This HYDROCARBON VOLUME PARAMETER describes the possible range for the depth that must be drilled to penetrate the POTENTIAL RESERVOIR FACIES (R). Evaluation of this parameter is accomplished by entering depth estimates at seven probability levels (fractiles) ranging from 100 percent (total certainty that at least this value will be attained) to 0 percent (total certainty that this value will not be exceeded). Intermediate fractile values indicate the relative confidence (subjective probability) that the reservoir is at least as deep as the recorded fractile value.

NUMBER OF ACCUMULATIONS: This hydrocarbon volume parameter describes the range of possible values for the number of undiscovered accumulations within the play. Evaluation of this attribute is accomplished by recording the estimated number of ACCUMULATIONS at seven probability levels (fractiles) ranging from 100 percent (total certainty that at least this value will be attained) to 0 percent (total certainty that this value will not be exceeded). Fractiles indicate the relative confidence (subjective probability) that the number of undiscovered accumulations is at least as great as the recorded fractile value. This estimate is dependent on the play attributes being favorable and the existence of accumulation(s) within the play. The number of accumulations considers only those accumulations larger than the threshold size.

AVERAGE RATIO OF ASSOCIATED-DISSOLVED GAS TO OIL: A point estimate of the volume of gas both dissolved in or otherwise associated with a barrel of oil in undiscovered oil accumulations in a play.

AVERAGE RATIO OF NGL TO NON-ASSOCIATED GAS: A point estimate of the volume of natural gas liquids contained in a million cubic feet of gas in undiscovered gas accumulation in a play.

AVERAGE RATIO OF NGL TO ASSOCIATED-DISSOLVED GAS: A point estimate of the volume of natural gas liquids contained in a million cubic feet of associated-dissolved gas in oil accumulations in a play.

F. ESTIMATION PROCEDURES FOR FIELD SIZE DISTRIBUTIONS IN THE U.S. GEOLOGICAL SURVEY NATIONAL OIL AND GAS RESOURCE ASSESSMENT

by

J.C. Houghton, G.L. Dolton, R.F. Mast, C.D. Masters, and D.H. Root

Introduction

This report describes the process of selecting field size distributions for the play analysis performed by the USGS for the National oil and gas resource assessment. Estimates of undiscovered hydrocarbons were generated for each of 250 plays in the continental United States, and almost every play had assigned to it a predicted field size distribution for undiscovered accumulations. These new procedures are a major change from the procedures used previously by the USGS.

There are a number of reasons for our selection of procedures. Perhaps the most important is that the estimated sizes of discovered fields having known recoveries greater than 1 million barrels of oil (bbl) and/or 6 billion cubic feet (bcf) of gas is now available for most U.S. oil and gas provinces (NRG Associates, 1986).

For the first time, we were able to analyze discovery records for accumulations in geologically defined plays. We therefore decided that estimating distributions and correlations for parameters for each play, such as reservoir thickness, percent trap fillup, reservoir porosity, and geothermal gradient, would be less accurate and much more time consuming than estimating the field size distributions of the undiscovered fields directly. In addition to the discovery record for a play, exploration and development maps, drilling statistics, and other information are used. Numbers of fields are assessed subjectively, using these data.

The disaggregation of basin analysis to play analysis permits us to perform the assessment on more geologically homogeneous units. A play is in part characterized by its field size distribution, which can be modeled by analog comparison either with earlier stages of the play history or by using data from similar plays from other areas. The continental U.S., being maturely explored, offers a play library containing many examples that permit us to compare field size distributions. Operating at a play level permits a finer degree of analysis and a better critique.

The statistics were not designed to produce the assessment directly by projection from the historical to the undiscovered. Rather, the statistics on discovery history and known recoveries help guide the estimates, and the procedures are similar to those outlined in Baker and others (1986). The geologists are able to control the estimating by adjusting the procedures at any point to allow the final size estimates to conform to their best judgement.

The statistics were designed to be as transparent as possible. In fitting distributions to data and in applying the statistical procedures, we attempted to make the statistical operations obvious and objective.

These criteria led us to decide that we wanted to estimate field size distributions by using as a guide an analog field size distribution fit to a sample that as closely as possible matched the play we were estimating. That guide was just a starting point. We then used many different pieces of data from the discovery record and other sources to adjust the shape and size of the guide to conform to our judgement as to size of undiscovered accumulations.

Field size distributions and numbers of undiscovered fields also permitted economic analysis that was previously impossible. We expect that policy analysts, economists, engineers, and others will be able to better use our estimates of undiscovered hydrocarbons by using the estimates as inputs to their models.

The Choice of the Truncated Shifted Pareto Distribution

Before we describe the statistical field size distribution, we should discuss the way in which the data are disaggregated. Large accumulations in a play tend to be discovered before small ones because large accumulations generally are easier to find. One way to view this process is displayed graphically in figure II.F.1. The histogram in the figure represents data from the Minnelusa play in the Powder River basin; the data will be described later in this report. The curves in the figure that overlay the distribution bound three wedges that represent three different time periods in the exploration. The bottom wedge represents the sizes of fields found early, the middle wedge the fields found in the middle period, and the top wedge the fields found most recently. The curves were calculated by dividing 68 fields into thirds based on order of discovery and fitting each third using a truncated shifted Pareto (TSP) distribution. This distribution and method of fitting will be described later in this section. Note that in figure II.F.1 both axes are distorted for easier viewing. An undistorted histogram would be impossible to view -- the histogram would look like an "L-shaped" curve and would follow the axes without separation. Other plots in this report also distort the axes.

The wedges portray the general pattern of size changes over time. If only fields above some cutoff size are considered, so that economics plays a small role, big fields seem to be found relatively early in the discovery period, whereas small fields are found throughout the discovery period. In searching for a guide for estimating sizes of future discoveries in a play, the best analog is often the fields discovered most recently; we usually used the last third. The guide, the entire discovery record, including earlier discoveries, and many other variables influence the prediction of the sizes of the undiscovered accumulations.

We use the TSP distribution to model (fit) the entire record, the early, middle and late discoveries (each of the wedges portrayed in fig. II.F.1), and the fields estimated to be discovered in the future. The TSP distribution is described in some detail in Houghton (1988). We choose it because it is simple, flexible, and has a J-shape. The J-shape is important because we believe that in most cases the number of fields increases rapidly as the size decreases.

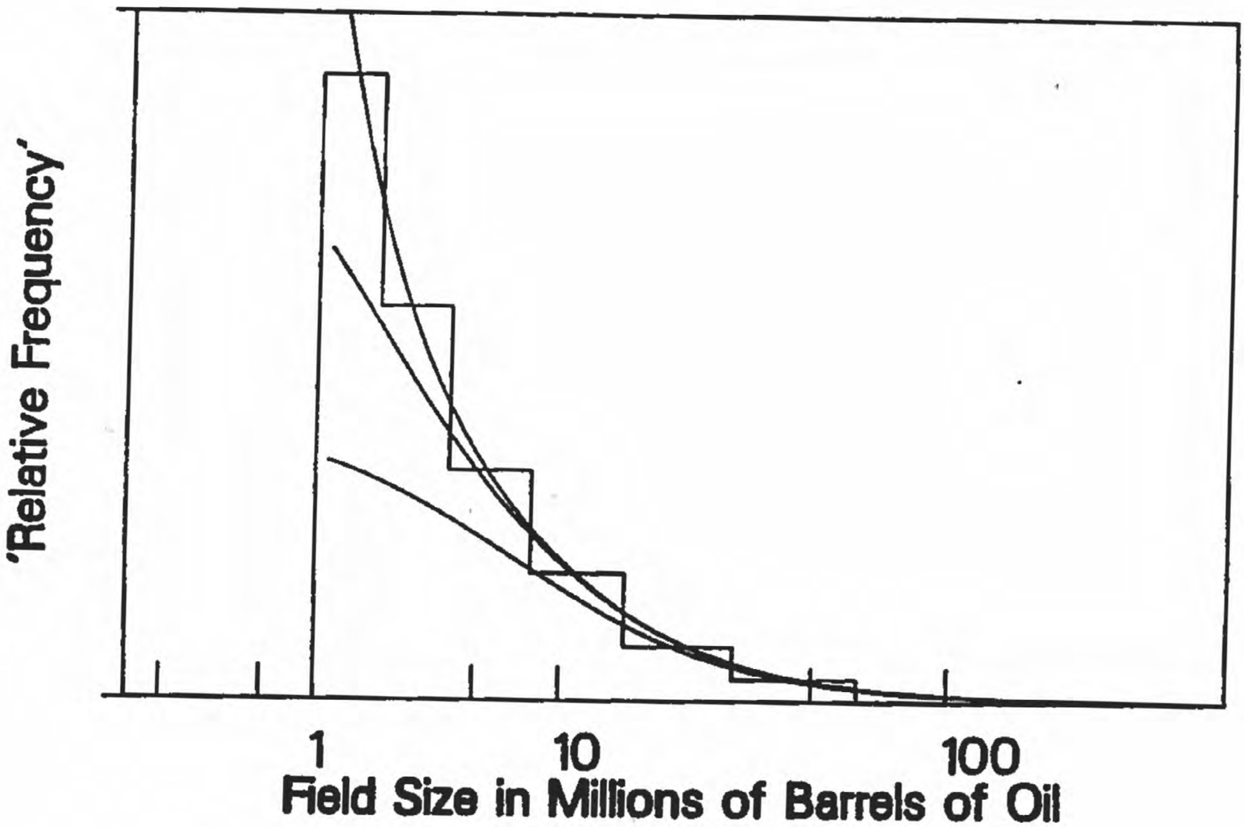

Figure II.F.1. Efficiency as portrayed by "wedges" of discoveries for the 68 fields of the Minnelusa play containing 1 million barrels of oil or more.

We found the TSP distribution preferable to the lognormal distribution. Houghton (1988) showed that lognormal method-of-moment fitting procedures fit an uncensored data set poorly over the range of the data. Lognormal maximum-likelihood procedures fit the data better but do not preserve the sample mean; thus, the amount of oil in the model of the data does not match the amount of oil in the data to which it was fitted.

Lognormal distributions that were truncated on the left side fit the Minnelusa data much better than do fits to uncensored data. Small fields, at least in the Minnelusa play, do not fit the lognormal distribution well. Lognormal distributions truncated on both the left and the right tails were not investigated.

If we use a lognormal distribution instead of a TSP distribution, we probably would truncate both sides, as we do with a TSP; the right side to reflect physical limits on the sizes of accumulations, and the left side to reflect censoring of the data and the effects of economics. We probably would add a shift parameter (making it three-parameter lognormal) to add flexibility. Preliminary analysis of the three-parameter lognormal, truncated at an upper limit and at 1 million barrels, indicates that the results of using a lognormal distribution is unlikely to be very different from those using a TSP distribution.

The TSP distribution is written in the reverse form (Houghton, 1988) and is defined as:

$$x = a\left[(T^u+(1-T^u)G)^{-b}-1\right] + x_c$$

where

x is the field size in million bbl,

$0 < T^u < 1$, an amount of probability truncated from the right-hand tail,

$G(x)$ the complementary cumulative distribution function, written here as G,
$0 < b < 1$, a shape parameter indicating the thickness of the right-hand tail, and

$x_c > 0$, the left-hand tail cutoff, set at a known recovery of 1 million bbl or 6 billion cubic feet of gas.

A fitting procedure was devised that does not use the sample variance or other higher moments. This procedure is desirable when fitting data with thick tails because relying on moments higher than the mean, such as the variance, makes the estimates very sensitive to small changes in the largest fields.

The fitting procedure also preserves the first mean. This is important in order to keep from introducing statistical information that is unintuitive to the geologist. The method of maximum likelihood, for example, often causes the mean of the distribution to differ greatly from the mean of the sample. This suggests to the geologist that the statistics indicate more (or less) hydrocarbon in the model of the play than in the play itself. For instance, a maximum-likelihood fit to a lognormal distribution of the 152 fields identified in the Minnelusa (the small fields as well as to the 68 fields greater than 1 million bbl discussed later) approximately doubles the amount of oil actually discovered.

Neither the parameters of a distribution nor the moments (other than the first) are items the geologist can use easily in a subjective assessment. Instead, we describe the shape and size of the distribution by using the quantiles of the distribution. These are portrayed in figure II.F.2.

The size distribution of fields can be thought of as containing two factors: size and shape. The size can be thought of as the mean of the distribution, and the shape is sometimes put in the context of dispersed versus concentrated habitat (Coustau, 1980). A concentrated habitat is one in which a few fields contain a relatively large fraction of the hydrocarbons. A dispersed habitat is one in which there are more fields of average size. For example, if one were describing income distribution for a country, a concentrated distribution would have most of the wealth in a small upper class and a dispersed distribution would have most of the wealth in a large middle class population.

Both size and shape must be estimated by the geologists, but shape is a difficult concept to quantify. We attempt to make it easier by classifying all possible shapes into seven concentration classes, numbered from 1, most dispersed, to 7, most concentrated. For any particular class, the cutoff is always 1 million barrels of oil or 6 billion cubic feet of gas, and the size (mean) can take on any value greater than the cutoff. The seven classes are portrayed graphically in figure II.F.3.

The seven classes were chosen to cover both extremes in habitat and to offer sufficient choices in between to adequately represent distributions in nature. The computer program used to determine which class best fits a data set starts by using the fitting procedures mentioned above (Houghton, 1988). Then, given the fitted distribution, it uses the ratio of the maximum (minus the cutoff) to the median (minus the cutoff) to determine in which class the data set belongs. The higher the ratio, the more concentrated the shape and the higher the concentration class. The ratios and the parameters of the distributions are presented in table II.F.1. An approximate method for fitting a data set is given in Appendix A.

Gas plays were processed in the same fashion as oil plays. Cutoff values were changed to 6 billion cubic feet of gas. Methods for assessing both oil and gas plays are described in another section of this report.

Small fields were not assessed by extrapolating the TSP to smaller fields, as discussed in Houghton (1988). The procedures used to assess fields less than 1 million barrels are explained in section II.G.

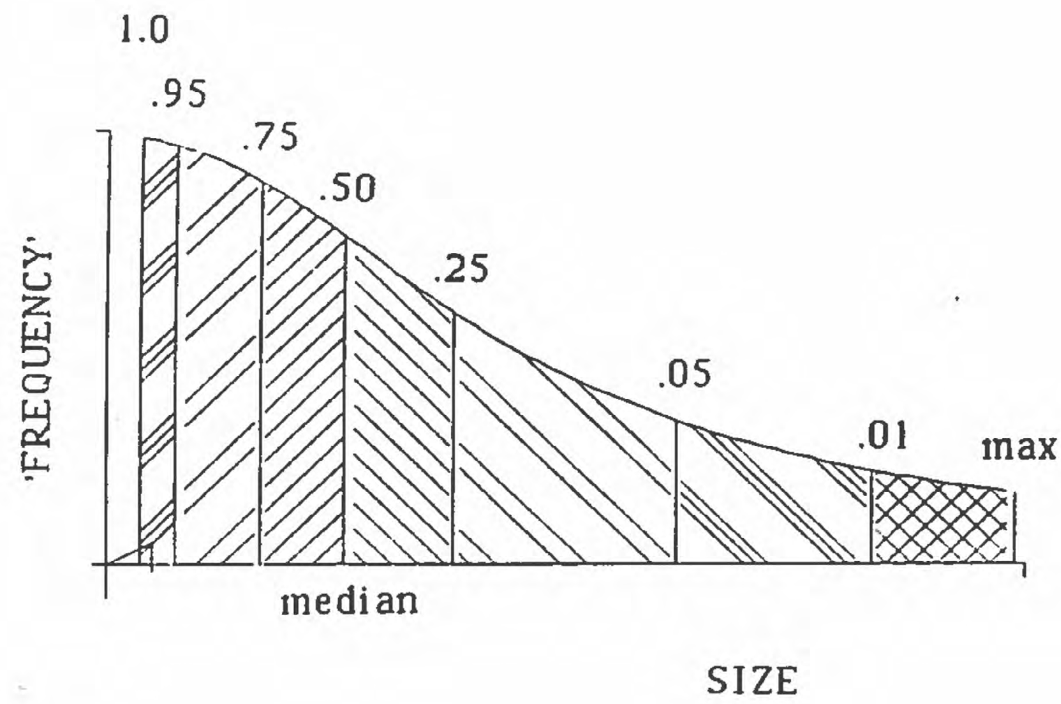

Figure II.F.2. The quantiles of a frequency density.

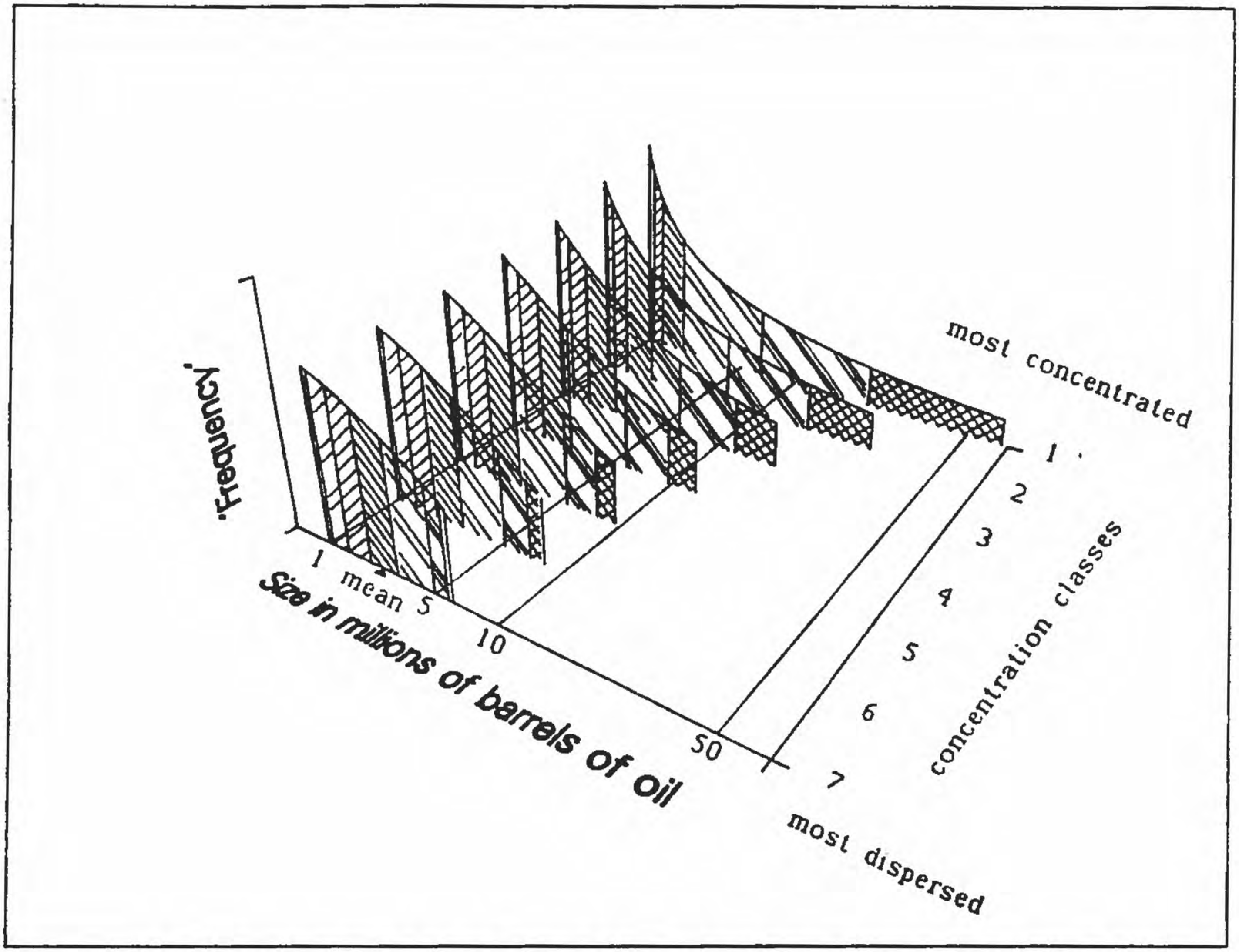

Figure II.P.3. The seven shape categories of a truncated shifted Pareto distribution with constant means.

Table II.F.1.--Shape categories for a truncated shifted Pareto distribution

category	b	T^u	ratio
1 (most dispersed)	.05	.05	<5.7
2	.05	.01	5.7 - 8.
3	.15	.01	8. - 12.
4	.35	.01	12. - 20.
5	.55	.01	20. - 40.
6	.85	.01	40. - 90.
7 (most concentrated)	.99	.005	90.+

The ratio of the maximum (minus the cutoff) to the median (minus the cutoff) determines which of the seven categories best fits the data.

How the Estimates are Made

We will use the "Minnelusa region" of the Powder River basin in Wyoming and Montana and the basin-margin structural play in the Bighorn basin of Wyoming and Montana to describe a hydrocarbon field size assessment in a primarily stratigraphic environment and a primarily structural environment.

A description of the Minnelusa play and the data is contained in Drew and others (1987), and the fields with known recoveries (cumulative production plus reserves) greater than 1 million bbl are presented by order of discovery in table II.F.2. These data were used to test the methodology. A total of 359 million bbl in 68 fields greater than 1 million bbl had been discovered through the end of 1981.

> "The Minnelusa sandstone play, on the broad east flank of the Powder River Basin, describes the occurrence of oil in a suite of primarily stratigraphic traps in the upper part of the Pennsylvanian and Permian Minnelusa formation. Reservoirs are principally quartzose aeolian dune sandstones of Wolfcampian age within a complex cyclic sequence of carbonates and sandstones of marine and non-marine origin."

The stratigraphic nature of the traps indicates that efficiency in discovery is less than would be expected for a play in which the fields are more easily identified, especially a structural play.

We divide the Minnelusa play into two subplays. The first is the "extensively explored"; the second is the "unexplored area", primarily down dip and much less drilled. In the first part of the Minnelusa assessment, we estimate the size of fields expected to be discovered in the explored area. Then, we will estimate the sizes in the unexplored portion of the Minnelusa.

Data are first examined to see if they properly represent the play notion that will be used to estimate future discoveries. Sometimes one or more fields are determined not to belong to the play or do not represent field sizes expected to be discovered and are removed from the analysis.

The statistics presented to the geologist include the discovery record, such as that presented in table II.F.2. In addition to the known recovery and discovery data itself, various statistics from the discovery record, presented in table II.F.3 are given to the geologists in preparation for an assessment. These data usually include statistics fit both to the entire record and to each third of the record:

number of fields
amount of oil
percent of the total
largest field and when it was discovered
the start and stop year
shape category from fitting the sample
median and the maximum (and the rest of the quantiles)

We usually start with a guide that is the TSP fit to the late third. Sometimes records are divided into two halves or all the fields are used as the guide. We sometimes fit a TSP to a sample with as few as four or five fields.

The guide is only the start of the estimation, and we analyze many aspects of the data to select a field-size distribution for undiscovered fields. We respect both the discovery history and other geological data. For instance, if the late third started relatively long ago, then the undiscovered distribution is less likely to include larger fields than if the most recent discoveries were relatively new.

The analysis behind the estimate for the extensively explored area of the Minnelusa play might include the following reasoning:

> The percent of oil found in each third has dropped from about 60 to 30 to 10. The fields are getting smaller, the medians having dropped from about 6 to 3 to 1.6. The largest field found in the last eight years for which we have data is 5 million bbl. The late third started in 1972. We will use the late third as the guide. We estimate that the median of the ones remaining to be discovered should be just a little lower than the guide, say 1.5, because the geologist could see no reason to counter the general trend of decreasing size. However, it should be noted the rate of decrease in the median size would predict a lower value for the median size of the undiscovered population than that assessed. This reflects the judgment of the assessors that the fields discovered will grow in size, and therefore the data understates the real median size.

Table II.F.2

Ultimate recovery in millions of barrels in fields of the Minnelusa play that are greater than one million barrels of oil (Data was constructed early in the assessment for testing) -- Fields are numbered in order of discovery

	year	mo	size	name		year	mo	size	name
1.	57	05	3.000	DONKEY CR	35.	66	11	2.200	KUEHNE RA, SE
2.	58	11	7.523	ROBINSON RA	36.	66	12	1.178	BREEN
3.	58	12	18.200	TIMBER CR	37.	66	12	9.676	LITTLE MITCHELL CR
4.	59	11	3.908	PRONG CR	38.	67	01	4.720	M D
5.	60	03	2.725	RAINBOW RA	39.	67	01	6.721	C-H
6.	60	03	51.747	RAVEN CR	40.	67	02	10.295	HAMM
7.	60	06	4.003	GUTHERY	41.	67	03	8.048	ROZET, W
8.	60	10	2.500	POWNALL RA	42.	67	08	3.820	WINDMILL
9.	61	05	4.133	ROCKY PT	43.	68	08	3.600	BISHOP RA, S
10.	61	08	6.500	MELLOTT RA	44.	69	05	4.340	KUMMERFELD
11.	61	11	1.573	ROBINSON RA,	45.	69	10	3.172	THOLSON RA
12.	61	11	2.100	ROBINSON RA,	46.	70	07	1.320	GIBBS & GIBBS, S
13.	62	06	14.580	HALVERSON	47.	72	01	3.200	WAGON SPOKE
14.	62	07	4.700	CAMP CR	48.	72	02	3.000	BONE PILE
15.	62	10	1.550	AM-KIRK	49.	72	05	1.506	REYNOLDS RA
16.	62	10	6.818	SEMLEK	50.	72	10	1.040	KIEHL
17.	62	11	11.000	REEL	51.	73	05	1.500	DEADMAN CR
18.	63	05	7.500	SLATTERY	52.	73	06	5.000	ROURKE GAP
19.	63	11	9.413	SEMLEK, W	53.	73	12	3.608	O K
20.	64	03	16.500	DILLINGER RA	54.	74	02	1.500	WOLFF
21.	64	05	14.800	DUVALL RA	55.	74	05	1.343	TEXAS TRAIL
22.	64	08	3.449	ROZET, E	56.	74	09	1.300	COUNTY LINE
23.	65	02	13.000	RENO	57.	75	01	1.750	SHARP
24.	65	04	1.156	BASIN	58.	75	04	3.400	BIG HAND
25.	65	05	1.500	PICKREL RA	59.	75	11	2.500	DUTCH
26.	65	06	1.400	BASIN, NW	60.	76	05	1.236	BREAKS
27.	65	06	3.490	KUEHNE RA	61.	76	06	2.531	MAYSDORF
28.	65	07	6.100	ROZET, S	62.	77	02	1.291	EITEL
29.	65	11	17.121	STEWART	63.	78	08	1.500	JEWEL, S
30.	66	03	7.136	WALLACE	64.	78	10	1.500	HAIGHT
31.	66	05	1.050	ROZET (N)	65.	80	02	1.200	STEWART, E
32.	66	06	1.527	KANE	66.	80	06	1.200	BRENNAN
33.	66	06	2.150	RENO, E	67.	81	09	1.000	SWARTZ DR
34.	66	08	1.212	ROEHRS	68.	81	12	2.490	EDSEL

II.F.3

Table ~~[illegible]~~

STATISTICS DERIVED FROM FIELDS IN THE MINNELUSA PLAY
AND THE ASSESSMENT OF FIELD SIZES

	no. of fields	total oil	ave field size	largest field	percent	period (years)	shape categ.	from fitting procedure: median	max	a	b	T^U
whole record	68	359	5.3	51.7	100	57/81	5	2.8	65	3.05	.673	.01
early third	23	211	9.2	51.7	59	57/65	4	5.9	63	21.8	.294	.01
middle third	23	103	4.5	17.1	29	65/70	4	2.9	34	5.62	.419	.01
late third	22	45	2.0	5.0	12	72/81	4	1.6	10	1.77	.402	.01

	no of fields	ave field size	from fitting to one of seven shapes: type	1.00	.95	.75	.50	.25	.05	0.00	a	b	T^U
whole record	68	5.3	5	1.0	1.1	1.8	3.0	5.9	17.5	52.5	4.4	.55	.01
early third	23	9.2	4	1.0	1.3	2.8	5.6	11.4	30.0	70.0	17.2	.35	.01
middle third	23	4.5	4	1.0	1.1	1.8	3.0	5.4	13.3	30.3	7.3	.35	.01
late third	22	2.0	4	1.0	1.0	1.2	1.6	2.3	4.6	9.7	2.2	.35	.01
explored	25	1.8	3	1.0	1.0	1.2	1.5	2.0	3.4	5.6	4.6	.15	.01
unexplored	130	*4.7	*5	1.0	1.1	1.6	2.7	5.3	15.3	50.0	-	-	-

statistics given to the assessors (all rows above except explored / unexplored)

estimates made by the assessors (explored, unexplored)

* approximately

Sometimes attention is focused on the means rather than the medians; infrequently, it is focused on the maximums. The means or medians are not always reduced from the guide. An assessment can be adjusted upwards for instance, if there are large unexplored areas that might indicate the play was expanding. We also subjectively can account for growth in analog fields by increasing the size of the predicted accumulations.

Shapes are analyzed in a similar manner. In the Minnelusa, the concentration class for each of the thirds is 4. This value is consistent with the Minnelusa's stratigraphic nature; field sizes tend to be heterogeneous (some relatively larger fields remain to be discovered) throughout the history. In structural plays, however, shapes often change over time from more concentrated to more dispersed. Larger fields are discovered earlier in the chronology, and a concentrated habitat can be converted to a dispersed habitat when the largest few fields are discovered and only small fields having relatively homogeneous sizes remain.

To some degree, we interpret efficiency in exploration to be reflected both by decreases in the median or mean and by changes in shape from concentrated to dispersed. The less efficient we think the discovery process has been and the more uncertain we are that the large fields have all been discovered, the more concentrated the shape we choose, leading to a thicker right-hand tail in the estimate. Note that two concentration classes having the same mean do not differ in the amount of oil each contains, given the same number of accumulations.

Once a median (or mean, or less commonly a maximum) for the assessment has been chosen and as the shape is being considered, we refer to tables that show quantiles and other information for a wide range of values of the median (or mean or maximum) for each of the shapes. Two rows from the lookup tables are presented in table II.F.4 and the Appendix B contains two lookup tables based on medians and means. There is a similar table for maximums. The first row in table II.F.4 represents the estimate for the explored area. The assessors chose a median of 1.5 and a class 3.

Other information in the lookup tables includes the first two moments of the distribution, the parameters of the distribution, and an indication about the size of the largest field as a function of the number of fields. For instance, for a median value of 1.5 and a shape of 3, the maximum possible size is 5.6 million bbl. If there are five fields found, however, then the median value of the largest field is 2.6; if 20 fields found, the median size of the largest field is 3.8. The size of the largest field expected to be discovered is an important consideration in the estimation process, and, especially with thick-tailed distributions, it can be substantially less than the upper bound.

This evaluation of the statistics applied to the three thirds can be visualized in two ways. Figure II.F.4 shows each third of the discovery record plotted on probability plotting paper generated for the TSP distribution. In general, a TSP distribution will plot as a straight line on the plotting paper; however, when more than one distribution is drawn on the same paper, the values of b and T^u will be different and one or more of the distributions will bend slightly. The plots of the three thirds for fields in the Minnelusa play show very consistent patterns of decrease in

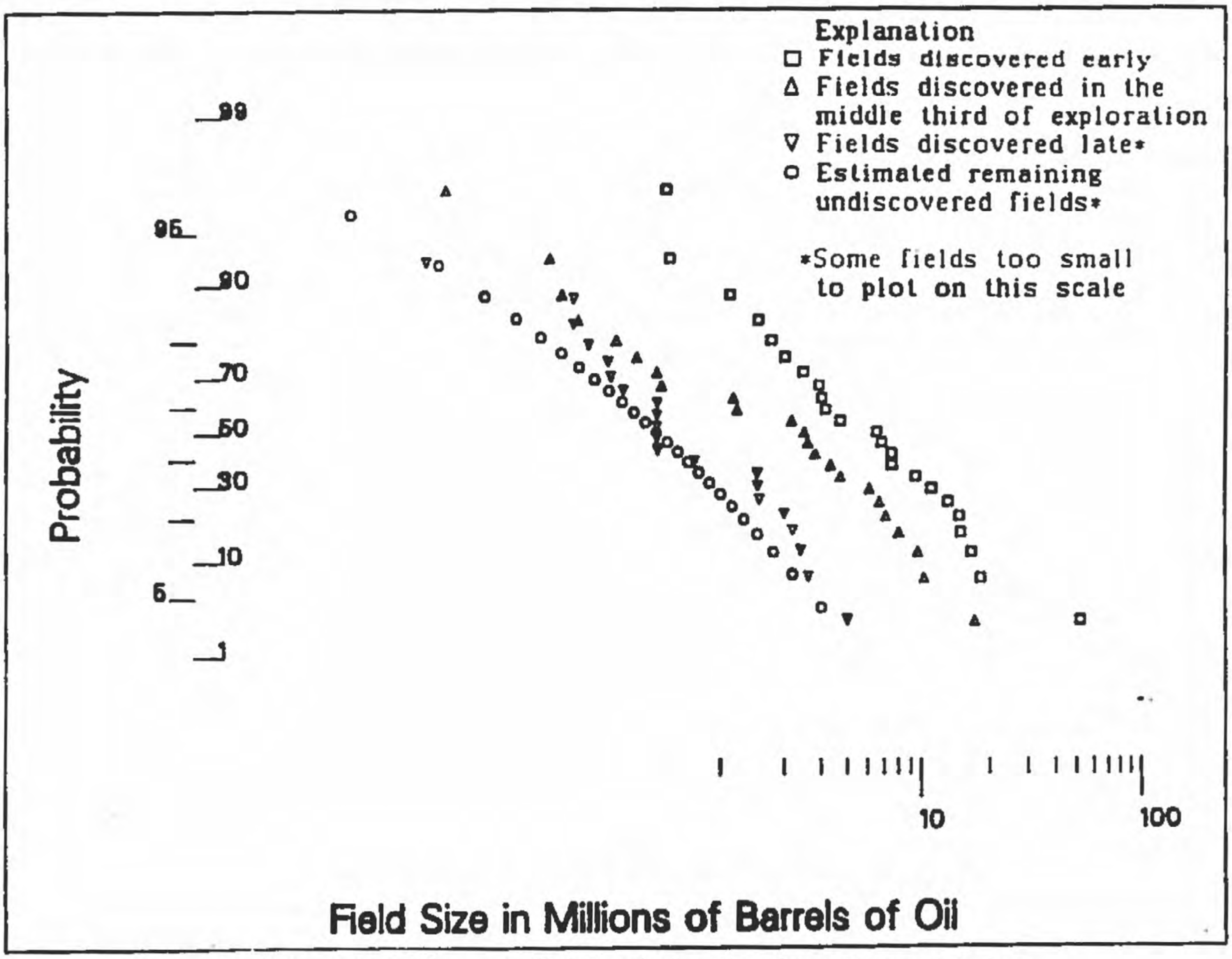

Figure II.F.4. The 68 largest fields of the Minnelusa play split into thirds by chronology and the field size estimate.

size. The circles represent medians of field size distributions for fields expected to be discovered, given the median estimate of the number of fields, 25.

Another way of visualizing the estimation of the sizes of undiscovered fields is to look at the plot containing frequency densities for each of the thirds and for the undiscovered fields in figure II.F.5. The sizes decrease from the early third through the late third, and then the estimate is decreased (and the shape changes to slightly more dispersed) from the late third to the distribution of the undiscovered fields. The quantiles can be read approximately from the graph.

The second part in assessing the Minnelusa play is to estimate the size distribution of the fields in the unexplored area. A suitable guide in this case is the sum of the discovered fields (all three thirds) and the estimated undiscovered fields. The field size distribution of the guide would approximate line 1 in table II.F.3 of the whole record; the lower average sizes result from the addition of the smaller undiscovered fields. The geologist would modify the guide to reflect differences in the unexplored area. The shape would likely be at least as concentrated as the class 5 recorded for the whole record, unless the geologist has a reason to the contrary. The assessors initially estimated a median value of 2.75 and a shape of 5. The line in the lookup table gives the quantiles shown in table II.F.4 and a mean of 4.7; note that this is less than the 5.3 mean from the whole record and more than the 4.3 mean that is the weighted average of the whole record plus the undiscovered.

The final estimate indicates some of the flexibility provided by this set of procedures. It is important to focus on the expected size of the largest field. The assessors estimated a median number of 25 fields. In this case, the geologists decided the predicted size of the largest field was too small. The maximum (0 percent) from that line on the lookup table is about 45 million bbl; there is only a 5 percent chance that the largest field is as large as about 40 million bbl (the 5 percent value would be 39.8 if there were 20 fields discovered). The largest field in the record of discoveries, Raven Creek, is slightly over 50 million bbl.

The assessors had several options. They could choose a more concentrated class. They could fit a TSP distribution somewhere between class 5 and class 6; they could increase the mean; or they could modify the quantiles directly, which is what happened in this particular case. The right-hand tail was increased slightly by moving the maximum quantile from 45 to 50. The resulting quantiles no longer exactly fit a TSP distribution, and the mean is increased slightly.

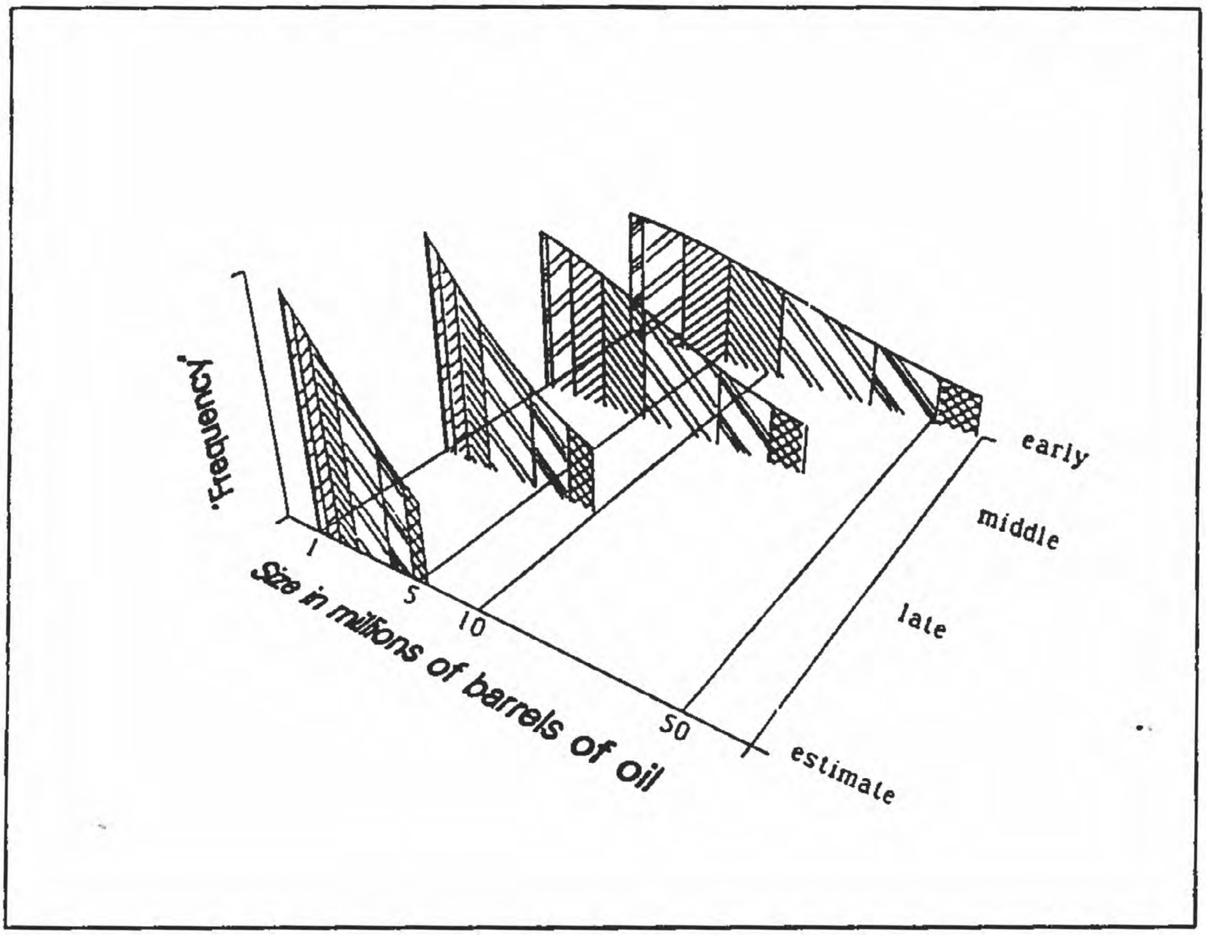

Figure II.F.5. The truncated shifted Pareto distribution fit to the record of discoveries in the Minnelusa play split into thirds and the estimated field size distribution.

Table II.F.4

TWO ROWS FROM THE MEDIAN LOOKUP TABLES

C	1.00	.95	.75	.50	.25	.05	0.00	MEAN	S.D.	A	B	T^u	N=5 95	50%	5%	N=20 95	50%	5%
3	1.00	1.04	1.20	1.50	2.05	3.44	5.61	1.76	0.79	4.633	0.15	0.01	1.58	2.60	4.69	2.54	3.78	5.30
5	1.00	1.11	1.65	2.75	5.26	15.28	45.47	4.69	5.50	3.837	0.55	0.01	3.07	8.56	30.06	8.15	18.62	39.82

Notes:

1.00, .95, ... , 0.00 -- quantiles

Mean, S.D. -- average, standard deviation

A,B,T^u -- three parameters of the TSP

N=5; 95%, 50%, 5% -- predicted quantiles of the largest field out of 5 fields

N=20; 95%, 50%, 5% -- predicted quantiles of the largest field out of 20 fields

The basin-margin structural play in the Bighorn basin is older and more depleted than the Minnelusa play (fig. II.F.6). The fields are presented in table II.F.5 and the statistics shown in table II.F.6. The reasoning behind the assessment is similar to that in the Minnelusa. The major differences are that the play is structural and that it is much older -- the late third started in 1947 and the last-recorded field in the data set was discovered in 1976. Two fields that are large relative to the sizes of fields found during the late third period were discovered early in the period. Even though these two fields were included in the late third, that period accounted for only 5 percent of the total oil.

The estimated distribution was taken from a lookup table based on maximums. A concentration class of 5 was chosen with a maximum of 20 million bbl. The median of this estimated size distribution (1.7 million bbl oil) is smaller than the late third (2.7 million bbl oil), and it is not much greater than the median of the explored subplay in the Minnelusa (1.5 million bbl oil). It does, however, have a thicker tail than the estimate in the Minnelusa to account for the possibility of a limited number of larger fields. Even with distributions that represent relatively small field sizes, the chance of a large field can stretch the shape to a higher concentration class, such as the #5 in this case.

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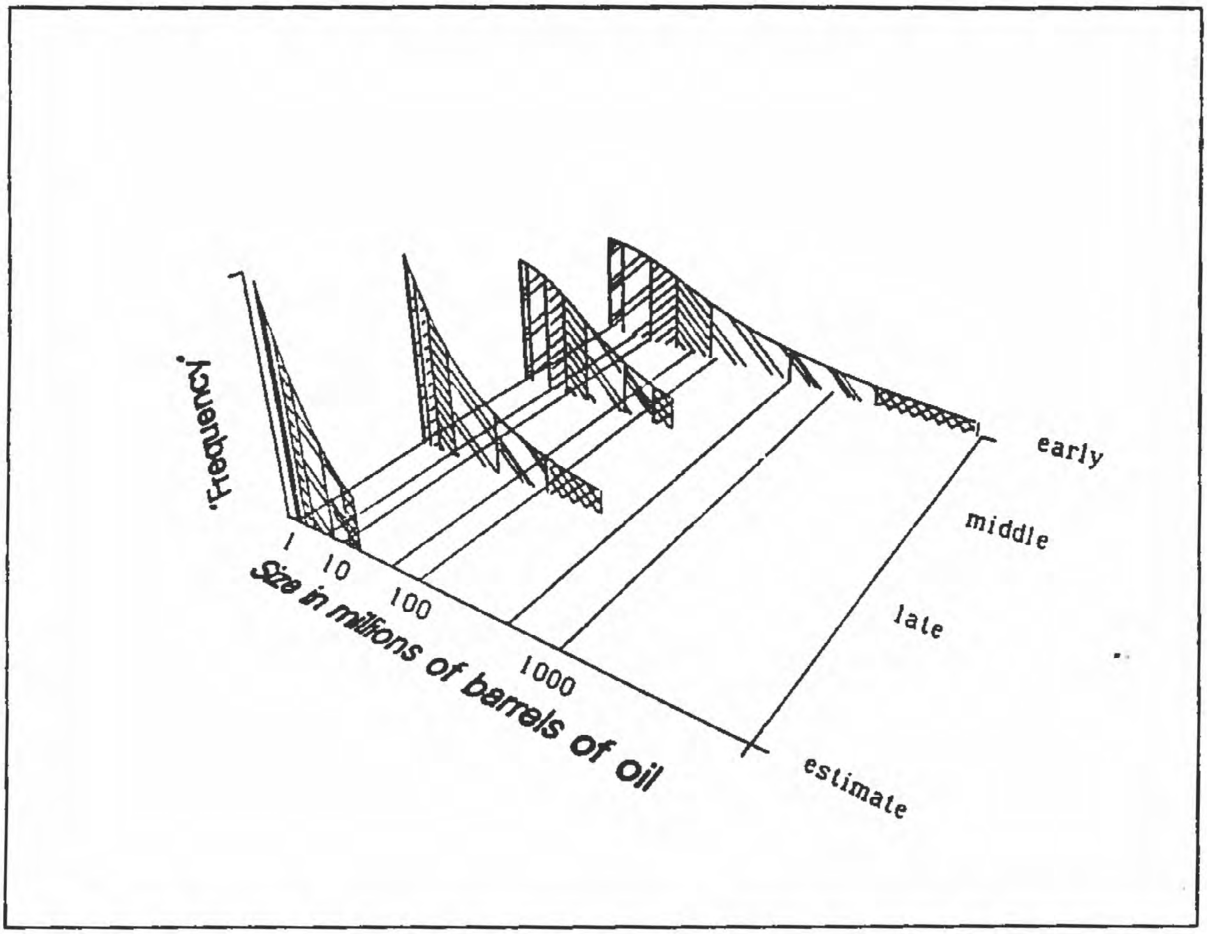

Figure II.F.6. The truncated shifted Pareto distribution fit to the record of discoveries in the Bighorn structural play split into thirds and the estimated field size distribution.

Table II.F.5
Ultimate recovery in millions of barrels in fields of the Bighorn Basin margin structural play that are greater than one million barrels of oil. -- Fields are sorted by order of discovery

Garland	00/00/1906	178.
Greybull	07/00/1907	1.05
Oregon Basin	08/00/1912	440.
Lamb	00/00/1913	1.
Torchlight	00/00/1913	16.8
Grass Creek	06/26/1914	195.
Little Buffalo Basin	11/04/1914	145.
Elk Basin	10/00/1915	532.
Big Polecat	00/00/1916	6.65
Warm Springs	00/00/1916	3.7
Hidden Dome	09/00/1917	6.8
Byron	00/00/1918	128.
Golden Eagle	00/00/1918	13.5
Hamilton Dome	09/00/1918	250.
Black Mountain	11/15/1922	17.2
Lake Creek & Northwest	07/01/1927	9.83
Fourbear	05/02/1928	25.
Frannie	08/00/1928	120.8
Sunshine, North	09/13/1928	2.5
Shoshone	00/00/1929	3.4
Walker Dome	00/00/1929	3.25
Dry Creek	03/31/1929	4.12
Spring Creek, South	00/00/1930	18.2
Pitchfork	11/30/1930	36.
Badger Basin	07/00/1931	2.8
Gooseberry	09/20/1937	7.6
Gebo	11/24/1943	29.5
Half Moon	09/20/1944	8.5
Elk Basin, South	09/19/1945	19.2
Zimmerman Butte	11/22/1945	1.24
Worland	03/21/1946	18.2
Neiber Dome	02/02/1947	3.6
Elk Basin, Northwest	08/20/1947	1.25
Sand Creek	09/08/1947	1.457
Silver Tip	04/22/1948	4.7
Sage Creek	06/15/1948	11.8
Little Sand Draw	02/19/1949	10.2
Murphy Dome	11/21/1949	38.4
Bonanza	01/02/1951	41.7
Whistle Creek	11/07/1951	5.2
Sage Creek, West	04/09/1952	1.3
Clark's Fork, North	03/01/1956	1.025
Alkali Anticline	05/08/1957	2.7
Deaver, North	07/18/1960	1.35
Ferguson Ranch	10/01/1963	4.
Homestead	05/01/1969	1.6
Willow Draw	11/13/1972	2.22
Cody	10/11/1976	5.20

II. F. 6

Table ~~3-6~~

STATISTICS DERIVED FROM FIELDS IN THE BIGHORN BASIN MARGIN STRUCTURAL PLAY
AND THE ASSESSMENT OF FIELD SIZES

	no. of fields	total oil	ave field size	largest field	percent	period (years)	from fitting procedure: median	max	a	b	T^u
whole record	48	2382	49.6	532.	100	06/76	14.3	1297	13.715	.99	.01
early third	16	1944	121.5	532.	82	06/27	33.9	3213	33.989	.99	.01
middle third	16	304	19.0	121.	13	28/47	8.6	267	13.250	.66	.01
late third	16	134	8.4	42.	5	47/76	3.0	198	2.081	.99	.01

	no of fields	ave field size	from fitting to one of seven shapes: type	1.00	.95	.75	.50	.25	.05	0.00	a	b	T^u
whole record	48	49.6	7	1.0	1.6	4.8	12.3	34.9	195.5	2193.	11.6	.99	.005
early third	16	121.5	7	1.0	2.5	10.4	29.1	84.1	483.0	5433.	28.8	.99	.005
middle third	16	19.0	5	1.0	1.5	4.2	9.5	21.7	70.6	218.	18.7	.55	.01
late third	16	8.4	7	1.0	1.1	1.6	2.7	6.1	30.5	334.	1.8	.99	.005

statistics given to the assessors

	no of fields	ave field size	type	1.00	.95	.75	.50	.25	.05	0.00	a	b	T^u
undiscovered	10	2.6	5	1.1	1.0	1.3	1.7	2.8	7.1	20.0	1.6	.55	.01

estimates made by the assessors

APPENDIX A

FITTING THE TRUNCATED SHIFTED PARETO DISTRIBUTION USING TABLES

1. Determine cutoff value, x_c (tables are based on 1 million barrels of oil).

Delete fields smaller than cutoff. Sort remaining fields by size.

2. Calculate the mean of the entire sample $\bar{x}$.

3. Determine the split where the mean lies. Count the number higher than the mean, N^u.

4. Calculate the mean of the N^u fields greater than the mean, call it $\bar{x}^u$.

5. Calculate two ratios $R_1 = \frac{N^u + .5}{N+1}$ and $R_2 = \frac{\bar{x}^u - x_c}{\bar{x} - x_c}$

6. Choose the column in the table by selecting the number closest to R_1 and choose the row by looking up in that column the number closest to R_2.

7. Use the row (the designated shape) and the mean $\bar{x}$ to determine the quantiles of the fit from the Lookup Table Based on Means (a similar table to Appendix B).

==================

Example:

fields: 1.0 2.0 3.0 5.0 10.0

$\bar{x} = 4.2$

$N^u = 2$

$\bar{x}^u = 7.5$

$R_1 = .42$

$R_2 = 2.03$

Choose column under .425 because close to .42

Choose row 5 because 2.03 matches 2.03

Using a mean of 4.25, which is close to 4.2, and a concentration class #5, the quantiles from Lookup Table Based on the Mean are:

1.0 1.1 1.6 2.5 4.8 13.6 40.2

APPENDIX A CONTINUED:

Table to Determine Class from Number of Fields and Incomplete Means

C	0.010	0.050	0.075	0.100	0.125	0.150	0.175	0.200	0.225	0.250
1	3.58066	3.21203	3.03512	2.88395	2.75173	2.63414	2.52818	2.43170	2.34312	2.26123
2	4.71328	3.79511	3.47234	3.22631	3.02735	2.86031	2.71637	2.58993	2.47721	2.37555
3	5.37295	4.16108	3.75709	3.45632	3.21754	3.02009	2.8521	2.70624	2.57748	2.46239
4	7.12679	5.05608	4.43416	3.99181	3.65286	3.38064	3.15474	2.96273	2.79649	2.65043
5	9.62167	6.19308	5.26272	4.62896	4.15932	3.79230	3.49474	3.24688	3.03608	2.85384
6	15.13271	8.35205	6.76171	5.74113	5.01860	4.47453	4.04702	3.70044	3.41267	3.16916
7	39.71446	13.00867	9.52520	7.58891	6.34094	5.46321	4.80907	4.30102	3.89395	3.55985

C	0.275	0.300	0.325	0.350	0.375	0.400	0.425	0.450	0.475	0.500
1	2.18505	2.11385	2.04702	1.98402	1.92445	1.86794	1.81421	1.76298	1.71403	1.66716
2	2.28299	2.19803	2.11955	2.04662	1.97854	1.91469	1.85458	1.79782	1.74405	1.69297
3	2.35845	2.26377	2.17691	2.09671	2.02229	1.95289	1.88791	1.82685	1.76928	1.71485
4	2.52058	2.40399	2.29844	2.20218	2.11388	2.03243	1.95694	1.88669	1.82107	1.75955
5	2.69417	2.55272	2.42622	2.31219	2.20870	2.11419	2.02743	1.94741	1.87329	1.80438
6	2.95991	2.77779	2.61757	2.47533	2.34803	2.23332	2.12933	2.03453	1.94770	1.86781
7	3.28025	3.04252	2.83770	2.65923	2.50221	2.36291	2.23841	2.12642	2.02510	1.93296

APPENDIX B

Lookup Table Based on the Median

C	1.00	.95	.75	.50	.25	.05	0.00	MEAN	S.D.	A	B	T^U	N=5 95	50%	5%	N=20 95	50%	5%
1	1.00	1.01	1.04	1.10	1.20	1.38	1.49	1.13	0.12	3.054	0.050	0.050	1.11	1.28	1.46	1.27	1.41	1.49
2	1.00	1.01	1.04	1.10	1.20	1.44	1.75	1.14	0.14	2.878	0.050	0.010	1.12	1.30	1.62	1.29	1.49	1.70
3	1.00	1.01	1.04	1.10	1.21	1.49	1.92	1.15	0.16	0.927	0.150	0.010	1.12	1.32	1.74	1.31	1.56	1.86
4	1.00	1.01	1.04	1.10	1.22	1.62	2.49	1.18	0.22	0.370	0.350	0.010	1.12	1.37	2.08	1.35	1.74	2.34
5	1.00	1.01	1.04	1.10	1.24	1.82	3.54	1.21	0.31	0.219	0.550	0.010	1.12	1.43	2.66	1.41	2.01	3.22
6	1.00	1.01	1.03	1.10	1.28	2.27	7.24	1.30	0.62	0.127	0.850	0.010	1.12	1.56	4.39	1.52	2.69	6.13
7	1.00	1.01	1.03	1.10	1.30	2.71	20.32	1.43	1.28	0.102	0.990	0.005	1.12	1.65	7.38	1.60	3.45	13.82

C	1.00	.95	.75	.50	.25	.05	0.00	MEAN	S.D.	A	B	T^U	N=5 95	50%	5%	N=20 95	50%	5%
1	1.00	1.01	1.08	1.20	1.39	1.75	1.99	1.27	0.23	6.108	0.050	0.050	1.23	1.56	1.92	1.54	1.81	1.97
2	1.00	1.01	1.08	1.20	1.40	1.87	2.49	1.29	0.28	5.755	0.050	0.010	1.23	1.60	2.24	1.58	1.97	2.41
3	1.00	1.01	1.08	1.20	1.42	1.98	2.84	1.31	0.32	1.853	0.150	0.010	1.23	1.64	2.48	1.62	2.11	2.72
4	1.00	1.01	1.08	1.20	1.45	2.25	3.97	1.35	0.43	0.740	0.350	0.010	1.23	1.74	3.17	1.71	2.47	3.69
5	1.00	1.01	1.07	1.20	1.49	2.63	6.08	1.42	0.63	0.439	0.550	0.010	1.24	1.86	4.32	1.82	3.01	5.44
6	1.00	1.01	1.07	1.20	1.55	3.54	13.48	1.60	1.23	0.254	0.850	0.010	1.24	2.11	7.78	2.04	4.38	11.25
7	1.00	1.01	1.07	1.20	1.59	4.43	39.65	1.86	2.56	0.205	0.990	0.005	1.24	2.30	13.76	2.20	5.89	26.64

C	1.00	.95	.75	.50	.25	.05	0.00	MEAN	S.D.	A	B	T^U	N=5 95	50%	5%	N=20 95	50%	5%
1	1.00	1.02	1.13	1.30	1.59	2.13	2.48	1.40	0.35	9.162	0.050	0.050	1.34	1.84	2.39	1.81	2.22	2.46
2	1.00	1.02	1.12	1.30	1.61	2.31	3.24	1.43	0.41	8.633	0.050	0.010	1.35	1.90	2.86	1.87	2.46	3.11
3	1.00	1.02	1.12	1.30	1.63	2.46	3.77	1.46	0.47	2.780	0.150	0.010	1.35	1.96	3.22	1.92	2.67	3.58
4	1.00	1.02	1.12	1.30	1.67	2.87	5.46	1.53	0.65	1.111	0.350	0.010	1.35	2.11	4.25	2.06	3.21	5.03
5	1.00	1.02	1.11	1.30	1.73	3.45	8.62	1.63	0.94	0.658	0.550	0.010	1.36	2.30	5.98	2.23	4.02	7.66
6	1.00	1.02	1.10	1.30	1.83	4.81	19.72	1.90	1.85	0.381	0.850	0.010	1.36	2.67	11.17	2.56	6.07	16.38
7	1.00	1.02	1.10	1.30	1.89	6.14	58.97	2.29	3.84	0.307	0.990	0.005	1.36	2.94	20.13	2.79	8.34	39.46

C	1.00	.95	.75	.50	.25	.05	0.00	MEAN	S.D.	A	B	T^U	N=5 95	50%	5%	N=20 95	50%	5%
1	1.00	1.03	1.17	1.40	1.79	2.51	2.97	1.53	0.46	12.217	0.050	0.050	1.46	2.12	2.85	2.09	2.62	2.94
2	1.00	1.03	1.16	1.40	1.81	2.74	3.98	1.57	0.55	11.511	0.050	0.010	1.46	2.20	3.48	2.16	2.95	3.82
3	1.00	1.03	1.16	1.40	1.84	2.95	4.69	1.61	0.63	3.707	0.150	0.010	1.46	2.28	3.95	2.23	3.22	4.44
4	1.00	1.03	1.15	1.40	1.90	3.49	6.94	1.71	0.87	1.481	0.350	0.010	1.47	2.48	5.33	2.41	3.95	6.38
5	1.00	1.02	1.15	1.40	1.97	4.26	11.16	1.84	1.26	0.877	0.550	0.010	1.47	2.73	7.64	2.63	5.03	9.87
6	1.00	1.02	1.14	1.40	2.10	6.08	25.95	2.20	2.46	0.508	0.850	0.010	1.48	3.22	14.56	3.07	7.76	21.50
7	1.00	1.02	1.13	1.40	2.18	7.86	78.30	2.72	5.13	0.410	0.990	0.005	1.49	3.59	26.51	3.39	10.79	52.27

C	1.00	.95	.75	.50	.25	.05	0.00	MEAN	S.D.	A	B	T^U	N=5 95	50%	5%	N=20 95	50%	5%
1	1.00	1.04	1.21	1.50	1.98	2.89	3.47	1.67	0.58	15.271	0.050	0.050	1.57	2.40	3.31	2.36	3.03	3.43
2	1.00	1.04	1.21	1.50	2.01	3.18	4.73	1.72	0.69	14.389	0.050	0.010	1.58	2.50	4.10	2.44	3.44	4.52
3	1.00	1.04	1.20	1.50	2.05	3.44	5.61	1.76	0.79	4.633	0.150	0.010	1.58	2.60	4.69	2.54	3.78	5.30
4	1.00	1.03	1.19	1.50	2.12	4.12	8.43	1.88	1.08	1.851	0.350	0.010	1.59	2.85	6.41	2.76	4.68	7.72
5	1.00	1.03	1.19	1.50	2.22	5.08	13.70	2.05	1.57	1.096	0.550	0.010	1.59	3.16	9.30	3.04	6.03	12.09
6	1.00	1.03	1.17	1.50	2.38	7.35	32.19	2.50	3.08	0.635	0.850	0.010	1.60	3.78	17.95	3.59	9.45	26.63
7	1.00	1.03	1.17	1.50	2.48	9.57	97.62	3.14	6.41	0.512	0.990	0.005	1.61	4.24	32.89	3.99	13.23	65.09

C	1.00	.95	.75	.50	.25	.05	0.00	MEAN	S.D.	A	B	T^U	N=5 95	50%	5%	N=20 95	50%	5%
1	1.00	1.06	1.31	1.75	2.47	3.83	4.70	2.00	0.86	22.906	0.050	0.050	1.86	3.10	4.47	3.04	4.05	4.64
2	1.00	1.05	1.31	1.75	2.51	4.27	6.59	2.08	1.04	21.583	0.050	0.010	1.86	3.25	5.66	3.17	4.66	6.28
3	1.00	1.05	1.30	1.75	2.57	4.66	7.92	2.14	1.19	6.950	0.150	0.010	1.87	3.40	6.54	3.31	5.16	7.45
4	1.00	1.05	1.29	1.75	2.69	5.68	12.14	2.32	1.62	2.776	0.350	0.010	1.88	3.77	9.12	3.65	6.53	11.08
5	1.00	1.05	1.28	1.75	2.82	7.12	20.06	2.58	2.36	1.644	0.550	0.010	1.89	4.24	13.45	4.06	8.55	17.64
6	1.00	1.04	1.26	1.75	3.07	10.53	47.79	3.25	4.62	0.953	0.850	0.010	1.90	5.17	26.42	4.89	13.67	39.45
7	1.00	1.04	1.25	1.75	3.22	13.86	145.93	4.22	9.61	0.768	0.990	0.005	1.91	5.86	48.84	5.48	19.35	97.14

C	1.00	.95	.75	.50	.25	.05	0.00	MEAN	S.D.	A	B	T^U	N=5 95	50%	5%	N=20 95	50%	5%
1	1.00	1.07	1.42	2.00	2.96	4.77	5.94	2.33	1.15	30.541	0.050	0.050	2.15	3.80	5.62	3.71	5.06	5.85
2	1.00	1.07	1.41	2.00	3.02	5.36	8.45	2.44	1.38	28.777	0.050	0.010	2.15	3.99	7.21	3.89	5.87	8.04
3	1.00	1.07	1.40	2.00	3.09	5.88	10.22	2.53	1.58	9.267	0.150	0.010	2.16	4.20	8.38	4.08	6.55	9.61
4	1.00	1.07	1.39	2.00	3.25	7.24	15.85	2.76	2.17	3.702	0.350	0.010	2.17	4.70	11.83	4.53	8.37	14.44
5	1.00	1.06	1.37	2.00	3.43	9.16	26.41	3.11	3.15	2.193	0.550	0.010	2.18	5.32	17.61	5.08	11.07	23.18
6	1.00	1.06	1.35	2.00	3.75	13.71	63.39	4.00	6.16	1.270	0.850	0.010	2.20	6.56	34.89	6.18	17.90	52.26
7	1.00	1.05	1.34	2.00	3.96	18.15	194.24	5.29	12.81	1.024	0.990	0.005	2.22	7.48	64.78	6.98	25.47	129.18

C	1.00	.95	.75	.50	.25	.05	0.00	MEAN	S.D.	A	B	T^U	N=5 95	50%	5%	N=20 95	50%	5%
1	1.00	1.09	1.52	2.25	3.46	5.71	7.17	2.67	1.44	38.177	0.050	0.050	2.43	4.50	6.78	4.39	6.08	7.06
2	1.00	1.09	1.52	2.25	3.52	6.45	10.31	2.79	1.73	35.971	0.050	0.010	2.44	4.74	8.76	4.61	7.09	9.81
3	1.00	1.09	1.50	2.25	3.61	7.10	12.53	2.91	1.98	11.583	0.150	0.010	2.45	5.00	10.23	4.85	7.94	11.76
4	1.00	1.08	1.48	2.25	3.81	8.80	19.56	3.20	2.71	4.627	0.350	0.010	2.46	5.62	14.54	5.41	10.21	17.80
5	1.00	1.08	1.46	2.25	4.04	11.20	32.76	3.64	3.93	2.741	0.550	0.010	2.48	6.40	21.76	6.11	13.59	28.73
6	1.00	1.07	1.43	2.25	4.44	16.89	78.98	4.75	7.70	1.588	0.850	0.010	2.51	7.95	43.36	7.48	22.12	65.08
7	1.00	1.07	1.42	2.25	4.70	22.43	242.55	6.36	16.02	1.280	0.990	0.005	2.52	9.10	80.73	8.47	31.58	161.23

C	1.00	.95	.75	.50	.25	.05	0.00	MEAN	S.D.	A	B	T^U	N=5 95	50%	5%	N=20 95	50%	5%
1	1.00	1.11	1.63	2.50	3.95	6.66	8.40	3.00	1.73	45.812	0.050	0.050	2.72	5.20	7.93	5.07	7.09	8.28
2	1.00	1.11	1.62	2.50	4.03	7.54	12.18	3.15	2.07	43.166	0.050	0.010	2.73	5.49	10.31	5.33	8.31	11.57
3	1.00	1.11	1.61	2.50	4.14	8.32	14.83	3.29	2.37	13.900	0.150	0.010	2.74	5.81	12.08	5.62	9.33	13.91
4	1.00	1.10	1.58	2.50	4.37	10.36	23.28	3.64	3.25	5.553	0.350	0.010	2.76	6.55	17.24	6.29	12.05	21.16
5	1.00	1.09	1.56	2.50	4.65	13.24	39.11	4.16	4.72	3.289	0.550	0.010	2.78	7.48	25.91	7.13	16.10	34.28
6	1.00	1.08	1.52	2.50	5.13	20.06	94.58	5.49	9.24	1.905	0.850	0.010	2.81	9.34	51.84	8.78	26.34	77.89
7	1.00	1.08	1.50	2.50	5.44	26.72	290.86	7.43	19.22	1.536	0.990	0.005	2.82	10.72	96.67	9.97	37.70	193.28

C	1.00	.95	.75	.50	.25	.05	0.00	MEAN	S.D.	A	B	T^U	N=5 95	50%	5%	N=20 95	50%	5%
1	1.00	1.13	1.73	2.75	4.44	7.60	9.64	3.33	2.01	53.447	0.050	0.050	3.01	5.90	9.09	5.75	8.11	9.49
2	1.00	1.13	1.72	2.75	4.53	8.63	14.04	3.51	2.42	50.360	0.050	0.010	3.02	6.24	11.86	6.05	9.53	13.33
3	1.00	1.12	1.71	2.75	4.66	9.55	17.14	3.67	2.77	16.217	0.150	0.010	3.03	6.61	13.92	6.39	10.72	16.06
4	1.00	1.12	1.68	2.75	4.94	11.92	26.99	4.08	3.79	6.478	0.350	0.010	3.05	7.47	19.95	7.17	13.90	24.52
5	1.00	1.11	1.65	2.75	5.26	15.28	45.47	4.69	5.50	3.837	0.550	0.010	3.07	8.56	30.06	8.15	18.62	39.82
6	1.00	1.10	1.61	2.75	5.82	23.24	110.18	6.24	10.78	2.223	0.850	0.010	3.11	10.73	60.31	10.07	30.57	90.71
7	1.00	1.09	1.59	2.75	6.17	31.01	339.17	8.50	22.43	1.792	0.990	0.005	3.13	12.34	112.62	11.46	43.82	225.32

C	1.00	.95	.75	.50	.25	.05	0.00	MEAN	S.D.	A	B	T^U	N=5 95	50%	5%	N=20 95	50%	5%
1	1.00	1.15	1.83	3.00	4.93	8.54	10.87	3.67	2.30	61.083	0.050	0.050	3.30	6.60	10.24	6.43	9.12	10.70
2	1.00	1.15	1.82	3.00	5.04	9.72	15.90	3.87	2.76	57.554	0.050	0.010	3.30	6.99	13.42	6.78	10.75	15.09
3	1.00	1.14	1.81	3.00	5.18	10.77	19.45	4.05	3.16	18.533	0.150	0.010	3.32	7.41	15.77	7.16	12.10	18.21
4	1.00	1.13	1.77	3.00	5.50	13.47	30.70	4.53	4.33	7.404	0.350	0.010	3.34	8.40	22.66	8.06	15.74	27.88
5	1.00	1.12	1.74	3.00	5.86	17.32	51.82	5.22	6.29	4.385	0.550	0.010	3.37	9.64	34.21	9.17	21.14	45.37
6	1.00	1.11	1.69	3.00	6.51	26.42	125.77	6.99	12.32	2.540	0.850	0.010	3.41	12.12	68.78	11.37	34.79	103.52
7	1.00	1.11	1.67	3.00	6.91	35.29	387.48	9.58	25.63	2.048	0.990	0.005	3.43	13.96	128.56	12.96	49.93	257.37

C	1.00	.95	.75	.50	.25	.05	0.00	MEAN	S.D.	A	B	T^U	N=5 95	50%	5%	N=20 95	50%	5%
1	1.0	1.2	2.0	3.5	5.9	10.4	13.3	4.3	2.9	76.35	0.050	0.050	3.9	8.0	12.6	7.8	11.2	13.1
2	1.0	1.2	2.0	3.5	6.0	11.9	19.6	4.6	3.5	71.94	0.050	0.010	3.9	8.5	16.5	8.2	13.2	18.6
3	1.0	1.2	2.0	3.5	6.2	13.2	24.1	4.8	4.0	23.17	0.150	0.010	3.9	9.0	19.5	8.7	14.9	22.5
4	1.0	1.2	2.0	3.5	6.6	16.6	38.1	5.4	5.4	9.25	0.350	0.010	3.9	10.2	28.1	9.8	19.4	34.6
5	1.0	1.2	1.9	3.5	7.1	21.4	64.5	6.3	7.9	5.48	0.550	0.010	4.0	11.8	42.5	11.2	26.2	56.5
6	1.0	1.1	1.9	3.5	7.9	32.8	157.0	8.5	15.4	3.18	0.850	0.010	4.0	14.9	85.7	14.0	43.2	129.2
7	1.0	1.1	1.8	3.5	8.4	43.9	484.1	11.7	32.0	2.56	0.990	0.005	4.0	17.2	160.5	15.9	62.2	321.5

C	1.00	.95	.75	.50	.25	.05	0.00	MEAN	S.D.	A	B	T^U	N=5 95	50%	5%	N=20 95	50%	5%
1	1.0	1.2	2.3	4.0	6.9	12.3	15.8	5.0	3.5	91.62	0.050	0.050	4.4	9.4	14.9	9.1	13.2	15.6
2	1.0	1.2	2.2	4.0	7.1	14.1	23.4	5.3	4.1	86.33	0.050	0.010	4.5	10.0	19.6	9.7	15.6	22.1
3	1.0	1.2	2.2	4.0	7.3	15.6	28.7	5.6	4.7	27.80	0.150	0.010	4.5	10.6	23.2	10.2	17.7	26.8
4	1.0	1.2	2.2	4.0	7.7	19.7	45.6	6.3	6.5	11.11	0.350	0.010	4.5	12.1	33.5	11.6	23.1	41.3
5	1.0	1.2	2.1	4.0	8.3	25.5	77.2	7.3	9.4	6.58	0.550	0.010	4.6	14.0	50.8	13.3	31.2	67.6
6	1.0	1.2	2.0	4.0	9.3	39.1	188.2	10.0	18.5	3.81	0.850	0.010	4.6	17.7	102.7	16.6	51.7	154.8
7	1.0	1.2	2.0	4.0	9.9	52.4	580.7	13.9	38.4	3.07	0.990	0.005	4.6	20.4	192.3	18.9	74.4	385.6

C	1.00	.95	.75	.50	.25	.05	0.00	MEAN	S.D.	A	B	T^U	N=5 95	50%	5%	N=20 95	50%	5%
1	1.0	1.3	2.7	5.0	8.9	16.1	20.7	6.3	4.6	122.17	0.050	0.050	5.6	12.2	19.5	11.9	17.2	20.4
2	1.0	1.3	2.6	5.0	9.1	18.4	30.8	6.7	5.5	115.11	0.050	0.010	5.6	13.0	25.8	12.6	20.5	29.2
3	1.0	1.3	2.6	5.0	9.4	20.5	37.9	7.1	6.3	37.07	0.150	0.010	5.6	13.8	30.5	13.3	23.2	35.4
4	1.0	1.3	2.5	5.0	10.0	25.9	60.4	8.1	8.7	14.81	0.350	0.010	5.7	15.8	44.3	15.1	30.5	54.8
5	1.0	1.2	2.5	5.0	10.7	33.6	102.6	9.4	12.6	8.77	0.550	0.010	5.7	18.3	67.4	17.3	41.3	89.7
6	1.0	1.2	2.4	5.0	12.0	51.8	250.5	13.0	24.6	5.08	0.850	0.010	5.8	23.2	136.6	21.7	68.6	206.0
7	1.0	1.2	2.3	5.0	12.8	69.6	774.0	18.2	51.3	4.10	0.990	0.005	5.9	26.9	256.1	24.9	98.9	513.7

C	1.00	.95	.75	.50	.25	.05	0.00	MEAN	S.D.	A	B	T^U	N=5 95	50%	5%	N=20 95	50%	5%
1	1.0	1.4	3.1	6.0	10.8	19.9	25.7	7.7	5.8	152.71	0.050	0.050	6.7	15.0	24.1	14.6	21.3	25.3
2	1.0	1.4	3.1	6.0	11.1	22.8	38.3	8.2	6.9	143.89	0.050	0.010	6.8	16.0	32.0	15.4	25.4	36.2
3	1.0	1.4	3.0	6.0	11.5	25.4	47.1	8.6	7.9	46.33	0.150	0.010	6.8	17.0	37.9	16.4	28.8	44.0
4	1.0	1.3	2.9	6.0	12.2	32.2	75.3	9.8	10.8	18.51	0.350	0.010	6.9	19.5	55.1	18.6	37.8	68.2
5	1.0	1.3	2.9	6.0	13.2	41.8	128.0	11.5	15.7	10.96	0.550	0.010	6.9	22.6	84.0	21.4	51.3	111.9
6	1.0	1.3	2.7	6.0	14.8	64.5	312.9	16.0	30.8	6.35	0.850	0.010	7.0	28.8	170.5	26.9	85.5	257.3
7	1.0	1.3	2.7	6.0	15.8	86.7	967.2	22.4	64.1	5.12	0.990	0.005	7.1	33.4	319.9	30.9	123.3	641.9

C	1.00	.95	.75	.50	.25	.05	0.00	MEAN	S.D.	A	B	T^U	N=5 95	50%	5%	N=20 95	50%	5%
1	1.0	1.4	3.5	7.0	12.8	23.6	30.6	9.0	6.9	183.25	0.050	0.050	7.9	17.8	28.7	17.3	25.4	30.1
2	1.0	1.4	3.5	7.0	13.1	27.2	45.7	9.6	8.3	172.66	0.050	0.010	7.9	19.0	38.2	18.3	30.2	43.3
3	1.0	1.4	3.4	7.0	13.5	30.3	56.3	10.2	9.5	55.60	0.150	0.010	7.9	20.2	45.3	19.5	34.3	52.6
4	1.0	1.4	3.3	7.0	14.5	38.4	90.1	11.6	13.0	22.21	0.350	0.010	8.0	23.2	66.0	22.2	45.2	81.6
5	1.0	1.4	3.2	7.0	15.6	49.9	153.5	13.7	18.9	13.16	0.550	0.010	8.1	26.9	100.6	25.5	61.4	134.1
6	1.0	1.3	3.1	7.0	17.5	77.3	375.3	19.0	37.0	7.62	0.850	0.010	8.2	34.4	204.3	32.1	102.4	308.6
7	1.0	1.3	3.0	7.0	18.7	103.9	1160.4	26.7	76.9	6.15	0.990	0.005	8.3	39.9	383.7	36.9	147.8	770.1

C	1.00	.95	.75	.50	.25	.05	0.00	MEAN	S.D.	A	B	T^U	N=5 95	50%	5%	N=20 95	50%	5%
1	1.0	1.5	3.9	8.0	14.7	27.4	35.5	10.3	8.1	213.79	0.050	0.050	9.0	20.6	33.4	20.0	29.4	35.0
2	1.0	1.5	3.9	8.0	15.1	31.5	53.2	11.0	9.7	201.44	0.050	0.010	9.1	22.0	44.5	21.2	35.1	50.3
3	1.0	1.5	3.8	8.0	15.6	35.2	65.6	11.7	11.1	64.87	0.150	0.010	9.1	23.4	52.7	22.6	39.9	61.2
4	1.0	1.5	3.7	8.0	16.7	44.7	105.0	13.3	15.2	25.91	0.350	0.010	9.2	26.9	76.8	25.7	52.6	95.1
5	1.0	1.4	3.6	8.0	18.0	58.1	178.9	15.8	22.0	15.35	0.550	0.010	9.3	31.2	117.2	29.6	71.5	156.3
6	1.0	1.4	3.4	8.0	20.3	90.0	437.7	22.0	43.1	8.89	0.850	0.010	9.4	39.9	238.2	37.3	119.3	359.8
7	1.0	1.4	3.3	8.0	21.7	121.0	1353.7	31.0	89.7	7.17	0.990	0.005	9.5	46.3	447.5	42.9	172.3	898.3

C	1.00	.95	.75	.50	.25	.05	0.00	MEAN	S.D.	A	B	T^U	N=5 95	50%	5%	N=20 95	50%	5%
1	1.0	1.6	4.3	9.0	16.7	31.2	40.5	11.7	9.2	244.33	0.050	0.050	10.2	23.4	38.0	22.7	33.5	39.8
2	1.0	1.6	4.3	9.0	17.2	35.9	60.6	12.5	11.0	230.22	0.050	0.010	10.2	24.9	50.7	24.1	40.0	57.4
3	1.0	1.6	4.2	9.0	17.7	40.1	74.8	13.2	12.7	74.13	0.150	0.010	10.3	26.6	60.1	25.6	45.4	69.9
4	1.0	1.5	4.1	9.0	19.0	50.9	119.8	15.1	17.3	29.62	0.350	0.010	10.4	30.6	87.6	29.2	60.0	108.5
5	1.0	1.5	4.0	9.0	20.5	66.3	204.3	17.9	25.2	17.54	0.550	0.010	10.5	35.6	133.9	33.7	81.6	178.5
6	1.0	1.4	3.8	9.0	23.0	102.7	500.1	25.0	49.3	10.16	0.850	0.010	10.6	45.5	272.1	42.5	136.2	411.1
7	1.0	1.4	3.7	9.0	24.7	138.2	1546.9	35.3	102.5	8.19	0.990	0.005	10.7	52.8	511.3	48.8	196.7	1026.5

C	1.00	.95	.75	.50	.25	.05	0.00	MEAN	S.D.	A	B	T^U	N=5 95	50%	5%	N=20 95	50%	5%
1	1.0	1.7	4.8	10.0	18.7	34.9	45.4	13.0	10.4	274.87	0.050	0.050	11.3	26.2	42.6	25.4	37.5	44.7
2	1.0	1.7	4.7	10.0	19.2	40.2	68.1	13.9	12.4	258.99	0.050	0.010	11.4	27.9	56.9	27.0	44.9	64.4
3	1.0	1.6	4.6	10.0	19.8	44.9	84.0	14.7	14.2	83.40	0.150	0.010	11.4	29.8	67.5	28.7	51.0	78.5
4	1.0	1.6	4.5	10.0	21.2	57.1	134.7	16.9	19.5	33.32	0.350	0.010	11.5	34.3	98.5	32.8	67.3	122.0
5	1.0	1.6	4.3	10.0	22.9	74.4	229.7	20.0	28.3	19.73	0.550	0.010	11.7	39.9	150.5	37.8	91.6	200.7
6	1.0	1.5	4.1	10.0	25.8	115.4	562.5	28.0	55.4	11.43	0.850	0.010	11.8	51.1	306.0	47.7	153.1	462.4
7	1.0	1.5	4.0	10.0	27.6	155.3	1740.2	39.6	115.3	9.22	0.990	0.005	11.9	59.3	575.0	54.8	221.2	1154.7

C	1.00	.95	.75	.50	.25	.05	0.00	MEAN	S.D.	A	B	T^U	N=5 95	50%	5%	N=20 95	50%	5%
1	1.0	1.9	5.8	12.5	23.6	44.4	57.8	16.3	13.2	351.23	0.050	0.050	14.2	33.2	54.2	32.2	47.7	56.8
2	1.0	1.8	5.7	12.5	24.2	51.1	86.7	17.5	15.9	330.94	0.050	0.010	14.2	35.4	72.4	34.2	57.1	82.0
3	1.0	1.8	5.6	12.5	25.1	57.2	107.1	18.5	18.2	106.57	0.150	0.010	14.3	37.8	85.9	36.4	64.9	100.0
4	1.0	1.8	5.5	12.5	26.9	72.7	171.8	21.3	24.9	42.57	0.350	0.010	14.5	43.5	125.5	41.6	85.7	155.6
5	1.0	1.7	5.3	12.5	29.0	94.8	293.2	25.3	36.2	25.21	0.550	0.010	14.6	50.7	192.0	48.0	116.8	256.1
6	1.0	1.6	5.0	12.5	32.7	147.2	718.5	35.5	70.8	14.61	0.850	0.010	14.9	65.0	390.7	60.6	195.3	590.5
7	1.0	1.6	4.9	12.5	35.0	198.2	2223.3	50.3	147.4	11.78	0.990	0.005	15.0	75.5	734.5	69.8	282.4	1475.1

C	1.00	.95	.75	.50	.25	.05	0.00	MEAN	S.D.	A	B	T^U	N=5 95	50%	5%	N=20 95	50%	5%
1	1.0	2.0	6.8	15.0	28.5	53.8	70.1	19.7	16.1	427.58	0.050	0.050	17.1	40.2	65.7	39.0	57.9	68.9
2	1.0	2.0	6.8	15.0	29.3	62.0	105.3	21.1	19.3	402.88	0.050	0.010	17.1	42.9	87.9	41.4	69.2	99.6
3	1.0	2.0	6.7	15.0	30.3	69.4	130.1	22.4	22.2	129.73	0.150	0.010	17.2	45.8	104.4	44.1	78.7	121.5
4	1.0	1.9	6.4	15.0	32.5	88.3	208.9	25.7	30.3	51.83	0.350	0.010	17.4	52.8	152.6	50.4	104.2	189.2
5	1.0	1.9	6.2	15.0	35.0	115.2	356.7	30.5	44.0	30.70	0.550	0.010	17.6	61.5	233.5	58.2	142.0	311.6
6	1.0	1.8	5.9	15.0	39.6	178.9	874.4	42.9	86.2	17.78	0.850	0.010	17.9	78.9	475.5	73.6	237.5	718.7
7	1.0	1.7	5.7	15.0	42.4	241.1	2706.4	61.0	179.4	14.34	0.990	0.005	18.0	91.7	893.9	84.7	343.5	1795.6

C	1.00	.95	.75	.50	.25	.05	0.00	MEAN	S.D.	A	B	T^U	N=5 95	50%	5%	N=20 95	50%	5%
1	1.0	2.4	8.9	20.0	38.3	72.6	94.8	26.3	21.9	580.29	0.050	0.050	22.8	54.2	88.8	52.6	78.2	93.2
2	1.0	2.4	8.8	20.0	39.4	83.8	142.6	28.3	26.2	546.76	0.050	0.010	22.9	57.9	119.0	55.9	93.6	134.8
3	1.0	2.3	8.7	20.0	40.7	93.8	176.2	30.0	30.1	176.07	0.150	0.010	23.0	61.9	141.3	59.5	106.5	164.5
4	1.0	2.3	8.4	20.0	43.7	119.5	283.2	34.5	41.2	70.34	0.350	0.010	23.2	71.3	206.7	68.0	141.0	256.4
5	1.0	2.2	8.1	20.0	47.2	156.0	483.8	41.1	59.8	41.66	0.550	0.010	23.5	83.1	316.5	78.6	192.3	422.5
6	1.0	2.1	7.6	20.0	53.3	242.5	1186.4	57.9	117.0	24.13	0.850	0.010	23.9	106.7	644.9	99.5	322.0	975.0
7	1.0	2.0	7.4	20.0	57.2	326.8	3672.5	82.5	243.5	19.46	0.990	0.005	24.1	124.1	1212.9	114.6	465.9	2436.5

APPENDIX B (CONT.)

Lookup Table Based on the Mean

C	1.00	.95	.75	.50	.25	.05	0.00	MEAN	S.D.	A	B	T^U	N=5 95	50%	5%	N=10 95	50%	5%
1	1.00	1.01	1.03	1.07	1.15	1.28	1.37	1.10	0.09	2.29	0.050	0.050	1.09	1.21	1.35	1.14	1.26	1.36
2	1.00	1.01	1.03	1.07	1.14	1.30	1.52	1.10	0.10	2.00	0.050	0.010	1.08	1.21	1.43	1.14	1.28	1.47
3	1.00	1.00	1.03	1.07	1.14	1.32	1.60	1.10	0.10	0.61	0.150	0.010	1.08	1.21	1.48	1.13	1.29	1.53
4	1.00	1.00	1.02	1.06	1.13	1.35	1.84	1.10	0.12	0.21	0.350	0.010	1.07	1.21	1.61	1.12	1.31	1.70
5	1.00	1.00	1.02	1.05	1.12	1.39	2.20	1.10	0.15	0.10	0.550	0.010	1.06	1.20	1.79	1.11	1.32	1.94
6	1.00	1.00	1.01	1.03	1.09	1.42	3.08	1.10	0.21	0.04	0.850	0.010	1.04	1.19	2.13	1.09	1.34	2.46
7	1.00	1.00	1.01	1.02	1.07	1.40	5.51	1.10	0.30	0.02	0.990	0.005	1.03	1.15	2.49	1.07	1.30	3.24

C	1.00	.95	.75	.50	.25	.05	0.00	MEAN	S.D.	A	B	T^U	N=5 95	50%	5%	N=10 95	50%	5%
1	1.00	1.01	1.06	1.15	1.29	1.57	1.74	1.20	0.17	4.58	0.050	0.050	1.17	1.42	1.69	1.29	1.53	1.72
2	1.00	1.01	1.06	1.14	1.28	1.61	2.04	1.20	0.19	4.01	0.050	0.010	1.16	1.42	1.87	1.27	1.55	1.94
3	1.00	1.01	1.05	1.13	1.27	1.64	2.21	1.20	0.21	1.21	0.150	0.010	1.15	1.42	1.97	1.27	1.57	2.06
4	1.00	1.01	1.04	1.11	1.26	1.71	2.69	1.20	0.25	0.42	0.350	0.010	1.13	1.42	2.23	1.25	1.61	2.40
5	1.00	1.01	1.04	1.09	1.23	1.77	3.41	1.20	0.30	0.21	0.550	0.010	1.11	1.41	2.57	1.22	1.65	2.88
6	1.00	1.00	1.02	1.07	1.18	1.85	5.16	1.20	0.41	0.08	0.850	0.010	1.08	1.37	3.26	1.18	1.67	3.91
7	1.00	1.00	1.02	1.05	1.14	1.80	10.01	1.20	0.60	0.05	0.990	0.005	1.06	1.30	3.98	1.13	1.60	5.47

C	1.00	.95	.75	.50	.25	.05	0.00	MEAN	S.D.	A	B	T^U	N=5 95	50%	5%	N=10 95	50%	5%
1	1.00	1.02	1.09	1.22	1.44	1.85	2.11	1.30	0.26	6.87	0.050	0.050	1.26	1.63	2.04	1.43	1.79	2.07
2	1.00	1.02	1.09	1.21	1.42	1.91	2.56	1.30	0.29	6.01	0.050	0.010	1.24	1.63	2.30	1.41	1.83	2.40
3	1.00	1.01	1.08	1.20	1.41	1.96	2.81	1.30	0.31	1.82	0.150	0.010	1.23	1.63	2.45	1.40	1.86	2.60
4	1.00	1.01	1.07	1.17	1.38	2.06	3.53	1.30	0.37	0.63	0.350	0.010	1.20	1.63	2.84	1.37	1.92	3.11
5	1.00	1.01	1.05	1.14	1.35	2.16	4.61	1.30	0.45	0.31	0.550	0.010	1.17	1.61	3.36	1.33	1.97	3.82
6	1.00	1.01	1.03	1.10	1.28	2.27	7.25	1.30	0.62	0.13	0.850	0.010	1.12	1.56	4.39	1.26	2.01	5.37
7	1.00	1.00	1.02	1.07	1.21	2.20	14.52	1.30	0.90	0.07	0.990	0.005	1.09	1.45	5.46	1.20	1.90	7.71

C	1.00	.95	.75	.50	.25	.05	0.00	MEAN	S.D.	A	B	T^U	N=5 95	50%	5%	N=10 95	50%	5%
1	1.00	1.02	1.13	1.30	1.59	2.13	2.48	1.40	0.34	9.16	0.050	0.050	1.34	1.84	2.39	1.57	2.05	2.43
2	1.00	1.02	1.11	1.28	1.56	2.22	3.08	1.40	0.38	8.02	0.050	0.010	1.32	1.83	2.73	1.55	2.10	2.87
3	1.00	1.02	1.11	1.26	1.55	2.28	3.42	1.40	0.41	2.43	0.150	0.010	1.30	1.84	2.94	1.53	2.14	3.13
4	1.00	1.02	1.09	1.23	1.51	2.42	4.37	1.40	0.49	0.84	0.350	0.010	1.27	1.84	3.46	1.49	2.23	3.81
5	1.00	1.01	1.07	1.19	1.46	2.55	5.82	1.40	0.60	0.42	0.550	0.010	1.22	1.82	4.15	1.45	2.30	4.76
6	1.00	1.01	1.05	1.13	1.37	2.70	9.33	1.40	0.82	0.17	0.850	0.010	1.16	1.74	5.52	1.35	2.34	6.83
7	1.00	1.00	1.03	1.09	1.28	2.60	19.03	1.40	1.20	0.10	0.990	0.005	1.11	1.60	6.95	1.26	2.20	9.95

C	1.00	.95	.75	.50	.25	.05	0.00	MEAN	S.D.	A	B	T^U	N=5 95	50%	5%	N=10 95	50%	5%
1	1.00	1.03	1.16	1.37	1.74	2.41	2.85	1.50	0.43	11.45	0.050	0.050	1.43	2.05	2.73	1.72	2.32	2.79
2	1.00	1.03	1.14	1.35	1.70	2.52	3.60	1.50	0.48	10.02	0.050	0.010	1.40	2.04	3.16	1.69	2.38	3.34
3	1.00	1.02	1.13	1.33	1.69	2.60	4.02	1.50	0.52	3.04	0.150	0.010	1.38	2.05	3.42	1.67	2.43	3.66
4	1.00	1.02	1.11	1.28	1.64	2.77	5.21	1.50	0.61	1.05	0.350	0.010	1.33	2.05	4.07	1.62	2.53	4.51
5	1.00	1.01	1.09	1.24	1.58	2.93	7.02	1.50	0.75	0.52	0.550	0.010	1.28	2.02	4.94	1.56	2.62	5.70
6	1.00	1.01	1.06	1.17	1.46	3.12	11.41	1.50	1.03	0.21	0.850	0.010	1.20	1.93	6.66	1.44	2.68	8.29
7	1.00	1.01	1.04	1.12	1.34	3.00	23.54	1.50	1.49	0.12	0.990	0.005	1.14	1.76	8.44	1.33	2.50	12.19

C	1.00	.95	.75	.50	.25	.05	0.00	MEAN	S.D.	A	B	T^U	N=5 95	50%	5%	N=10 95	50%	5%
1	1.00	1.03	1.19	1.45	1.88	2.70	3.22	1.60	0.52	13.74	0.050	0.050	1.52	2.26	3.08	1.86	2.58	3.15
2	1.00	1.03	1.17	1.42	1.84	2.82	4.11	1.60	0.58	12.03	0.050	0.010	1.48	2.25	3.60	1.82	2.65	3.81
3	1.00	1.03	1.16	1.39	1.82	2.92	4.63	1.60	0.62	3.64	0.150	0.010	1.46	2.26	3.90	1.80	2.72	4.19
4	1.00	1.02	1.13	1.34	1.77	3.12	6.06	1.60	0.74	1.26	0.350	0.010	1.40	2.26	4.69	1.74	2.84	5.21
5	1.00	1.02	1.11	1.28	1.69	3.32	8.23	1.60	0.89	0.62	0.550	0.010	1.34	2.23	5.72	1.67	2.94	6.64
6	1.00	1.01	1.07	1.20	1.55	3.55	13.49	1.60	1.23	0.25	0.850	0.010	1.24	2.11	7.79	1.53	3.01	9.74
7	1.00	1.01	1.05	1.14	1.41	3.40	28.04	1.60	1.79	0.14	0.990	0.005	1.17	1.91	9.93	1.40	2.81	14.42

C	1.00	.95	.75	.50	.25	.05	0.00	MEAN	S.D.	A	B	T^U	N=5 95	50%	5%	N=10 95	50%	5%
1	1.00	1.04	1.22	1.52	2.03	2.98	3.59	1.70	0.60	16.03	0.050	0.050	1.60	2.47	3.43	2.01	2.84	3.50
2	1.00	1.04	1.20	1.49	1.99	3.13	4.63	1.70	0.67	14.03	0.050	0.010	1.56	2.46	4.03	1.96	2.93	4.28
3	1.00	1.03	1.19	1.46	1.96	3.24	5.23	1.70	0.73	4.25	0.150	0.010	1.53	2.47	4.39	1.93	3.00	4.73
4	1.00	1.03	1.15	1.40	1.89	3.48	6.90	1.70	0.86	1.47	0.350	0.010	1.46	2.47	5.30	1.87	3.15	5.91
5	1.00	1.02	1.12	1.33	1.81	3.71	9.43	1.70	1.04	0.73	0.550	0.010	1.39	2.43	6.51	1.78	3.27	7.58
6	1.00	1.01	1.08	1.23	1.64	3.97	15.58	1.70	1.44	0.30	0.850	0.010	1.28	2.30	8.92	1.62	3.35	11.20
7	1.00	1.01	1.05	1.16	1.48	3.80	32.55	1.70	2.09	0.17	0.990	0.005	1.20	2.06	11.41	1.46	3.11	16.66

C	1.00	.95	.75	.50	.25	.05	0.00	MEAN	S.D.	A	B	T^U	N=5 95	50%	5%	N=10 95	50%	5%
1	1.00	1.04	1.25	1.60	2.18	3.26	3.96	1.80	0.69	18.32	0.050	0.050	1.69	2.68	3.77	2.15	3.10	3.86
2	1.00	1.04	1.23	1.56	2.13	3.43	5.15	1.80	0.77	16.04	0.050	0.010	1.64	2.67	4.46	2.10	3.20	4.74
3	1.00	1.04	1.21	1.52	2.10	3.56	5.84	1.80	0.83	4.86	0.150	0.010	1.61	2.68	4.87	2.07	3.29	5.26
4	1.00	1.03	1.18	1.45	2.02	3.83	7.74	1.80	0.98	1.68	0.350	0.010	1.53	2.68	5.91	1.99	3.45	6.62
5	1.00	1.02	1.14	1.38	1.92	4.09	10.64	1.80	1.19	0.83	0.550	0.010	1.45	2.64	7.30	1.89	3.59	8.52
6	1.00	1.01	1.09	1.27	1.74	4.39	17.66	1.80	1.64	0.34	0.850	0.010	1.32	2.48	10.05	1.71	3.68	12.66
7	1.00	1.01	1.06	1.19	1.55	4.20	37.06	1.80	2.39	0.19	0.990	0.005	1.23	2.21	12.90	1.53	3.41	18.90

C	1.00	.95	.75	.50	.25	.05	0.00	MEAN	S.D.	A	B	T^U	N=5 95	50%	5%	N=10 95	50%	5%
1	1.00	1.05	1.28	1.67	2.33	3.54	4.33	1.90	0.78	20.60	0.050	0.050	1.77	2.89	4.12	2.29	3.37	4.22
2	1.00	1.05	1.26	1.63	2.27	3.73	5.67	1.90	0.87	18.04	0.050	0.010	1.72	2.88	4.89	2.23	3.48	5.21
3	1.00	1.04	1.24	1.59	2.23	3.88	6.44	1.90	0.93	5.47	0.150	0.010	1.68	2.89	5.36	2.20	3.57	5.79
4	1.00	1.03	1.20	1.51	2.15	4.18	8.58	1.90	1.11	1.89	0.350	0.010	1.60	2.89	6.53	2.11	3.76	7.32
5	1.00	1.03	1.16	1.43	2.04	4.48	11.84	1.90	1.34	0.94	0.550	0.010	1.50	2.84	8.09	2.00	3.92	9.46
6	1.00	1.02	1.10	1.30	1.83	4.82	19.74	1.90	1.85	0.38	0.850	0.010	1.36	2.67	11.18	1.79	4.02	14.12
7	1.00	1.01	1.07	1.21	1.62	4.60	41.56	1.90	2.69	0.21	0.990	0.005	1.26	2.36	14.39	1.59	3.71	21.13

C	1.00	.95	.75	.50	.25	.05	0.00	MEAN	S.D.	A	B	T^U	N=5 95	50%	5%	N=10 95	50%	5%
1	1.00	1.06	1.31	1.75	2.47	3.83	4.70	2.00	0.86	22.89	0.050	0.050	1.86	3.10	4.46	2.44	3.63	4.58
2	1.00	1.05	1.29	1.70	2.41	4.04	6.19	2.00	0.96	20.05	0.050	0.010	1.80	3.09	5.33	2.37	3.75	5.68
3	1.00	1.05	1.26	1.66	2.37	4.20	7.04	2.00	1.04	6.07	0.150	0.010	1.76	3.10	5.84	2.33	3.86	6.32
4	1.00	1.04	1.22	1.57	2.28	4.54	9.43	2.00	1.23	2.10	0.350	0.010	1.66	3.10	7.14	2.24	4.07	8.02
5	1.00	1.03	1.18	1.47	2.15	4.87	13.05	2.00	1.49	1.04	0.550	0.010	1.56	3.05	8.87	2.11	4.24	10.41
6	1.00	1.02	1.12	1.33	1.92	5.24	21.82	2.00	2.06	0.42	0.850	0.010	1.40	2.86	12.31	1.88	4.35	15.57
7	1.00	1.01	1.08	1.23	1.69	5.00	46.07	2.00	2.99	0.24	0.990	0.005	1.28	2.51	15.88	1.66	4.01	23.37

C	1.00	.95	.75	.50	.25	.05	0.00	MEAN	S.D.	A	B	T^U	N=5 95	50%	5%	N=10 95	50%	5%
1	1.00	1.07	1.38	1.90	2.77	4.39	5.44	2.20	1.03	27.47	0.050	0.050	2.03	3.52	5.16	2.72	4.16	5.29
2	1.00	1.06	1.34	1.84	2.69	4.65	7.23	2.20	1.15	24.06	0.050	0.010	1.96	3.50	6.19	2.65	4.30	6.62
3	1.00	1.06	1.32	1.79	2.64	4.84	8.25	2.20	1.24	7.29	0.150	0.010	1.91	3.52	6.81	2.60	4.43	7.39
4	1.00	1.05	1.26	1.68	2.53	5.25	11.11	2.20	1.47	2.52	0.350	0.010	1.80	3.52	8.37	2.48	4.68	9.42
5	1.00	1.04	1.21	1.57	2.38	5.64	15.46	2.20	1.79	1.25	0.550	0.010	1.67	3.46	10.45	2.34	4.89	12.29
6	1.00	1.02	1.14	1.40	2.10	6.09	25.99	2.20	2.47	0.51	0.850	0.010	1.48	3.23	14.57	2.06	5.02	18.49
7	1.00	1.01	1.09	1.28	1.83	5.80	55.08	2.20	3.59	0.29	0.990	0.005	1.34	2.81	18.85	1.79	4.61	27.84

C	1.00	.95	.75	.50	.25	.05	0.00	MEAN	S.D.	A	B	T^U	N=5 95	50%	5%	N=10 95	50%	5%
1	1.00	1.08	1.44	2.05	3.06	4.96	6.18	2.40	1.21	32.05	0.050	0.050	2.20	3.94	5.85	3.01	4.68	6.01
2	1.00	1.07	1.40	1.98	2.97	5.25	8.27	2.40	1.35	28.07	0.050	0.010	2.12	3.92	7.06	2.92	4.85	7.55
3	1.00	1.06	1.37	1.92	2.92	5.48	9.46	2.40	1.45	8.50	0.150	0.010	2.06	3.94	7.78	2.87	5.01	8.45
4	1.00	1.05	1.31	1.79	2.79	5.95	12.80	2.40	1.72	2.94	0.350	0.010	1.93	3.94	9.60	2.73	5.30	10.83
5	1.00	1.04	1.25	1.66	2.61	6.41	17.86	2.40	2.09	1.46	0.550	0.010	1.79	3.87	12.02	2.56	5.54	14.17
6	1.00	1.03	1.16	1.47	2.29	6.94	30.15	2.40	2.88	0.59	0.850	0.010	1.56	3.60	16.84	2.23	5.69	21.40
7	1.00	1.02	1.11	1.33	1.97	6.60	64.10	2.40	4.18	0.33	0.990	0.005	1.40	3.12	21.83	1.92	5.21	32.32

C	1.00	.95	.75	.50	.25	.05	0.00	MEAN	S.D.	A	B	T^U	N=5 95	50%	5%	N=10 95	50%	5%
1	1.00	1.09	1.50	2.20	3.36	5.52	6.92	2.60	1.38	36.63	0.050	0.050	2.38	4.36	6.54	3.30	5.21	6.72
2	1.00	1.08	1.46	2.11	3.25	5.86	9.31	2.60	1.54	32.08	0.050	0.010	2.28	4.34	7.92	3.19	5.40	8.49
3	1.00	1.07	1.42	2.05	3.19	6.12	10.67	2.60	1.66	9.72	0.150	0.010	2.21	4.36	8.74	3.13	5.58	9.52
4	1.00	1.06	1.35	1.91	3.04	6.66	14.48	2.60	1.97	3.36	0.350	0.010	2.06	4.36	10.83	2.98	5.91	12.23
5	1.00	1.05	1.28	1.76	2.84	7.19	20.27	2.60	2.39	1.66	0.550	0.010	1.90	4.28	13.60	2.78	6.18	16.05
6	1.00	1.03	1.19	1.53	2.47	7.79	34.31	2.60	3.29	0.68	0.850	0.010	1.64	3.97	19.10	2.41	6.36	24.32
7	1.00	1.02	1.13	1.37	2.10	7.40	73.11	2.60	4.78	0.38	0.990	0.005	1.45	3.42	24.80	2.05	5.81	36.79

C	1.00	.95	.75	.50	.25	.05	0.00	MEAN	S.D.	A	B	T^U	N=5 95	50%	5%	N=10 95	50%	5%
1	1.00	1.10	1.56	2.35	3.65	6.09	7.66	2.80	1.55	41.21	0.050	0.050	2.55	4.78	7.24	3.59	5.73	7.44
2	1.00	1.09	1.52	2.25	3.53	6.47	10.34	2.80	1.73	36.09	0.050	0.010	2.44	4.75	8.79	3.47	5.95	9.42
3	1.00	1.08	1.48	2.18	3.47	6.76	11.88	2.80	1.87	10.93	0.150	0.010	2.37	4.78	9.71	3.40	6.15	10.58
4	1.00	1.07	1.40	2.02	3.30	7.37	16.17	2.80	2.21	3.78	0.350	0.010	2.20	4.78	12.06	3.23	6.52	13.64
5	1.00	1.05	1.32	1.85	3.07	7.96	22.68	2.80	2.68	1.87	0.550	0.010	2.01	4.69	15.17	3.00	6.83	17.93
6	1.00	1.03	1.21	1.60	2.65	8.64	38.48	2.80	3.70	0.76	0.850	0.010	1.72	4.34	21.36	2.59	7.04	27.23
7	1.00	1.02	1.14	1.42	2.24	8.20	82.13	2.80	5.38	0.43	0.990	0.005	1.51	3.72	27.78	2.19	6.42	41.27

C	1.00	.95	.75	.50	.25	.05	0.00	MEAN	S.D.	A	B	T^U	N=5 95	50%	5%	N=10 95	50%	5%
1	1.00	1.11	1.63	2.50	3.94	6.65	8.40	3.00	1.72	45.79	0.050	0.050	2.72	5.20	7.93	3.87	6.26	8.15
2	1.00	1.10	1.57	2.39	3.81	7.08	11.38	3.00	1.92	40.10	0.050	0.010	2.60	5.17	9.65	3.74	6.51	10.36
3	1.00	1.09	1.53	2.31	3.74	7.40	13.09	3.00	2.07	12.15	0.150	0.010	2.52	5.20	10.68	3.67	6.72	11.64
4	1.00	1.08	1.44	2.13	3.55	8.08	17.85	3.00	2.46	4.20	0.350	0.010	2.33	5.20	13.29	3.47	7.14	15.04
5	1.00	1.06	1.35	1.95	3.31	8.73	25.09	3.00	2.98	2.08	0.550	0.010	2.12	5.10	16.75	3.23	7.48	19.81
6	1.00	1.04	1.23	1.67	2.84	9.48	42.64	3.00	4.11	0.85	0.850	0.010	1.80	4.71	23.62	2.76	7.71	30.15
7	1.00	1.02	1.16	1.47	2.38	9.00	91.14	3.00	5.98	0.48	0.990	0.005	1.57	4.02	30.75	2.32	7.02	45.74

C	1.00	.95	.75	.50	.25	.05	0.00	MEAN	S.D.	A	B	T^U	N=5 95	50%	5%	N=10 95	50%	5%
1	1.00	1.13	1.70	2.69	4.31	7.36	9.32	3.25	1.94	51.51	0.050	0.050	2.94	5.72	8.80	4.23	6.92	9.05
2	1.00	1.11	1.65	2.57	4.17	7.84	12.68	3.25	2.16	45.11	0.050	0.010	2.81	5.69	10.73	4.09	7.19	11.53
3	1.00	1.10	1.60	2.47	4.08	8.20	14.60	3.25	2.33	13.67	0.150	0.010	2.71	5.72	11.89	4.00	7.44	12.98
4	1.00	1.08	1.49	2.28	3.87	8.96	19.96	3.25	2.76	4.73	0.350	0.010	2.49	5.72	14.82	3.78	7.90	16.79
5	1.00	1.07	1.40	2.07	3.59	9.70	28.10	3.25	3.36	2.34	0.550	0.010	2.26	5.61	18.71	3.50	8.29	22.16
6	1.00	1.04	1.26	1.75	3.07	10.54	47.85	3.25	4.63	0.95	0.850	0.010	1.90	5.18	26.45	2.98	8.54	33.79
7	1.00	1.03	1.18	1.52	2.55	10.00	102.41	3.25	6.72	0.54	0.990	0.005	1.64	4.40	34.47	2.48	7.77	51.33

C	1.00	.95	.75	.50	.25	.05	0.00	MEAN	S.D.	A	B	T^U	N=5 95	50%	5%	N=10 95	50%	5%
1	1.00	1.14	1.78	2.87	4.68	8.07	10.25	3.50	2.16	57.24	0.050	0.050	3.15	6.25	9.66	4.59	7.58	9.94
2	1.00	1.13	1.72	2.74	4.52	8.59	13.98	3.50	2.40	50.12	0.050	0.010	3.01	6.21	11.81	4.43	7.88	12.70
3	1.00	1.12	1.66	2.64	4.43	9.00	16.11	3.50	2.59	15.18	0.150	0.010	2.90	6.25	13.10	4.33	8.15	14.31
4	1.00	1.09	1.55	2.42	4.19	9.85	22.07	3.50	3.07	5.25	0.350	0.010	2.66	6.25	16.36	4.09	8.67	18.55
5	1.00	1.07	1.44	2.19	3.88	10.67	31.12	3.50	3.73	2.60	0.550	0.010	2.40	6.12	20.68	3.78	9.10	24.51
6	1.00	1.05	1.29	1.83	3.30	11.60	53.05	3.50	5.14	1.06	0.850	0.010	2.01	5.64	29.28	3.20	9.38	37.43
7	1.00	1.03	1.20	1.58	2.72	11.00	113.68	3.50	7.47	0.60	0.990	0.005	1.71	4.78	38.19	2.65	8.52	56.93

C	1.00	.95	.75	.50	.25	.05	0.00	MEAN	S.D.	A	B	T^U	N=5 95	50%	5%	N=10 95	50%	5%
1	1.00	1.15	1.86	3.06	5.05	8.77	11.17	3.75	2.37	62.96	0.050	0.050	3.37	6.77	10.53	4.95	8.23	10.83
2	1.00	1.14	1.79	2.92	4.87	9.35	15.28	3.75	2.65	55.13	0.050	0.010	3.21	6.74	12.89	4.77	8.57	13.87
3	1.00	1.13	1.73	2.80	4.77	9.80	17.62	3.75	2.85	16.70	0.150	0.010	3.09	6.77	14.31	4.67	8.87	15.64
4	1.00	1.10	1.60	2.56	4.51	10.73	24.17	3.75	3.38	5.78	0.350	0.010	2.83	6.77	17.90	4.40	9.44	20.30
5	1.00	1.08	1.48	2.30	4.17	11.64	34.13	3.75	4.10	2.86	0.550	0.010	2.54	6.63	22.65	4.06	9.91	26.87
6	1.00	1.05	1.32	1.92	3.53	12.67	58.26	3.75	5.65	1.17	0.850	0.010	2.11	6.10	32.11	3.42	10.22	41.08
7	1.00	1.03	1.22	1.64	2.90	12.00	124.94	3.75	8.22	0.66	0.990	0.005	1.78	5.15	41.91	2.81	9.27	62.52

C	1.00	.95	.75	.50	.25	.05	0.00	MEAN	S.D.	A	B	T^U	N=5 95	50%	5%	N=10 95	50%	5%
1	1.00	1.17	1.94	3.25	5.42	9.48	12.10	4.00	2.59	68.68	0.050	0.050	3.58	7.30	11.39	5.31	8.89	11.73
2	1.00	1.15	1.86	3.09	5.22	10.11	16.57	4.00	2.89	60.15	0.050	0.010	3.41	7.26	13.98	5.11	9.26	15.04
3	1.00	1.14	1.79	2.97	5.11	10.60	19.13	4.00	3.11	18.22	0.150	0.010	3.28	7.30	15.52	5.00	9.58	16.97
4	1.00	1.11	1.66	2.70	4.83	11.62	26.28	4.00	3.69	6.30	0.350	0.010	2.99	7.30	19.43	4.71	10.21	22.06
5	1.00	1.09	1.53	2.42	4.46	12.60	37.14	4.00	4.47	3.12	0.550	0.010	2.68	7.14	24.62	4.34	10.72	29.22
6	1.00	1.06	1.35	2.00	3.76	13.73	63.47	4.00	6.17	1.27	0.850	0.010	2.21	6.57	34.93	3.64	11.06	44.72
7	1.00	1.04	1.23	1.70	3.07	13.00	136.21	4.00	8.97	0.72	0.990	0.005	1.85	5.53	45.63	2.98	10.03	68.11

C	1.00	.95	.75	.50	.25	.05	0.00	MEAN	S.D.	A	B	T^U	N=5 95	50%	5%	N=10 95	50%	5%
1	1.00	1.18	2.02	3.44	5.79	10.18	13.02	4.25	2.80	74.41	0.050	0.050	3.80	7.82	12.26	5.67	9.55	12.62
2	1.00	1.17	1.93	3.26	5.57	10.87	17.87	4.25	3.13	65.16	0.050	0.010	3.61	7.78	15.06	5.46	9.95	16.21
3	1.00	1.15	1.86	3.13	5.46	11.40	20.65	4.25	3.37	19.74	0.150	0.010	3.47	7.82	16.73	5.33	10.30	18.30
4	1.00	1.12	1.71	2.84	5.15	12.50	28.39	4.25	3.99	6.83	0.350	0.010	3.16	7.82	20.97	5.02	10.97	23.81
5	1.00	1.10	1.57	2.54	4.75	13.57	40.15	4.25	4.85	3.38	0.550	0.010	2.82	7.66	26.59	4.62	11.53	31.57
6	1.00	1.06	1.38	2.05	3.99	14.79	68.67	4.25	6.68	1.38	0.850	0.010	2.31	7.03	37.76	3.86	11.90	48.36
7	1.00	1.04	1.25	1.76	3.24	14.00	147.48	4.25	9.71	0.78	0.990	0.005	1.92	5.91	49.35	3.14	10.78	73.70

C	1.00	.95	.75	.50	.25	.05	0.00	MEAN	S.D.	A	B	T^U	N=5 95	50%	5%	N=10 95	50%	5%
1	1.00	1.20	2.09	3.62	6.15	10.89	13.95	4.50	3.02	80.13	0.050	0.050	4.01	8.35	13.13	6.03	10.21	13.52
2	1.00	1.18	2.00	3.44	5.93	11.63	19.17	4.50	3.37	70.17	0.050	0.010	3.81	8.30	16.14	5.80	10.63	17.38
3	1.00	1.16	1.93	3.29	5.80	12.20	22.16	4.50	3.63	21.26	0.150	0.010	3.66	8.35	17.94	5.67	11.01	19.63
4	1.00	1.13	1.77	2.99	5.47	13.39	30.49	4.50	4.30	7.35	0.350	0.010	3.32	8.35	22.50	5.33	11.74	25.57
5	1.00	1.10	1.62	2.66	5.03	14.54	43.16	4.50	5.22	3.64	0.550	0.010	2.96	8.17	28.55	4.89	12.34	33.92
6	1.00	1.07	1.41	2.17	4.22	15.85	73.88	4.50	7.20	1.48	0.850	0.010	2.41	7.50	40.59	4.09	12.74	52.00
7	1.00	1.04	1.27	1.82	3.41	15.00	158.75	4.50	10.46	0.84	0.990	0.005	1.99	6.29	53.07	3.31	11.53	79.30

C	1.00	.95	.75	.50	.25	.05	0.00	MEAN	S.D.	A	B	T^U	N=5 95	50%	5%	N=10 95	50%	5%
1	1.00	1.21	2.17	3.81	6.52	11.60	14.87	4.75	3.23	85.85	0.050	0.050	4.23	8.87	13.99	6.39	10.86	14.41
2	1.00	1.19	2.08	3.61	6.28	12.39	20.47	4.75	3.61	75.18	0.050	0.010	4.01	8.82	17.22	6.14	11.32	18.55
3	1.00	1.17	1.99	3.46	6.14	13.00	23.67	4.75	3.89	22.78	0.150	0.010	3.85	8.87	19.15	6.00	11.73	20.96
4	1.00	1.14	1.82	3.13	5.79	14.27	32.60	4.75	4.61	7.88	0.350	0.010	3.49	8.87	24.04	5.64	12.51	27.32
5	1.00	1.11	1.66	2.78	5.32	15.50	46.17	4.75	5.59	3.90	0.550	0.010	3.10	8.68	30.52	5.17	13.15	36.27
6	1.00	1.07	1.43	2.25	4.45	16.91	79.08	4.75	7.71	1.59	0.850	0.010	2.51	7.96	43.42	4.31	13.57	55.65
7	1.00	1.05	1.29	1.87	3.59	16.00	170.01	4.75	11.21	0.90	0.990	0.005	2.06	6.67	56.79	3.47	12.28	84.89

C	1.00	.95	.75	.50	.25	.05	0.00	MEAN	S.D.	A	B	T^U	N=5 95	50%	5%	N=10 95	50%	5%
1	1.00	1.22	2.25	4.00	6.89	12.30	15.80	5.00	3.45	91.58	0.050	0.050	4.44	9.40	14.86	6.75	11.52	15.31
2	1.00	1.20	2.15	3.79	6.63	13.15	21.76	5.00	3.85	80.19	0.050	0.010	4.21	9.34	18.30	6.49	12.01	19.72
3	1.00	1.19	2.06	3.62	6.48	13.80	25.18	5.00	4.15	24.29	0.150	0.010	4.04	9.40	20.36	6.33	12.44	22.29
4	1.00	1.15	1.88	3.27	6.11	15.15	34.70	5.00	4.92	8.40	0.350	0.010	3.66	9.40	25.57	5.95	13.27	29.08
5	1.00	1.12	1.70	2.90	5.61	16.47	49.18	5.00	5.96	4.16	0.550	0.010	3.24	9.19	32.49	5.45	13.96	38.62
6	1.00	1.07	1.46	2.34	4.68	17.97	84.29	5.00	8.22	1.70	0.850	0.010	2.61	8.42	46.24	4.53	14.41	59.29
7	1.00	1.05	1.31	1.93	3.76	17.00	181.28	5.00	11.96	0.96	0.990	0.005	2.13	7.04	60.50	3.64	13.04	90.48

C	1.00	.95	.75	.50	.25	.05	0.00	MEAN	S.D.	A	B	T^U	N=5 95	50%	5%	N=10 95	50%	5%
1	1.00	1.25	2.41	4.37	7.63	13.72	17.65	5.50	3.88	103.02	0.050	0.050	4.87	10.45	16.59	7.47	12.84	17.09
2	1.00	1.23	2.29	4.14	7.33	14.67	24.36	5.50	4.33	90.22	0.050	0.010	4.61	10.39	20.46	7.17	13.39	22.06
3	1.00	1.21	2.19	3.95	7.17	15.40	28.20	5.50	4.67	27.33	0.150	0.010	4.41	10.45	22.78	7.00	13.87	24.95
4	1.00	1.17	1.99	3.55	6.74	16.92	38.92	5.50	5.53	9.45	0.350	0.010	3.99	10.44	28.65	6.57	14.81	32.59
5	1.00	1.13	1.79	3.13	6.19	18.40	55.21	5.50	6.71	4.68	0.550	0.010	3.52	10.22	36.43	6.01	15.58	43.32
6	1.00	1.08	1.52	2.50	5.14	20.09	94.70	5.50	9.25	1.91	0.850	0.010	2.81	9.35	51.90	4.97	16.09	66.58
7	1.00	1.06	1.35	2.05	4.10	19.00	203.82	5.50	13.45	1.07	0.990	0.005	2.28	7.80	67.94	3.96	14.54	101.67

C	1.00	.95	.75	.50	.25	.05	0.00	MEAN	S.D.	A	B	T^U	N=5 95	50%	5%	N=10 95	50%	5%
1	1.00	1.28	2.56	4.75	8.36	15.13	19.50	6.00	4.31	114.47	0.050	0.050	5.30	11.50	18.32	8.19	14.15	18.88
2	1.00	1.25	2.44	4.48	8.04	16.19	26.96	6.00	4.81	100.24	0.050	0.010	5.01	11.43	22.63	7.86	14.76	24.40
3	1.00	1.23	2.32	4.28	7.85	17.00	31.22	6.00	5.19	30.37	0.150	0.010	4.79	11.50	25.20	7.67	15.30	27.61
4	1.00	1.19	2.10	3.84	7.38	18.69	43.13	6.00	6.14	10.50	0.350	0.010	4.32	11.49	31.72	7.19	16.34	36.10
5	1.00	1.15	1.88	3.37	6.76	20.34	61.23	6.00	7.46	5.20	0.550	0.010	3.81	11.24	40.36	6.56	17.20	48.03
6	1.00	1.09	1.58	2.67	5.60	22.21	105.11	6.00	10.28	2.12	0.850	0.010	3.01	10.28	57.55	5.41	17.77	73.86
7	1.00	1.06	1.39	2.17	4.45	21.00	226.35	6.00	14.94	1.19	0.990	0.005	2.42	8.55	75.38	4.29	16.05	112.85

C	1.00	.95	.75	.50	.25	.05	0.00	MEAN	S.D.	A	B	T^U	N=5 95	50%	5%	N=10 95	50%	5%
1	1.00	1.31	2.72	5.12	9.10	16.54	21.35	6.50	4.74	125.92	0.050	0.050	5.73	12.55	20.06	8.90	15.47	20.67
2	1.00	1.28	2.58	4.83	8.74	17.71	29.55	6.50	5.29	110.27	0.050	0.010	5.41	12.47	24.79	8.54	16.14	26.74
3	1.00	1.26	2.46	4.60	8.54	18.60	34.25	6.50	5.70	33.41	0.150	0.010	5.17	12.55	27.62	8.33	16.74	30.27
4	1.00	1.21	2.21	4.12	8.02	20.46	47.34	6.50	6.76	11.55	0.350	0.010	4.65	12.54	34.79	7.80	17.88	39.61
5	1.00	1.16	1.97	3.61	7.34	22.27	67.25	6.50	8.20	5.72	0.550	0.010	4.09	12.26	44.30	7.12	18.82	52.73
6	1.00	1.10	1.64	2.84	6.06	24.33	115.52	6.50	11.31	2.33	0.850	0.010	3.21	11.21	63.21	5.85	19.44	81.15
7	1.00	1.07	1.43	2.28	4.79	23.00	248.89	6.50	16.44	1.31	0.990	0.005	2.56	9.31	82.82	4.62	17.55	124.04

C	1.00	.95	.75	.50	.25	.05	0.00	MEAN	S.D.	A	B	T^U	N=5 95	50%	5%	N=10 95	50%	5%
1	1.00	1.33	2.88	5.50	9.83	17.96	23.20	7.00	5.17	137.36	0.050	0.050	6.16	13.60	21.79	9.62	16.78	22.46
2	1.00	1.31	2.72	5.18	9.44	19.23	32.15	7.00	5.77	120.29	0.050	0.010	5.81	13.51	26.95	9.23	17.52	29.08
3	1.00	1.28	2.59	4.93	9.22	20.20	37.27	7.00	6.22	36.44	0.150	0.010	5.55	13.60	30.04	9.00	18.17	32.93
4	1.00	1.23	2.32	4.40	8.66	22.23	51.56	7.00	7.37	12.60	0.350	0.010	4.98	13.59	37.86	8.42	19.41	43.12
5	1.00	1.18	2.06	3.84	7.92	24.20	73.28	7.00	8.95	6.24	0.550	0.010	4.37	13.29	48.24	7.68	20.44	57.43
6	1.00	1.11	1.70	3.00	6.52	26.45	125.93	7.00	12.34	2.54	0.850	0.010	3.41	12.14	68.87	6.29	21.12	88.44
7	1.00	1.07	1.47	2.40	5.14	25.00	271.42	7.00	17.93	1.43	0.990	0.005	2.70	10.07	90.26	4.95	19.05	135.22

C	1.00	.95	.75	.50	.25	.05	0.00	MEAN	S.D.	A	B	T^U	N=5 95	50%	5%	N=10 95	50%	5%
1	1.00	1.36	3.03	5.87	10.57	19.37	25.05	7.50	5.60	148.81	0.050	0.050	6.59	14.64	23.52	10.34	18.10	24.25
2	1.00	1.33	2.87	5.53	10.15	20.75	34.74	7.50	6.25	130.32	0.050	0.010	6.22	14.56	29.11	9.91	18.89	31.41
3	1.00	1.30	2.72	5.26	9.91	21.80	40.29	7.50	6.74	39.48	0.150	0.010	5.93	14.65	32.46	9.67	19.60	35.60
4	1.00	1.24	2.43	4.69	9.30	24.00	55.77	7.50	7.99	13.65	0.350	0.010	5.32	14.64	40.93	9.04	20.95	46.63
5	1.00	1.19	2.14	4.08	8.49	26.14	79.30	7.50	9.69	6.76	0.550	0.010	4.65	14.31	52.17	8.23	22.06	62.14
6	1.00	1.12	1.75	3.17	6.97	28.57	136.34	7.50	13.36	2.76	0.850	0.010	3.61	13.07	74.52	6.73	22.79	95.72
7	1.00	1.08	1.51	2.52	5.48	26.99	293.96	7.50	19.43	1.55	0.990	0.005	2.84	10.82	97.70	5.28	20.56	146.41

C	1.00	.95	.75	.50	.25	.05	0.00	MEAN	S.D.	A	B	T^U	N=5 95	50%	5%	N=10 95	50%	5%
1	1.00	1.39	3.19	6.25	11.31	20.78	26.90	8.00	6.04	160.26	0.050	0.050	7.02	15.69	25.25	11.06	19.41	26.03
2	1.00	1.36	3.01	5.88	10.85	22.27	37.34	8.00	6.73	140.34	0.050	0.010	6.62	15.60	31.28	10.60	20.27	33.75
3	1.00	1.32	2.85	5.59	10.60	23.40	43.31	8.00	7.26	42.52	0.150	0.010	6.31	15.70	34.88	10.33	21.03	38.26
4	1.00	1.26	2.54	4.97	9.94	25.77	59.98	8.00	8.60	14.70	0.350	0.010	5.65	15.69	44.01	9.66	22.48	50.14
5	1.00	1.21	2.23	4.32	9.07	28.07	85.32	8.00	10.44	7.28	0.550	0.010	4.93	15.34	56.11	8.79	23.68	66.84
6	1.00	1.13	1.81	3.34	7.43	30.69	146.75	8.00	14.39	2.97	0.850	0.010	3.81	13.99	80.18	7.17	24.47	103.01
7	1.00	1.09	1.55	2.63	5.83	28.99	316.49	8.00	20.92	1.67	0.990	0.005	2.99	11.58	105.13	5.61	22.06	157.59

C	1.00	.95	.75	.50	.25	.05	0.00	MEAN	S.D.	A	B	T^U	N=5 95	50%	5%	N=10 95	50%	5%
1	1.00	1.42	3.34	6.62	12.04	22.20	28.75	8.50	6.47	171.71	0.050	0.050	7.45	16.74	26.99	11.78	20.73	27.82
2	1.00	1.38	3.15	6.23	11.55	23.78	39.93	8.50	7.21	150.36	0.050	0.010	7.02	16.64	33.44	11.28	21.64	36.09
3	1.00	1.35	2.99	5.92	11.28	25.00	46.34	8.50	7.78	45.55	0.150	0.010	6.69	16.75	37.30	11.00	22.46	40.92
4	1.00	1.28	2.65	5.26	10.57	27.54	64.20	8.50	9.22	15.75	0.350	0.010	5.98	16.74	47.08	10.28	24.02	53.65
5	1.00	1.22	2.32	4.56	9.65	30.01	91.35	8.50	11.18	7.80	0.550	0.010	5.21	16.36	60.05	9.34	25.30	71.54
6	1.00	1.14	1.87	3.50	7.89	32.81	157.16	8.50	15.42	3.18	0.850	0.010	4.02	14.92	85.83	7.61	26.15	110.30
7	1.00	1.09	1.59	2.75	6.17	30.99	339.03	8.50	22.42	1.79	0.990	0.005	3.13	12.33	112.57	5.94	23.57	168.78
C	1.00	.95	.75	.50	.25	.05	0.00	MEAN	S.D.	A	B	T^U	N=5 95	50%	5%	N=10 95	50%	5%
1	1.00	1.45	3.50	7.00	12.78	23.61	30.59	9.00	6.90	183.15	0.050	0.050	7.88	17.79	28.72	12.50	22.04	29.61
2	1.00	1.41	3.30	6.57	12.26	25.30	42.53	9.00	7.69	160.39	0.050	0.010	7.42	17.69	35.60	11.97	23.02	38.43
3	1.00	1.37	3.12	6.24	11.97	26.60	49.36	9.00	8.30	48.59	0.150	0.010	7.07	17.80	39.72	11.67	23.89	43.58
4	1.00	1.30	2.76	5.54	11.21	29.31	68.41	9.00	9.83	16.80	0.350	0.010	6.31	17.79	50.15	10.90	25.55	57.16
5	1.00	1.24	2.41	4.79	10.22	31.94	97.37	9.00	11.93	8.32	0.550	0.010	5.49	17.38	63.98	9.90	26.92	76.24
6	1.00	1.15	1.93	3.67	8.35	34.94	167.57	9.00	16.45	3.39	0.850	0.010	4.22	15.85	91.49	8.05	27.82	117.58
7	1.00	1.10	1.63	2.87	6.52	32.99	361.56	9.00	23.91	1.91	0.990	0.005	3.27	13.09	120.01	6.27	25.07	179.96
C	1.00	.95	.75	.50	.25	.05	0.00	MEAN	S.D.	A	B	T^U	N=5 95	50%	5%	N=10 95	50%	5%
1	1.00	1.47	3.66	7.37	13.51	25.02	32.44	9.50	7.33	194.60	0.050	0.050	8.31	18.84	30.45	13.22	23.36	31.40
2	1.00	1.43	3.44	6.92	12.96	26.82	45.12	9.50	8.18	170.41	0.050	0.010	7.82	18.73	37.76	12.66	24.40	40.77
3	1.00	1.39	3.25	6.57	12.65	28.20	52.38	9.50	8.82	51.63	0.150	0.010	7.45	18.85	42.14	12.33	25.32	46.24
4	1.00	1.32	2.87	5.82	11.85	31.08	72.62	9.50	10.45	17.85	0.350	0.010	6.64	18.84	53.22	11.52	27.08	60.67
5	1.00	1.25	2.50	5.03	10.80	33.87	103.39	9.50	12.68	8.84	0.550	0.010	5.77	18.41	67.92	10.46	28.54	80.95
6	1.00	1.16	1.99	3.84	8.81	37.06	177.98	9.50	17.47	3.60	0.850	0.010	4.42	16.78	97.14	8.49	29.50	124.87
7	1.00	1.11	1.66	2.98	6.86	34.99	384.10	9.50	25.41	2.03	0.990	0.005	3.41	13.84	127.45	6.60	26.58	191.15
C	1.00	.95	.75	.50	.25	.05	0.00	MEAN	S.D.	A	B	T^U	N=5 95	50%	5%	N=10 95	50%	5%
1	1.00	1.50	3.81	7.75	14.25	26.43	34.29	10.00	7.76	206.05	0.050	0.050	8.74	19.89	32.18	13.93	24.67	33.19
2	1.00	1.46	3.58	7.27	13.67	28.34	47.72	10.00	8.66	180.44	0.050	0.010	8.22	19.77	39.93	13.34	25.77	43.11
3	1.00	1.42	3.38	6.90	13.34	29.80	55.40	10.00	9.33	54.66	0.150	0.010	7.83	19.90	44.56	13.00	26.75	48.90
4	1.00	1.34	2.98	6.11	12.49	32.85	76.84	10.00	11.06	18.90	0.350	0.010	6.98	19.89	56.29	12.13	28.62	64.18
5	1.00	1.26	2.58	5.27	11.37	35.81	109.41	10.00	13.42	9.35	0.550	0.010	6.05	19.43	71.85	11.01	30.16	85.65
6	1.00	1.17	2.04	4.00	9.27	39.18	188.40	10.00	18.50	3.82	0.850	0.010	4.62	17.71	102.80	8.93	31.18	132.15
7	1.00	1.11	1.70	3.10	7.21	36.99	406.63	10.00	26.90	2.15	0.990	0.005	3.55	14.60	134.89	6.93	28.08	202.33
C	1.00	.95	.75	.50	.25	.05	0.00	MEAN	S.D.	A	B	T^U	N=5 95	50%	5%	N=10 95	50%	5%
1	1.00	1.56	4.13	8.50	15.72	29.26	37.99	11.00	8.62	228.94	0.050	0.050	9.60	21.99	35.65	15.37	27.30	36.76
2	1.00	1.51	3.87	7.97	15.07	31.38	52.91	11.00	9.62	200.49	0.050	0.010	9.02	21.86	44.25	14.71	28.53	47.79
3	1.00	1.46	3.65	7.55	14.71	33.01	61.45	11.00	10.37	60.74	0.150	0.010	8.59	22.00	49.40	14.33	29.61	54.22
4	1.00	1.38	3.20	6.67	13.77	36.39	85.26	11.00	12.29	21.00	0.350	0.010	7.64	21.99	62.44	13.37	31.69	71.20
5	1.00	1.29	2.76	5.74	12.53	39.67	121.46	11.00	14.91	10.39	0.550	0.010	6.61	21.48	79.73	12.13	33.40	95.05
6	1.00	1.19	2.16	4.34	10.19	43.42	209.22	11.00	20.56	4.24	0.850	0.010	5.02	19.56	114.11	9.81	34.53	146.73
7	1.00	1.12	1.78	3.33	7.90	40.99	451.70	11.00	29.89	2.39	0.990	0.005	3.84	16.11	149.76	7.59	31.09	224.70
C	1.00	.95	.75	.50	.25	.05	0.00	MEAN	S.D.	A	B	T^U	N=5 95	50%	5%	N=10 95	50%	5%
1	1.00	1.61	4.44	9.25	17.20	32.09	41.69	12.00	9.48	251.83	0.050	0.050	10.46	24.09	39.11	16.81	29.93	40.34
2	1.00	1.56	4.16	8.66	16.48	34.42	58.10	12.00	10.58	220.54	0.050	0.010	9.83	23.94	48.58	16.08	31.28	52.47
3	1.00	1.51	3.91	8.21	16.08	36.21	67.49	12.00	11.41	66.81	0.150	0.010	9.35	24.10	54.24	15.67	32.47	59.55
4	1.00	1.41	3.42	7.24	15.04	39.93	93.69	12.00	13.52	23.10	0.350	0.010	8.30	24.09	68.58	14.61	34.76	78.22
5	1.00	1.32	2.94	6.21	13.68	43.54	133.51	12.00	16.40	11.43	0.550	0.010	7.17	23.53	87.60	13.24	36.64	104.46
6	1.00	1.21	2.27	4.67	11.11	47.66	230.04	12.00	22.61	4.66	0.850	0.010	5.42	21.42	125.42	10.70	37.88	161.30
7	1.00	1.14	1.86	3.57	8.59	44.99	496.77	12.00	32.88	2.63	0.990	0.005	4.12	17.62	164.64	8.25	34.10	247.07

C	1.00	.95	.75	.50	.25	.05	0.00	MEAN	S.D.	A	B	T^U	N=5 95	50%	5%	N=10 95	50%	5%
1	1.00	1.67	4.75	10.00	18.67	34.91	45.39	13.00	10.35	274.73	0.050	0.050	11.32	26.19	42.58	18.25	32.56	43.92
2	1.00	1.61	4.44	9.36	17.89	37.45	63.29	13.00	11.54	240.58	0.050	0.010	10.63	26.03	52.90	17.46	34.03	57.15
3	1.00	1.56	4.18	8.87	17.45	39.41	73.54	13.00	12.45	72.88	0.150	0.010	10.11	26.20	59.08	17.00	35.33	64.87
4	1.00	1.45	3.64	7.81	16.32	43.46	102.11	13.00	14.75	25.20	0.350	0.010	8.97	26.19	74.72	15.85	37.82	85.24
5	1.00	1.35	3.11	6.69	14.83	47.41	145.55	13.00	17.89	12.47	0.550	0.010	7.73	25.58	95.47	14.35	39.88	113.87
6	1.00	1.22	2.39	5.01	12.03	51.90	250.86	13.00	24.67	5.09	0.850	0.010	5.83	23.27	136.73	11.58	41.24	175.87
7	1.00	1.15	1.94	3.80	9.28	48.99	541.84	13.00	35.87	2.87	0.990	0.005	4.40	19.13	179.51	8.91	37.11	269.44

C	1.00	.95	.75	.50	.25	.05	0.00	MEAN	S.D.	A	B	T^U	N=5 95	50%	5%	N=10 95	50%	5%
1	1.00	1.73	5.06	10.74	20.14	37.74	49.09	14.00	11.21	297.62	0.050	0.050	12.18	28.29	46.04	19.68	35.19	47.49
2	1.00	1.66	4.73	10.06	19.29	40.49	68.48	14.00	12.50	260.63	0.050	0.010	11.43	28.11	57.23	18.83	36.78	61.83
3	1.00	1.60	4.44	9.52	18.82	42.61	79.58	14.00	13.48	78.96	0.150	0.010	10.86	28.30	63.92	18.34	38.19	70.19
4	1.00	1.49	3.86	8.38	17.60	47.00	110.54	14.00	15.98	27.30	0.350	0.010	9.63	28.28	80.87	17.08	40.89	92.26
5	1.00	1.38	3.29	7.16	15.98	51.28	157.60	14.00	19.39	13.51	0.550	0.010	8.29	27.62	103.35	15.46	43.12	123.27
6	1.00	1.24	2.51	5.34	12.95	56.15	271.68	14.00	26.73	5.51	0.850	0.010	6.23	25.13	148.04	12.46	44.59	190.45
7	1.00	1.16	2.02	4.03	9.97	52.99	586.91	14.00	38.86	3.11	0.990	0.005	4.69	20.64	194.39	9.56	40.12	291.81

C	1.00	.95	.75	.50	.25	.05	0.00	MEAN	S.D.	A	B	T^U	N=5 95	50%	5%	N=10 95	50%	5%
1	1.00	1.78	5.38	11.49	21.61	40.56	52.79	15.00	12.07	320.52	0.050	0.050	13.04	30.39	49.51	21.12	37.82	51.07
2	1.00	1.71	5.02	10.75	20.70	43.53	73.68	15.00	13.47	280.68	0.050	0.010	12.23	30.20	61.55	20.20	39.54	66.51
3	1.00	1.65	4.71	10.18	20.19	45.81	85.63	15.00	14.52	85.03	0.150	0.010	11.62	30.39	68.76	19.67	41.05	75.51
4	1.00	1.53	4.08	8.94	18.87	50.54	118.97	15.00	17.20	29.40	0.350	0.010	10.30	30.38	87.01	18.32	43.96	99.28
5	1.00	1.41	3.46	7.64	17.14	55.14	169.64	15.00	20.88	14.55	0.550	0.010	8.85	29.67	111.22	16.58	46.36	132.68
6	1.00	1.26	2.62	5.67	13.87	60.39	292.50	15.00	28.78	5.93	0.850	0.010	6.63	26.99	159.35	13.34	47.94	205.02
7	1.00	1.17	2.09	4.27	10.66	56.99	631.98	15.00	41.84	3.34	0.990	0.005	4.97	22.15	209.27	10.22	43.13	314.19

C	1.00	.95	.75	.50	.25	.05	0.00	MEAN	S.D.	A	B	T^U	N=5 95	50%	5%	N=10 95	50%	5%
1	1.00	1.84	5.69	12.24	23.08	43.39	56.49	16.00	12.93	343.41	0.050	0.050	13.90	32.49	52.97	22.56	40.45	54.64
2	1.00	1.76	5.31	11.45	22.11	46.57	78.87	16.00	14.43	300.73	0.050	0.010	13.04	32.29	65.88	21.57	42.29	71.19
3	1.00	1.70	4.97	10.83	21.56	49.01	91.67	16.00	15.56	91.11	0.150	0.010	12.38	32.49	73.60	21.00	43.91	80.84
4	1.00	1.56	4.30	9.51	20.15	54.08	127.39	16.00	18.43	31.50	0.350	0.010	10.96	32.48	93.15	19.56	47.03	106.30
5	1.00	1.44	3.64	8.11	18.29	59.01	181.69	16.00	22.37	15.59	0.550	0.010	9.42	31.72	119.09	17.69	49.60	142.08
6	1.00	1.28	2.74	6.01	14.79	64.63	313.33	16.00	30.84	6.36	0.850	0.010	7.03	28.84	170.66	14.22	51.30	219.59
7	1.00	1.19	2.17	4.50	11.35	60.99	677.05	16.00	44.83	3.58	0.990	0.005	5.26	23.66	224.14	10.88	46.14	336.56

C	1.00	.95	.75	.50	.25	.05	0.00	MEAN	S.D.	A	B	T^U	N=5 95	50%	5%	N=10 95	50%	5%
1	1.00	1.89	6.00	12.99	24.56	46.22	60.19	17.00	13.80	366.30	0.050	0.050	14.76	34.59	56.44	23.99	43.08	58.22
2	1.00	1.82	5.59	12.15	23.52	49.61	84.06	17.00	15.39	320.78	0.050	0.010	13.84	34.37	70.20	22.94	45.04	75.87
3	1.00	1.74	5.23	11.49	22.93	52.21	97.72	17.00	16.59	97.18	0.150	0.010	13.14	34.59	78.44	22.34	46.78	86.16
4	1.00	1.60	4.52	10.08	21.42	57.62	135.82	17.00	19.66	33.61	0.350	0.010	11.62	34.58	99.30	20.79	50.10	113.32
5	1.00	1.47	3.82	8.59	19.44	62.88	193.74	17.00	23.86	16.63	0.550	0.010	9.98	33.77	126.96	18.80	52.84	151.49
6	1.00	1.30	2.85	6.34	15.71	68.87	334.15	17.00	32.89	6.78	0.850	0.010	7.43	30.70	181.98	15.10	54.65	234.16
7	1.00	1.20	2.25	4.73	12.03	64.99	722.12	17.00	47.82	3.82	0.990	0.005	5.54	25.17	239.02	11.54	49.15	358.93

C	1.00	.95	.75	.50	.25	.05	0.00	MEAN	S.D.	A	B	T^U	N=5 95	50%	5%	N=10 95	50%	5%
1	1.00	1.95	6.31	13.74	26.03	49.04	63.89	18.00	14.66	389.20	0.050	0.050	15.62	36.69	59.90	25.43	45.71	61.80
2	1.00	1.87	5.88	12.84	24.92	52.64	89.25	18.00	16.35	340.83	0.050	0.010	14.64	36.46	74.53	24.31	47.80	80.55
3	1.00	1.79	5.50	12.14	24.30	55.41	103.76	18.00	17.63	103.25	0.150	0.010	13.90	36.69	83.28	23.67	49.64	91.48
4	1.00	1.64	4.74	10.65	22.70	61.16	144.25	18.00	20.89	35.71	0.350	0.010	12.29	36.68	105.44	22.03	53.17	120.34
5	1.00	1.50	3.99	9.06	20.60	66.75	205.78	18.00	25.35	17.67	0.550	0.010	10.54	35.82	134.84	19.92	56.08	160.89
6	1.00	1.32	2.97	6.67	16.63	73.11	354.97	18.00	34.95	7.21	0.850	0.010	7.84	32.56	193.29	15.99	58.00	248.74
7	1.00	1.21	2.33	4.97	12.72	68.99	767.19	18.00	50.81	4.06	0.990	0.005	5.82	26.68	253.90	12.20	52.15	381.30

C	1.00	.95	.75	.50	.25	.05	0.00	MEAN	S.D.	A	B	T^U	N=5 95	50%	5%	N=10 95	50%	5%
1	1.00	2.00	6.63	14.49	27.50	51.87	67.59	19.00	15.52	412.09	0.050	0.050	16.49	38.79	63.37	26.87	48.34	65.37
2	1.00	1.92	6.17	13.54	26.33	55.68	94.44	19.00	17.31	360.88	0.050	0.010	15.44	38.54	78.85	25.68	50.55	85.23
3	1.00	1.84	5.76	12.80	25.67	58.61	109.81	19.00	18.67	109.33	0.150	0.010	14.66	38.79	88.12	25.00	52.50	96.80
4	1.00	1.68	4.96	11.21	23.98	64.70	152.67	19.00	22.12	37.81	0.350	0.010	12.95	38.78	111.59	23.27	56.24	127.35
5	1.00	1.53	4.17	9.53	21.75	70.61	217.83	19.00	26.84	18.71	0.550	0.010	11.10	37.86	142.71	21.03	59.32	170.30
6	1.00	1.34	3.09	7.01	17.55	77.36	375.79	19.00	37.01	7.63	0.850	0.010	8.24	34.41	204.60	16.87	61.35	263.31
7	1.00	1.22	2.41	5.20	13.41	72.99	812.26	19.00	53.80	4.30	0.990	0.005	6.11	28.20	268.77	12.86	55.16	403.67

C	1.00	.95	.75	.50	.25	.05	0.00	MEAN	S.D.	A	B	T^U	N=5 95	50%	5%	N=10 95	50%	5%
1	1.00	2.06	6.94	15.24	28.97	54.69	71.29	20.00	16.38	434.99	0.050	0.050	17.35	40.89	66.83	28.31	50.97	68.95
2	1.00	1.97	6.45	14.24	27.74	58.72	99.63	20.00	18.28	380.92	0.050	0.010	16.24	40.63	83.18	27.05	53.30	89.91
3	1.00	1.88	6.03	13.45	27.05	61.81	115.85	20.00	19.71	115.40	0.150	0.010	15.42	40.89	92.95	26.34	55.36	102.13
4	1.00	1.72	5.18	11.78	25.25	68.24	161.10	20.00	23.35	39.91	0.350	0.010	13.61	40.88	117.73	24.51	59.31	134.37
5	1.00	1.56	4.34	10.01	22.90	74.48	229.87	20.00	28.33	19.75	0.550	0.010	11.66	39.91	150.58	22.14	62.56	179.70
6	1.00	1.36	3.20	7.34	18.46	81.60	396.61	20.00	39.06	8.05	0.850	0.010	8.64	36.27	215.91	17.75	64.71	277.88
7	1.00	1.24	2.49	5.43	14.10	76.98	857.33	20.00	56.79	4.54	0.990	0.005	6.39	29.71	283.65	13.52	58.17	426.04

C	1.00	.95	.75	.50	.25	.05	0.00	MEAN	S.D.	A	B	T^U	N=5 95	50%	5%	N=10 95	50%	5%
1	1.00	2.34	8.50	18.99	36.34	68.82	89.78	25.00	20.69	549.46	0.050	0.050	21.65	51.38	84.15	35.49	64.12	86.83
2	1.00	2.22	7.89	17.72	34.77	73.91	125.59	25.00	23.08	481.17	0.050	0.010	20.26	51.06	104.80	33.91	67.06	113.30
3	1.00	2.11	7.35	16.73	33.90	77.81	146.08	25.00	24.89	145.77	0.150	0.010	19.21	51.39	117.15	33.00	69.66	128.74
4	1.00	1.90	6.27	14.62	31.64	85.93	203.23	25.00	29.49	50.41	0.350	0.010	16.93	51.37	148.45	30.69	74.65	169.47
5	1.00	1.71	5.22	12.38	28.66	93.82	290.10	25.00	35.79	24.95	0.550	0.010	14.47	50.15	189.94	27.70	78.77	226.73
6	1.00	1.45	3.78	9.01	23.06	102.81	500.72	25.00	49.34	10.17	0.850	0.010	10.65	45.55	272.46	22.16	81.47	350.75
7	1.00	1.30	2.88	6.60	17.55	96.98	1082.69	25.00	71.73	5.73	0.990	0.005	7.81	37.26	358.03	16.81	73.22	537.89

C	1.00	.95	.75	.50	.25	.05	0.00	MEAN	S.D.	A	B	T^U	N=5 95	50%	5%	N=10 95	50%	5%
1	1.00	2.62	10.06	22.74	43.70	82.96	108.28	30.00	25.00	663.93	0.050	0.050	25.95	61.88	101.48	42.68	77.27	104.71
2	1.00	2.48	9.33	21.20	41.81	89.10	151.54	30.00	27.89	581.41	0.050	0.010	24.27	61.49	126.43	40.77	80.83	136.70
3	1.00	2.35	8.68	20.01	40.75	93.81	176.30	30.00	30.08	176.14	0.150	0.010	23.00	61.89	141.35	39.67	83.97	155.35
4	1.00	2.09	7.37	17.45	38.02	103.62	245.36	30.00	35.64	60.91	0.350	0.010	20.25	61.87	179.17	36.88	89.99	204.57
5	1.00	1.85	6.10	14.75	34.43	113.16	350.33	30.00	43.24	30.14	0.550	0.010	17.27	60.39	229.31	33.27	94.97	273.76
6	1.00	1.54	4.36	10.68	27.66	124.02	604.83	30.00	59.62	12.29	0.850	0.010	12.66	54.83	329.02	26.56	98.24	423.61
7	1.00	1.36	3.27	7.76	21.00	116.98	1308.04	30.00	86.68	6.93	0.990	0.005	9.23	44.81	432.41	20.10	88.26	649.74

C	1.00	.95	.75	.50	.25	.05	0.00	MEAN	S.D.	A	B	T^U	N=5 95	50%	5%	N=10 95	50%	5%
1	1.00	2.90	11.63	26.49	51.06	97.09	126.78	35.00	29.32	778.40	0.050	0.050	30.25	72.37	118.80	49.86	90.42	122.59
2	1.00	2.73	10.76	24.69	48.85	104.29	177.50	35.00	32.70	681.65	0.050	0.010	28.28	71.91	148.05	47.62	94.59	160.09
3	1.00	2.58	10.00	23.29	47.61	109.82	206.53	35.00	35.26	206.51	0.150	0.010	26.80	72.39	165.55	46.34	98.27	181.96
4	1.00	2.28	8.47	20.29	44.40	121.32	287.49	35.00	41.78	71.41	0.350	0.010	23.57	72.36	209.88	43.06	105.34	239.67
5	1.00	2.00	6.98	17.12	40.19	132.49	410.56	35.00	50.70	35.34	0.550	0.010	20.08	70.63	268.67	38.83	111.17	320.79
6	1.00	1.64	4.94	12.35	32.25	145.23	708.94	35.00	69.90	14.41	0.850	0.010	14.67	64.11	385.57	30.97	115.00	496.47
7	1.00	1.42	3.66	8.93	24.45	136.97	1533.39	35.00	101.62	8.12	0.990	0.005	10.65	52.37	506.79	23.40	103.31	761.59

C	1.00	.95	.75	.50	.25	.05	0.00	MEAN	S.D.	A	B	T^U	N=5 95	50%	5%	N=10 95	50%	5%
1	1.00	3.18	13.19	30.23	58.42	111.22	145.28	40.00	33.63	892.87	0.050	0.050	34.55	82.87	136.12	57.05	103.57	140.48
2	1.00	2.99	12.20	28.17	55.88	119.48	203.45	40.00	37.51	781.90	0.050	0.010	32.29	82.34	169.68	54.48	108.35	183.49
3	1.00	2.81	11.32	26.56	54.46	125.82	236.75	40.00	40.45	236.88	0.150	0.010	30.59	82.89	189.75	53.01	112.58	208.58
4	1.00	2.47	9.57	23.13	50.79	139.01	329.62	40.00	47.93	81.91	0.350	0.010	26.89	82.85	240.60	49.25	120.68	274.77
5	1.00	2.15	7.86	19.49	45.95	151.83	470.79	40.00	58.16	40.54	0.550	0.010	22.88	80.87	308.04	44.39	127.37	367.81
6	1.00	1.73	5.52	14.02	36.85	166.44	813.05	40.00	80.18	16.53	0.850	0.010	16.68	73.39	442.13	35.38	131.77	569.34
7	1.00	1.48	4.05	10.10	27.90	156.97	1758.74	40.00	116.57	9.32	0.990	0.005	12.07	59.92	581.17	26.69	118.35	873.44

C	1.00	.95	.75	.50	.25	.05	0.00	MEAN	S.D.	A	B	T^U	N=5 95	50%	5%	N=10 95	50%	5%
1	1.00	3.45	14.75	33.98	65.78	125.35	163.77	45.00	37.94	1007.34	0.050	0.050	38.85	93.37	153.45	64.24	116.72	158.36
2	1.00	3.24	13.63	31.65	62.92	134.67	229.41	45.00	42.32	882.14	0.050	0.010	36.30	92.77	191.30	61.34	122.12	206.89
3	1.00	3.04	12.65	29.84	61.32	141.82	266.98	45.00	45.64	267.24	0.150	0.010	34.39	93.38	213.95	59.67	126.88	235.19
4	1.00	2.66	10.67	25.96	57.17	156.70	371.75	45.00	54.07	92.41	0.350	0.010	30.21	93.35	271.32	55.44	136.02	309.87
5	1.00	2.29	8.74	21.86	51.72	171.17	531.02	45.00	65.61	45.73	0.550	0.010	25.69	91.11	347.40	49.96	143.57	414.84
6	1.00	1.82	6.10	15.69	41.44	187.65	917.16	45.00	90.46	18.65	0.850	0.010	18.69	82.67	498.68	39.78	148.53	642.20
7	1.00	1.54	4.44	11.26	31.35	176.96	1984.09	45.00	131.51	10.51	0.990	0.005	13.48	67.48	655.55	29.99	133.40	985.30

C	1.00	.95	.75	.50	.25	.05	0.00	MEAN	S.D.	A	B	T^U	N=5 95	50%	5%	N=10 95	50%	5%
1	1.00	3.73	16.31	37.73	73.14	139.48	182.27	50.00	42.25	1121.81	0.050	0.050	43.15	103.86	170.77	71.42	129.87	176.24
2	1.00	3.50	15.07	35.14	69.95	149.86	255.36	50.00	47.13	982.38	0.050	0.010	40.31	103.20	212.93	68.19	135.88	230.28
3	1.00	3.27	13.97	33.12	68.17	157.82	297.20	50.00	50.82	297.61	0.150	0.010	38.18	103.88	238.15	66.34	141.19	261.80
4	1.00	2.85	11.77	28.80	63.55	174.40	413.89	50.00	60.21	102.92	0.350	0.010	33.53	103.84	302.04	61.62	151.37	344.97
5	1.00	2.44	9.62	24.23	57.48	190.50	591.25	50.00	73.07	50.93	0.550	0.010	28.49	101.35	386.76	55.52	159.77	461.87
6	1.00	1.92	6.68	17.35	46.04	208.86	1021.27	50.00	100.74	20.77	0.850	0.010	20.70	91.95	555.24	44.19	165.30	715.07
7	1.00	1.61	4.83	12.43	34.79	196.96	2209.44	50.00	146.45	11.70	0.990	0.005	14.90	75.03	729.93	33.28	148.44	1097.15

C	1.00	.95	.75	.50	.25	.05	0.00	MEAN	S.D.	A	B	T^U	N=5 95	50%	5%	N=10 95	50%	5%
1	1.00	4.29	19.44	45.23	87.87	167.74	219.26	60.00	50.87	1350.75	0.050	0.050	51.76	124.85	205.42	85.79	156.17	212.00
2	1.00	4.01	17.94	42.10	84.03	180.24	307.28	60.00	56.75	1182.87	0.050	0.010	48.34	124.06	256.18	81.91	163.41	277.07
3	1.00	3.74	16.62	39.67	81.88	189.83	357.65	60.00	61.19	358.35	0.150	0.010	45.77	124.88	286.54	79.68	169.80	315.03
4	1.00	3.22	13.97	34.47	76.32	209.78	498.15	60.00	72.50	123.92	0.350	0.010	40.17	124.83	363.47	73.99	182.05	415.16
5	1.00	2.74	11.38	28.97	69.01	229.18	711.71	60.00	87.98	61.33	0.550	0.010	34.10	121.83	465.49	66.65	192.17	555.92
6	1.00	2.10	7.84	20.69	55.23	251.27	1229.48	60.00	121.30	25.01	0.850	0.010	24.72	110.52	668.35	53.01	198.83	860.79
7	1.00	1.73	5.61	14.76	41.69	236.95	2660.15	60.00	176.34	14.09	0.990	0.005	17.74	90.14	878.70	39.87	178.54	1320.85

C	1.00	.95	.75	.50	.25	.05	0.00	MEAN	S.D.	A	B	T^U	N=5 95	50%	5%	N=10 95	50%	5%
1	1.00	4.85	22.56	52.72	102.59	196.00	256.26	70.00	59.49	1579.69	0.050	0.050	60.36	145.85	240.07	100.16	182.47	247.76
2	1.00	4.52	20.81	49.07	98.10	210.62	359.19	70.00	66.37	1383.36	0.050	0.010	56.36	144.91	299.43	95.62	190.93	323.87
3	1.00	4.20	19.26	46.23	95.59	221.83	418.10	70.00	71.57	419.09	0.150	0.010	53.36	145.87	334.94	93.01	198.41	368.25
4	1.00	3.60	16.17	40.15	89.08	245.17	582.41	70.00	84.79	144.92	0.350	0.010	46.81	145.82	424.91	86.36	212.74	485.36
5	1.00	3.03	13.14	33.71	80.54	267.85	832.17	70.00	102.89	71.72	0.550	0.010	39.71	142.31	544.22	77.77	224.58	649.98
6	1.00	2.29	9.00	24.03	64.42	293.69	1437.70	70.00	141.85	29.25	0.850	0.010	28.74	129.08	781.45	61.82	232.36	1006.52
7	1.00	1.85	6.39	17.09	48.59	276.94	3110.85	70.00	206.23	16.48	0.990	0.005	20.58	105.25	1027.46	46.46	208.63	1544.56

C	1.00	.95	.75	.50	.25	.05	0.00	MEAN	S.D.	A	B	T^U	N=5 95	50%	5%	N=10 95	50%	5%
1	1.00	5.41	25.69	60.22	117.31	224.26	293.25	80.00	68.12	1808.63	0.050	0.050	68.96	166.84	274.71	114.54	208.77	283.53
2	1.00	5.03	23.68	56.04	112.17	241.00	411.10	80.00	75.99	1583.84	0.050	0.010	64.39	165.77	342.68	109.33	218.46	370.66
3	1.00	4.67	21.91	52.78	109.30	253.84	478.55	80.00	81.94	479.82	0.150	0.010	60.94	166.87	383.34	106.35	227.02	421.47
4	1.00	3.97	18.36	45.82	101.85	280.56	666.67	80.00	97.08	165.93	0.350	0.010	53.45	166.80	486.35	98.74	243.43	555.56
5	1.00	3.33	14.90	38.45	92.06	306.53	952.63	80.00	117.81	82.11	0.550	0.010	45.32	162.79	622.94	88.90	256.98	744.03
6	1.00	2.48	10.16	27.37	73.62	336.11	1645.92	80.00	162.41	33.49	0.850	0.010	32.77	147.64	894.56	70.64	265.89	1152.25
7	1.00	1.98	7.18	19.43	55.48	316.93	3561.55	80.00	236.12	18.87	0.990	0.005	23.42	120.36	1176.22	53.04	238.72	1768.26

C	1.00	.95	.75	.50	.25	.05	0.00	MEAN	S.D.	A	B	T^U	N=5 95	50%	5%	N=10 95	50%	5%
1	1.00	5.96	28.81	67.72	132.04	252.52	330.24	90.00	76.74	2037.57	0.050	0.050	77.57	187.83	309.36	128.91	235.07	319.29
2	1.00	5.54	26.55	63.01	126.24	271.37	463.01	90.00	85.61	1784.33	0.050	0.010	72.41	186.63	385.93	123.05	245.99	417.45
3	1.00	5.13	24.56	59.33	123.00	285.84	539.00	90.00	92.31	540.56	0.150	0.010	68.53	187.87	431.74	119.68	255.62	474.70
4	1.00	4.35	20.56	51.49	114.61	315.95	750.93	90.00	109.37	186.93	0.350	0.010	60.09	187.79	547.78	111.11	274.11	625.75
5	1.00	3.62	16.66	43.19	103.59	345.20	1073.09	90.00	132.72	92.51	0.550	0.010	50.93	183.27	701.67	100.03	289.38	838.09
6	1.00	2.66	11.32	30.70	82.81	378.53	1854.14	90.00	182.97	37.73	0.850	0.010	36.79	166.20	1007.67	79.45	299.42	1297.98
7	1.00	2.10	7.96	21.76	62.38	356.93	4012.25	90.00	266.01	21.26	0.990	0.005	26.25	135.47	1324.98	59.63	268.81	1991.96

C	1.00	.95	.75	.50	.25	.05	0.00	MEAN	S.D.	A	B	T^{u}	N=5 95	50%	5%	N=10 95	50%	5%
1	1.00	6.52	31.94	75.21	146.76	280.78	367.24	100.00	85.36	2266.51	0.050	0.050	86.17	208.82	344.01	143.28	261.37	355.05
2	1.00	6.04	29.42	69.97	140.32	301.75	514.92	100.00	95.22	1984.82	0.050	0.010	80.43	207.48	429.18	136.76	273.51	464.24
3	1.00	5.60	27.20	65.89	136.71	317.85	599.45	100.00	102.68	601.30	0.150	0.010	76.12	208.86	480.13	133.02	284.23	527.92
4	1.00	4.73	22.76	57.17	127.38	351.33	835.20	100.00	121.66	207.93	0.350	0.010	66.73	208.78	609.22	123.48	304.80	695.95
5	1.00	3.91	18.42	47.93	115.12	383.88	1193.56	100.00	147.63	102.90	0.550	0.010	56.54	203.75	780.40	111.15	321.78	932.14
6	1.00	2.85	12.47	34.04	92.00	420.95	2062.35	100.00	203.53	41.97	0.850	0.010	40.81	184.77	1120.78	88.27	332.95	1443.70
7	1.00	2.23	8.74	24.09	69.28	396.92	4462.96	100.00	295.90	23.65	0.990	0.005	29.09	150.57	1473.74	66.22	298.90	2215.67

G. SMALL FIELD ASSESSMENT
by
D.H. Root and E.D. Attanasi

Introduction

The assessment of fields containing more than 1 million barrels of crude oil or 6 billion cubic feet of gas was prepared at the geologic play level by geologists for nearly all U.S. petroleum provinces. The play analysis was restricted to fields for which there exists a relatively complete and accurate data set. Although smaller fields are numerous, the data set for these fields is so incomplete and inaccurate that it was not practical to analyze the potential of the small fields on a play basis. An alternative, statistically based approach was used to estimate remaining resources in smaller fields.

The introductory discussion on field size distributions is designed to show that (1) observed field size distributions evolve over time toward distributions wherein the relative frequency of fields within predetermined size classes increases monotonically with a declining field size, and (2) even though the preponderance of fields are in the smaller field size classes, most of the hydrocarbons are contained in the larger field size classes. These observations appear to hold true for both oil and gas fields.

Field Size Distributions

In the early years of exploration, the observed distribution of sizes of known fields is quite different from that of the distribution in later years. Figures II.G.1 and II.G.2 show the relative frequency distributions and the relative distributions of hydrocarbons by size class of known oil fields as of 1943 (left bar), 1963 (center bar), and 1984 (right bar). Field size classes used in the analysis are defined on a barrel of oil-equivalent basis (BOE) and are presented in table II.G.1. Figures II.G.3 and II.G.4 show similar graphs for fields of nonassociated gas. Figures II.G.1 through II.G.4 pertain to fields having at least 1 million barrels of crude oil or 6 billion cubic feet of gas. In figures II.G.1 and II.G.3, the three distributions show a shift to the left, that is, to smaller size classes. By 1984, even though fields smaller than class 10 (16 million BOE) accounted for three-fourths of the oil fields, they contained less than 8 percent of the hydrocarbons contained in oil fields. Similarly for gas fields, three-fourths of the fields were smaller than class 10 (96 BCF) but contained less than 11 percent of the hydrocarbons in gas fields. When fields are broken into depth intervals, the effect of greater depth on the distribution of field size is to delay the shift to the increase in frequency of small fields.

Data on small fields are usually sparse, particularly reserve information. Using field production data as of December, 1985 purchased from Petroleum Information, Inc., Denver, Colorado, field reserves were estimated from average reserve to production ratios computed for individual petroleum provinces with the large-field data base (NRG Associates, 1986). Estimates of ultimate recovery for the small fields were then computed by adding the estimated reserves to cumulative field production. Figures II.G.5 and II.G.6 are based on the Petroleum Information data and show the relative frequencies in size classes 1 to 19 for oil and gas fields, respectively. These figures show that the shift of the distribution mass to small fields observed in the large-field data base extends to fields smaller than 1 million BOE.

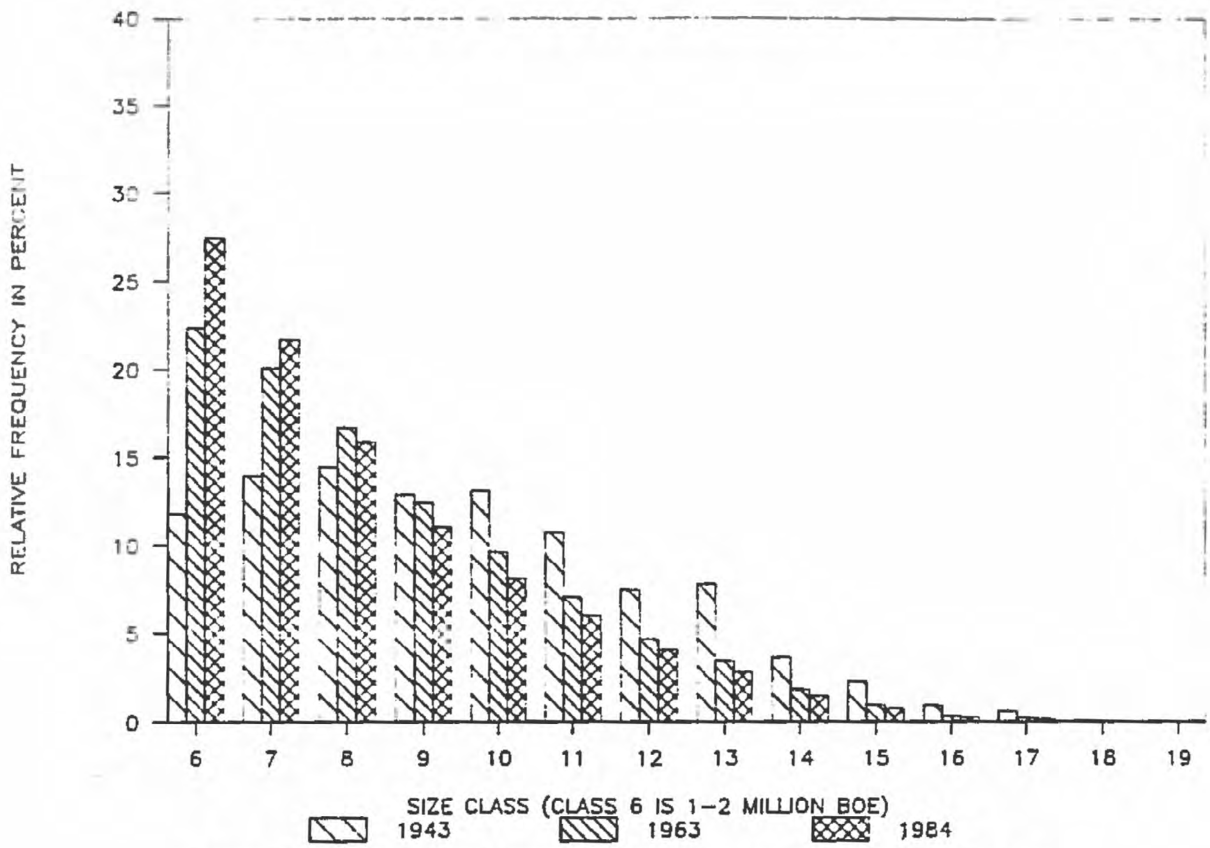

Figure II.G.1. Relative frequencies of oil field size classes in the Lower 48 States for fields greater than 1 MM BOE. Relative frequency expressed in percent of number of fields. Shown separately for cumulative discoveries to 1943, to 1963, and to 1984. Classes shown in table II.G.1, in recoverable quantities.

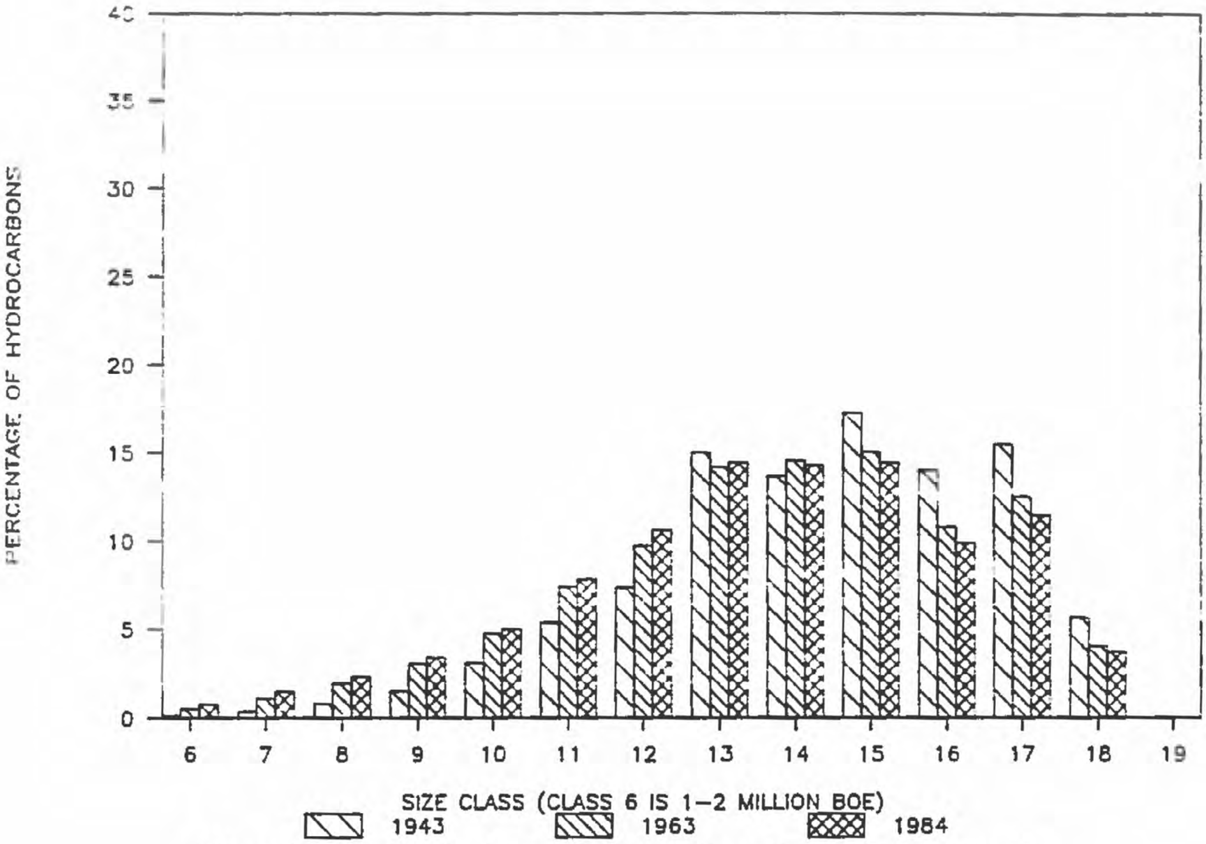

Figure II.G.2. Distribution by field size class of volumes of recoverable oil and associated gas (BOE) in Lower 48 States in fields greater than 1 MM BOE. Distribution expressed as percent of volume. Shown separately for cumulative discoveries to 1943, to 1963, and to 1984. Classes shown in table II.G.1., in recoverable quantities.

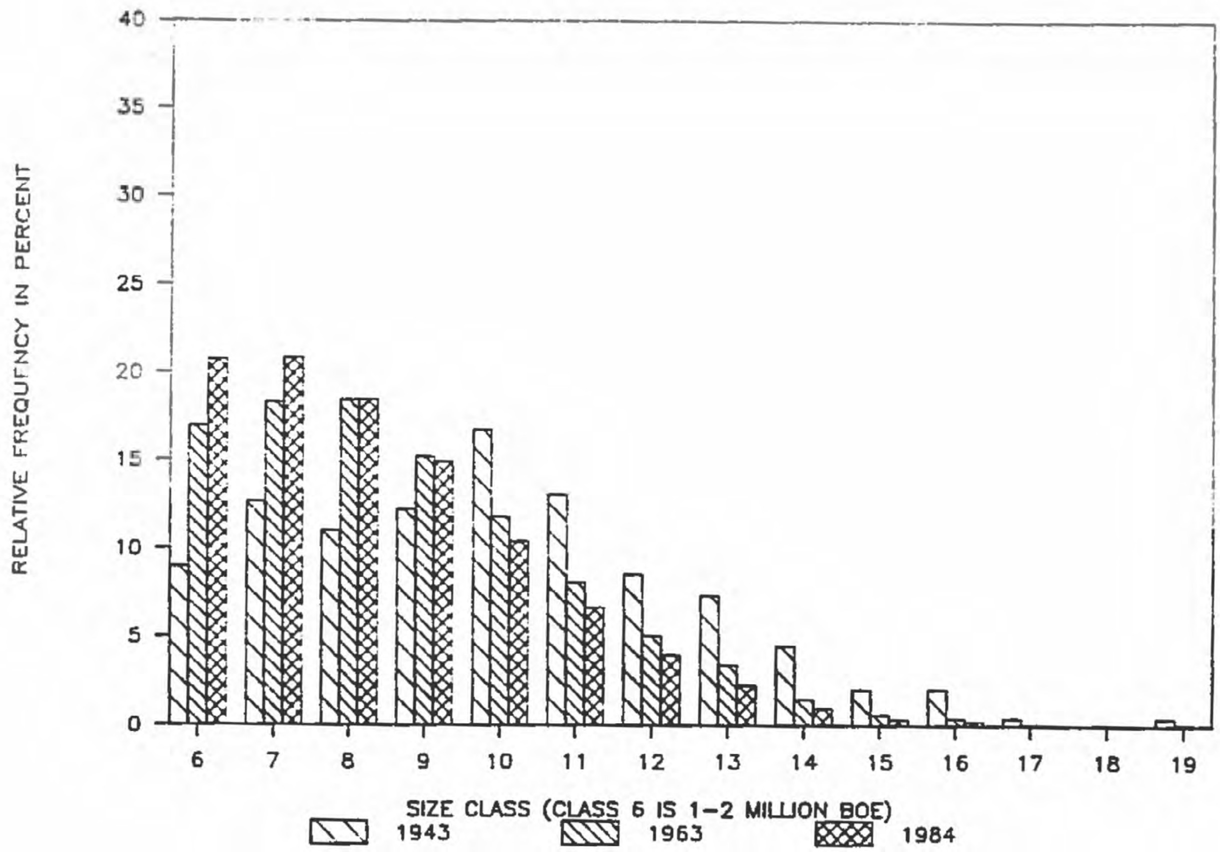

Figure II.G.3. Relative frequencies of gas field size classes in the Lower 48 States in fields greater than 1 MM BOE (6 BCF). Relative frequency expressed in percent of number of fields. Shown separately for cumulative discoveries to 1943, to 1963, and to 1984. Classes shown in table II.G.1., in recoverable quantities.

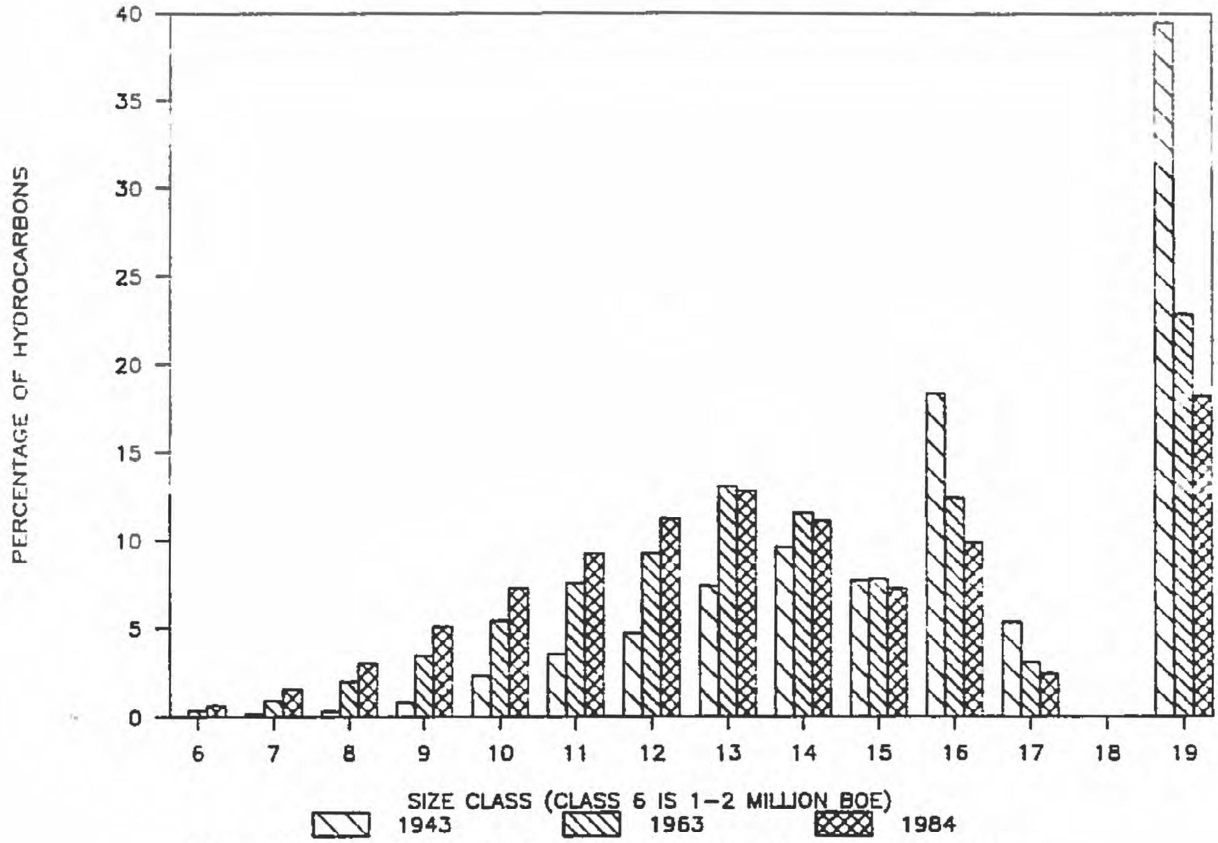

Figure II.G.4. Distribution by field size class of volume of discovered recoverable nonassociated gas and natural gas liquids (NGL) in Lower 48 States in fields greater than 1 MM BOE. Distribution expressed as percent of volume. Shown separately for cumulative discoveries to 1943, to 1963, and to 1984. Classes shown in table II.G.1., in recoverable quantities.

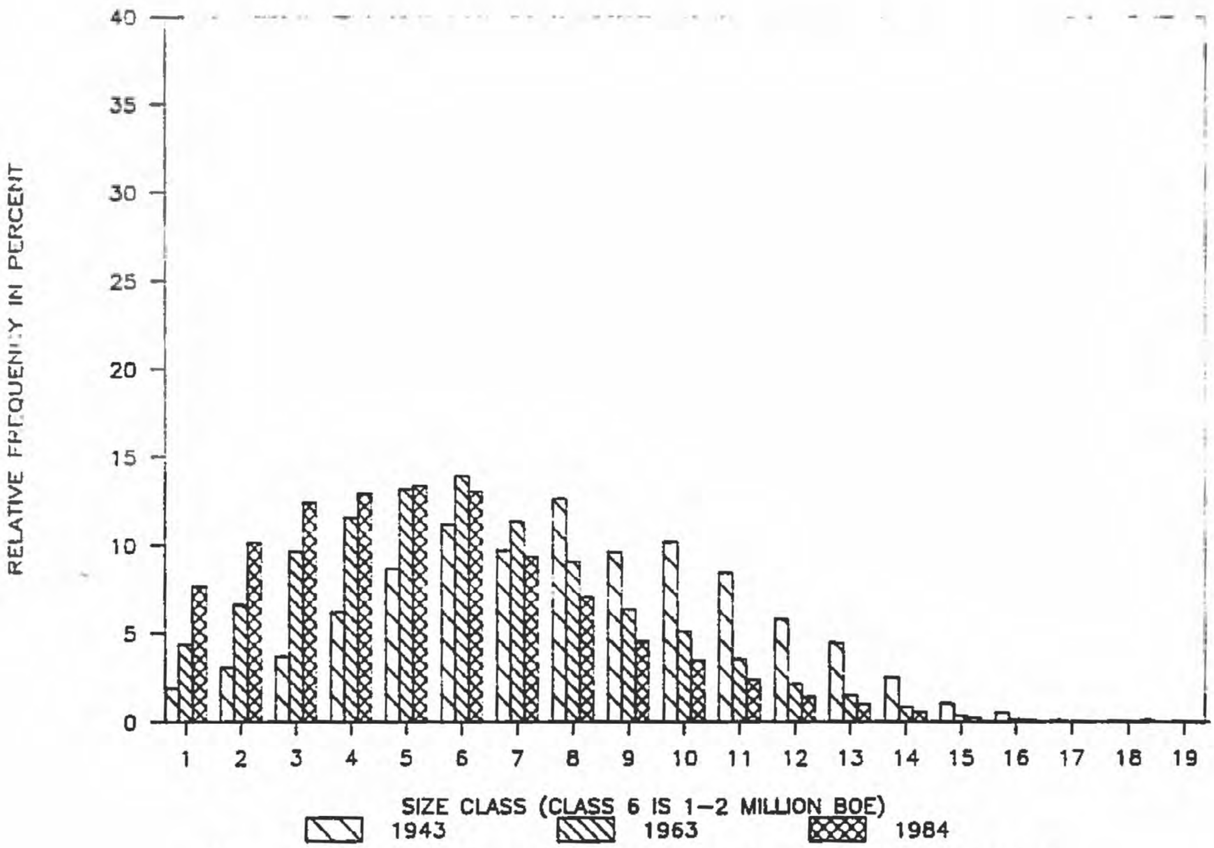

Figure II.G.5. Relative frequencies of oil field size classes for all oil fields in the Lower 48 States. Relative frequency expressed in percent of number of total fields, including those smaller than 1 MM BOE. Shown separately for cumulative discoveries to 1943, to 1963, and to 1984. Classes shown in table II.G.1., in recoverable quantities.

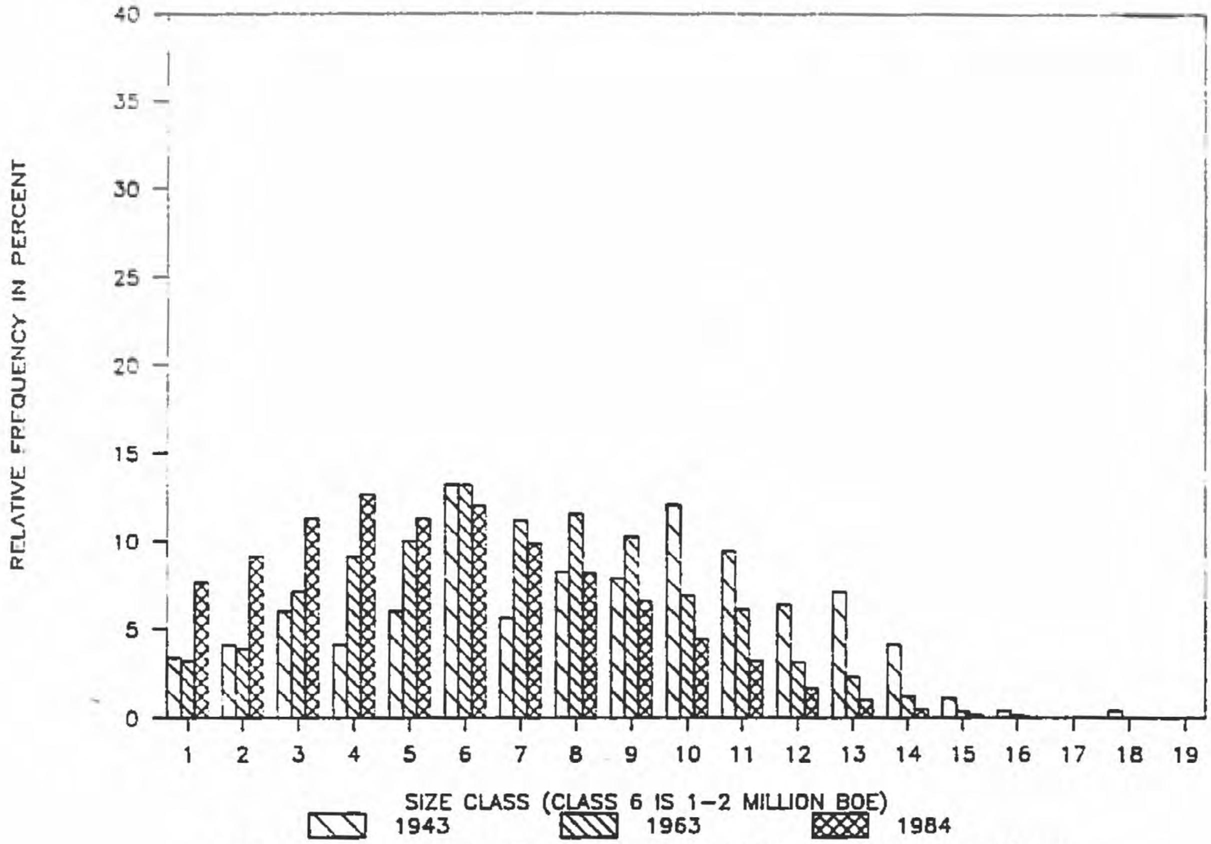

Figure II.G.6. Relative frequencies of gas field size classes for all gas fields in the Lower 48 States. Relative frequency expressed in percent of number of total fields, including those smaller than 1 MM BOE (6 BCF). Shown separately for cumulative discoveries to 1943, to 1963, and to 1984. Classes shown in table II.G.1., in recoverable quantities.

Table II.G.1. Field size classes

Class	Oil field size MMBO (range)			Gas field size BCF (range)		
1	0.03125	-	0.0625	0.1875	-	0.375
2	0.0625	-	0.125	0.375	-	0.75
3	0.125	-	0.25	0.75	-	1.5
4	0.25	-	0.5	1.5	-	3
5	0.5	-	1	3	-	6
6	1	-	2	6	-	12
7	2	-	4	12	-	24
8	4	-	8	24	-	48
9	8	-	16	48	-	96
10	16	-	32	96	-	192
11	32	-	64	192	-	384
12	64	-	128	384	-	768
13	128	-	256	768	-	1536
14	256	-	512	1536	-	3072
15	512	-	1024	3072	-	6144
16	1024	-	2048	6144	-	12288
17	2048	-	4096	12288	-	24576
18	4096	-	8192	24576	-	49152
19	8192	-	16384	49152	-	98304
20	16384	-	32768	98304	-	196608

Small Field Assessment

In the Lower 48 States, assessment geologists have relied on the historical discovery size distributions, drilling density maps, and other geologic data when they subjectively assessed the remaining oil and gas at the play level for fields larger than 1 million barrels of oil or 6 billion cubic feet of gas. From the play level assessments, the expected number of oil and gas fields in each size class was computed. The expected values for the play assessments were aggregated to province levels and added to the historical data on past discoveries to arrive at an estimated in-situ distribution of (combined oil and gas) fields expressed in terms of BOE size classes.

The in-situ large-field distribution is shown in figure II.G.7 where the bars on the right represent the fields discovered through 1984 and bars on the left are the estimated numbers of in-situ fields. In classes 6 through 16, each class has more fields than the next larger class. As a simple extrapolation to classes 1 to 5 the ratios of the estimated ultimate (in-situ) number of fields in successive size classes were assumed constant. For classes 6 through 11 of the data shown in figure II.G.7, the successive ratios vary from 1.17 to 1.69. The extrapolation procedure described above amounts to assuming that the in-situ field size distribution of fields containing less than 1 million BOE of hydrocarbons is log-geometric with the ratio of successive size classes used as the log-geometric multiplier (Drew and others, 1982; Schuenemeyer and Drew, 1983).

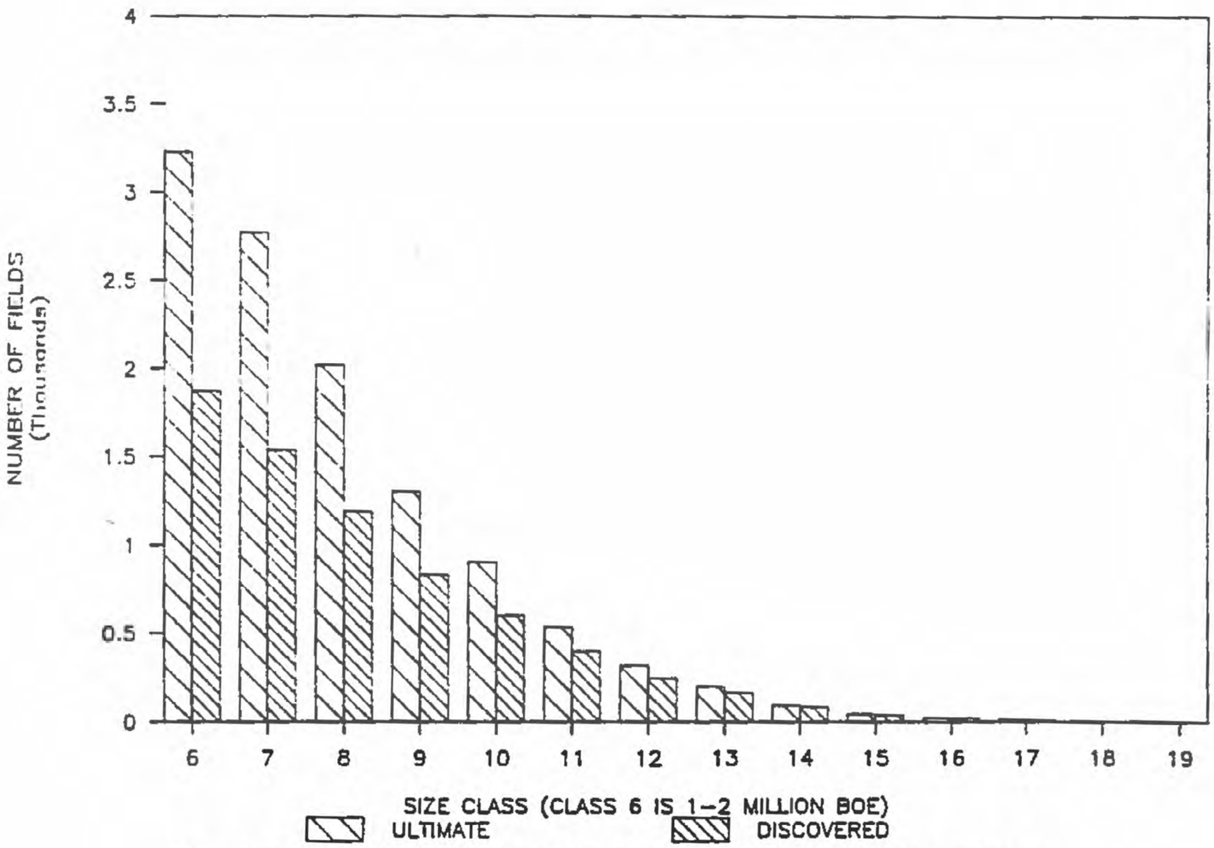

Figure II.G.7. Field size class distributions of the discovered and of the ultimate (discovered plus undiscovered) number of oil and gas fields estimated in the Lower 48 States greater than 1 MM BOE. Classes shown in table II.G.1., in recoverable quantities.

Actual estimates of the numbers of small fields were calculated by province and different ratios were used for different provinces. The ratios for the provinces were constrained to between 1 and 1.6. For all provinces, a subjective estimate was made by the geologists of the oil and associated-dissolved gas, and gas liquids in small crude oil fields and the amount of gas and liquids in nonassociated gas fields. Model parameters were then chosen to conform to the subjective estimate. The analytical form of the estimated model is:

$$N(I) = CR^{-I} \qquad (1)$$

where N(I) is the ultimate number of fields in size class I, C is the number of fields in the first size class, and R is the ratio (geometric multiplier) between the ultimate number of fields in successive size classes. The parameters C and R are chosen to give a best fit in the least-squares sense for the numbers of fields in classes 7 through 11 in each petroleum province. Once C and R have been selected, the ultimate number of fields can be estimated from equation (1) and the number of undiscovered fields computed by subtracting the number of discovered fields from the estimated ultimate number of fields. The estimated ultimate number of fields in size classes less than 1 million BOE were divided into oil and gas fields according to the subjective assessments.

To enhance the economic utility of these projections, the number of estimated undiscovered small fields in each province was assigned to one of four depth intervals, 0 to 5,000, 5,000 to 10,000, 10,000 to 15,000 and greater than 15,000 feet. This allocation to depth intervals was in the same proportion as that of the ultimate (discovered and estimated) fields in the 1 to 5 million BOE sizes in each province.

Expected ultimate numbers of fields in each size class were aggregated across regions to arrive at an assessment for the onshore and state waters of the Lower 48 States. The result is presented in figure II.G.8. For each size class, the bars to the left represent the ultimate number of fields (assessed, undiscovered, and discovered) and the bars to the right represent discovered fields. Figure II.G.9, which appears as the reverse image of figure II.G.8, represents the relative percentage of hydrocarbons accounted for by each size class. Size classes 1 through 5 are estimated to contain about 89 percent of the ultimate number of fields but about 5 percent of the ultimately recoverable hydrocarbons. Currently, fields in classes 1 through 5 account for 69 percent of the discovered fields and less than 2 percent of the hydrocarbons.

The small fields account for about 94 percent of the estimated undiscovered fields in the Lower 48 States. Small fields are expected to contain about 25 percent of the total hydrocarbons in undiscovered oil fields and about 13 percent of the total hydrocarbons in undiscovered gas fields. When the economic screen was placed on the small fields none of the offshore Lower 48 States small fields was estimated to be commercially developable. However, for the onshore lower 48 States about 52 percent of the small oil fields and 46 percent of the small gas fields were shown to be commercially developable. Because more hydrocarbons were contained in the larger size classes, it is estimated that 73 percent of the total hydrocarbons in small oil fields and 66 percent of the hydrocarbons in small nonassociated gas fields were in commercially developable fields.

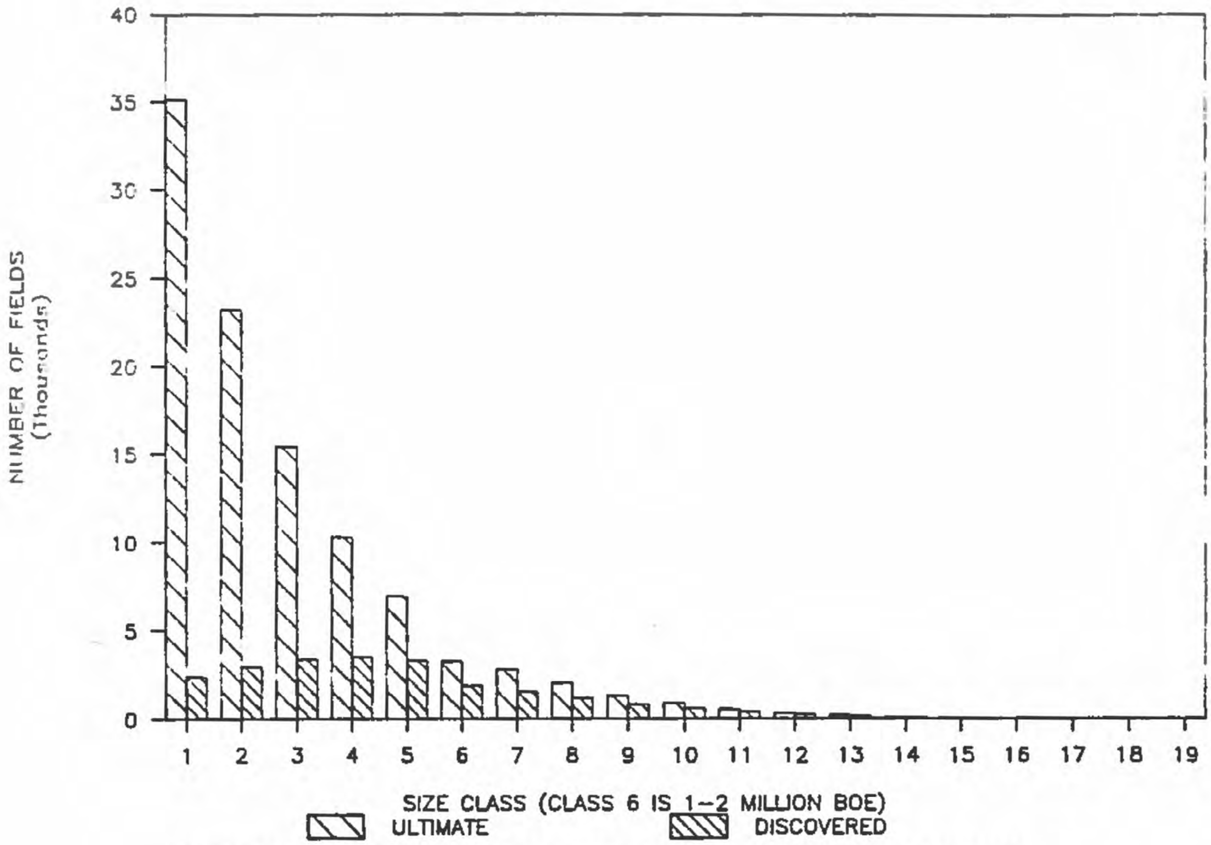

Figure II.G.8. Field size class distributions of the discovered and of the ultimate (discovered plus and undiscovered) number of oil and gas fields estimated in the Lower 48 States, including those less than 1 MM BOE. Classes shown in table II.G.1., in recoverable quantities.

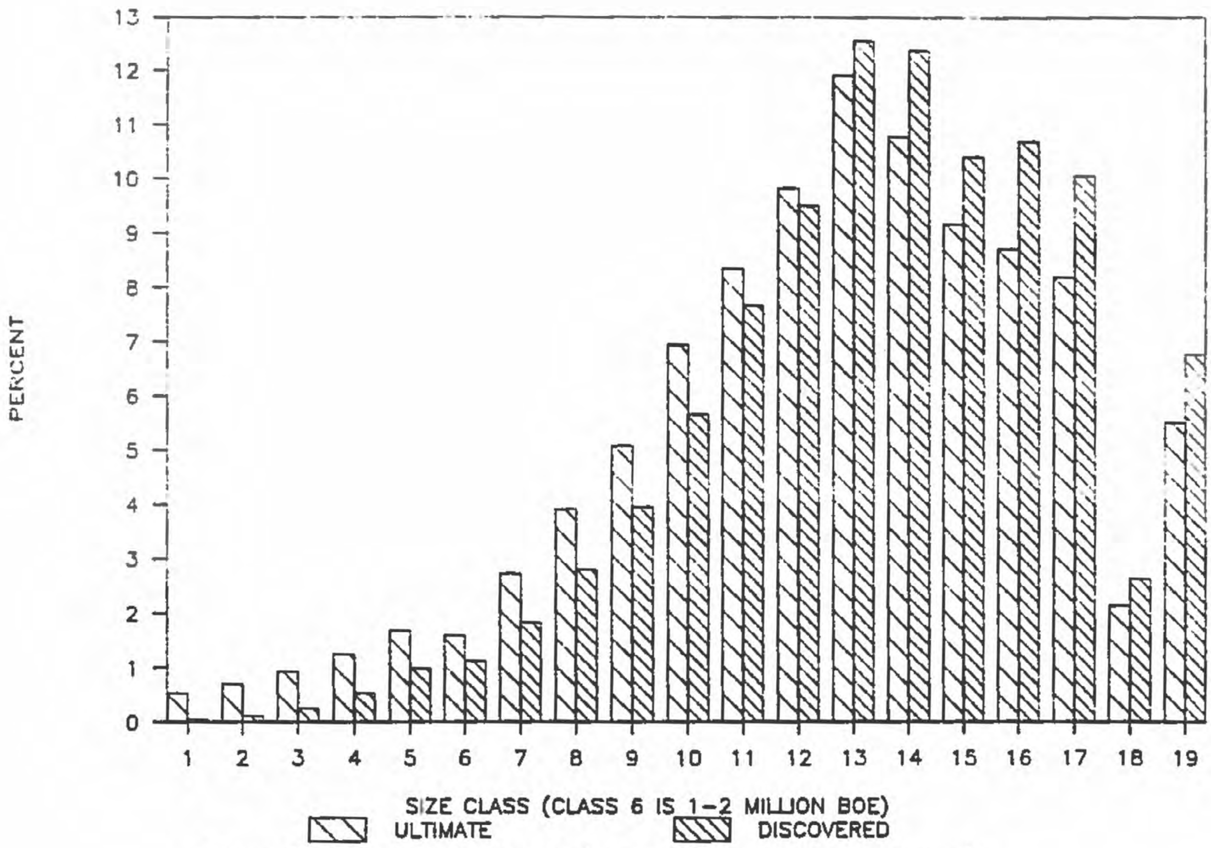

Figure II.G.9. Distribution of the total volume of hydrocarbons, in percent, by field size class for all fields in the Lower 48 States, including those less than 1 MM BOE. Shown are volumes for both discovered fields and those undiscovered fields estimated to exist. Classes shown in table II.G.1., in recoverable quantities.

Table II.G.2 shows the regional breakdown of the small fields. The highest concentration of small oil fields is in the Rocky Mountain and northern Great Plains (Region 4) and in the Mid-Continent (Region 7), while the Gulf Coast (Region 6) and the Mid-Continent (Region 7) have the highest number of small gas fields. Because most of the fields assessed in the Eastern United States (Regions 8a, 8b, 8c, and 9) are expected to be shallow, these regions contain the highest proportion of fields that are expected to be commercially developable.

Table II.G.2.--Number of undiscovered in-situ and commercially developable small oil and nonassociated gas fields by USGS region.

		Undiscovered oil and gas fields			
		Oil fields		Nonassociated gas fields	
Region Name	Region No.	In-situ	Commercially developable	In-situ	Commercially developable
Pacific Coast	2	515	220	493	210
Colorado Plateau and Basin and Range	3	1,125	377	912	455
Rocky Mountains and N. Great Plains	4	11,661	3,247	1,866	834
West Texas and East New Mexico	5	9,421	4,760	3,398	1,924
Gulf Coast	6	7,194	3,594	9,744	3,349
Mid-Continent	7	11,131	6,573	5,878	1,945
Michigan Eastern Interior Appalachian Atlantic Coast	8a 8b 8c 9	9,191	7,330	4,704	3,600
TOTAL		50,238	26,101	26,995	12,317

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H. INFERRED AND INDICATED RESERVES
by
D.H. Root

Introduction

Inferred and indicated reserves represent those quantities of oil or gas that will be produced from known fields beyond proved reserves. Indicated reserves are reported by oil and gas operators to EIA. They are the oil "that may become economically recoverable from known reservoirs through the application of improved recovery techniques using current technology" (EIA, 1987). The concept of indicated reserves applies only to oil, whereas the concept of inferred reserves applies to both oil and gas. Inferred reserves are not reported by the operators. Their existence is inferred from the historical experience that additions to reserves continue to derive from increases in the estimates of the sizes of known fields, even from fields several decades old. These increases can derive from the extension of known reservoirs, the discovery of new reservoirs in known field, or from revisions to the estimates of the fraction of oil or gas in place that may be recovered.

Method of Estimation

The growth factor for fields of a given age is the ratio of the ultimate amount of oil or gas that the field will produce to the current sum of past production and proved reserves. Growth factors for oil and gas fields of different years of discovery in the Lower 48 States were calculated by a method described in Appendix F of USGS Circular 860 (Dolton and others, 1981). The growth factors and the amounts of growth expected as of the end of 1979 (table II.H.1) are slightly different than those presented in Circular 860 because of the availability of one additional year of reserve growth data (API, AGA and CPA, 1980). The expected future growth in table II.H.1 includes indicated reserves. The inferred plus indicated reserves shown in table II.H.1 as of 1979 have been augmented by more post-1979 discoveries that have not yet fully grown and diminished by further development that has occurred since 1979 of fields discovered before 1980.

Because the reserve growth data series upon which table II.H.1 is based ended in 1979, those results for the Lower 48 States must be updated to the end of 1986 and an estimate for Alaska's inferred reserves must also be made. In the Lower 48 States, the recoverable oil and gas discovered in each of the years since 1979 were estimated by assuming that the discovery rates in barrels of oil and thousands of cubic feet of natural gas per foot of exploratory drilling were 14 bbl/ft and 140 MCF/ft, respectively. These assumed discovery rates are those that occurred in the late 1970's (table II.H.2). Because these discovery rates already contain an allowance for growth, some of the oil and gas discovered in the Lower 48 States since 1979 has not yet been credited to proved reserves and is in the inferred or indicated reserve category.

Table II.H.1--Annual petroleum discoveries in the Lower 48 States.

YEAR	OIL LOWER 48 DISCOVERIES MMBBL	OIL GROWTH FACTORS	OIL DISCOVERIES WITH GROWTH	GAS LOWER 48 DISCOVERIES BCF	GAS GROWTH FACTORS	GAS DISCOVERIES WITH GROWTH
1979	75	8.862	661	2735	4.142	11328
1978	116	4.049	469	3045	2.309	7030
1977	365	2.782	1015	4609	1.793	8264
1976	239	2.336	559	4726	1.573	7434
1975	384	2.028	779	6876	1.469	10101
1974	391	1.842	721	6394	1.303	8331
1973	579	1.812	1049	9444	1.311	12381
1972	322	1.755	565	7967	1.302	10374
1971	606	1.707	1034	8289	1.302	10793
1970	735	1.672	1228	4646	1.291	5998
1969	599	1.617	969	6671	1.267	8452
1968	982	1.603	1574	6311	1.238	7813
1967	707	1.575	1114	5159	1.249	6444
1966	513	1.558	800	8239	1.284	10579
1965	772	1.531	1182	8609	1.289	11096
1964	857	1.502	1287	9545	1.265	12075
1963	497	1.470	731	12825	1.325	16993
1962	974	1.454	1416	11075	1.294	14331
1961	506	1.431	724	9788	1.288	12607
1960	1023	1.436	1468	12871	1.288	16578
1959	754	1.434	1081	7661	1.276	9775
1958	1181	1.428	1687	19980	1.268	25335
1957	2077	1.422	2954	15818	1.251	19788
1956	1941	1.400	2718	19979	1.247	24914
1955	1545	1.390	2148	10299	1.220	12564
1954	2163	1.372	2967	16169	1.228	19856
1953	2179	1.352	2945	12589	1.226	15434
1952	1317	1.339	1763	16818	1.232	20720
1951	1746	1.321	2307	11319	1.218	13787
1950	2814	1.302	3664	14194	1.198	17004
1949	3453	1.299	4486	25626	1.200	30751
1948	3429	1.301	4461	8417	1.143	9620
1947	1610	1.275	2053	14338	1.100	15771
1946	1497	1.273	1906	6845	1.118	7653
1945	2196	1.257	2760	13987	1.112	15553
1944	2725	1.256	3423	11757	1.129	13273
1943	1366	1.244	1699	8526	1.131	9642
1942	1463	1.261	1845	9248	1.138	10524
1941	2246	1.227	2756	15419	1.163	17933
1940	3670	1.217	4467	13313	1.189	15829
1939	1977	1.209	2390	12100	1.176	14230
1938	4055	1.201	4871	14859	1.163	17281
1937	3421	1.193	4081	21544	1.154	24861
1936	7109	1.162	8260	24482	1.144	28007
1935	2495	1.154	2879	13665	1.120	15304
1934	3877	1.133	4393	13561	1.134	15378
1933	1577	1.129	1780	4081	1.124	4587
1932	587	1.126	661	4007	1.123	4500

Table II.H.1--continued.

1931	2475	1.121	2774	5406	1.122	6065
1930	7656	1.114	8529	10563	1.132	11957
1929	3754	1.125	4223	15129	1.106	16733
1928	2948	1.105	3257	10132	1.080	10942
1927	1779	1.094	1946	13645	1.077	14696
1926	4771	1.126	5372	4929	1.062	5234
1925	1063	1.116	1186	1012	1.050	1063
1924	905	1.056	955	2351	1.033	2429
1923	1212	1.038	1258	1843	1.026	1891
1922	1374	1.031	1417	39121	1.019	39864
1921	1947	1.017	1980	5135	1.011	5192
1920	2260	1.010	2282	2230	1.004	2239
PRE-1920	27131	1.000	27131	92351	1.000	92351
TOTALS	136986		165061	734270		869534

Table II.H.2.--Petroleum discoveries in the Lower 48 States for 2,100 million feet of exploratory drilling, 1859-1979.

Unit of drilling (10^8 ft)	Oil (MMBBL)	Gas (TCF)
1	27.140	92.358
2	16.420	72.792
3	34.720	106.599
4	28.160	133.910
5	11.620	52.369
6	9.210	53,137
7	3.860	31.814
8	4.920	30.624
9	3.350	26.667
10	3.950	31.354
11	2.700	32.872
12	2.060	27.489
13	2.030	30.088
14	1.960	18.408
15	1.660	17.004
16	2.480	13.794
17	2.920	22.456
18	1.790	24.674
19	1.430	17.658
20	1.420	14.210
21	0.900	13.385
Totals	164.700	863.662

Sources: Pre-1970 drilling data derived from figures 49 and 62, Hubbert (1974). Drilling data 1970 through 1979, AAPG (1970-1979).

Growth factors were used to calculate the amounts of oil and gas discovered since 1979 that have been credited to proved reserves and the amounts that remain to be credited to proved reserves, that is, the amounts that are now in inferred and indicated reserves (table II.H.3). The results of the calculations indicate that in the Lower 48 States the inferred reserves of gas are 96 TCF and the inferred and indicated reserves of oil are 16 BBO (table II.H.3).

Table II.H.3.--Estimates of proved discoveries 1980 to 1986 and associated inferred reserves as of 1986 for the Lower 48 States.

Discovery Year	Exploratory Drilling* MM FT	Discovered Oil (MM BBLS)			Discovered Gas (BCF)		
		Proved	Inferred	Total	Proved	Inferred	Total
1986	46	73	576	650	1,569	4,929	6,497
1985	69	240	731	971	4,204	5,503	9,708
1984	81	409	729	1,139	6,350	5,035	11,385
1983	69	415	554	970	6,164	3,532	9,695
1982	88	610	628	1,238	8,428	3,953	12,380
1981	101	769	647	1,416	10,870	3,294	14,164
1980	74	570	463	1,033	7,882	2,451	10,334
Totals	530	3,087	4,329	7,416	45,466	28,697	74,163

	Oil (MM BBLS)	Gas (BCF)
Proved Reserves (12/31/79)	18,127	162,976
Proved Reserves (12/31/86)	20,014	158,922
Production 1980-1986	17,890	117,576
Reserve Additions 1980-86	19,777	113,522
From Post-79 fields	3,087	45,466
From Pre-1980 fields	16,690	68,056
Inferred Reserves in Pre-80 fields	11,385	67,208
In Post-79 fields	4,329	28,697
In all Lower 48 fields	15,715	95,905

*Source: API (1987)

Regional Breakdown

After the inferred and indicated reserves were estimated for the Lower 48 States, the amounts of oil and gas were subdivided into a number of regions consistent with the Minerals Management Service estimate of inferred reserves in Federal offshore areas (table II.H.4).

The growth factors from table II.H.1 were applied to the fields in the field file from NRG Associates, Inc. (1986) which includes only those fields with known resources greater than 1 million barrels oil equivalent. The result of that calculation was to produce an estimate of inferred plus indicated reserves for each field in the file and these were combined to give estimates for the petroleum regions in the Lower 48 States. The inferred and indicated reserves from table II.H.3 were then allocated to the various regions proportional to the results of the calculations based on the field file. The results of this allocation in the Lower 48 States are shown in table II.H.4.

An inferred and indicated oil reserve for Alaska was estimated on the assumption that the ratio of inferred and indicated reserves to proved reserves in Alaska was the same as the like ratio in the onshore Lower 48 States. A similar procedure was followed in the case of gas except there were assumed to be no inferred gas reserves on the North Slope.

The result of applying these assumptions is that the inferred and indicated reserves of oil in Alaska are 6,379 million barrels and the inferred reserves of gas 3,000 billion cubic feet (table II.H.4).

Table II.H.4.--Regional breakdown of inferred and indicated reserves.

	Crude Oil Indicated Reserves (MM BBL)	Crude Oil Inferred Reserves (MM BBL)	Natural Gas Inferred Reserves (TCF)
Onshore:			
1	902	5,477	3,000
2	600	541	2,599
3	121	323	4,947
4	207	1,129	3,608
5	1,026	2,810	12,943
6	546	4,280	41,002
7	24	1,359	18,289
8	38	698	5,041
9	0	32	3
State Offshore:			
1	*	*	*
2	18	75	*
6	2	920	1,300
Federal Offshore:			
1	0	0	0
2	**	**	270
6	**	**	5,790
Total	3,483	18,245	98,758

* Included with onshore.

** Included in measured reserves.

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I. MINIMUM COMMERCIALLY DEVELOPABLE FIELD SIZES FOR ONSHORE AND STATE OFFSHORE REGIONS OF THE UNITED STATES

by

E.D. Attanasi

Introduction

This chapter describes the criteria used to compute the minimum size field that could be commercially developed for various onshore and State offshore regions of the United States. The nature and scope of the geologic assessment, in part, determines the framework for computing the minimum commercially developable field sizes. The purpose of the economic analysis was to screen the projected distribution of undiscovered fields to determine what portion of these fields, if identified, might be developed commercially at a given price and cost structure. The analysis does not imply that the fields determined to be developable are worth exploring for. Exploration and delineation drilling costs occurring prior to the decision to produce a field are considered to be sunk and not to enter the field production decision.

For each province (and subsurface depth or water depth interval), the size of the minimum commercially developable field was identified. Fields smaller than the minimum size were then excluded from the assessed distribution of commercially developable undiscovered fields. For the onshore Lower 48 analysis, results of the minimum commercially developable field size analysis were applied (1) to confirm the assumption used by USGS assessors that fields containing at least 1 million barrels of crude oil (MMBO) or at least 6 billion cubic feet (BCF) of natural gas are generally commercially developable, and (2) to screen "small" fields containing less than 1 MMB of crude oil or 6 BCF of natural gas to determine what portion of those small fields would be commercially developable. Alternatively, the results of the minimum field size analysis were applied to the assessed undiscovered fields located in State offshore areas and in onshore Alaska in order to truncate the geologically assessed distribution of undiscovered fields having at least 1 MM bbl of crude oil or 6 BCF of natural gas.

The following section briefly describes the general physical and economic assumptions common to the analyses. The discussion then focuses on analysis of onshore fields in the Lower 48 States, fields in State offshore areas, and finally the Alaskan fields.

General Assumptions

This analysis considered only undiscovered conventional oil and gas resources recoverable by conventional technology. Specifically, minimum economic field sizes were not estimated for tar sands, very heavy oil fields or for tight gas reservoirs. The geologic play assessments did not include information on oil and gas quality; this analysis, therefore, also ignored product quality variations. In almost all instances, the economic field size calculations were prepared at the province level rather than the more detailed play level. Table II.I.1 presents the field size categories used in the Lower 48 onshore and State offshore minimum field size analyses.

Table II.I.1 Field size classes

Class	Oil field size MMBBL (range)			Gas field size BCF (range)		
1	0.03125	-	0.0625	0.1875	-	0.375
2	0.0625	-	0.125	0.375	-	0.75
3	0.125	-	0.25	0.75	-	1.5
4	0.25	-	0.5	1.5	-	3
5	0.5	-	1	3	-	6
6	1	-	2	6	-	12
7	2	-	4	12	-	24
8	4	-	8	24	-	48
9	8	-	16	48	-	96
10	16	-	32	96	-	192
11	32	-	64	192	-	384
12	64	-	128	384	-	768
13	128	-	256	768	-	1536
14	256	-	512	1536	-	3072
15	512	-	1024	3072	-	6144
16	1024	-	2048	6144	-	12288
17	2048	-	4096	12288	-	24576
18	4096	-	8192	24576	-	49152
19	8192	-	16384	49152	-	98304
20	16384	-	32768	98304	-	196608

The values of cost-related parameters used in the analysis were chosen to reflect industry conditions in 1986. Computations were also based on provisions of the Federal 1986 Tax Reform Act. Provisions of the Windfall Profits Tax were excluded from the analysis. Fields were considered commercially developable if a discounted cash-flow analysis showed that an after-tax return of 8 percent could be achieved. The assumed price path was chosen to fall within the MMS price envelope. More specifically, it was assumed that the initial price of crude oil (and natural gas liquids), at $18 per barrel, declined 2 percent per year from the start of 1987 through 1989 and then increased at 4 percent per year thereafter. Likewise, the initial gas price of $1.80 per MCF declined 1 percent per year from the start of 1987 to 1989 and then increased at a rate of 5.5 percent per year thereafter. However, the price of gas was constrained so that it would not exceed 75 percent of the oil price when compared on a BTU basis.

<u>Analysis of Onshore Fields, Lower 48 States</u>

The analysis was designed to provide an economic screen for sifting the province-wide distribution of undiscovered oil and gas fields. Province specific data, such as the gas to oil ratios and natural gas liquids to natural gas ratios derived from the geologic assessment, were used in the economic analysis. Table II.I.2 presents the ratios used in the Lower 48 States onshore analysis. Individual State tax regimes could not be included in the analysis because many of the provinces include parts of more than one State. To be consistent and to partially offset this understatement of tax liability, a uniform 12.5 percent royalty was applied to the analysis of oil and nonassociated gas fields.

The general scheme for the onshore analysis is to determine whether the development of an identified representative field in a particular field size class and depth category produced a projected cash flow sufficient to pay operating expenses and provide an after-tax real rate of return of at least 8 percent to investors. The discounted cash flow computations test whether the typical production well from the representative field meets this condition. Well production continues until the operator's income is insufficient to cover the sum of the estimated direct operating expenses and production related taxes. Technical data used to test fields include field designs, well production profiles, and cost relationships. Some of the technical relationships and data were drawn from an earlier study of the Permian basin (USGS, 1980; Attanasi and others, 1981) and a DOE study of nonassociated natural gas prospects (DOE, 1986).

Onshore field development in the Lower 48 States was assumed to be complete in 1 year. For fields larger than 1 MM bbl of crude oil (or 6 BCF of gas), it was assumed that for every 10 successful development wells an additional 2 dry holes would be drilled. In fields smaller than 1 MM bbl (or 6 BCF of gas), 4 dry holes would be drilled for each set of 10 successful wells. For oil, secondary recovery projects were not evaluated because the objective was to identify the minimum commercial field size class. It was assumed that 30 percent of the drilling cost of development wells is tangible and therefore capitalized over 7 years. Of the remaining 70 percent of the drilling costs (that is, the intangible costs), 70 percent is expensed immediately and 30 percent is depreciated over the next 5 years. All dry hole costs are expensed in the year incurred. Because exploration costs were excluded from the analysis, depletion allowances were not computed. The onshore oil and gas pipeline network in these mature areas is sufficiently dense that transport cost to a pipeline was assumed to be negligible. The following sections describe the approach, document modifications, and identify supplemental sources of data.

<u>Oil field development costs, operating costs, field design, and well production</u>.--Oil field development costs included the cost of drilling and completing production wells, the cost of dry development wells, and the cost of lease equipment (surface producing equipment from wellhead to flange). In the Permian basin study, drilling cost functions for oil wells and dry holes (Attanasi and others, 1981) were adjusted using regional cost indices to reflect 1986 regional drilling costs. The regional classification generally followed that used by the DOE in its "Indexes and estimates of domestic well drilling costs 1984 and 1985" (1985). The one exception was to use the Rocky Mountain area cost indices for Nevada and Idaho rather than applying the west coast costs to these areas. Annual operating costs and lease equipment costs were adjusted in a similar manner using the data in "Costs and Indices for Domestic Oil and Gas Field Equipment and Production Operations 1986" (DOE, 1987). Per well lease equipment and operating costs were specified as functions of field depth and region.

Table II.I.2--Province ratios of associated gas to crude oil, natural gas liquids in associated gas, and natural gas liquids in nonassociated gas

Province name	(No.)	Oil fields MCF gas/oil (bbl)	Oil fields NGL/gas (bbl)	Nonassociated gas fields NGL/gas (bbl)
W. Oregon-Washington	072	0.000	0.000	0.000
Sacramento	073	0.000	0.000	0.000
San Joaquin	074	1.789	0.052	0.052
Los Angeles	075	1.192	0.053	0.000
Ventura	076	1.694	0.040	0.022
Santa Maria	077	0.900	0.055	0.000
Central Coastal	078	0.800	0.029	0.000
Sonoma-Livermore	079	1.000	0.000	0.000
Humboldt	080	0.000	0.000	0.000
Eastern California	081A	0.000	0.000	0.001
E. Basin and Range	082	0.023	0.000	0.012
W. Basin and Range	083	0.020	0.000	0.015
Idaho-Snake River	084	0.000	0.000	0.000
Paradox Basin	085	0.991	0.006	0.016
Uinta-Piceance	086	1.153	0.020	0.006
Park Basin	087	1.701	0.000	0.000
San Juan Basin	088	1.306	0.000	0.015
Albuquerque-Santa Fe	089	1.169	0.000	0.000
Wyoming Thrust Belt	090	1.500	0.000	0.049
Northern Arizona	091	0.120	0.000	0.000
S. Central New Mexico	092	0.411	0.000	0.000
S. Arizona-SW New Mexico	093	1.499	0.000	0.000
Williston	094	0.708	0.060	0.040
Sweetgrass Arch	096	0.837	0.001	0.001
Central Montana	097	0.080	0.000	0.000
Montana Overthrust	098	1.000	0.000	0.022
Southwest Montana	099	1.000	0.000	0.017
Wind River	100	2.154	0.003	0.008
Powder River	101	1.176	0.024	0.009
Southwest Wyoming	102	1.407	0.040	0.011
Bighorn	103	0.699	0.007	0.014
Denver Basin	104	1.193	0.086	0.000
Las Animas	105	0.100	0.000	0.000
Raton-Sierra Grande	106	0.501	0.000	0.005
Permian Basin	107	2.005	0.061	0.017
Palo Duro	108	0.140	0.000	0.005
Bend Arch	110	0.795	0.050	0.041
Marathon	111	0.000	0.000	0.003
Western Gulf	112	3.386	0.032	0.026
East Texas	113	1.159	0.061	0.031
La.-Miss. Salt Domes	114	1.596	0.027	0.077
Anadarko	115	1.716	0.027	0.022
Arkoma	116	0.500	0.000	0.000
Central Kansas Uplift	117	0.235	0.025	0.000
Cherokee Platform	118	1.382	0.025	0.000
Nemaha Uplift	120	1.000	0.025	0.000

Table II.I.2--continued.

Salina	121	0.000	0.000	0.000
Sedgwick	122	2.000	0.000	0.030
Southern Oklahoma	123	1.183	0.025	0.053
Iowa Shelf	125	0.000	0.000	0.000
Michigan Basin	127	1.519	0.063	0.014
Illinois Basin	128	1.000	0.025	0.013
Cincinnati Arch	129	0.422	0.025	0.015
Black Warrior	130	1.500	0.010	0.005
Appalachian Basin	131	0.000	0.000	0.000
Blue Ridge Overthrust	132	0.000	0.000	0.000
Atlantic Coastal Plain	135	0.300	0.000	0.000
Southern Florida	136	0.085	0.000	0.000

Well production rates determined the revenue stream and the field design determined the total potentially producible hydrocarbons per well. Oil well production schedules as well as field design were based, in part, on those used in the Permian basin study (Attanasi and others, 1981); however, because regional data were not available, well production schedules or recovery per well could not be adjusted regionally. The reserves per well were adjusted to reflect the set of size classes used in this study. Decline rates for primary production from the Permian basin study were applied to the corresponding field size class. The average province-wide gas to oil ratios were adjusted for field depth using data from the Permian basin study. Although the field design information represents standard engineering practices in the Permian basin, its application elsewhere is not expected to substantially bias the overall assessment.

Nonassociated gas field development costs, operating costs, field design, and well production.--The approach used in the nonassociated gas field analysis is similar to that used in oil field analysis. The technical data are from the DOE report entitled "An economic analysis of natural gas resources and supply" (1986). This report provides analytical relationships for estimating regional drilling costs, regional lease equipment costs, and regional operating costs. Cost estimates were updated to 1986 levels by using the publications entitled "Indexes and estimates of domestic well drilling costs" (DOE, 1985) and "Costs and indices for domestic oil and gas field equipment and production operations 1986" (DOE, 1987) and other sources. Per well lease equipment costs and operating costs were specified as a function of field depth and initial production rate.

Data from "An economic analysis of natural gas resources and supply" (DOE, 1986) also were used to construct field designs that reflected regional variations. The reserve production schedules for typical wells in fields of similar size and depth were based on data obtained from wells in analogous fields in the Permian basin (Attanasi and others, 1981). While the resulting well production schedules reflect some regional differences, they are consistent with empirical production characteristics of known fields.

Results: Minimum commercially developable field sizes.--The results of the analysis show that, with very few exceptions, the assessed fields of 1 MM bbl or 6 BCF or larger would be commercially developable. In the Lower 48 States onshore, a total expected value of 0.91 crude oil fields out of 2,098 undiscovered accumulations larger than 1 MM bbl would not be developable. Oil fields were assessed to depths below 15,000 feet in only a few areas; the frequency of deep nonassociated gas fields was much greater. However, the economic screen showed an expected value of only 2.5 nonassociated gas fields out of the estimated 2,295 undiscovered nonassociated gas accumulations (larger than 6 BCF) are not commercially developable.

The economic screen applied to the undiscovered field size distribution is an approximation in the sense that the field size classes are discrete and the size evaluation is made at a field size near the mid-point of the size class. Specifically, if the representative field for a particular field size class is evaluated as commercially developable then the entire size class is considered economic at that depth. Minimum commercially developable field sizes increase with increasing depth interval. Minimum commercial field sizes also reflect relative regional costs associated with field development.

Table II.I.3 shows the estimated numbers of undiscovered in-situ and undiscovered commercially developable small fields in the onshore Lower 48 States. At depths of less than 5,000 feet, about 76 percent of the small oil fields are developable; in the 5,000-10,000 foot depth interval, 33 percent of the small fields are developable; and at depths from 10,000 to 15,000 feet, only 3 percent of the undiscovered small fields are developable. The proportion of undiscovered small fields expected to be commercial varies from 27 percent of the fields in the smallest size class to more than 90 percent of the fields in size class 5 (0.5 to 1 million BOE). Overall, 52 percent of the undiscovered small oil fields are estimated to be commercially developable.

Table II.I.3 also shows that most of the undiscovered small nonassociated gas fields in the 0-5,000 foot depth interval are commercially developable; about 39 percent of the small gas fields in the 5,000-10,000 foot interval and 7 percent of the small gas fields in the 10,000-15,000 foot interval are commercially developable. Below 15,000 feet, no small gas fields are commercially viable. The proportion of small gas fields commercially developable ranges from 28 percent of the fields in size class 1 to 90 percent of the fields in size class 5. Overall, 46 percent of the assessed undiscovered small gas fields are estimated to be commercially developable.

Table II.I.3--Numbers of undiscovered small crude oil and nonassociated gas fields - in situ and commercially developable

	CRUDE OIL FIELDS									
	In situ					Commercially developable				
Size class	All depths*	0-5	5-10	10-15	>15	All depths*	0-5	5-10	10-15	>15
1	22427	11900	8091	2310	126	6098	6097	0	0	0
2	13597	7045	5032	1440	79	7979	6719	1261	0	0
3	7858	3924	3011	876	48	6299	3916	2383	0	0
4	4278	2057	1701	494	27	3809	2057	1694	58	0
5	2081	903	897	265	15	1916	903	897	116	0
TOTAL*	50241	25829	18732	5385	295	26101	19692	6235	174	0
	NONASSOCIATED GAS FIELDS									
	In situ					Commercially developable				
1	10962	3627	3952	2271	1112	3038	3038	0	0	0
2	7114	2285	2593	1514	720	2807	2279	527	0	0
3	4501	1408	1657	981	454	3046	1408	1637	0	0
4	2737	860	1006	601	270	1907	860	1006	41	0
5	1700	530	631	376	164	1526	530	631	365	0
TOTAL*	27014	8710	9839	5743	2720	12324	8115	3801	406	0

*Totals may not add due to rounding.

Analysis of fields in offshore State waters - Lower 48 States

Minimum commercially developable field sizes for offshore fields located in state waters were also calculated. Results show that, for most areas, the minimum offshore field size is greater than 1 MM bbl of crude oil or 6 BCF of gas. Because the areas of individual offshore provinces often encompass the jurisdiction of different states or local governments, the tax regimes of individual jurisdictions were not included in the analysis. Rather, a uniform 16.7 percent royalty rate was applied to offset the understatement of tax liability.

For a given field size and water-depth category, the Discounted Cash Flow (DCF) analysis was applied to the representative oil or nonassociated gas field. For cost estimation purposes, fields were located in areas bound by water-depth contours at 60, 240, 390, and 660 feet. In particular, the representative field for each water-depth interval was sited at 40, 150, 317, and 515 feet of water depth, respectively. To simplify the cost calculation for the offshore areas, all wells were assumed drilled to a depth of 11,500 feet.

Development drilling, completion, platform, platform equipment, and platform operating costs were fully allocated to individual production wells so that the production well net cash flow streams included these components. The production well cash flow streams were then aggregated to the field level using the field development profiles presented in Attanasi and Haynes (1983).

The economic life of the production well ends when the sum of direct operating costs and production-related taxes exceed operator income. Costs were developed initially for fields in the Gulf of Mexico. From its historical data base and industry sources, the MMS has prepared a set of cost multipliers (see table II.I.4) that can be used to adjust Gulf of Mexico drilling, completion, platform, platform equipment and operating costs to estimate costs for other Lower 48 States offshore areas.

Table II.I.4.--Cost adjustment factors as multiples of costs in the Gulf of Mexico

State offshore area	Platform	Drilling & completion	Oil field equipment	Gas field equipment	Operation
Southern California	1.00	1.00	1.50	1.20	1.00
Central California	1.05	1.00	1.50	1.20	1.05
Northern California	1.10	1.025	1.50	1.20	1.10
Washington-Oregon	1.15	1.10	1.50	1.20	1.20
Atlantic	1.30	1.10	1.10	1.10	1.40

Analysis of field development costs and design costs.--Field-development and field-design costs include drilling and well completion costs, platform costs, costs of oil and gas processing equipment, and platform abandonment costs. Costs of drilling and equipping development wells depend on water depth and the type of drilling rig used, that is, mobile or platform rig. Development-well drilling time was assumed to be 30 days; an additional 15 days was required for well completion. Details of the methodology for computing drilling and well completion costs are documented in Attanasi and Haynes (1983, 1984). Drilling, platform, and operating costs from this study were adjusted to reflect sustainable long-run cost levels consistent with those prevailing during 1986. For every 10 development wells, it was assumed that an additional 2 dry production wells were drilled.

Platform costs were specified as a function of the water depth and the number of well slots. The costs of platform equipment were based on the expected peak production capacity of wells serviced by the platform. Platform abandonment costs were estimated as the present worth of half of the original platform installation costs discounted over the life of the field. Platform operating costs were estimated as a function of the number of wells serviced by the platform and the water depth of the field.

Engineering information on well productivity and well production profiles were prepared for an earlier study by the Dallas Field Office of the Energy Information Administration (EIA) (John Wood, personal communication, September, 1977) using historical data from fields in the Gulf of Mexico offshore Texas and Louisiana. From these EIA data, configurations of development wells, production platforms, and processing equipment were devised to estimate investment and operating costs for the representative field (see Attanasi and Haynes, 1983, 1984)[2]. Estimated costs also included a pipeline for tying platforms to a trunkline with a 15-inch pipe (Attanasi and Haynes, 1984).

Results: Minimum commercially developable field sizes.--Geologic provinces assessed as having undiscovered fields in State offshore areas in the Lower 48 States are the Western Gulf basin, Louisiana-Mississippi Salt basin, Western Oregon-Washington, Humboldt basin, Los Angeles basin, Ventura basin, Santa Maria basin, Atlantic Coastal plain, and South Florida. The offshore commercial field size analyses used province assessment data to estimate associated gas to oil and natural gas liquids to gas ratios so that by-product credits could be computed. The minimum commercially developable field size was assumed to be at the Lower bound of the smallest field size class tested to be economic. Table II.I.5 presents the results of this analysis for fields located in 40 feet and 150 feet of water. The results shown here are entirely consistent with the minimum field sizes computed by the Minerals Management Service in these areas.

According to the geologic assessment, state waters of the Lower 48 States are expected to represent only about 6 percent of the hydrocarbons in undiscovered crude oil fields and 4 percent of the hydrocarbons in undiscovered gas fields located in the Lower 48 States onshore and State offshore areas. Overall, there are expected to be 333 crude oil fields, of which 233 contain less than 1 MM bbl, and 307 natural gas fields, of which 124 contain less than 6 BCF of gas. According to table II.I.5, none of those fields having less than 1 MM bbl (or 6 BCF) is expected to be commercially developable.

Table II.I.5.--Minimum commercially developable field sizes in State offshore waters, Lower 48 States.

Province	Oil field (MM BBL)		Nonassociated gas field (BCF)	
	40 ft	150 ft	40 ft	150 ft
Western Gulf basin	2	2	12	12
Louisiana-Mississippi Salt basins	2	2	6	6
W. Oregon-Washington	-	-	24	24
Humboldt basin	-	-	24	24
Los Angeles basin	2	2	-	-
Ventura basin	2	2	12	12
Santa Maria basin	2	2	-	-
Atlantic Coastal Plain	4	4	24	24
South Florida	2	4	12	24

[2]Because the original engineering data pertained to a set of slightly different field size classes, some adjustments were made to the final costs. Recoverable reserves per well were also adjusted, but the production profile (in terms of the fraction of well reserves produced) was the same as for the original data.

Analysis of Fields in Alaska

Cook Inlet Area.--The oil and gas resources of southern Alaska are concentrated around the Cook Inlet area. Both the onshore and offshore oil and nonassociated gas economic field analyses for the Cook Inlet area used the same algorithms as those applied in the Lower 48 States onshore and State offshore areas. However, the Lower 48 States costs were adjusted using Joint Association Survey (JAS) data, American Petroleum Institute (1985 and 1986), Beck and Wiig (1977), and local industry and government sources. The Alaska State tax provisions were also incorporated in the analysis.

In particular for onshore oil and gas fields, operating and lease equipment costs were doubled and drilling costs were adjusted by comparing the Rocky Mountain drilling cost estimate with data published in various issues of the JAS. Because there are established local markets for oil and gas, the assumed wellhead price path was the same as the price path used for the Lower 48 States. The computations show a minimum commercially developable oil field size of 2 MM bbl for shallow fields and 4 MM bbl for deeper fields, and a minimum commercially developable gas field size to a depth of 10,000 feet of 12 BCF and for deeper fields of 24 BCF.

The offshore field development costs for the State waters of the upper Cook Inlet were also derived as multiples of the costs in the Gulf of Mexico. According to data presented in Beck and Wiig (1977), offshore Cook Inlet field operating costs are estimated to be about two times the Gulf of Mexico field operating costs. In addition, Cook Inlet platform costs are 30 percent higher, oil and gas equipment costs are 20 percent higher, and drilling costs are 10 percent higher. Results show the minimum developable offshore field size to be 4 MM bbl for oil fields and 24 BCF for gas fields.

Arctic Regions Onshore.--Onshore Alaska's Arctic regions are still frontier areas and great uncertainty surrounds field production characteristics and costs of developing and producing oil and gas fields in a hostile environment. However, the literature describes evolving and innovative field development and production techniques that appear to have substantially reduced the costs and risks of operating in Arctic regions. For example, according to published reports (Harris, 1987a), estimated costs associated with the development of the Endicott field were $3.4 billion in 1981. By 1985, costs were reestimated to be $2.0 billion. This field began production in 1987, and actual development costs are expected to be $1.1 billion. Along with the hostile environment, the remoteness of production from markets and the lack of infrastructure account for the high costs and large minimum economic field sizes.

Nonassociated natural gas fields were assumed not to be commercially developable for their gas resources until a means of transport to market is in place. It is, however, possible that a sufficiently large nonassociated gas field would be commercially developable for its natural gas liquids. Because the assessed undiscovered nonassociated gas field sizes are very large and the liquids to gas yields are sufficiently high, it appears that such a nonassociated gas field could be developed for their liquids in either the Barrow Arch or the Eastern Overthrust play that extends into Arctic National Wildlife Refuge (ANWR) (see fig. II.I.1).

Such a field would probably be developed as a gas field (that is, on similar well spacing), the liquids stripped from the gas, and the gas reinjected into the reservoir. This cycling process would continue until the yields became too lean to meet net operating costs. Neither the earlier National Petroleum Council (NPC) Arctic Study (1981) nor the Bureau of Land Management's ANWR Study (U.S. Department of Interior, 1986) appears to have considered such a possibility,[3] so cost data for such a configuration in Arctic areas are not available in the open literature. Costs will depend on the NGL yield of the gas, but there may be instances where the development and production costs of such nonassociated gas fields for NGL will be less than an oil field of equivalent size (that is, in terms of barrels of liquids). The variability in NGL yields even across individual plays is not adequately captured in the assessment. So, nonassociated gas field development for natural gas liquids only was not formally incorporated in the economic analysis.

Because production experience is limited in Arctic areas, the field production profile applied in the National Petroleum Council reports (1981a, 1981b) was assumed. Peak field production is 9.1 percent of reserves per year. Initial production in the first year is 20 percent of the peak and, in the second year, 70 percent of the peak. Peak production occurs in years 3, 4, and 5. Field production is assumed to decline at 12 percent per year starting in year 6. Fields smaller than 500 million barrels are assumed to begin production during the second year of development well drilling, whereas larger fields do not begin production until the fourth year of development well drilling.[4] Costs include development drilling, the facilities, and internal pipelines, but no costs associated with exploration and delineation drilling. This assumption allows the development program to carry only incremental costs of additional site development. The initial costs of access and development are carried by the exploration and delineation drilling program.

Facilities costs include drill pads, flow lines from the drilling sites, the central processing facility (cpf) and all other infrastructure required for housing workers, including amenities. These costs were taken from Young and Hauser (1986) and the National Petroleum Council (1981a, 1981b). Facilities costs from Young and Hauser provide more detailed data for the smaller fields than does the NPC study cost function. The costs for smaller fields from Young and Hauser were adjusted to 1981 levels to be consistent with other NPC costs (1981a, 1981b); the 1981 levels then were adjusted to 1986 dollars using the West Coast equipment cost indices in

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[3]It is generally understood that the Point Thompson field contains about 350 million barrels of natural gas liquids and 5 to 6 TCF of natural gas and would be developed for its liquids.

[4]In terms of the overall field development investment profile, large fields are assumed to begin production in the fourth year of investment, whereas smaller fields begin production one year earlier.

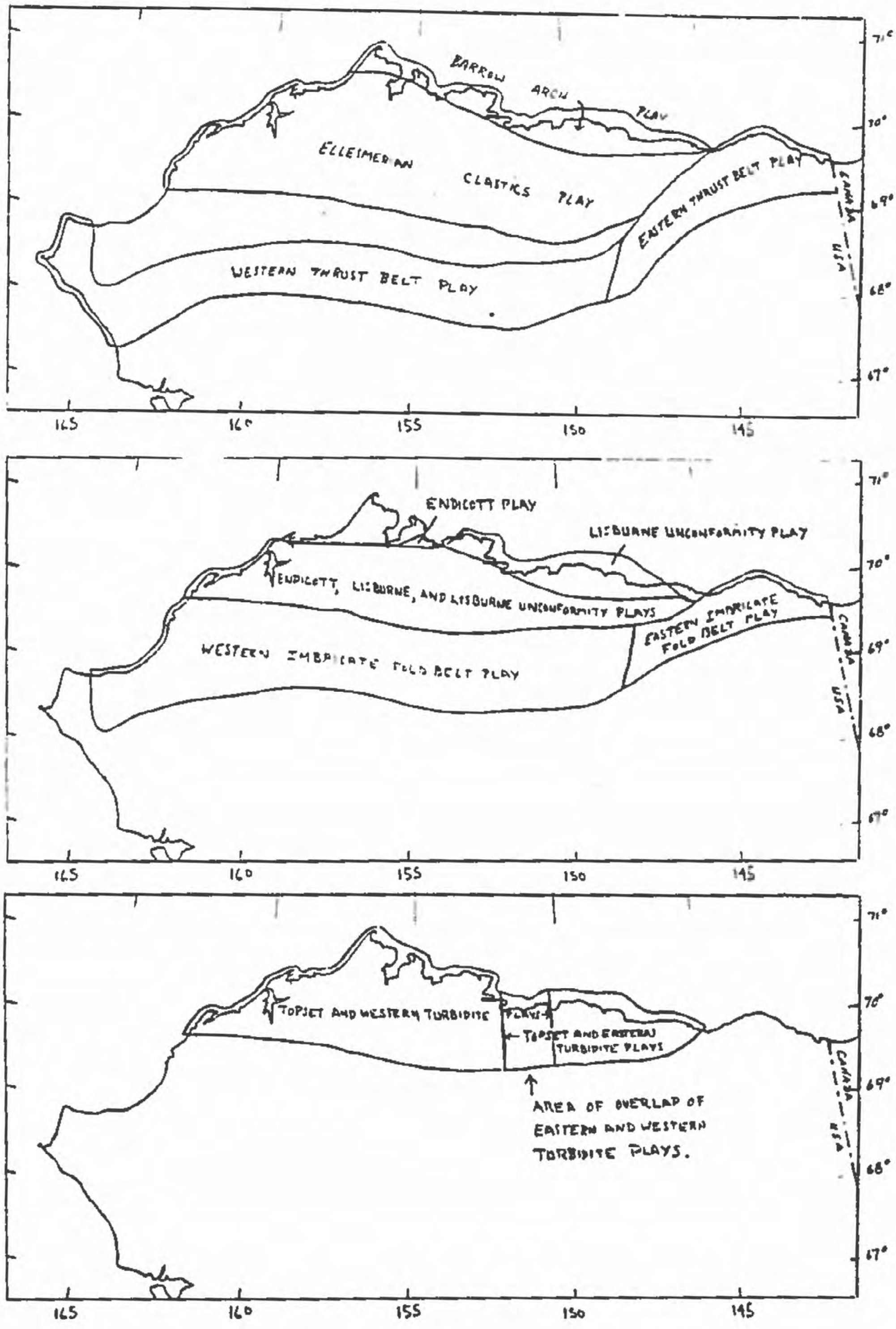

Figure II.I.1. Approximate locations of plays assessed in northern Alaska.

"Costs and indexes for domestic oil and gas field equipment and production operations 1986" (DOE, 1986). The facilities costs are assumed to include a natural gas liquids plant for stripping natural gas liquids from the associated gas. Field operating costs were adjusted in a similar fashion. Cost adjustments from earlier studies could only capture the trend in general costs levels to 1986 and do not reflect the rather dramatic cost reductions (see Harris, 1987a; Paige and Dayton, 1987) attributed to more efficient equipment and field design and industry learning.

According to the JAS, development drilling costs have declined dramatically during the last 6 years in Northern Alaska. Because the USGS study attempts to capture long-run industry conditions, drilling costs applied to various areas in Northern Alaska reflect the existence of a mature industry. Average production well drilling and equipping costs were, therefore, assumed to be $1.6 million for depths to 10,000 feet and $3 million for wells deeper than 10,000 feet. For plays in remote areas (interior to the coast), production well costs were increased by 29 percent.

Average well productivity for a class 15 field, assuming 0.4 water and gas injection wells per producer, was estimated to be about 7.5 million barrels per well by the NPC. Well productivity was then scaled to smaller field size classes using productivity data from a set of North Sea fields (personal communications, John Haynes, Global Marine, Inc.). Table II.I.6 shows the well productivities used in the field analysis.

The analysis incorporated the following Alaskan State taxes: income tax, royalty tax, severance tax, and ad valorem tax on tangible assets. Federal taxes included 16.67 percent royalty; income tax provisions were again in accordance with the 1986 Federal Tax Reform Act. The price path for crude oil and NGL applied in the Lower 48 States was assumed to represent the landed West Coast price. Northern Alaska well-head prices were therefore net of all transportation costs. All royalty taxes were based on well-head prices.

Transportation costs include the costs of transporting the output to the Trans-Alaska Pipeline System (TAPS), the TAPS tariff, and the cost of transportation to the U.S. West Coast. For each play, the (east-west) distance to TAPS was estimated from a central north-south locus of points that bisected the play. Figure II.I.1 shows the approximate locations of the plays. The estimated distance was used as a basis for computing costs associated with the pipeline to TAPS. The pipeline to TAPS was assumed to be built by a separate entity and the pipeline tariff charges assured investors of an 8 percent after-tax return on investment. The pipeline costs were estimated from the 1984 data presented in Young and Hauser (1986) and adjusted to 1986 costs. Following Young and Hauser (1986), annual pipeline operating costs were assumed to be 2 percent of investment costs. The separate pipeline business entity was subject to Alaskan State income and ad valorem taxes and all relevant Federal taxes.

Table II.I.6.--Assumed average productivity of oil wells by field size class, onshore Arctic Alaska.

Field Size Class[1]	Field size (MM bbl)	Average productivity per well[2] (MM bbl)
12	64 - 128	[illegible]
13	128 - 256	4.2
14	256 - 512	5.4
15	512 - 1024	7.5
16	1024 - 2048	10.0

[1]See table II.I.1.

[2]Assumes 0.4 water injectors per production well.

It should be recognized that for some fields in remote western areas, it will be less costly to build a pipeline to an offshore port area and ship the product to a staging area or directly to the West Coast.[5] The transportation costs developed by the MMS in their analysis for fields in the Chukchi Sea and Norton Sound are less than the transportation costs associated with areas closer to TAPS that were assumed to use TAPS. Transportation costs for the Hope basin area only slightly exceed Beaufort Sea transport costs, which include the TAPS charges.

The TAPS tariff was assumed to be $3.00 per barrel, and the transport cost from Valdez to the U.S. West Coast was assumed to be $1.15 per barrel. According to a U.S. Commerce Department report, the expected (mid-point) results of the TAPS court litigation show the TAPS tariff declining to $2.05 per barrel in 1995 and $1.52 per barrel in 2000 (U.S. Department of Commerce, 1986). Actual future reductions in the TAPS tariff might be offset by sending more of the crude oil to Gulf of Mexico ports.

Results of the minimum commercial field size analysis are shown in table II.I.7. Because the Northern Alaska minimum field sizes are expected to be large, the upper and lower bounds were evaluated as well as the midpoints of each size class. For the entire size class to be considered as commercial, the lower boundary value had to be evaluated as economic.

[5]All costs associated with individual field production facilities were calculated based on a stand-alone field. Pipeline tariff calculations assumed, however, that the pipeline operated at a minimum capacity of 65 percent of a pipeline sized for 250,000 barrels per day throughput.

If the size class midpoint field was evaluated as economic but the lower boundary value was not, then only fields at least as large as the midpoint field size class were considered commercially developable. As is currently the practice (Harris, 1987b), natural gas liquids in associated gas are assumed to be stripped from the gas and sent with the crude oil through the pipeline. After stripping, the gas is injected into the reservoir.

Minimum field sizes are not shown for the Ellesmerian clastic play, the Paleo-topographic Lisburne play, and the Kandik play because the maximum possible field sizes associated with these plays are not large enough to be commercially developable. The Lisburne, Endicott, Alaska Interior and Bristol Tertiary plays are nonassociated gas plays and their maximum possible sizes appear to be insufficient to be commercially developable for the liquids alone. The Eastern and Western Imbricate Fold Belts and the Eastern and Western Thrust Belts were considered as remote areas.

Because of the relatively large field sizes involved and the effects of scale economies, the minimum commercially developable stand-alone field size is reasonably robust. The dominant cost component of onshore field development is the cost associated with facilities such as drilling pads, roads infrastructure, the internal pipeline network, and the so-called central processing facility. If two fields were in close enough proximity to share facilities, these individual minimum field sizes would probably decline to 250 million barrels. Similarly, if three fields shared facilities, in some areas the minimum commercially developable field size would decline to just under 200 million barrels.

Analysis of fields in Arctic regions - offshore.--Minimum offshore field sizes computed by the MMS for the areas they considered show minimum field size to be independent of water depth. Consequently, these minimum sizes were used to truncate the distribution of undiscovered fields. The minimum field sizes were associated with Minerals Management planning areas. Table II.I.8 shows the minimum field size and area. Nonassociated gas fields were assumed to be not commercially developable.

Conclusions

Engineering and geologic data used in the determination of the minimum field sizes do not include special reservoir or geologic characteristics associated with individual plays; and economic data do not very well reflect local economic conditions. However, imposing the economic screen on the conventional oil and gas resource base does permit one to make reasonable inferences about the proportion of assessed oil and gas resources that would be commercially developable if identified. Moreover, the models developed provide a basis for predicting how that proportion might change with changing prices, interest rates, costs, and tax rates. In future assessments, analytical screening models should be prepared to determine the impact of innovative technologies on the minimum commercially developable field sizes for small offshore field development and to screen currently producible resources in heavy oil and tight gas reservoirs.

Table II.I.7.--Minimum commercially developable field sizes for northern Alaska oil plays.

	Play	GOR[1] (MCF/bbl)	LGR[2] (bbl/MMCF)	Distance to TAPS (miles)	Commercially developable field size (MM bbl) ≤10,000 ft	>10,000 ft
Arctic	Topset	0.010	0.0	100	384	384
Coastal	E. Turbidite	1.000	40.0	50	384	384
Plain	Barrow Arch	.750	40.0	75	384	384
Northern Foothills	Imbricate fold belt, W.	1.5	15.0	150	384	384
	Imbricate fold belt, E.	0.6	30.0	75	384	384
Southern	Thrust belt, W.	1.0	10.0	150	384	384
Foothills	Thrust belt, E.	1.0	15.0	75	384	384

[1]Gas to oil ratio
[2]NGL to gas ratio

Table II.I.8.--Minerals Management Service minimum economically developable field sizes for Arctic offshore State waters in million barrels of oil equivalent.

Area	Minimum field size MMBOE
Beaufort Sea	
Eastern	259
Central	220
Western	275
Chukchi Sea	204
Hope	159
Norton Sound	294

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III MMS METHODOLOGY

A. PRESTO III Methodology

The primary problem complicating any resource assessment is an insufficient amount of information. The methodology employed for the assessment must be based on the amount and relative accuracy of the information available. Ideally, from an assessment standpoint, each prospect (a geologic feature which could potentially trap commercial quantities of hydrocarbons) would be drilled and, if hydrocarbon bearing, additional delineation wells would be drilled to define the size and reservoir characterization of the accumulation. Since this is not physically possible, this approach is simulated by MMS, using a computer program called PRESTO, an acronym for Probabilistic Resource ESTimates Offshore. Each prospect is modeled mathematically, with uncertain geologic variables represented by a range of possible values. Each prospect is then "drilled," and the results of this simulated drilling are accumulated in a range of possible results, with associated probabilities of occurrence.

This chapter reviews various phases of the MMS resource assessment methodology, from the initial step of acquiring essential geologic and geophysical information used to identify potential hydrocarbon traps to the final translation of the available information into numerical representations that can be used in the computer simulation. In general, PRESTO uses an analysis of risk to control the relative contributions of zones, prospects, and basins to the overall resource assessment. Ranges of values for reservoir variables are sampled to obtain zone and prospect level resources. Economic viability is tested and the results aggregated to basin and area results. After the individual elements comprising the PRESTO model are described in this chapter, a sample step-by-step account of a program run is presented to illustrate the functioning of the various interrelated elements.

The term "PRESTO," used in this text, refers to the third generation of the program, PRESTO III. The phrase "PRESTO methodology" refers to the probabilistic range-of-values approach as represented by the PRESTO computer program.

OVERVIEW

Responsibility for the MMS resource assessment is shared by four Regional OCS offices: Alaska, Atlantic, Gulf of Mexico, and Pacific. The geologists, geophysicists, petroleum engineers, and economists in these offices provide their expertise to derive specific model inputs. Headquarters personnel oversee the assessment and are responsible for the methodology used. The resource estimates presented in this report represent a massive, cooperative effort.

PRESTO allows the evaluator to mathematically represent each geologic prospect identifiable from seismic data, as well as potential unmapped prospects. Petroleum exploration is characterized by uncertainty, from whether hydrocarbons exist in commercial quantities anywhere in a frontier area to the actual size of the accumulations if hydrocarbons do exist.

PRESTO allows this uncertainty to be expressed in terms of risk assessments and ranges of values for uncertain variables. To reflect this uncertainty in the results, the estimates are presented as ranges with an associated probability of commercial hydrocarbons existing in at least one of the prospects in the area assessed.

DATA ACQUISITION AND INTERPRETATION

Before the simulated drilling program can be run, an inventory of potential geologic targets must be developed. The first step in identifying these prospects is to acquire available pertinent geologic and geophysical (G&G) data and information.

A major responsibility of MMS is to regulate exploration and development activities on the Outer Continental Shelf (OCS). These activities are controlled by issuing prelease permits for gathering G&G data and postlease permits for drilling to individual companies. These permits ensure adequate protection for acquatic life, prohibit interference with operations on existing leases, establish operating procedures, and specify requirements for data disclosure. Pursuant to permit or lease terms, MMS inspects and selectively acquires proprietary G&G information collected by industry. Geophysical data acquired are primarily reflection seismic surveys. Geologic data used to identify geologic features which may act as traps for oil and natural gas accumulations include well logs and information from cores and cuttings.

The MMS also has access to information from Continental Offshore Stratigraphic

Test (COST) wells, which are joint ventures sponsored by the oil and gas industry to obtain geologic information in unexplored areas. Finally, the results of exploratory and develoment drilling on leased blocks are also available to MMS in the form of well logs or other pertinent data resulting from such operations. Further details on MMS data acquisition activities can be found in Geological and Geophysical Data Acquisition (OCS Report, MMS 87-0003).

Common depth point (CDP) seismic data are most useful for developing a regional geologic framework. Initially, broad, regional exploration plays are developed. Data are analyzed, interpreted, and assimilated into prior analyses. Ultimately the focus shifts to the prospect level in preparation for a proposed lease sale or a major assessment. For the current assessment, MMS had acquired the following amounts of CDP seismic data by the end of December, 1986 (Tirey, 1987, p. 22):

Offshore Region	Estimated Line Miles of CDP Seismic Data
Alaska	332,500
Atlantic	180,000
Gulf of Mexico	347,000
Pacific	99,000
Total	958,500

Geologic information was available from COST wells, exploration wells, and production wells. At the time of this assessment (January 1, 1987), exploration in the Atlantic OCS had resulted in 46 exploratory and 5 COST wells. The Alaska OCS area had 67 exploratory and 14 COST wells. The number of exploration and development wells drilled in the mature producing areas included approximately 925 wells in the Pacific and 24,000 wells in the Gulf of Mexico (USDOI, 1987, pp.E1-E6). Additional information was also available for this assessment from wells in State waters and onshore.

As potential hydrocarbon traps are identified through interpretation of the seismic data, detailed subsurface maps are developed. These maps, in conjunction with additional analyses, are used to provide a range of values for the productive acreage, thickness, and hydrocarbon type for each prospect. Figure ~~3-1~~ III.A.1 shows an example of a typical subsurface structure map.

SIMULATION TECHNIQUES

Since resource assessments often must rely on an incomplete or inadequate geologic and geophysical data base, the original version of PRESTO used a modeling technique called Monte Carlo sampling to quantify uncertainty by incorporating subjective judgment in an objective manner. This method has become a standard technique in the petroleum industry for making decisions under conditions of uncertainty. The technique enables the evaluator to incorporate a range of possible values and specify the distribution type (such as normal, lognormal) for uncertain variables, rather than being restricted to single-point estimates. A computer is necessary to perform the many computations required by this method. The computer program code contains equations which specify the relationship among each variable and the outcome. Many iterations or trials are performed, each time randomly selecting a value for each variable, substituting the values into the equations, performing the calculations, and saving the results. Upon completion of all the trials, ranges of possible outcomes have been created and stored.

III. A.1

Figure ~~8~~. Sample subsurface structure map.

A simple example would be to solve the following equation using Monte Carlo techniques:

$$\underline{A} * \underline{B} = \underline{C}$$

where the variable A can range from 1 to 10, and variable B ranges from 2 to 8 (both are continuous, uniform distributions). This problem was run using 10 Monte Carlo trials. The computer contains an algorithm for generating pseudorandom numbers, which are used to randomly select values for the variables. (The numbers are termed pseudorandom to indicate that although random numbers are generated, with a cycle of roughly one million numbers before repetition, the same sequence of "random" numbers can be reproduced by using the same random number seed). Ten values were randomly selected from the distributions for both variables. These values were used in ten computations to yield the following ten results:

(4.0, 7.2, 10.4, 21.7, 21.8, 26.7, 27.5, 45.3, 56.8, 75.0)

The solutions ranged from a low of 4.0 to a high of 75.0, with the mean or average amount equal to 29.6.

This same process is used in a more complex form in the PRESTO program. Each trial yields one solution which represents one possible state of future.

Although the basic concepts are unchanged from the original PRESTO I, the PRESTO III version has undergone considerable program restructuring to accommodates not only Monte Carlo sampling but also the option of using Latin Hypercube sampling. Latin Hypercube sampling (LHS) is similar to the Monte Carlo approach. However, where Monte Carlo sampling randomly selects values from a variable's input distribution, LHS first divides the distribution into equal probability areas and then randomly samples each area. The number of areas is equal to the sample size. If LHS had been used in the previous example, the probability distribution for variable _A_ and variable _B_ would first have been divided into 10 equal probability areas. Then a value would have been randomly chosen from each of the areas until all 10 areas had been sampled. This sampling procedure ensures that the entire distribution is represented. The resulting 10 pairs of numbers would yield a range of estimates including 10 possible solutions.

The LHS is advantageous when the sample size is very small, for example, when the risk factors are very high. This procedure assures a more even sampling with fewer trials than the Monte Carlo approach, which could allow a cluster of sampled values owing to the random number selection. Although the option of using Monte Carlo sampling is available; the current assessment used LHS exclusively, because of improved sampling capability with small sample sizes. Previous testing has shown that with the more efficient sampling of LHS, 500 simulations are sufficient in all but the highest risk areas. For the current assessment, 1,000 trials were used exclusively.

RISK ANALYSIS

The PRESTO model architecture is comprised of four levels: area, basin (or subarea), prospect, and zone. The methodology is one of prospect summation. Prospect zone resources are computed and summed to the prospect level; prospects are summed to the basin level; and basin results are summed to the area level. At any level, a risk of hydrocarbons being absent exists. PRESTO accounts for this risk through an interrelated four level risk hierarchy. This hierarchy controls the relative contribution of one element to the overall assessment.

The first level of risk considered is the unconditional area risk. Geologists assess the risk that the area as modeled does not contain hydrocarbon resources in any of the prospects. The risk analysis continues, developing unconditional risks for each basin, each prospect in the basins, and finally for the zones within each prospect. (Most assessments only consider one zone per prospect in which case zone risk equals prospect risk; however, some areas require two or three zones having different reservoir characteristics to be assessed.)

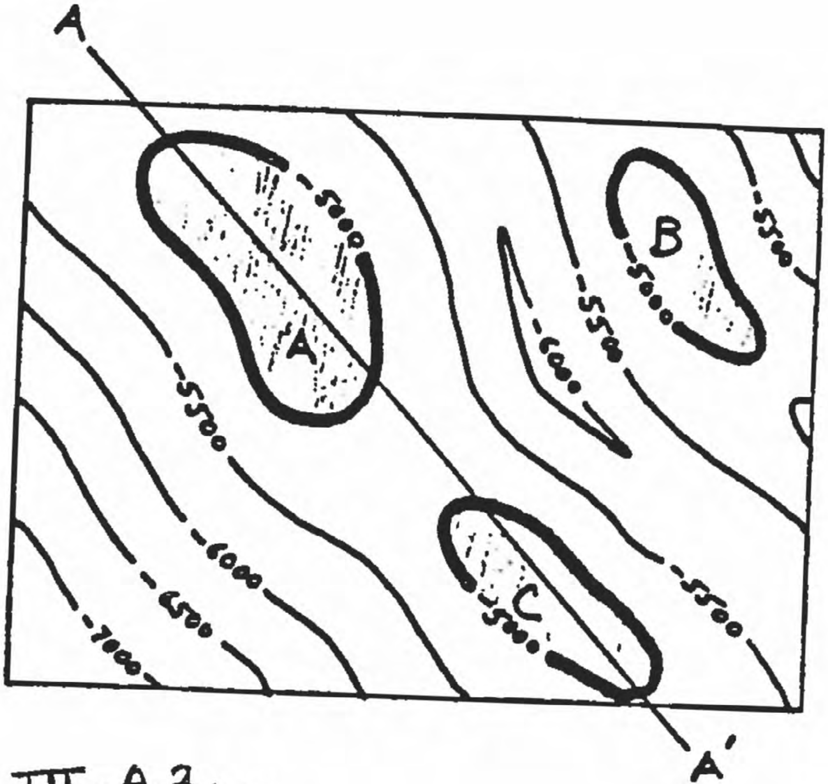
To control the relative contribution of each level to the overall assessment, the unconditional risks estimated by the geologists are used to generate conditional risks. Unconditional area and basin risks are used to compute a conditional basin risk for each basin. The conditional basin risk reflects the probability that the basin is dry, given that the area contains hydrocarbons (the condition). The conditional prospect risk is calculated from the unconditional basin risk and the individual unconditional prospect risk, and estimates the probability that the prospect will be dry, given the basin contains hydrocarbons. Conditional zone risks are computed in a similar fashion.

Each pass through the PRESTO model represents one possible state of nature. Each prospect in every basin is "drilled." Whether the prospect contains hydrocarbons or not on that particular trial is controlled by the conditional probabilities and the random numbers generated by the computer. The mechanics of this process are clarified with a numerical example in the description of a single pass through the model (see section entitled <u>PRESTO - Functional Elements</u>).

PROSPECT AND ZONE MODELING

If a prospect is drilled and found to be hydrocarbon bearing on a trial, then each zone within the prospect is tested. Resources are calculated for the productive zones based on sampling of the range of values for the zone variables. Figures III.A.2 ~~2-2~~ and III.A.3 ~~2-3~~ illustrate several prospects on a plan view (subsurface structure map) and side view (subsurface cross section).

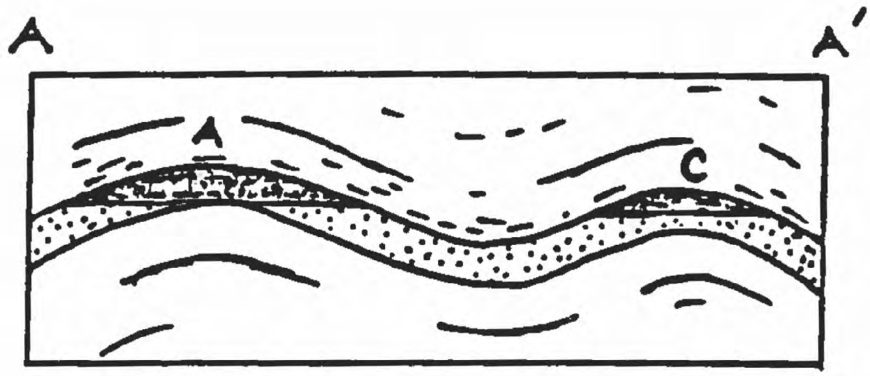
The evaluator must supply values and distribution type for each of the following variables (variable names in parentheses):



III. A. 2.

Figure ~~4~~. Sample subsurface map (cartoon)

Shows 3 prospects and location of cross-section line.
Contour lines show subsea depth.



III.A.3

Figure ~~8~~. Sample subsurface cross-section along line A-A' in Figure 4 (cartoon). Shows potential hydrocarbon accumulations in Prospects A and C.

1. Probability of oil only (OPROB)

2. Probability of gas only (GPROB)

3. Proportion of the reservoir gas-bearing, if a mixture (PROP)

4. Areal extent, acres (AREA)

5. Zone pay thickness, feet (THIC)

6. Oil recovery factor, stock tank barrels per acre-foot (OREC)

7. Gas recovery factor, thousand cubic feet per acre-foot (GREC)

8. Solution gas-to-oil ratio, standard cubic feet per stock tank barrrel (GOR)

9. Condensate yield, stock tank barrels per million cubic feet of gas (YIELD)

One advantage of this evaluation procedure is that individual subject matter specialists can determine the ranges. For example, geologists and geophysicists can enter values for risks, productive acreage, and net pay; petroleum engineers can enter oil and gas recovery factors, which are based on reservoir conditions, pressure-temperature relationships, and recovery efficiencies; and economists and engineers can determine economic cutoffs. These specialists are best suited not only to derive the ranges, but also to use their judgment to select a proper distribution type for the possible variable values. Available distribution options for the variables include fixed (single point), normal, lognormal, uniform, loguniform, and triangular distributions.

On each trial that a prospect is hydrocarbon bearing, the physical properties for the zone on that trial are determined by sampling the distribution for each zone variable. A random number is generated and entered into an algorithm that yields one value from the variable distribution. A different random number is generated and a value is derived for the second variable, and so on until all variables that define the zone attributes have been sampled. The selected values are then entered into the following equations to calculate zone resources:

1. Volume of oil, thousands of barrels = (AREA)(THIC)(1-PROP)(OREC)(.001)
2. Volume of nonassociated and associated gas, million cubic feet = (AREA)(THIC)(PROP)(GREC)(.001)
3. Volume of condensate, thousands of barrels = (YIELD)(Volume of nonassociated and associated gas)(.001)
4. Volume of solution gas, million cubic feet = (GOR)(oil, thousands of barrels)(1000)

If a prospect contains more than one zone, all of the zones are tested and resources computed in a similar manner. The resources for all zones are summed together to yield the prospect resources on that trial.

Previous versions of the PRESTO program accessed an inventory of prospects identified through geophysical mapping. In certain areas where data were sparse, geologic trends were sometimes projected by adding in a number of unmapped postulated prospects based on the prospect density in the analog area. PRESTO III provides a more structured and documentable set of procedures for determining resources in areas having sparse data.

Inputs for identified prospects are entered into the model first. Then the evaluator is requested to analyze the possibilities for unidentified prospects, and if the unidentified option is used, to select from three possible assessment methods (see Figure III.A.4). All three methods require a distribution for the number of unidentified prospects. The types of distributions which can be selected for the number of unidentified prospects variable are the same as for the zone input variables. In addition, the option of using a user-defined, free-form distribution is also available. An average prospect risk is required for the sampling of the number distribution. The evaluator then selects the method for generating resources.

In method one, all zone and prospect properties are specified in the same way as identified prospects. This method assumes the most geologic knowledge, a priori. The second method uses an average value of prospect resources derived from the identified resources. Note that this method does require identified prospects in the database. Method three is the most general form, allowing direct input of a probability distribution for barrels of oil equivalent (BOE). The BOE distribution is sampled once for each productive prospect on a trial.

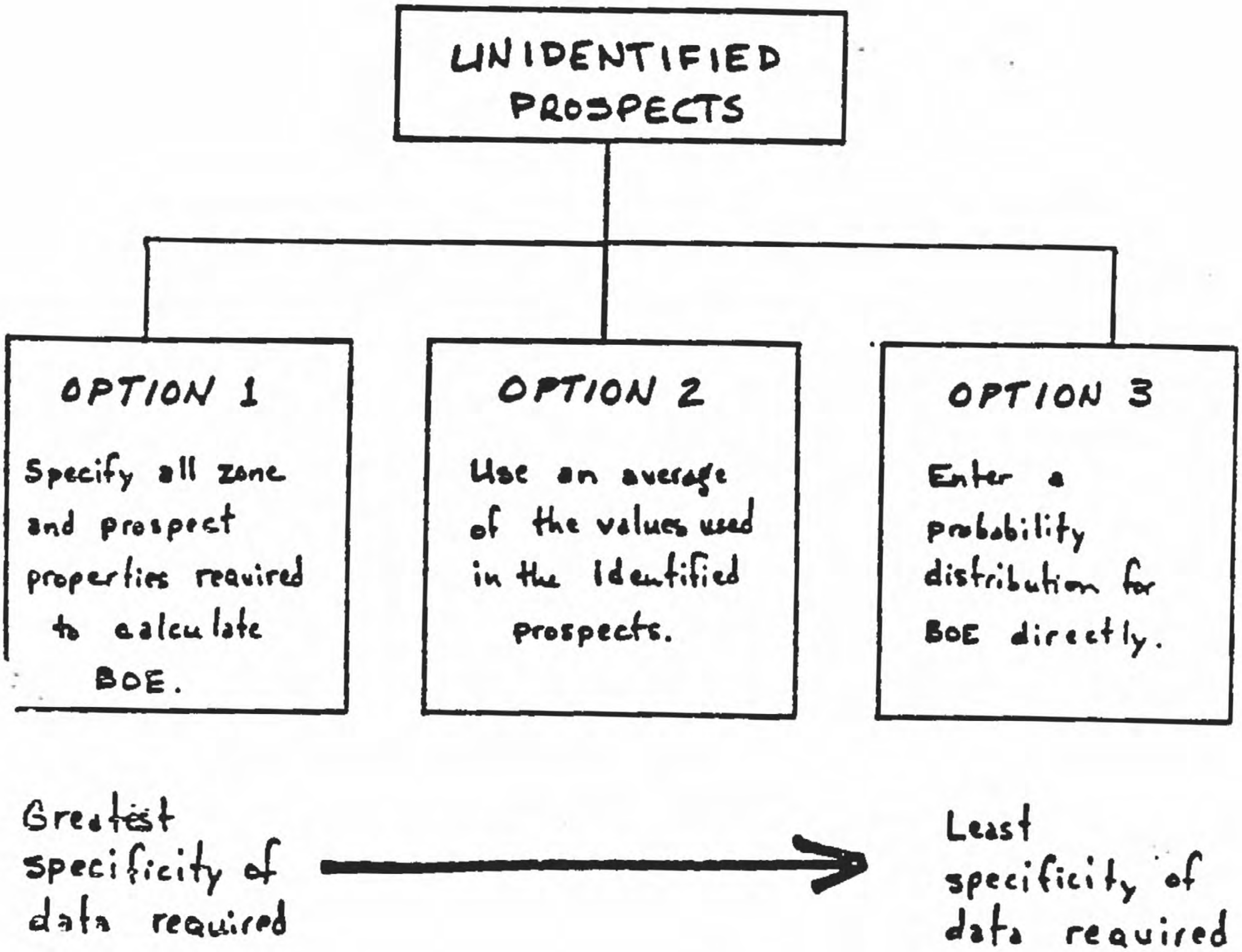


Figure ~~6~~ III.A.4. Assessment options for unidentified prospects.

The unidentified prospects option (method 1, 2, or 3) can also be used to model a stratigraphic play. Oftentimes, the lateral extent of such a play is uncertain, owing to facies changes or sudden permeability differences. The number of prospects distribution allows a different number of stratigraphic traps to be sampled on each trial, then appropriate risk factors applied. The normal procedures for identified prospects are best suited for structural traps, where areal limits are better defined.

The unidentified prospect option shares an advantage of the prospect specific input: as new information becomes available, either from collecting additional seismic data or from the results of new drilling, the prospect inventory, variable distributions, and risk factors can be updated.

ECONOMICS

At this point, the program has simulated drilling the modeled prospect, has simulated hydrocarbon discovery, and calculated the amount of resources. Computing resources through the sampling procedures parallels the actual situation of an operator drilling delineation wells to determine the volume of resources accumulated in a field. Then, the operator would decide whether to continue with development of the discovery by installing a platform, drilling production wells, and constructing pipeline facilities. To make such a determination, the PRESTO program compares the prospect resources computed for the trial to a minimum economic field size (MEFS).

The MEFS represents the smallest field size that will yield a prescribed minimum rate of return under the conditions being modeled. These MEFS estimates are derived using another MMS program, named MONTCAR. MONTCAR is a discounted cash flow model, which accommodates varying economic conditions and prospect-specific costs relative to depth of the producing formation, water depth, distance from shore, platform size, and so forth. The MONTCAR program is run to determine the minimum reserves having a positive net present worth. This minimum value can be based on a single prospect or can represent an average for a grouping of similar prospects under similar physical and economic conditions. The MEFS considers only prospect-specific costs (after exploration and delineation), and not costs associated with regional infrastructure which would be shared by any discoveries.

On a specific trial, if a prospect's resources exceed the MEFS, then the prospect results are adequate for the economic development of that field on that trial. These results are stored for later use in developing final ranges of outcomes. If the calculated resources are less than the MEFS, the resources for that prospect are considered insufficient for development and the results are set to zero for that trial.

Often, a prospect in a frontier area without an existing transportation infrastructure is abandoned, although it has sufficient resources to justify production in a more mature production area. While the resource estimates and attendant production incomes are adequate to balance prospect-specific costs, they are not high enough to pay for an area transportation network. To address this problem, PRESTO includes the option of two additional economic hurdles, a minimum basin (or subarea) reserve (MBR) and a minimum area reserve (MAR).

Prospect resources surviving the MEFS test are summed to the basin (or subarea) level. For each trial, basin level resources are compared to a MBR. The MBR is a single point variable, representing the smallest volume of resources that would justify a basinwide transportation network. If the basin resources are greater than the MBR, the results for the basin are stored. If the basin resources are below the cutoff, then resources for all prospects in that basin are considered to be non-commercial and set to zero for that trial.

Similarly, resources for all basins on a trial are summed to the area level and compared to a MAR. The MAR is the minimum volume necessary to justify an areawide transportation network and associated plant facilities. If the cumulative resources for all the basins do not exceed the MAR, then resources for all prospects in all basins in the area are set to zero for that trial. Both the MBR and MAR are computed exogenously, using an oil transportation model and a gas transportation model. Note that both the MBR and MAR are options. Depending on the conditions being modeled, either the MBR, or the MAR, or both, or neither may be used.

Having the three economic cutoffs could generate additional trials with zero resources, which were not included in the original assessment of area geologic risk. PRESTO modifies the input area geologic risk to account for this additional economic component.

This report shows estimates of undiscovered, economically recoverable resources resulting from assumptions for both base case and high case economic scenarios. The base case economic scenario assumed a starting price of $18 per barrel for oil and $1.80 per thousand cubic feet (Mcf) for gas. Other blanket or areawide assumptions incorporated in the base case assessment include:

1. after tax discount rate of 6-8-10 percent (triangular distribution),

2. two time periods, the initial period lasting 3 years, to reflect current near-term economics with a more optimistic second period,

3. inflation factors of 4 percent (first period) and 7 percent (second period),

4. triangular distributions for annual percent change in real oil price of (-4, -3, -2) in the first period and (+3, +4, +5) in the second period,

5. triangular distributions for annual percent change in real gas price of (-3, -2, -1) in the first period and (+4.5, +5.5, +6.5) in the second period,

6. price adjustments based on estimated API gravity of the oil, and

7. each point on the gas price curve (price versus time) did not exceed 75 percent of the corresponding point on the oil price curve, when compared on a BTU basis. This ceiling on the gas price reflects increased market competition between gas and residual fuel oil as oil prices decline.

Other economic and engineering variables are specific to representative prospects. The MMS has compiled estimates of drilling, production, and operating costs for each OCS region. These costs are routinely updated based on new information from numerous sources including oil and gas operators and contractors.

III.A.1
Table ~~34~~ shows the range of MEFS's, MBR's, and MAR's computed for each offshore region for the current base case assessment.

III A.1

Table ~~Z-1.~~ Minimum Economic Resource Size, by Field, Basin, and Area
Base Case Economic Scenario
(all values in MMBOE)

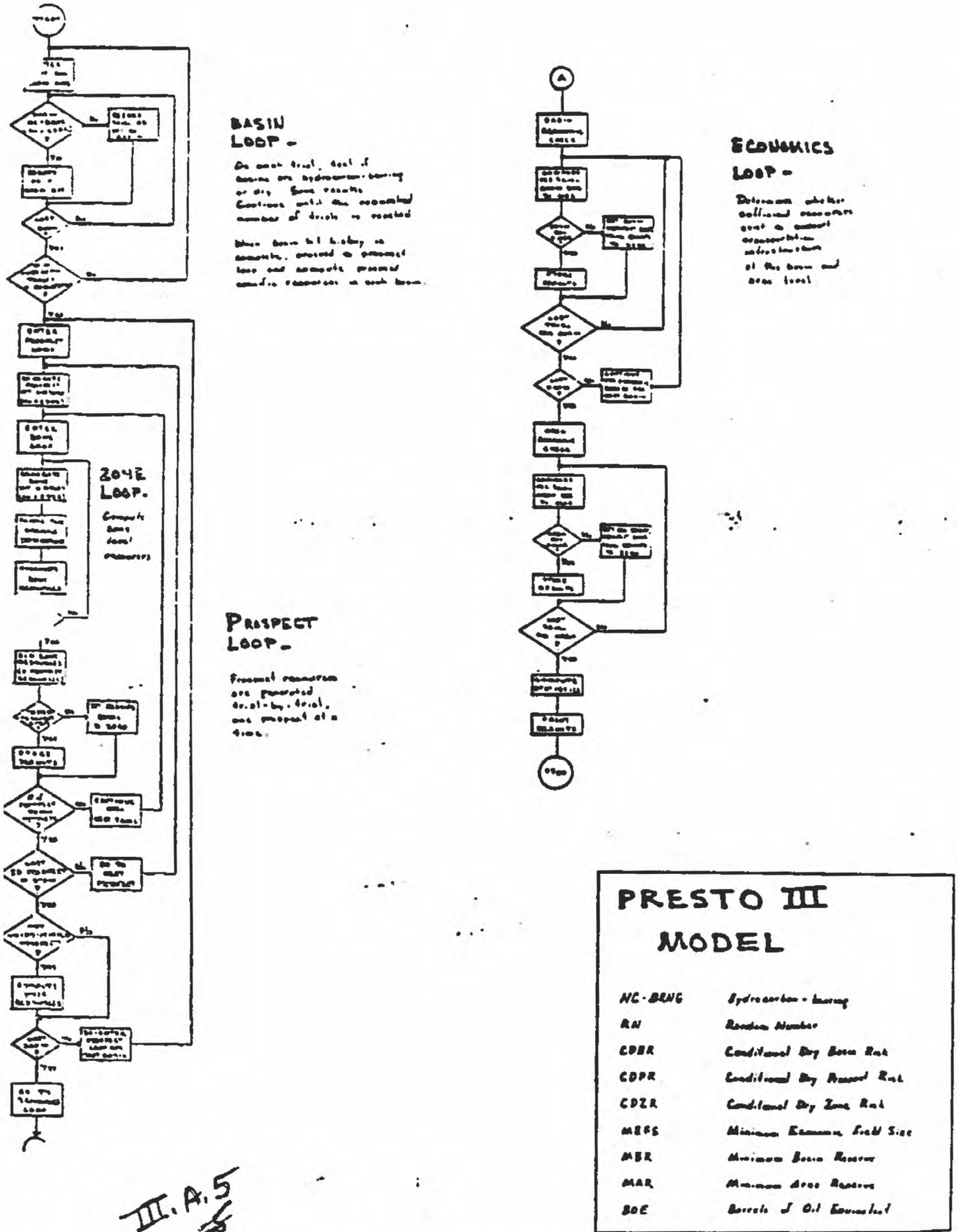
ning Area	MEFS		MBR		MAR	
	Min.	Max.	Min.	Max.	Min.	Max.
ALASKA						
Arctic	160	280	0	0	190	810
Bering Sea	50	300	0	0	150	300
Southern Alaska	45	135	0	0	85	135
ATLANTIC	5	1000	0	0	120	440
GULF OF MEXICO	3	690	0	7400	0	0
PACIFIC	3	190	0	175	0	0

The previous sections of this chapter have described the various elements of the PRESTO model. This section will describe how those individual functional elements work together by focussing on the flow of the fundamental program logic. Emphasis is placed on the concepts, generalizing where possible, for clarity.

PRESTO is divided into three parts: 1) the input processor for entering data, 2) the computational module, and 3) the output processor. The entire program has approximately 15,000 lines of computer code. The many subroutines of the program have been summarized in the conceptual flowchart in Figure III.A.5, which is a roadmap for a single pass through the PRESTO model.

This section describes calculation of the resources, which occurs in the computational module. To illustrate the concepts, a sample program run will be traced, assuming 1000 simulations.

The computer program begins by reading the input data, such as the ranges for random variables. The first data used by the program is related to the risk factors. PRESTO needs to determine how frequently a prospect will be simulated as being hydrocarbon bearing. The presence of an adequate and thermally mature hydrocarbon source, open migration paths, geologic formations which could be possible reservoirs, and finally suitable trapping mechanisms or seals is reflected in the unconditional geologic risks assessed for a four-level risk hierarchy. Figure III.A.6 shows a sample



III.A.5

Figure 7. PRESTO III conceptual flowchart

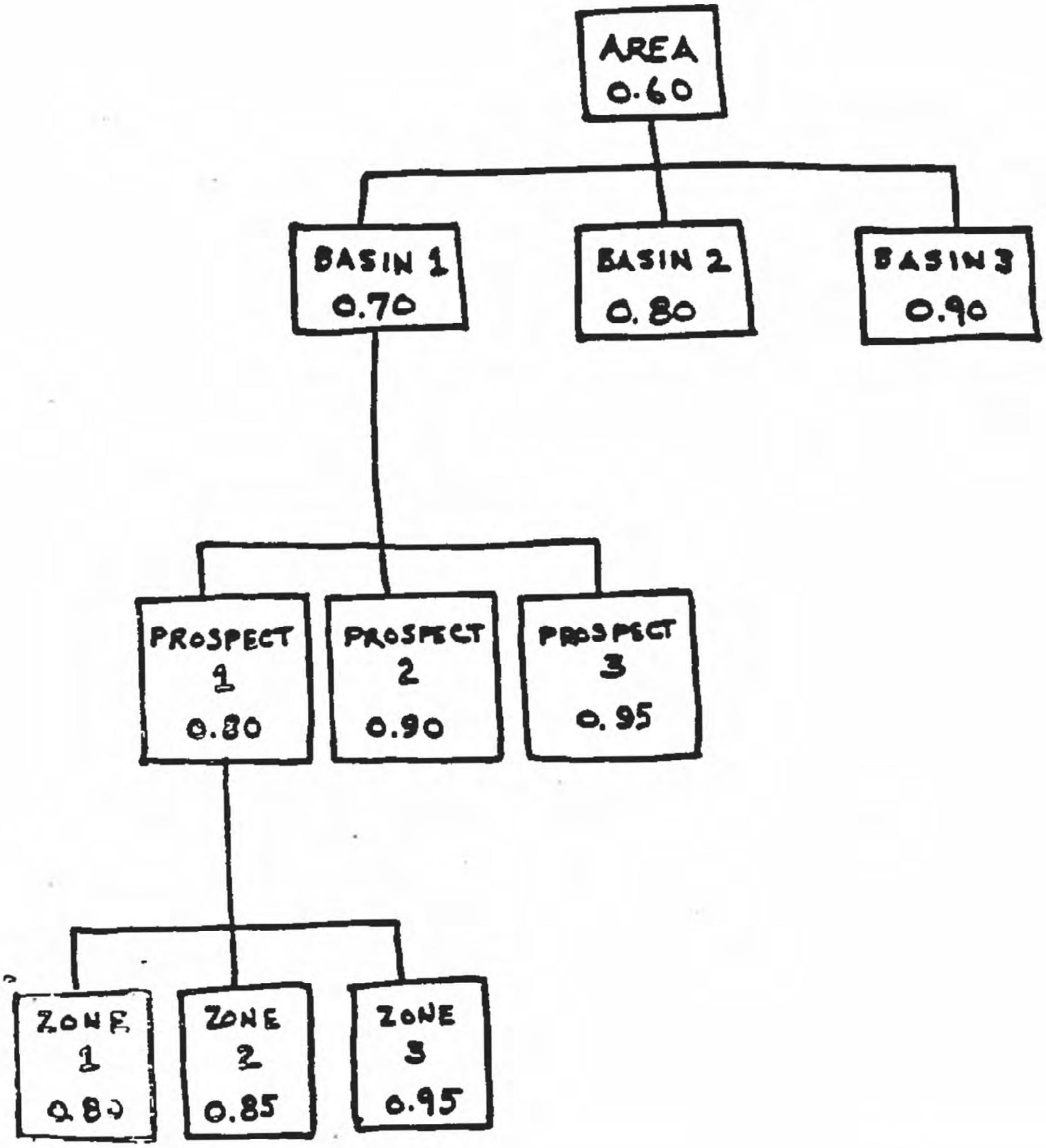


Figure ~~9~~ III.A.6. Risk hierarchy: an example of input unconditional risks hierarchy, from the area level down to the zone level, with sample unconditional dry risks shown. Note that although only a few prospects are shown on this illustration, an actual basin could contain hundreds of prospects. The program converts the estimated unconditional risks to conditional risks as shown on Figure III.A.7. Also shown on this figure are the projected number of geologically successful trials or "hits" (regardless of economic considerations). The random numbers selected will cause the actual number of hits to be slightly different than the projection, in the same way that flipping a coin 100 times seldom results in exactly 50 "heads" and 50 "tails".

Implicit in the program logic is the assumption that hydrocarbons exist in the area. Accepting this condition requires modifying the input unconditional risks accordingly. Conditional basin risks are computed, given the condition that hydrocarbons exist in the area. Conditional prospect risks are computed given that hydrocarbons exist in the basin, and conditional zone risks are computed given that hydrocarbons exist in the prospect.

In this example, consider Basin 1 in Figure III.A.6. The probability that Basin 1 is dry is equivalent to the probability that the area is dry (area risk) plus the probability that the area is productive (1 - area

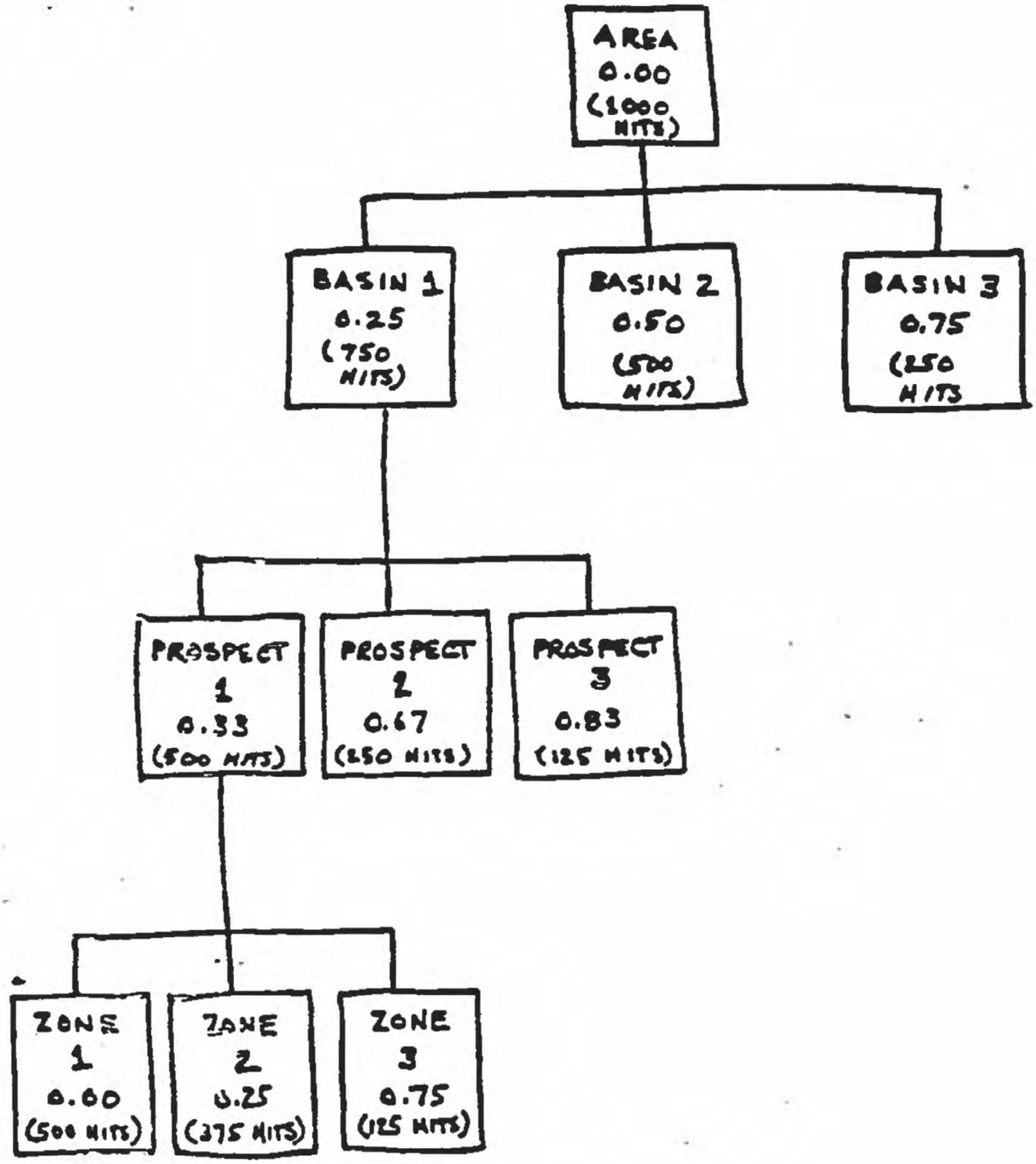


Figure III.A.7. Conditional risks computed by program for sampling purposes, with estimated number of hits (given perfect sampling).

risk) multiplied by the conditional probability that the basin is dry given that the area is hydrocarbon bearing (conditional dry basin risk). That is,

Basin risk = area risk + (1 - area risk)(conditional dry basin risk)

Rewriting the above equation in terms of the conditional risk,

$$\text{Conditional dry basin risk} = \frac{\text{basin risk} - \text{area risk}}{1 - \text{area risk}}$$

Using the input unconditional risks shown on Figure ~~2-6~~ III.A6, PRESTO calculates conditional dry basin risks, as shown on Figure ~~2-7~~ III.A7. Given a basin risk of 0.70 and a 60 percent chance that the area does not contain hydrocarbons (area risk = 0.60):

$$\text{Conditional dry basin risk, Basin 1} = \frac{0.70 - 0.60}{1 - 0.60} = 0.25$$

Therefore, if the area does contain hydrocarbons, Basin 1 has a 25 percent chance of being dry. That is, on approximately 75 percent of the trials, Basin 1 will contain hydrocarbons. Conditional dry basin risks for Basins 2 and 3 (Figure ~~2-6~~ III A6) are computed using the same equation.

In simulating the exploratory drilling process, PRESTO generates a different random number to compare to the conditional dry basin risk for every trial. The random numbers are greater than zero but less than one. If the number is less than the conditional dry basin risk, the basin is considered dry on that trial. If the random number exceeds the conditional dry basin risk, the basin is considered to have hydrocarbons in at least one prospect in the basin on that trial.

As shown on the flowchart, Figure ~~2-5~~ III.A.5, PRESTO can be thought of in sections corresponding to various loops over all the trials. The first such loop encountered is the basin loop. On each trial in the loop, different random numbers are generated and compared to the conditional dry basin risk for each basin to determine whether the basin is hydrocarbon bearing on that trial. The program continues on with this sampling until it reaches 1,000 trials with at least one basin hit. The basin hit history, showing which basins were hydrocarbon bearing on each trial, is saved.

Once the basin sampling is complete, the program executes a loop over the prospects in each basin. A prospect hit history is developed in a fashion similar to the basin hit history. In the example, Basin 1 would be hydrocarbon bearing on roughly 750 of the 1,000 trials. If Basin 1 is hydrocarbon bearing, then the contribution of Prospect 1 is controlled by the conditional dry prospect risk. Given an unconditional prospect risk of 0.80 and an unconditional basin risk of 0.70:

$$\text{Conditional dry prospect risk, Prospect 1} = \frac{0.80 - 0.70}{1 - 0.70} = 0.33$$

Therefore, if Basin 1 is hydrocarbon bearing, Prospect 1 will also be hydrocarbon bearing on roughly 67 percent of the 750 Basin 1 trials, or on approximately 500 trials. Similar computations would follow for all other prospects in Basin 1 and for all prospects in Basins 2 and 3.

Zones within a prospect are tested in the same manner. In the example, Zone 1 unconditional risk is the same as Prospect 1 unconditional risk. Therefore,

$$\text{Conditional dry zone risk, Zone 1} = \frac{0.80 - 0.80}{1 - 0.80}$$

$$= 0.00$$

The random number will always be greater than zero, so in this example, Zone 1 will have resources on every trial that Prospect 1 is hydrocarbon bearing. Note that in most cases, information is only included for one zone per prospect, in which case zone risk would always equal prospect risk. In areas having significant changes in lithology, reservoir characteristics, or formation depths, additional zones may be included.

After the basin hit history is developed and stored in memory, PRESTO proceeds through the prospect loop one prospect at a time. Based on the number of hits in Basin 1, Prospect 1 would be sampled to develop a prospect/zone hit history. This history would determine the sample size for sampling the zone specific variables. In the example, if sampling were perfect, Prospect 1, Zone 1 would contribute on 500 trials. Random numbers would be generated 500 times and used to select 500 values for the variable

AREA from the Zone 1 AREA distribution. Another 500 random numbers would be used to select 500 values of THIC, and so on until all Zone 1 variables were sampled. These 500 values from each variable would be used in the resource volume equations to yield 500 possible solutions for the amount of resources in the zone.

Part of the PRESTO bookkeeping functions is to track resources from each zone and prospect on every trial. Zone resources are summed to yield prospect resources on the trial. The gas components are totaled, converted to barrels of oil equivalent (BOE), and added to the oil volumes to yield a total BOE value for the prospect. Conversion of the gas can be based on either an energy (Btu) or economic equivalence.

If unidentified prospects are included in the data base, they are treated like a single final prospect in the basin. On each trial, a distribution of values for the number of unidentified prospects is sampled to select the number of unidentified prospects to be considered on that trial. An average conditional dry prospect risk is computed from an average unconditional dry prospect risk for the unidentified prospects and the unconditional dry basin risk. Based on the number of unidentified prospects selected for the trial, random numbers are generated to determine the number of prospects considered hydrocarbon bearing on the trial. PRESTO then computes resources for those unidentified prospects based on the resource generation option selected. The resources generated for each unidentified prospect are compared to an average MEFS to determine economic viability.

Once all of the identified and unidentified prospects in a basin have been tested and resources estimated, PRESTO proceeds to the next basin. The program continues in a like fashion until all of the zones and prospects in all of the basins have been checked and evaluated, resulting in a per trial matrix of possible resource values.

Upon completion of the prospect/zone loop, the program enters an economic loop to test whether sufficient resources exist to warrant the development of individual prospects and entire basins and areas. The per trial prospect resources are compared to the prospect's minimum economic field size (MEFS) and, if they exceed the MEFS, the resource volumes are stored along with the trial number. If the prospect resources are below the MEFS, the resources for the prospect are set to zero for the trial. Basin level resources for a trial are compared to the minimum basin reserve, and if greater, the trial results are saved. If the basin resources are below the minimum basin reserve, the resources for all prospects and zones in that basin are set to zero for that trial. When all basins have been checked, basin level resources are summed to the area level and compared to a minimum area reserve. Similarly, if resources for the area on a trial are below the minimum area reserve, all basin, prospect, and zone resources are set to zero for that trial.

A simple numerical example may illustrate these concepts more clearly. Of the many trials and prospets in an actual run, this example examines a small window of 3 trials and 2 prospects contained in 1 basin. The results of the risking process produced the following:

Trial	Prospect 1	Prospect 2
1	productive	dry
2	dry	productive
3	productive	productive

The model then computes the resources for productive trials, starting with Prospect 1. The number of productive trials for Prospect 1 determines the sample size. Variable distributions are sampled, and resources computed. Hypothetical results are shown below (resources shown converted to million barrels of oil eqivalent):

Trial	Prospect 1	Prospect 2
1	5	0 (dry)
2	0 (dry)	15
3	15	20

After resources are computed for all prospects in all basin on all trails, the program proceeds through the economics loop. For this example, assume the MEFS is 10 mmboe for both prospects, and the MBF is 20 mmboe for the basin. All prospects are compared to their MEFS. Resources for Prospect 1, Trial 1 are less than the MEFS, indicating insufficient resources to justify production. These resources are set to zero.

Trial	Prospect 1	Prospect 2
1	0 (noneconomic)	0 (dry)
2	0 (dry)	15
3	15	20

Once all prospect resources are compared to their MEFS, the resources for the entire basin are compared to the MBR in a similar fashion. Using an MBR of 20 mmboe, only Trial 3 has total basin resources (35 mmboe) greater than the MBR. Since total basin resources for Trials 1 and 2 are less than the MBR, development of basin resources would not proceed under these two possible states of nature, and the economic resources for the prospects are set to zero for these two trials.

Trial 1	Prospect 1	Prospect 2
1	0	0
2	0	0
3	15	20

In a similar fashion, total results from all basins are summed for each trial and compared to the MAR. If these total results are less than the MAR, insufficient resources exist on that trial to justify development of the entire area. All prospects in all basins for that trial would be set to zero.

Owing to the economic cutoffs used by PRESTO, additional zero (no resource) trials can be generated when resources are discovered but are of insufficient size to warrant development, as seen in Trials 1 and 2 of the previous example. The original input area geologic risk is modified to account for the additional nonproducing trials that were geologically successful but economic failures. The equation for adjusting the area geologic risk to incorporate the additional economic risk follows:

$$\begin{aligned}\text{Revised area risk} &= \text{geologic risk} + \text{economic risk}\\ &= (\text{input area risk}) +\\ &\quad (1 - \text{input risk})(\text{TOT} - \text{NL})/(\text{TOT})\end{aligned}$$

where TOT is the total number of trials requested by user and NL is the number of economic trials.

As an example, a PRESTO run having an input area risk of 0.60 required 1,133 trials to establish 1,000 trials where at least one basin was hit. This means that on the basin loop, all basins were tested as dry on 133 of the 1,133 trials. Since this is a manifestation of the sampling and not representative of actual risks, these 133 dry trials are ignored. The area had economic resources on 894 trials. The area risk would be modified to account for the economic risk as follows:

$$\begin{aligned}\text{Revised area risk} &= (0.60) + (1 - 0.60)\\ &\quad (1{,}000 - 894)/(1{,}000)\\ &= 0.64\end{aligned}$$

The revision to the risk becomes important when the number of zero trials are used to derive risked resources.

Upon completion of all economic checks, PRESTO has amassed a vast array of resource data at the prospect, zone, and basin levels. These data are sorted and ranked, yielding probability distributions of resource values. These results are described further in the next section on PRESTO outputs.

OUTPUT

PRESTO is used to generate a range of possible resource values for an area. Two primary resource distributions are provided as PRESTO output, a conditional distribution and a risked (or unconditional) distribution. These two categories address different needs.

Until drilling operations actually commence in a frontier exploration area, the presence or absence of economically recoverable hydrocarbons is unknown. To evaluate the potential results of drilling in an area, the assumption is often made that hydrocarbons exist in the area. If recoverable quantities of hydrocarbons exist in the area of study (the condition), conditional undiscovered resource estimates represent the range of possible resources present. However, conditional estimates do not incorporate the risk that the area may be devoid of any recoverable oil or gas. They are often used by MMS to assess the potential environmental impacts if leasing, production, and development were to occur in an area.

Conditional resources can be estimated under different conditions, as long as the conditions are defined. The condition described in the above paragraph is more generic, referring to recoverable resources. However, the condition can be more confining, such as an estimate of economically recoverable resources. In this case, the condition is that economically recoverable resources occur in at least one commercial accumulation.

Risked (unconditional) resource estimates do incorporate an assessment of the risk that the area is devoid of hydrocarbon accumultions. The estimates are risked by removing the condition and factoring in the probability that the area is dry. Risked resource estimates average the resources calculated for each productive trial along with all of the nonproductive zero trials. Risked resource estimates are primarily used for economic decisions where the risk that hydrocarbons may not exist in the area cannot be ignored. This risk can be relatively high in frontier exploration areas.

These two categories of resource estimates are related by the marginal probability. The marginal probability (MP) is an estimate of the chance that a particular event will occur and is expressed as a decimal fraction. For economically recoverable resource estimates, the marginal probability is defined as a measure of the probability that commercial quantities of hydrocabons exist in at least one accumulation in the area being assessed. A MP of 1.00 indicates a virtual certainty that commercial hydrocarbons exist in an area. The Central Gulf of Mexico Planning Area is an example of an area with a MP of 1.00. Since this MP corresponds to an area risk of 0.00, the condition has been met and the conditional and risked distributions are the same. Conversely, a low MP reflects a high area risk with a correspondingly large difference between the conditional and risked distributions. The previous sample pass through the PRESTO model showed an input geologic risk of 0.60 that was adjusted to 0.64. The final MP for this example would equal (1 - adjusted area risk) or (1 - 0.64). Therefore, MP is 0.36. This MP implies a 36 percent chance that economically recoverable resources exist in the area assessed.

PRESTO produces distributions of resource values, both conditional and risked. The PRESTO output includes a distribution of resource values for each prospect and for basinwide and areawide results. Distributions for area results are presented on a percentile table, which shows estimates at every fifth percentile. A percentile corresponds to a point on the distribution with a "percent greater than or equal to" value. Commonly, the 95th and 5th percentiles are reported. The 95th percentile represents a low estimate on the distribution of possible values, with a 95 percent chance of that amount or greater occurring. The 5th percentile represents a high estimate, with a 5 percent chance of that amount or greater occurring.

Although a range of resource estimates as shown by the 95th and 5th percentiles properly reflects the uncertainty associated with resource assessment, oftentimes a single representative value is needed. The mean value is usually accepted as the best indicator of central tendency, since it incorporates both the probability and magnitude of the estimates. The mean of a distribution, also referred to as the expected value, is the arithmetic average of all the values in the distribution. For the risked mean, this average also includes all zero values.

Other indicators of central tendency are the mode and median. The mode, also known as the "most likely" estimate, is the value in the distribution having the greatest likelihood of occurrence. It corresponds to the peak of the distribution when represented as a probability density function. The median is the value that divides a distribution into two equal probability parts, and it corresponds to the 50th percentile. Figure ~~2-8~~ III A.8 depicts the relationship of the mean, mode, and median on a probability density function. The probability density function relates the magnitude of the resources to the probability of occurrence.

Figures ~~2-9~~ III A.9 and ~~2-10~~ III A.10 illustrate conditional and risked distributions. They are presented in the form of complementary cumulative distributions, with resource volumes shown on the horizontal axis, and cumulative percentages (i.e. "percent greater than or equal to") shown on the vertical axis. The first point on the conditional curve is at 100 percent greater than or equal to; the conditional curve assumes resources exist. The first point on the risked curve is at the 25th percentile. This point indicates a 75 percent chance of no commercial (zero) resources and corresponds to the MP of 0.25. The 50th percentile (median) estimate is shown to be 2.9 billion barrels of oil on the conditional curve. The median indicates a 50 percent chance that the volume of oil is 2.9 billion barrels or greater, if hydrocarbons exist in the area. The conditional mean for this example is shown as 2.8 billion barrels.

A unique attribute of these distributions is that the conditional mean multiplied by the marginal probability equals the risked mean. More

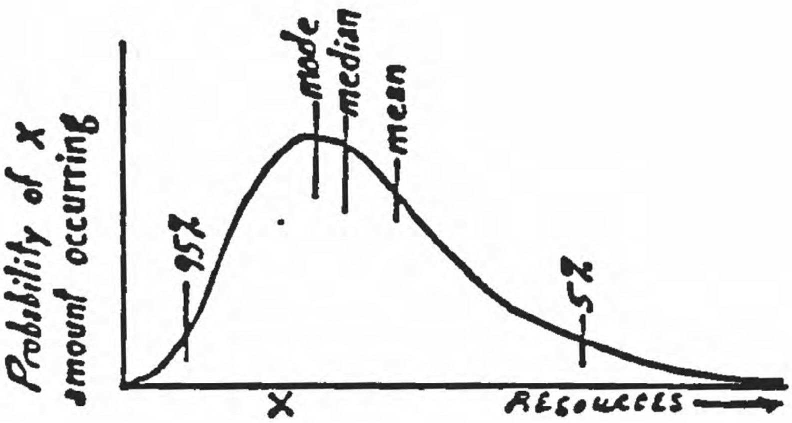


Figure III.A.8 ~~10~~. Probability density function, indicators of central tendency (cartoon)

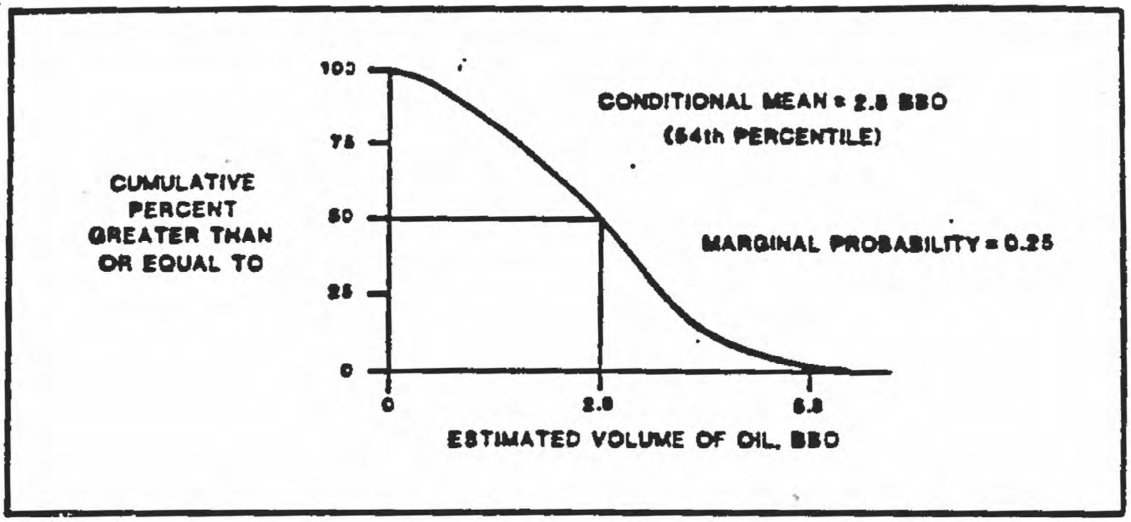


FIGURE 4. Example of a conditional oil distribution.

Figure ~~4~~ III.A.9

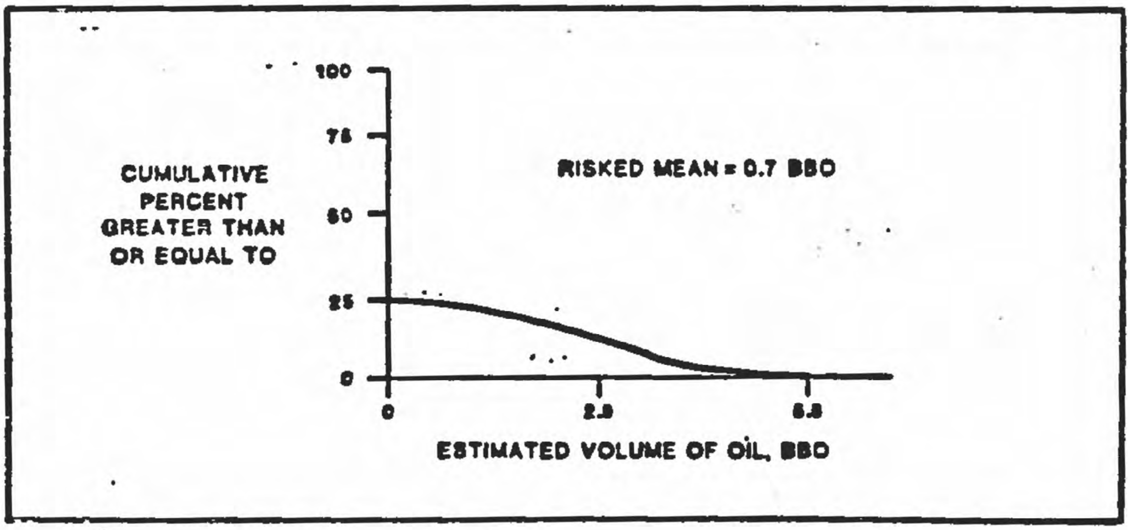


Figure 5. Example of a risked oil distribution.

Figure ~~5~~ III.A.10

precisely, the risked mean represents multiplying the chance of success (MP) times the average amount if successful (conditional mean) and adding it to the chance of failure (risk) multiplied by the average amount if dry (zero). This attribute is only valid for the mean case and is not applicable to estimates at other percentiles. Using the examples in Figures ~~8-9~~ III.A.9 and ~~9-10~~ III.A.10, the conditional mean of 2.8 billion barrels of oil multiplied by MP of 0.25 gives a risked mean value of 0.7 billion barrels.

Risked estimates are preferred for comparison. By incorporating risk, resources for vastly different areas are estimated on the same, unconditional basis. Conditional estimates are based on quantitatively different condition as reflected by the MP, and are not suitable for direct comparison. Similarl conditional means cannot be added or subtracted, whereas arithmetic operation can be applied to the risked means.

SUMMARY

The PRESTO computer program has changed substantially since the 1984 assessment. The MMS resource assessment methodology draws on a substantial database developed through the years as a result of lease sale activities. The PRESTO computer program, by allowing a range of estimates for geologic and reservoir variables, permits inputs from literally hundreds of regional geologists, geophysicists, and petroleum engineers. The methodology has the following advantages:

1) prospect specific, allowing areas or tracts to be added or deleted, then reassessed

2) reproducible, allowing estimates to be updated as new information becomes available

3) flexible, accommodating data from frontier to mature areas in terms of petroleum exploration and development.

The next chapter describes how the assessment of undiscovered economically recoverable resources is used by MMS to estimate resources for the undiscovere resource base.

Minimum Economic Field Size

A. Methodology

The Probabilistic Resource Estimates OCS (PRESTO) Program is a computer program which estimates the undiscovered oil and gas resource distributions of basins and/or planning areas using a simulated exploration process. The program uses zone risk, prospect risk, basin or subarea risk, area risk, and a random number generator in every trial of a Monte Carlo process to determine success or failure of exploration. When a PRESTO prospect is successful, each of the engineering and geologic variables are sampled and conditional resources are estimated. Conditional resources are estimates of undiscovered resources, given the condition that hydrocarbons exist in the area. If conditional resources are simulated to exist (i.e., as a result of a successful exploration program), PRESTO assumes that a prudent operator's decision to develop is based solely upon the field's profitability. The profitability determination is made in PRESTO by comparing the conditional resource level of the prospect against its minimum economic field size (MEFS). The MEFS represents the average conditional resources per producing trial necessary to result in an average net present worth (NPW) of zero (unrisked mean range of values (MROV) = 0) for the prospect. The MEFS for each PRESTO prospect is determined by a Monte Carlo Range-of-Values (MONTCAR) Program evaluation. A copy of a paper entitled "Brief Description of MONTCAR Methodology" is attached (Attachment 1).

The MEFS is defined as the minimum conditional amount of the oil and gas resources, on a BOE basis, that will pay for the cost of developing and

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transporting the future production from a representative prospect to the market. The MEFS estimation does not consider exploration and delineation well costs, and the market is defined as the point where the hydrocarbons are priced for sale. Further, a representative prospect is one that has similar physical characteristics with a group of prospects being assessed in PRESTO, i.e., similar water depths, drilling depths (potential pay horizon), distance from shore, recoveries, etc. The representative prospect idea is necessary for efficiency in workload associated with estimating MEFS for individual prospects. In addition, the costs of transportation are represented in MONTCAR as tariffs or actual costs and are based on a scenario for the transportation of the area's production.

Minerals Management Service (MMS) geoscientists, engineers, and economists estimate values for all of the deterministic and variable inputs, the latest cost profiles, and the economic assumptions for the MONTCAR evaluations of all representative prospects. The resulting MEFS data are plotted so that the graph can be used to estimate the MEFS for all similar prospects in the area.

For MONTCAR MEFS evaluations, scheduling does not include the time required for exploration and delineation activities. Scheduling begins at the point in which the operator commits to developing the lease. Also, the decision to develop or abandon the lease is assumed to be independent of the lease acquisition costs, the cost of exploratory and delineation wells, sunk rental costs, and any other costs associated with exploration activities conducted prior to the operator's commitment to develop the lease(s).

At the point where the MEFS is used in PRESTO, only the cost of development and production are of concern to the operator and not the "sunk" costs of lease acquisition and exploration. A subtle complication occurs because the cash bonuses paid to acquire the field are treated differently for tax purposes depending upon whether the field is produced or abandoned, so they are not entirely sunk costs. For only positive bonus bid, the net effect is to increase somewhat the MEFS, because the value of the bonus writeoff is higher if the field is abandoned. However, we expect nominal bonuses for fields found to contain resources near the break-even producible size and, in any event, the extent to which this tax effect is given serious consideration by the lessee in the development decision is problematic. Accordingly, the analysis assumes that the tax treatment of the cost bonus bid does not effect the MEFS. Thus, for MEFS evaluations, MONTCAR models the prospects with the operator at a go or no-go decision point just prior to the development phase.

Care is taken in determining the transportation costs for MEFS evaluations, with area or basin transportation costs common to all prospects being separated from prospect-specific transportation costs. The area or basin costs are for the estimation of the area or basin minimum reserve and associated tariffs. These tariffs are input in MONTCAR in addition to prospect-specific transportation costs for the MEFS evaluations.

The MONTCAR documentation for the subroutine MEFS is attached (Attachment 2). Alaska used a similar iterative process to the one described in Attachment 2, but it has such a wide variety of prospect conditions that the MONTCAR iterations were done by charting several computer results per prospect. The Alaska procedure also resulted in a prospect conditional present worth of approximately zero.

-A-

B. National Assessment

1. MEFS Envelopes

Based on the above methodology, MEFS's were estimated in each MMS Region. For the Federal offshore areas of the contiguous United States, because the water depth is of such significance in determining platform cost, especially in deep water and harsh environments, and because platform cost is of major significance in determining the economic viability in such areas, it is generally necessary to develop a curve of MEFS versus water depth for each geologic trend and/or planning area. Using such a curve, the MEFS of individual PRESTO prospects are estimated by determining what trend it is in, its water depth, and where that depth falls on the curve. This would then be the MEFS PRESTO input for that prospect. A set of such curves for all trends compose the attached MEFS envelopes (Attachments 3 and 4). This process was repeated twice, with two different sets of economic and cost assumptions, one a base case scenario (starting oil price = $18/bbl) and one a high case scenario (starting oil price = $30/bbl). The base case scenario was used for the National Assessment PRESTO evaluations, and high case scenarios were for illustrative purposes to show the affects of economics on the resource assessment. In Alaska, the MEFS varied from 45 to 300 million barrels of oil equivalent (BOE) and from 20 to 95 million BOE for the base and high case scenarios, respectively.

2. Economic and Cost Parameters

The envelopes of the real market price paths appear on Attachments 5 and 6 for the base case scenario and Attachments 7 and 8 for the high case scenario. During the first period, oil and gas prices are assumed to decline for 2 to 3 years for the high and base case scenarios, respectively. Prices are assumed to increase during the second period. The price envelopes were constructed using some of the following MONTCAR inputs:

a. Public and private after-tax discount rate distribution (triangular) having a minimum of 6, most probable of 8, and maximum of 10 percent parameters.

b. Base case scenario parameters of:

Starting prices: \$18/bbl (oil) (January 1, 1987)
\$1.80/mcf (gas)

Time to second period: 3 years

Inflation: 4 percent (1st period)
7 percent (2nd period)

Real oil and gas price change distribution (triangular):

	Oil	Gas
1st period:	-4, -3, -2 percent	-3, -2, -1 percent
2nd period:	3, 4, 5 percent	4.5, 5.5, 6.5 percent

c. High case scenario parameters of:

Starting prices: \$30/bbl (oil)

\$3/mcf (gas)

Time to second period: 2 years

Inflation: 5 percent (1st period)
8 percent (2nd period)

Real oil and gas price change distribution (triangular):

	Oil	Gas
1st period:	-15, -10, -8 percent	-14, -9, -7 percent
2nd period:	2, 3, 4 percent	4, 5, 6 percent

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Adjustments for API gravity are as follows:

Gravity Range °API	Base Case Scenario Price Adjustment \$/bbl/tenth °API	High Case Scenario Price Adjustment \$/bbl/tenth °API
Above 40°	.00	.0
34.0° to 40.0°	.01	.01
Below 34.0°	.015	.02

The gas price was dependent on the oil price with a triangular direct dependency. The second real oil price change distribution and both real gas price change distributions were dependent on the first real oil price change distribution with triangular direct dependencies. The landed price of gas did not exceed 75 percent (base case scenario), and 100 percent (high case scenario) of the landed price of oil.

The differences in the oil/gas price ratios are consistent with the historic role of gas. Also, when oil prices are high, oil and gas prices should be closer to parity than when oil prices are low. This is the case because higher oil prices will encourage more fuel switching for small variations from parity. Over the next several years, the gas bubble is expected to decline because of reduced supplies and increased demand. The current supply situation has resulted in a relative gas price, on an equivalent Btu-basis with oil, of about two-thirds. In our assessment, the future relative price of gas will rise, but tend to remain below parity with oil in the short and mid-term.

The economic assumptions are entered in MONTCAR and define the market price paths for each trial in the Monte Carlo process. The program removes the costs of transportation at the appropriate time, and wellhead prices could subsequently be estimated. All MONTCAR Federal tax provisions conformed to the 1986 Tax Reform Act. For royalty purposes, the following assumptions were made:

Region	Water Depth (meters)	Royalty Rate
Gulf of Mexico	>400	1/8
	<400	1/6
Atlantic-Pacific	>200	1/8
	<200	1/6
Alaska		1/8

The following tangible fractions were used by MONTCAR in the cash flow estimations:

Costs	Tangible Fractions
Platforms	0.50
Production Wells	0.25
Completions	0.25
Production Equipment	1.00

Cost information was developed in conjunction with regional MMS personnel from MMS records, proprietary industry data, and contracted cost studies. All costs were reviewed by headquarters and regional personnel for consistency purposes. Costs for the base case scenario attempted to capture the dramatic decline in costs associated with the decline in oil prices during 1985-1986. Both costs and prices are inflated in MONTCAR evaluations, but only prices are assumed to have real changes in value over time in addition to inflation.

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Based on the Lewin and Associates, Inc., study titled "Relationship of Oil Field Costs to Oil Prices and Other Market Factors," and as a result of testing regional MEFS computer runs, the cost parameters in the base case scenario were escalated by the following multiplier distribution to obtain costs for the high case scenario:

Minimum	1.00
Most Probable	1.27
Maximum	1.50

This distribution and all cost multiplier distributions were tied to the first real oil price change distribution with triangular direct dependencies.

Based on the analysis of the cost files, which were created by the MMS Regions for tract evaluation purposes, the costs for the Federal offshore areas of the contiguous United States were estimated to have the following cost uncertainties:

Costs	Minimum	Most Probable	Maximum
Platforms	0.85	1.00	1.15
Platform Wells	0.80	1.00	1.20
Operating	0.90	1.00	1.10

Regional differences in geology, engineering, and environmental parameters resulted in different cost scenarios among planning areas. In general, Gulf of Mexico and Southern California costs were similar and established a standard for comparison with costs from other Regions. Costs were escalated for frontier Pacific, Atlantic, and Alaska. Place differentials of platform costs in the Federal offshore areas of the contiguous United States varied as much as 30 percent among planning areas, while platform well costs varied 10 percent, production equipment costs, 50 percent, and operating costs, 40 percent. Place differentials in Alaska

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were considerably higher because of the severe environment. When prospect-specific environmental conditions (i.e., subsea completions, sulfur in crude or gas, etc.) required changes in prospect costs, cost multipliers were employed.

Increases in production well drilling and completion costs for frontier Alaska, Pacific, and Atlantic Regions, as compared to the Gulf of Mexico were attributed to higher operating costs of drilling rigs and vessels because they lack supporting infrastructure in these areas. Increases in production equipment costs of the Pacific Region were attributed to the low oil API gravity and high sulphur content of the oil and gas production as well as differences in environmental and engineering parameters. Smaller increases in production equipment costs for the Atlantic Region, as compared to the Gulf of Mexico were primarily attributed to higher costs of transporting this equipment to locations. The regional differences in platform costs are attributable to the variation in design parameters to account for regional oceanographic data, climate, ice, and earthquake structural requirements.

3. Scheduling Parameters

For platform scenarios in the Federal offshore areas of the contiguous United States, it was assumed that fixed platforms will be used to 1,100 feet of water depth, compliant platforms (i.e., Guyed Tower and Tension Leg Platforms) will be installed from 1,100 to 3,000 feet of water depth, and, in deeper water, floating platforms will be anchored with subsea completions. The transportation scenarios were mostly based on new pipelines or extensions of existing pipelines. In Alaska, fixed platforms were assumed with offshore loading being the transportation scenario for the Gulf of Alaska and Bering Sea areas, and pipelines with subsequent tankering for all areas north of the Bering Sea Strait.

The maximum number of slots per platform was set at 60 and, in Alaska arctic waters, set at 90. The minimum number of platforms per prospect was set at 1 and the maximum was set at 5. Two drilling rigs were assumed for platforms with more than 24 slots. The average number of development wells expected to be drilled and completed per year, with one rig, is shown in Attachment 9. Regional deviations from this average graph of well drilling rate versus drilling depth were dependent on the types of formations drilled, formation fluid pressures, climate conditions, and water depth. One completion per production well was assumed for this assessment. Based on prospect-specific water depths, delay for platform design, fabrication, and installation varied from 1 to 4 years, with platform costs being paid during these years.

4. Geologic and Engineering Parameters

For the Federal offshore areas of the contiguous United States, geologic and engineering parameters were entered in MONTCAR in ranges (distributions) to quantify the uncertainty of the inputs. In Alaska, these inputs were selected as representing the most probable parameters within a range of uncertainty.

Ranges of the average geologic and engineering parameters are listed in Attachment 10 as they were estimated by MONTCAR MEFS evaluations. In addition, it was assumed that gas production will not be declined and will be produced at the initial rates if water drive gas reservoirs were modeled. For other than water drive gas reservoirs, on the average, 70 percent of the reserves will be produced before an exponential gas decline commences. For oil production, the following distribution was assumed for the fraction of the reserves to be produced before production decline commences:

Minimum = 0.10
Most probable = 0.15
Maximum = 0.20

This distribution was used by all MMS Regions except for the Alaska Region which assumed that 40 percent of the oil reserves will be produced before production decline commences. Exponential oil decline was used by all MMS Regions except for the Pacific Region which assumed hyperbolic oil declines. The oil decline rates varied from 0.16 to 0.80, and the gas decline rates varied from 0.00 to 0.34 across the U.S. Federal offshore areas.

Attachments

[redacted]

Brief Description of MONTCAR Methodology

Determination of the resource economic value of a tract offered for lease involves calculating the amount of economically recoverable resources, estimating recovery factors, production profiles, exploration and development costs, operating costs, and performing a discounted cash-flow analysis. The Minerals Management Service uses a computer simulation model to determine the resource economic value of certain OCS tracts offered for lease by the Federal Government.

The computer model utilizes the Monte Carlo or range-of-values technique of handling calculations with uncertain input data. It provides a means to handle a series of subjective judgments about each individual variable. The burden of expressing the uncertainty is transferred from one or two individuals to the many experts in the various disciplines involved in the evaluation. This method explicitly recognizes the probabilistic nature of all variables affecting the evaluation and calculates a large number of possible outcomes based upon random samples from input probability distributions.

Much of the geological and engineering data (e.g., areal extent and thickness of the hydrocarbon pay zone, porosity, initial water saturation, recovery factors, production rates, product prices, costs, etc.) used to evaluate a tract is known with varying degrees of uncertainty. Providing a single number for the resource economic value of a tract is somewhat misleading since it provides no insight as to the relative uncertainty involved. The Monte Carlo technique provides a range of resource economic values (net present worth (NPW)) for the tract with the probability of each value occurring being a direct consequence of the data uncertainty.

The logic of the Monte Carlo simulation method can be described as a five-step process.

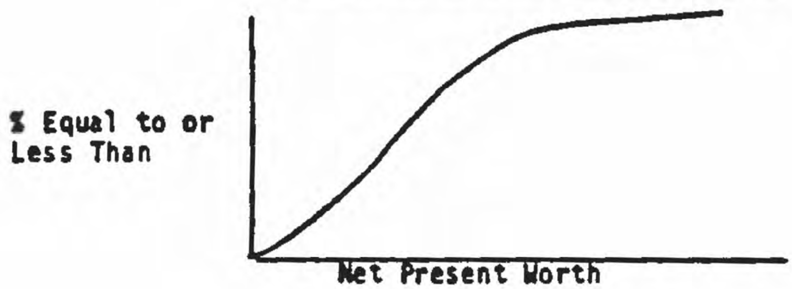
Step 1. Estimate the range and distribution of possible values of each variable that will affect the ultimate outcome of the venture. This requires judgments from geophysicists, geologists, paleontologists, stratigraphers, economists, and engineers. The most critical step in the process is quantifying the uncertainty involved through the use of these probability distributions. The amount of data concerning the prospect in question, the amount of information about the trend within which a prospect is located, and the experience of the scientists making the evaluation will dictate the type and shape of the probability distribution curves for each variable.

Step 2. Select, at random, one value from the distribution of each variable. Compute the tract value using this combination of selected values. This determines one point in the final distribution of possible tract values. Select, at random, a second value from the distribution of each of the variables. Again compute the resulting tract value. This is the second point in the distribution of possible tract values. The random selection is statistically done in such a way that, if a large number of random selections are made (1,000 or more), the distribution of the randomly selected values closely resembles the distribution that was read in.

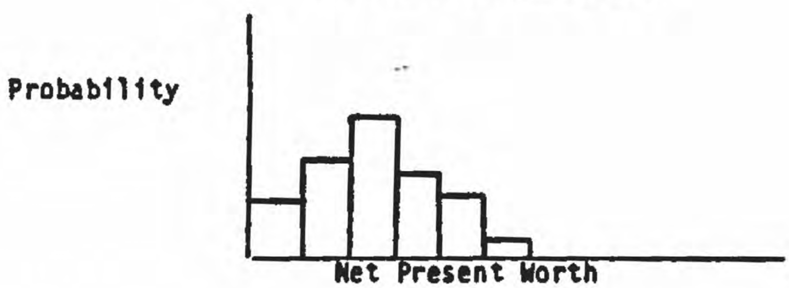
Step 3. Repeat the process 1,000 or more times, each time with a set of values selected at random from the distribution of each variable. Enough combinations of variables should be considered to adequately describe the shape and range of the distribution of tract values.

Step 4. The final output is a number of possible NPW values for the tract whether it is productive or dry. The program generates a cumulative probability distribution plot and a probability histogram for the productive NPW values, for example:

Cumulative Probability Distribution



Probability Histogram



The method in effect constitutes a shift of emphasis regarding subjective judgments. Instead of requiring a single judgment about how a series of variables will interact collectively, a series of judgments are made on how each individual variable will occur.

Step 5. The means of the productive and dry NPW distributions are determined, the probability of hydrocarbons being present, and factors for bonus write-off and depletion are applied to determine the expected (risked) NPW of the tract. This is the mean of the range of values (MROV) commonly referred to as the Government's reservation price.

The program also calculates what the expected NPW would be today if a tract was not leased until a later date, taking into account differences in income and excise tax payments and royalty or profit share payments; this is called the delayed MROV (DMROV).

Description of MEFS (all entry points):

When the mean value of the unrisked present worth (PW) of a prospect modelled in MONTCAR is zeroed, the resulting resource level becomes the minimum economic field size (mefs). The resource level is taken as the mean over the producing trials of the conditional, undiscovered, economically recoverable resources, measured in units of equivalent barrels of oil (BOE). A Newton-Raphson iteration process uses the number of producing acres (ACRE) to drive the PW to zero. In the present context, the term "iteration" refers to a complete iteration of the entire multi-trial Monte Carlo evaluation (simulation) process, as distinguished from a single Monte Carlo trial. Throughout each such iteration, the value of the ACRE variable (productive acres) varies within a very narrow range defined by a triangular distribution imposed by the program. Other Monte Carlo variables generally have wider, user-defined distributions.

Ideal behavior calls for the PW to approach zero as the resource level approaches the mefs. However, because of possible changes in the number of platforms and/or production wells from trial to trial within a Monte Carlo simulation, or between one iteration and the next, the PW may exhibit a sawtooth type of variation with respect to increasing acreage, instead of a monotonic increasing behavior.

The MEFS subroutine is entered though each of its entry points -- MEFIN, MEFADJ, and MEFOUT -- just once during each iteration. Each iteration results in one complete MONTCAR evaluation and printout. For the first iteration, MEFS uses the minimum value from the user-input triangular distribution for ACRE; from this, it develops a narrow triangular distribution for the ACRE variable, which it uses throughout the iteration. On the second iteration, the minimum number of producing acres is either doubled or halved from that of the first iteration, according to whether the PW is less than or greater than the zero band (defined below); again, a very narrow triangular distribution is developed for use throughout that iteration. In a multiple-horizon run, these adjustments to the ACRE triangular distributions are made for all horizons. The zero band refers to a dollar range, on either side of \$0.0 unrisked PW, which is sufficiently narrow so that the PW can be considered to be zeroed. The program presently uses a zero bandwidth of -\$50,000 to +\$100,000.

For the third and successive iterations, the ideal case is the one in which the PW increases with increasing acreage [i.e., the slope, (delta PW) / (delta A) > 0]. In this case the producing acres (A_i) is predicted by the following formula (the Newton-Raphson formula):

Case (a): Ideal case:

$$A_{i+1} = A_i - PW_i \left[\frac{A_i - A_{i-1}}{PW_i - PW_{i-1}} \right]$$

where A = producing acres (> 0)

PW = unrisked present worth (averaged over all producing trials)

i = current iteration

$i-1$ = previous iteration

$i+1$ = next iteration

$$(\text{delta } A) = A_i - A_{i-1}, \quad (\text{delta } PW) = PW_i - PW_{i-1}$$

In the abnormal situation in which the slope, (delta PW)/(delta A), is < 0, either the numerator (delta PW), or the denominator (delta A), must be negative -- but not both. Therefore two cases arise.

(Case i) $(\text{delta } A) = A_i - A_{i-1} < 0$ and $(\text{delta } PW) = PW_i - PW_{i-1} > 0$

The next value for the acres is

$$A_{i+1} = A_i \left[\frac{A_i}{A_{i-1}} \right]$$

The reader should note that because $A_i / A_{i-1} < 1$, $A_{i+1} < A_i$.

(Case ii) $(\text{delta } A) = A_i - A_{i-1} > 0$ and $(\text{delta } PW) = PW_i - PW_{i-1} < 0$

The next value for the acres is

$$A_{i+1} = A_{i-1} \left[\frac{A_{i-1}}{A_i} \right]$$

Because $A_{i-1} / A_i < 1$, $A_{i+1} < A_{i-1}$.

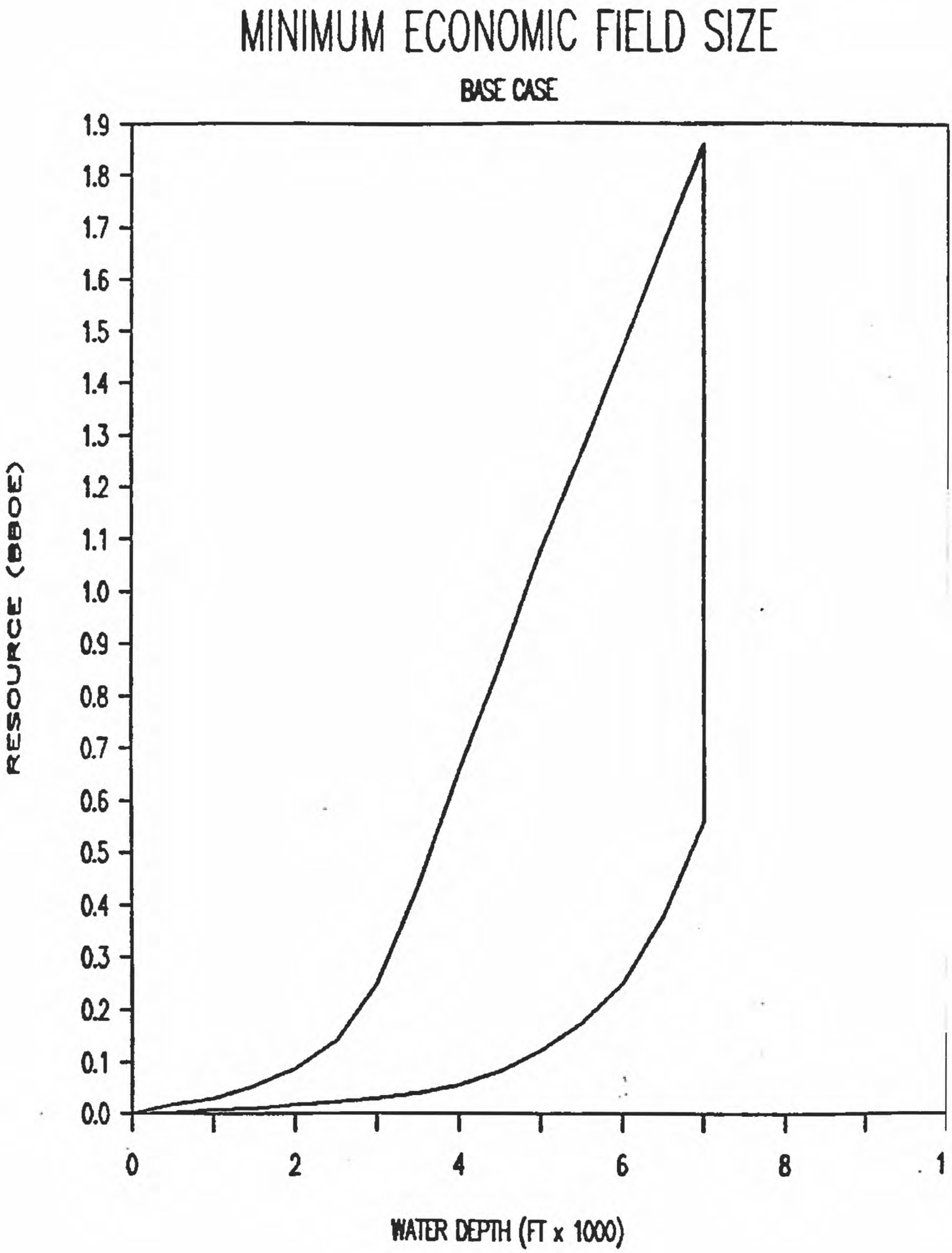
MEFS allows up to 20 iterations for the PW to converge to the $0.0 bandwidth. Generally, 4 or 5 iterations will be sufficient for convergence if platform costs and production well costs stay approximately the same for those iterations around the $0.0 bandwith.

If A_{i+1} is predicted to be negative, then the iterative process is stopped.

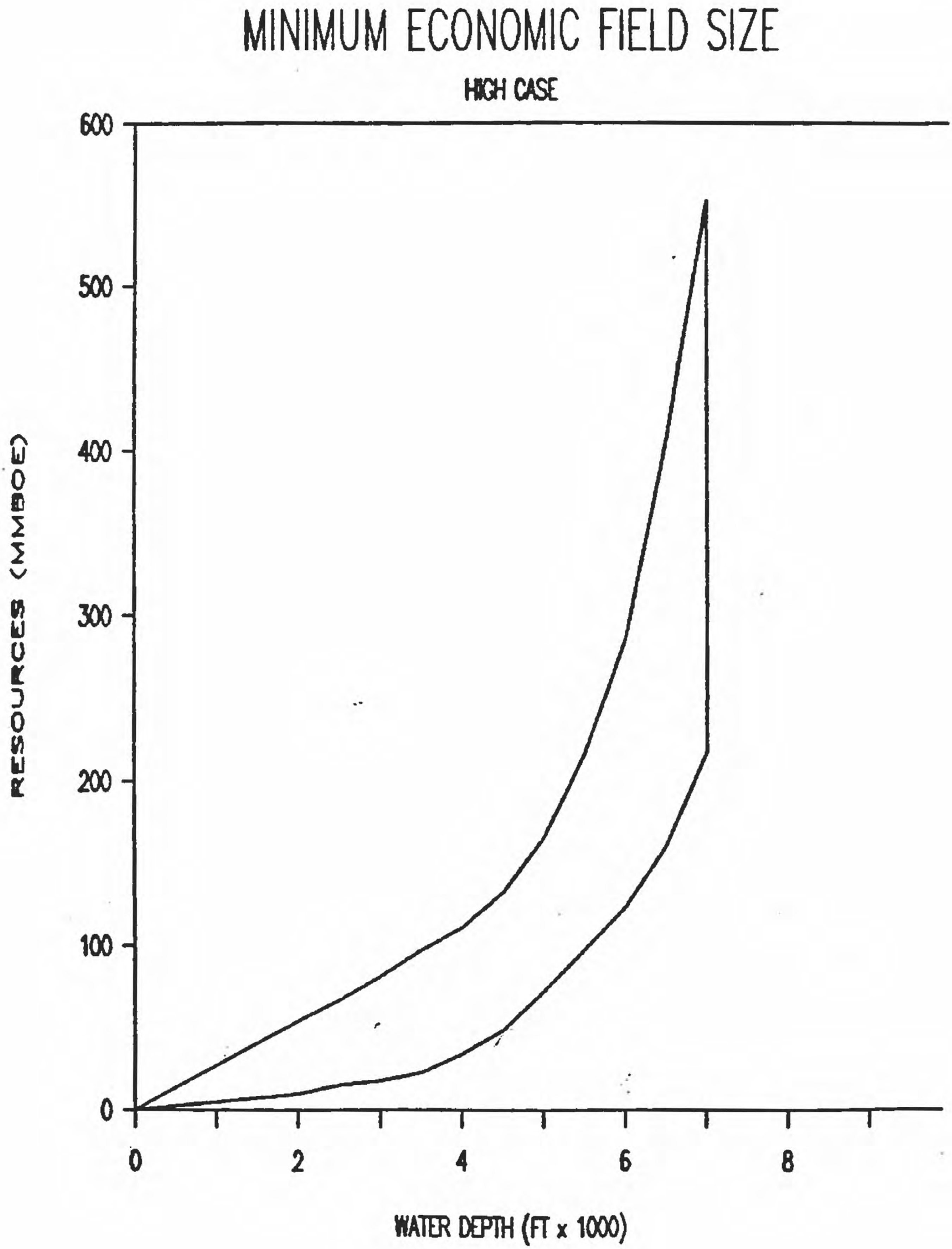
MEFS prints the following summary table at the end of a minimum economic field size determination and is shown below for a test run which required four iterations to zero the PW:

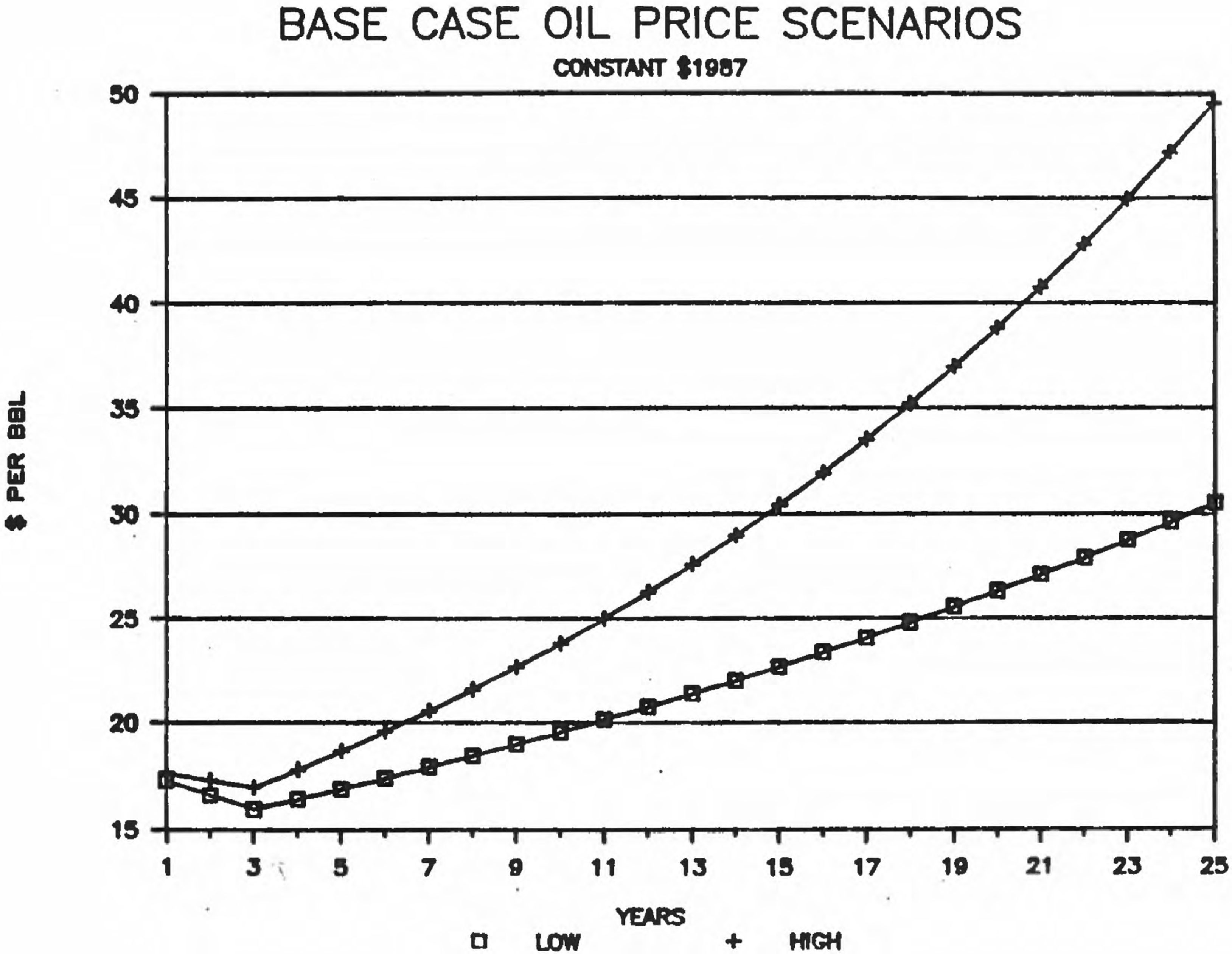
No.	Acres	Mean $P.W.,Unrisked	OIL(BBLS)	GAS(MCF)	BOE(OIL+GAS)
1	830.00	33445952.	4808388.	41234592.	12145504.
2	415.00	10458808.	2557362.	21952896.	6463571.
3	226.18	-145005.	1599184.	13471680.	3996280.
4	228.76	-15034.	1618834.	13620815.	4042466.

The minimum economic field size is the BOE value in the lower right-hand corner, and is approximately 4 million BOE for this test run. The reader should note that the "Mean $P.W., Unrisked" value, -$15034, falls within the $0.0 bandwith. If it had not been within the $0.0 bandwith after the 20th iteration, the result would have been considered non-convergent, and the last value in the table would not be regarded as the minimum economic field size.



MINIMUM ECONOMIC FIELD SIZE
BASE CASE
RESOURCE (BBOE)
1.9
1.8
1.7
1.6
1.5
1.4
1.3
1.2
1.1
1.0
0.9
0.8
0.7
0.6
0.5
0.4
0.3
0.2
0.1
0.0
0
2
4
6
8
1
WATER DEPTH (FT x 1000)

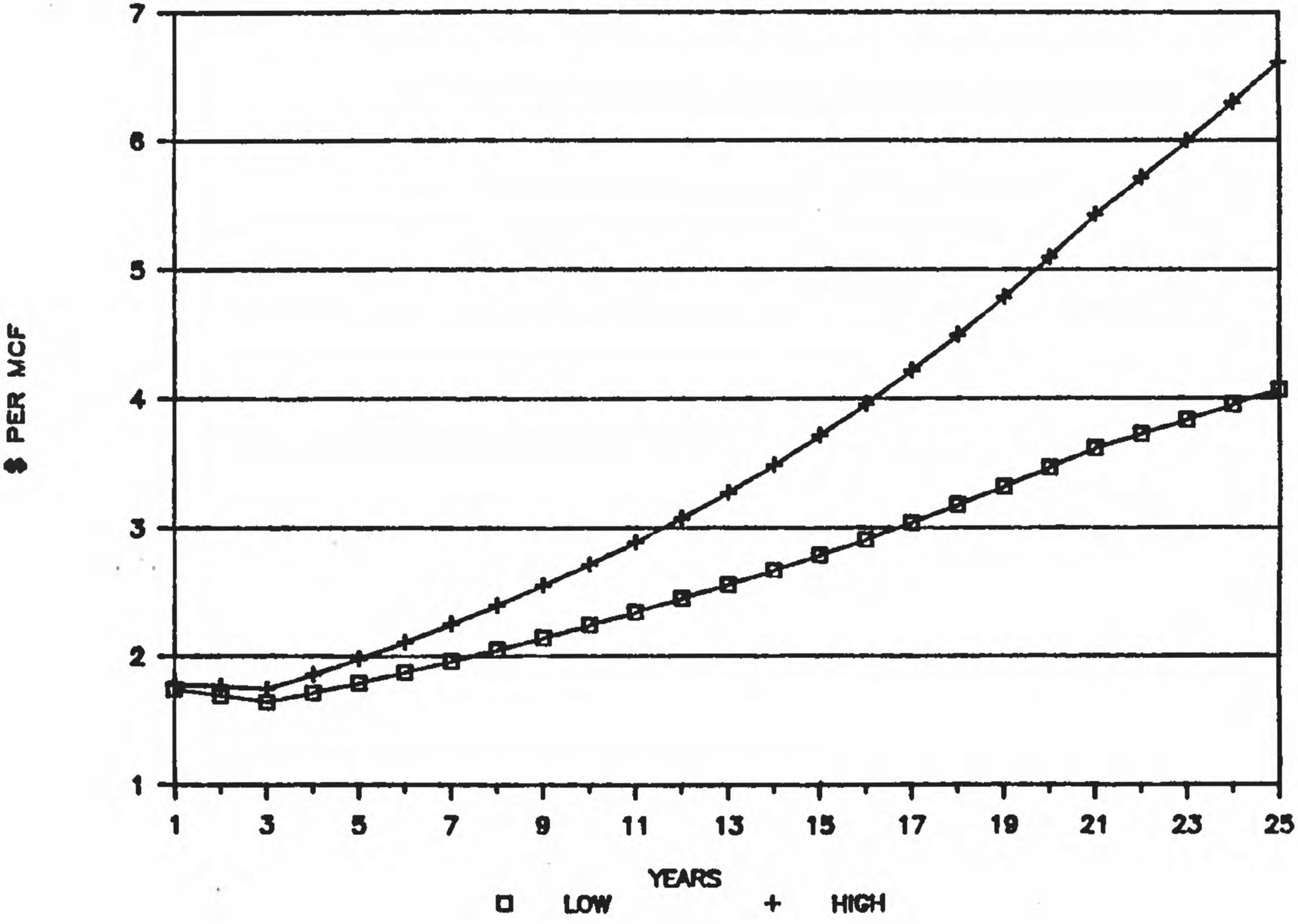

MINIMUM ECONOMIC FIELD SIZE
HIGH CASE
600
500
400
300
200
100
0
RESOURCES (MMBOE)
0
2
4
6
8
WATER DEPTH (FT x 1000)



Attachment 5

BASE CASE GAS PRICE SCENARIOS

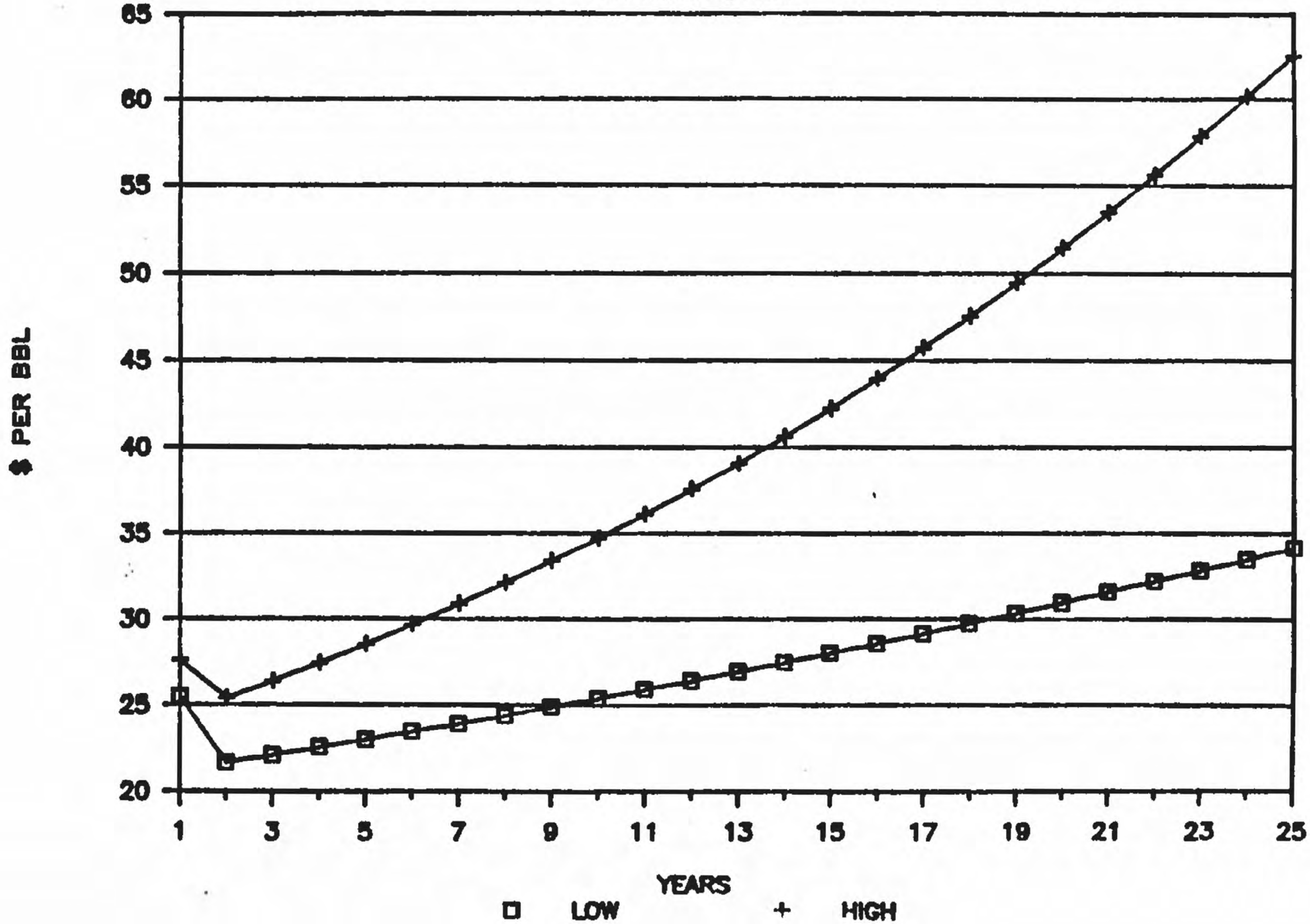
CONSTANT $1987



Attachment 6

HIGH CASE OIL PRICE SCENARIOS

CONSTANT $1987



Attachment 7

IV. ONSHORE PETROLEUM REGIONS OF THE UNITED STATES

A. INTRODUCTION

This chapter relates the oil and gas resources of the United States to the geology of its contained petroleum provinces. The following discussions provide a broad outline of the geology of the United States and that of the hydrocarbon potential of 80 onshore petroleum provinces grouped within 9 geographic regions (fig. IV.A.1).

Provinces are based on natural geologic entities and may include a single dominant structural element or a number of contiguous elements. Their boundaries follow State and county lines where possible, thus facilitating the use of production, reserve, and other data sets or compilations reported for political units. Provinces are named for structural, physiographic, or geographic features within the province.

Regions are geographic in character. Their formulation represents an attempt to group the petroleum provinces along broad geologic lines. For example, the Mid-Continent and Eastern Interior Basin Regions together cover the geologic entity referred to as the Stable Interior (fig. IV.A.2). The Atlantic Coastal Plain Region is essentially the Atlantic Coastal plain.

B. GEOLOGIC FRAMEWORK OF THE UNITED STATES
by
G.L. Dolton

The resource endowment of the United States is contained within that large element of earth's crust known as the North American plate that makes up the continental landmass of North America and its submerged margins. Within the North American plate, sedimentary rocks have been preserved in basins, arches, and in belts of highly folded and faulted rocks that provide sites for hydrocarbon generation and accumulation (fig. IV.A.2).

This continent has seen a long and varied geologic history, reaching back over 3.5 billion years, and is the product of mantle and crustal forces of a global scale acting on relatively thin, coherent, crustal plates of rock. It can be viewed, in a broad sense, as having been created by accretion or aggregation of numerous fragments of crystalline and sedimentary rocks that have been variously combined, deformed, sheared, rifted and altered by the enormous forces of plate tectonic processes.

The earliest crustal amalgamations occurred during the Precambrian. They are poorly understood, but produced a stable cratonic core of crystalline and metamorphic rocks. During the succeeding Paleozoic, this core became the site of shelf and basinal deposition in shallow cratonic basins, interrupted by occasional periods of warping and erosion. Basins and geoclines at the craton or shelf margin accumulated thicker sequences and aprons of rock. North America was rimmed by foredeeps and foldbelts through most of mid and late Paleozoic. Plate movements caused large continental fragments to collide with the eastern margin of the old North American craton and produce the highly deformed Appalachian fold and thrust

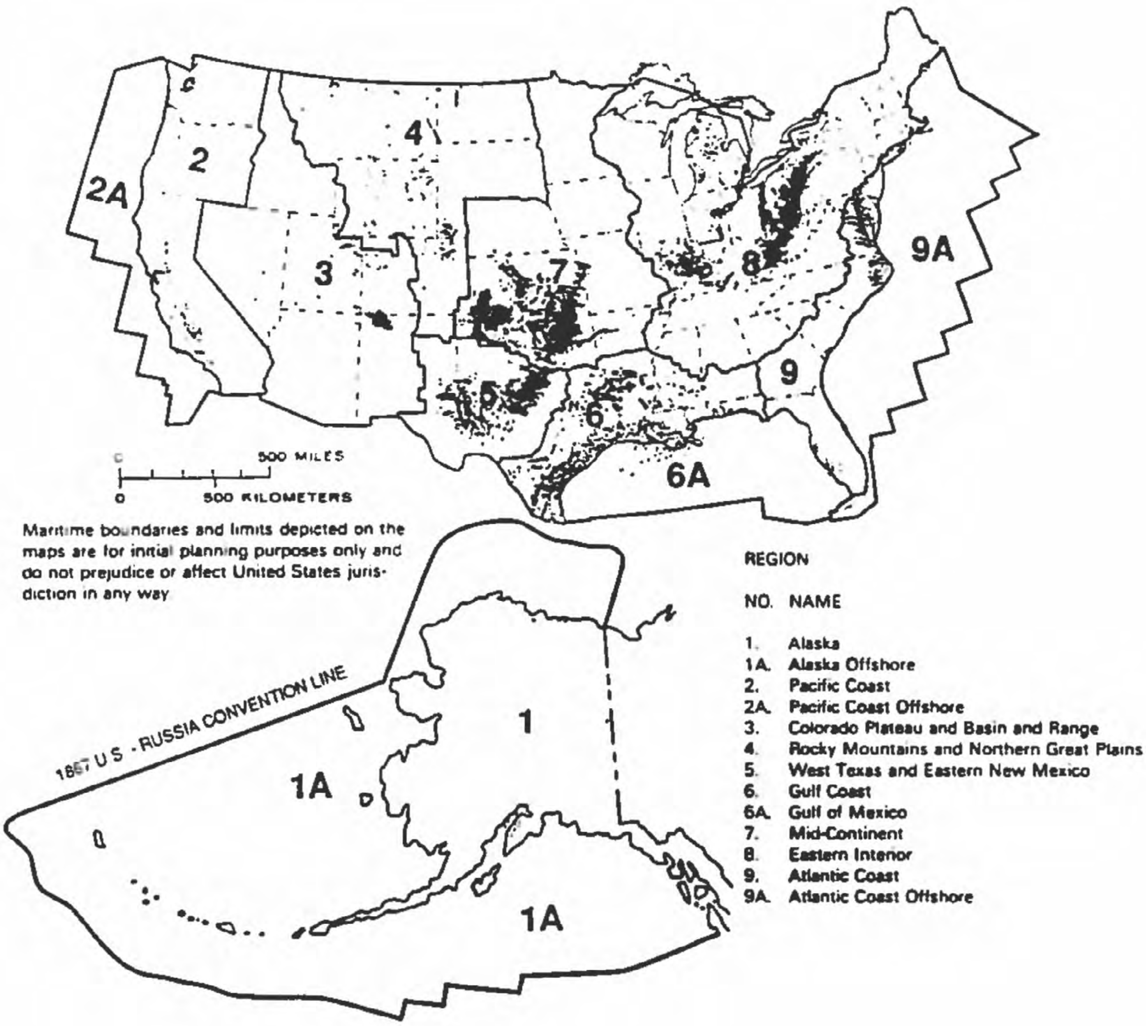


Figure IV.A.1. Map of petroleum Regions and general distribution of oil and gas fields in the United States. (Vlissides and Quiren, 1964, modified.)

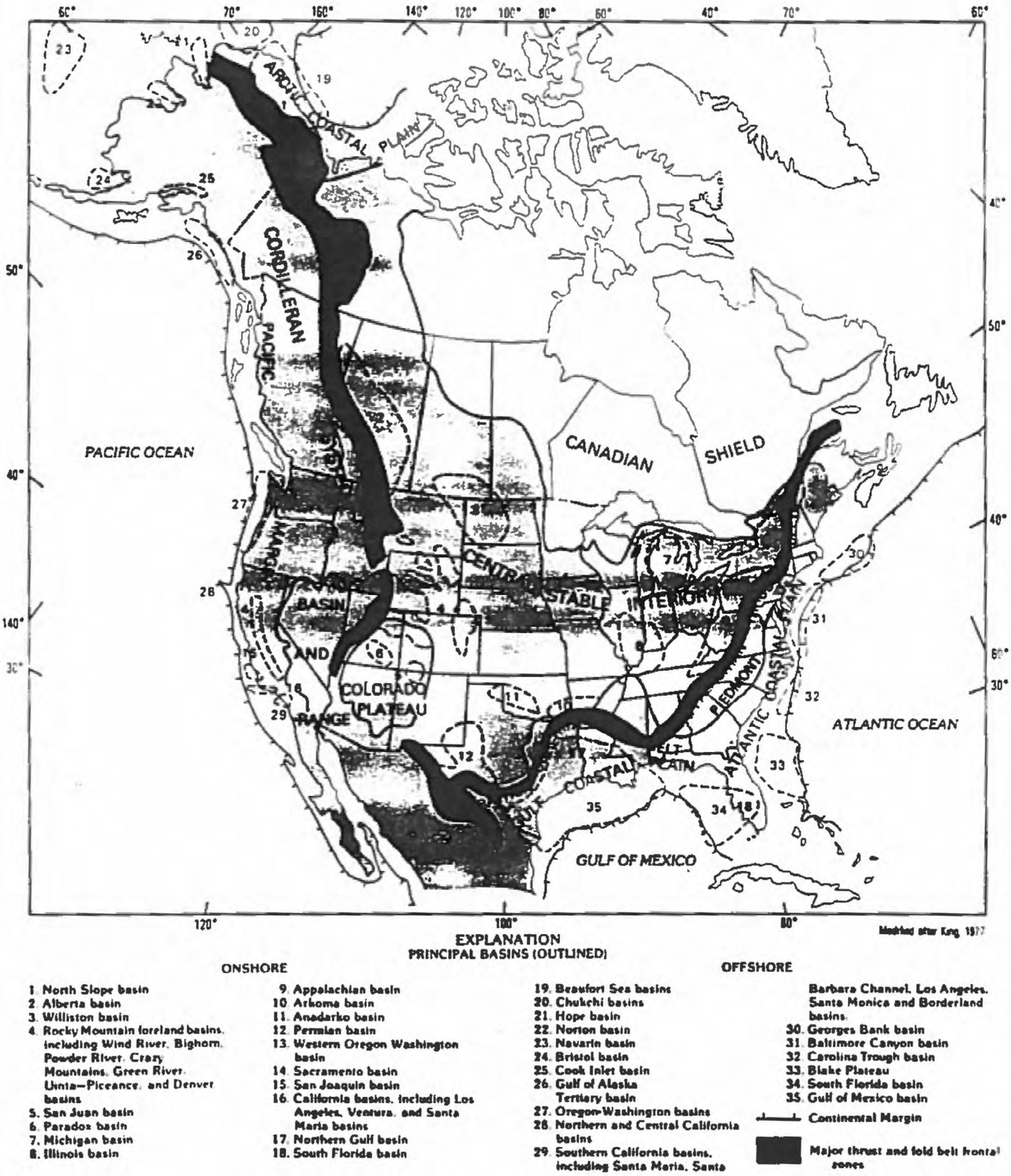


Figure IV.A.2. Generalized tectonic map of North America showing major basins. Modified after King, 1972.

belt system. A similar crustal collision took place along the southern margin, producing the Ouachita System of folded and thrust rocks and causing breakup of parts of the old Central Stable Shelf margin in that region, extending also inland to parts of the Rocky Mountains. In Alaska and Arctic islands, late Devonian deformation (Ellesmerian orogeny) occurred.

During the Paleozoic, Mesozoic and Tertiary, a complex history of deposition, continental accretion, and folding at the continental margin was taking place in western North America. Episodically during this time, the Pacific oceanic plate was moving toward the North American continent, passing beneath its margin and causing strong compression of the sedimentary cover, breakup of parts of the craton margin, basin formation, and emplacement of batholiths. The compression produced older fold belts, now seen only in fragments, as well as the highly visible Cordilleran thrust belt of Cretaceous-Tertiary age, all overprinted by later tectonic events. As the North American continental plate eventually moved over spreading centers of the Pacific Ocean plates, extensional faulting, rifting and emplacement of extensive basaltic rocks occurred. Development of the petroleum-rich Pacific coastal basins and the rather depauperate basins of the Basin and Range region occurred during the Tertiary.

During the Mesozoic, the present Atlantic Ocean, Arctic Ocean, and Caribbean basins opened and huge thicknesses of relatively undeformed strata accumulated in passive margins. Carbonate sediments predominated early in this history in the Gulf and Atlantic coast areas, whereas terrigenous sediments predominated later and thoughout this episode in Arctic Alaska.

Today, the continent consists of a relatively stable interior surrounded by zones of highly deformed rocks, which in turn are onlapped by the young rocks of the Atlantic and Gulf coastal plains (fig. IV.A.2).

Petroleum Distribution

The Canadian Shield is an outcrop of the ancient, tectonically stable core of the continent. The igneous and metamorphic rocks of this shield are not prospective for hydrocarbons. In the Central Stable Interior, the old crystalline core is overlain by a relatively thin cover of sedimentary rock that fills a number of structurally simple intracratonic basins separated from each other by broad arches. Stronger deformation at the margins of the Central Stable Interior produced deep basins such as the Permian and Anadarko basins, uplifts such as the Wichita system, and the basins and uplifts of the present and ancestral Rocky Mountain systems. Hydrocarbons are contained in cratonic basins such as the Michigan, Illinois, and Williston basins, in deformed foreland basins such as the Appalachian and Arkoma basins, in complex marginal basins such as the rich Anadarko and Permian basins, and in the intermontane Rocky Mountain basins. Most of the basins produce oil and gas from Paleozoic reservoir rocks (fig. IV.B.1). However, the younger Mesozoic and Tertiary Rocky Mountain basins also produce large amounts of oil and gas from Jurassic, Cretaceous and Tertiary sedimentary reservoir rocks.

Belts of rock deformed by intense folding and thrusting ring the Central Stable Interior. These include the Cordilleran thrust belt, which stretches from Alaska to Mexico, the Appalachian thrust and fold belt, and

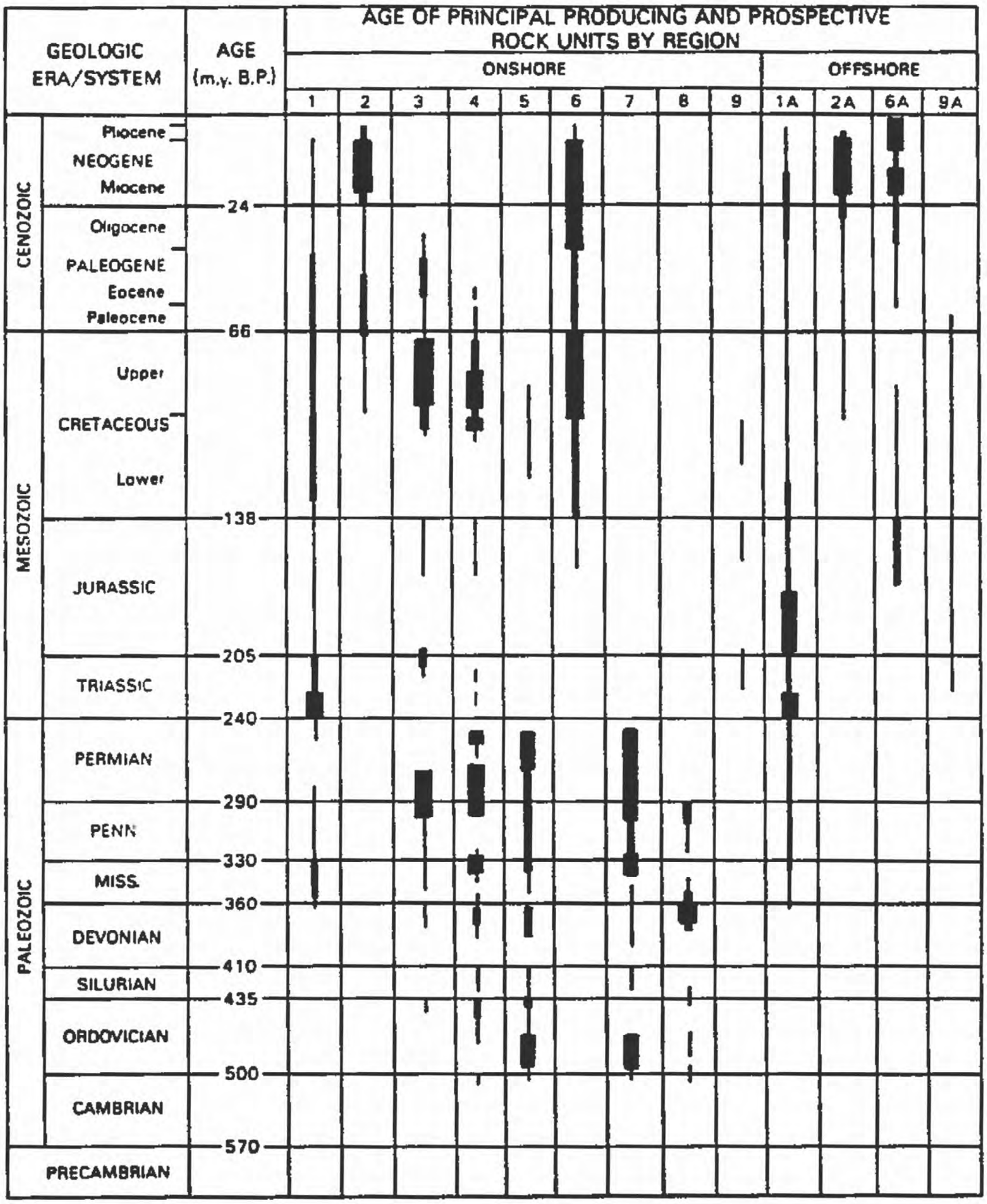


Figure IV.B.1. Age and importance of principal productive and prospective reservoir rocks by Region. Width of column proportional to significance of reservoir.

the Ouachita System (fig. IV.A.2). Accompanying these belts are metamorphosed rocks of more intensely deformed terranes. The frontal zones of these thrust belts are often the sites for hydrocarbon accumulations.

Mesozoic and Cenozoic sedimentary rocks lap onto the Ouachita System to form the Gulf Coastal Plain; these rocks thicken southward into the Gulf of Mexico where they exceed 50,000 ft. Basins in these areas are superposed on a complex basement rock foundation that may include not only continental crust, but transitional and oceanic crust as well. Basins of the Gulf Coast, influenced by salt tectonics, have been highly productive of both oil and gas from reservoir rocks of Mesozoic and Cenozoic age. Mesozoic and Cenozoic sedimentary rocks of the Atlantic Coastal Plain that lap onto the Appalachian system form a wedge of sedimentary rocks that thickens seaward along most of the Atlantic margin from a few hundred feet to more than 50,000 ft, but, to date, have produced commercial oil only in peninsular Florida.

The Cordilleran System and its major structural elements, including the Cordilleran thrust belt, are part of a broad, deformed western margin of the North American plate. The complex structures of this part of the continent indicate that it has been tectonically active through much of geologic time. Probably initially a passive continental margin, it has a later complex history related to collision and to crustal accretion and to compression and shearing of the western margin of North America. The petroleum-prospective areas of the Rocky Mountains and Colorado Plateau are found not only within the folded rocks of the frontal thrust belt, but in Cretaceous and Tertiary foreland and intermontane basins and in the older Paleozoic basins at the western margin of the Central Stable Interior. These basins contain Paleozoic and Mesozoic Tertiary rocks in highly productive settings.

In the Great Basin, where the crust has undergone extensional faulting, a large number of Tertiary basins underlain by Paleozoic or Mesozoic rocks, adjoined by uplifts, and locally associated with abundant volcanic rocks, have been produced. To date, little petroleum has been found in this region. However, very rich Cenozoic petroleum basins are found to the far west along the Pacific margin, such as the Los Angeles and Ventura basins.

Alaska is divided into two major structural elements. The Arctic Coastal Plain, which is a relatively uncomplicated area of rocks deposited on a portion of the old stable interior of the continent, is onlapped by a wedge of younger rocks that thicken into the Arctic Ocean and is bounded by the Cordilleran system to the south, a highly complex system that contains folded rocks of the Brooks Range and crustal fragments accreted to the western margin of North America. Alaska's production is from two major areas. In southern Alaska, the Cook Inlet produces from rocks of Cenozoic age. The Arctic coastal plain of the North Slope, which includes the supergiant Prudhoe Bay Field, produces from rocks of Paleozoic, Mesozoic, and Cenozoic age.

The petroleum production, reserves and resource potential of each region are shown by table IV.B.1. Regional discussions provide an outline of the geology of the United States as related to known and prospective petroleum potential and are discussed generally from west to east. Each chapter carries with it a summary of estimates of undiscovered resources.

These sections represent a very brief synthesis of an extensive, province by province analysis of the petroleum geology.

Table IV.B.1.--Conventional oil and gas resources by region. Oil in billion barrels; gas in trillion cubic feet

U.S. Onshore and State Waters

Region		Produced Resources (Cumulative Production)	Reserves: Measured	Reserves: Inferred & indicated	Undiscovered Recoverable Resources: F95	Mean	F5
1	Oil	6.1	6.9	6.4	3.6	13.2	31.3
	Gas	3.8	32.7	3.0	15.6	57.9	138.6
2	Oil	20.3	4.7	1.2	1.5	3.5	6.6
	Gas	33.2	3.9	2.6	5.5	11.0	19.1
3	Oil	3.1	0.6	0.4	0.5	1.5	3.4
	Gas	24.7	17.1	4.9	9.6	21.3	39.3
4	Oil	7.1	1.2	1.3	2.7	4.5	6.9
	Gas	13.1	7.6	3.6	7.0	15.2	27.8
5	Oil	30.2	5.4	3.8	1.5	2.6	4.0
	Gas	82.2	16.7	12.9	11.9	20.1	31.3
6	Oil	43.1	3.7	5.7	2.4	4.2	6.7
	Gas	285.6	33.6	42.3	51.2	82.5	123.6
7	Oil	17.3	1.1	1.4	1.2	1.9	2.7
	Gas	145.4	37.5	18.3	16.2	28.7	46.0
8	Oil	8.4	0.5	0.7	1.3	1.8	2.4
	Gas	33.9	8.2	5.0	10.8	17.2	25.6
9	Oil	0.1	<0.1	<0.1	0.1	0.2	0.5
	Gas	<0.1	<0.1	<0.1	<0.1	<0.1	<0.1

Mean value totals may not be equal to the sums of the constituent means due to independent rounding.

Fractile values are not additive.

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C. REGION 1, ALASKA
by K.J. Bird and L.B. Magoon

Geologic Framework

Region 1 includes all of onshore Alaska and the submerged state offshore lands (fig. IV.C.1). The geology of Alaska is varied and complex. Current theories hold that much of the North American Cordillera is a vast mosaic or collage of 50 or more crustal blocks (terranes) that originated somewhere other than North America. Movement of tectonic plates resulted in the collision and accretion of these terranes to the ancestral North American cratonic margin, mostly during Mesozoic and early Cenozoic time. For Alaska, the net result of this interpretation is that, except for a small part in east-central Alaska, the entire area is composed of accreted terranes. Prior to 250 million years ago, according to this interpretation, there was no continental land mass, only ocean basin, in the position of Alaska.

Alaska has nearly 20 sedimentary basins or alluviated lowlands, which may overlie sedimentary basins (fig. IV.C.1). Some of these basins extend offshore beneath State and Federal waters. In addition to these basins, many areas of Alaska consist of ancient sedimentary basins that have been structurally deformed, metamorphosed, and intruded by igneous rocks. These ancient basins generally consist of interbedded marine shale and sandstone (flysch) and rare to abundant volcanic rocks and are referred to as flysch belts. In this assessment, they are regarded as having negligible petroleum potential.

Most basins in Alaska are the result of sediment accumulations formed in crustal downwarpings or pull-aparts in response to terrane accretion or later large-scale postaccretionary horizontal translations. A few basins result from sediment that accumulated prior to, during, and after terrane accretion. In most Alaskan basins, it is the sedimentary loading imposed after terrane accretion that provided the necessary deep burial and attendant heating to mature the petroleum source rocks. In Alaska, the petroleum-prospective basins can be grouped into three categories: (1) composite basins, such as the North Slope, (2) Cenozoic nonmarine basins, found mostly in interior Alaska, and (3) Cenozoic marine basins, such as the Gulf of Alaska basin.

Composite basins.--The North Slope basin and the so-called Kandik basin are examples of composite basins. The North Slope basin encompasses the northern part of the Brooks Range and all lands to the north, including parts of the offshore. The petroleum-prospective rocks of the North Slope consist of two sequences of sedimentary rock: an older (Paleozoic-Mesozoic) sequence derived from a cratonic source and a younger (Mesozoic-Cenozoic) sequence derived from an orogenic source located opposite the craton (fig. IV.C.2). The occurrence of two sequences of opposite polarity is a characteristic of the entire eastern Cordilleran thrust belt and adjacent central stable interior region of Canada and the United States (fig. IV.A.2).

In northern Alaska, the older sequence, of Mississippian to early Cretaceous age, is composed mostly of marine sandstone, shale, and carbonate rocks generally less than 8,000 ft thick. The clastic sediments were

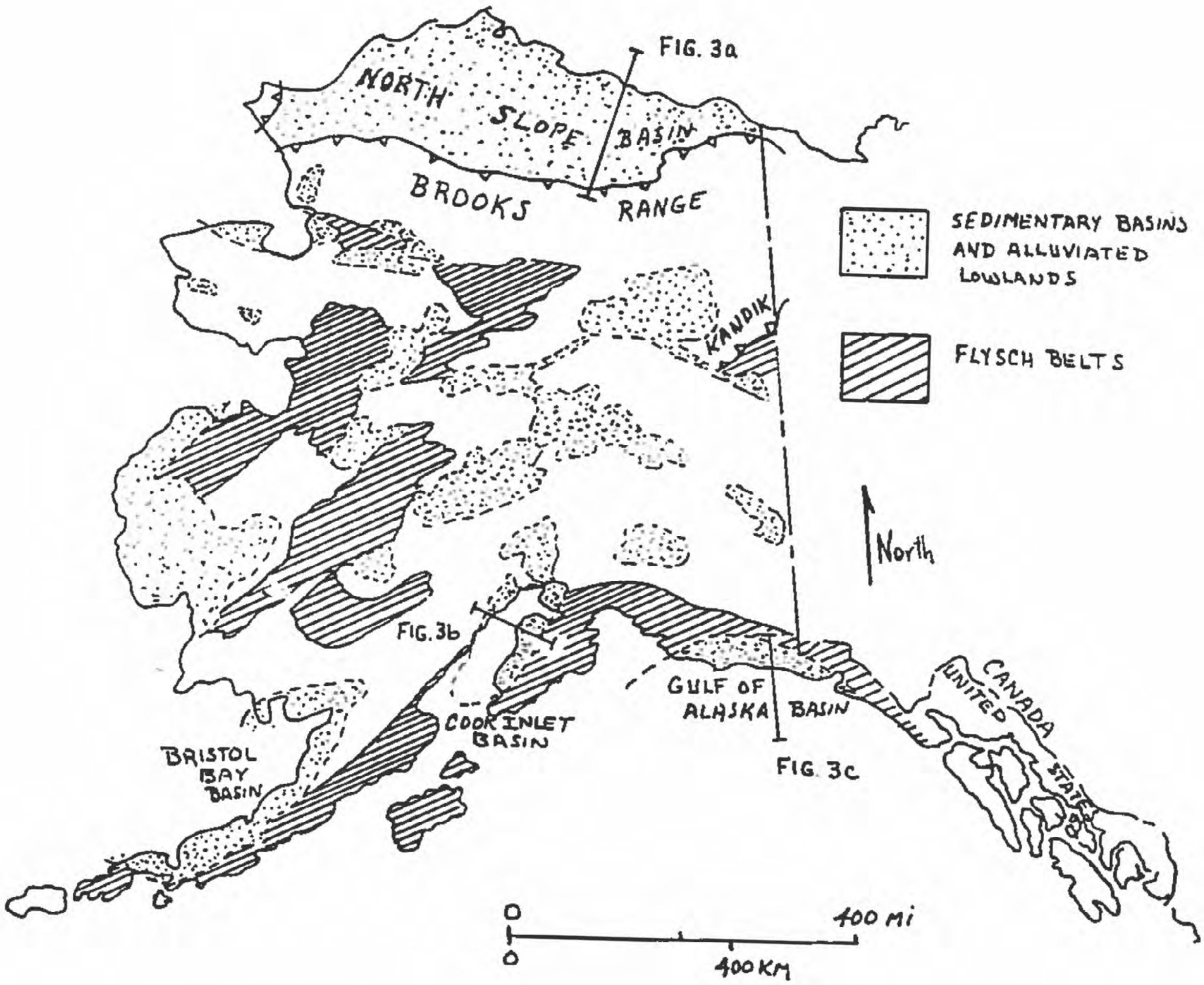

Figure IV.C.1. Petroleum Region 1 (Alaska) showing petroleum-prospective basins and non-prospective flysch belts (adapted from C.E. Kirschner, unpublished).

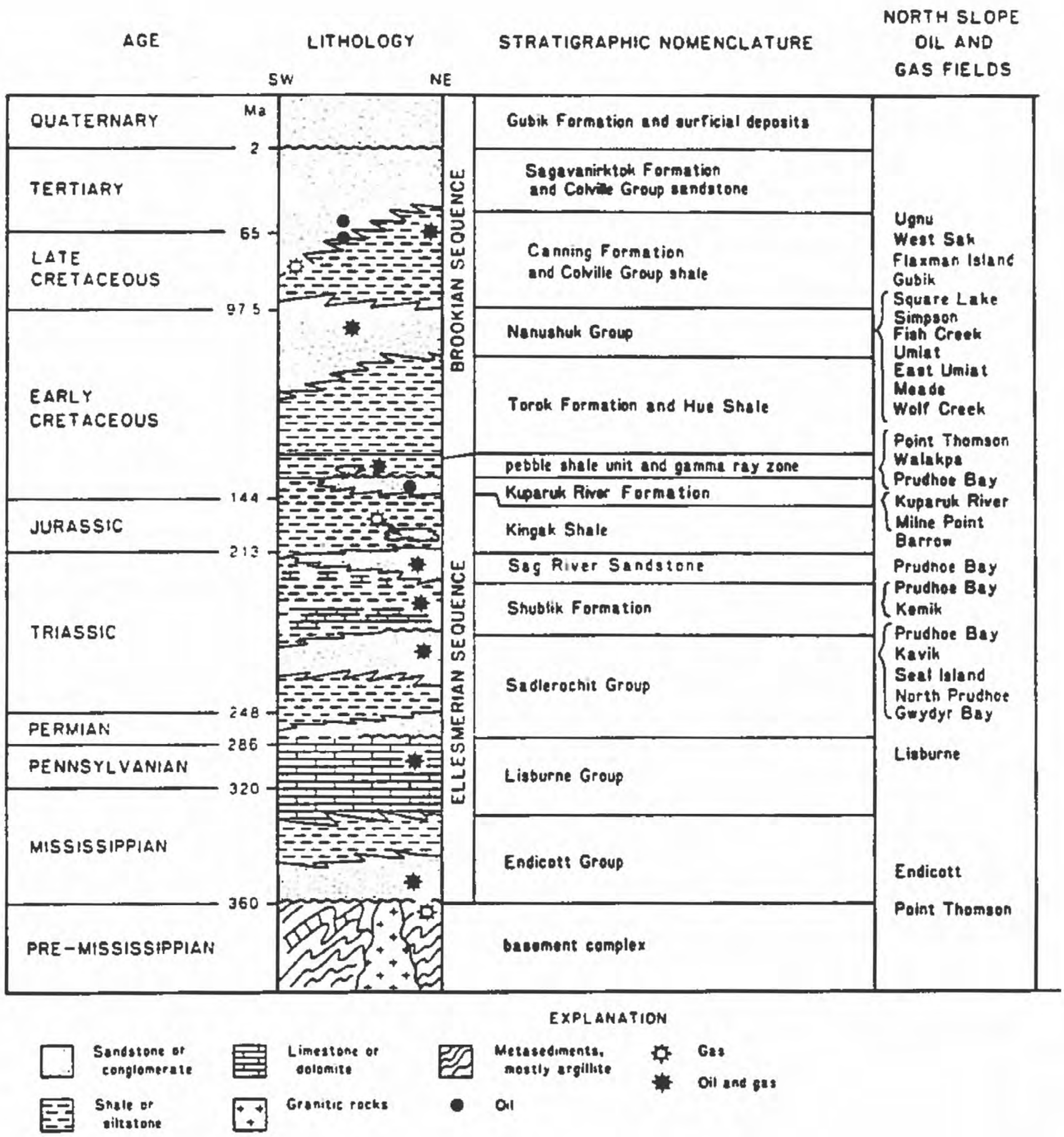

Figure IV.C.2. Generalized stratigraphic column for the North Slope, exclusive of the allochthonous rocks in the Brooks Range, showing stratigraphic locations of oil and gas fields (from Bird, 1987).

derived from a northern (present-day location), stable, continental landmass. The younger sequence, of Cretaceous and Tertiary age, is composed of marine and nonmarine sandstone and shale as thick as 20,000 ft thick. These sediments originated from uplift and erosion of the ancestral Brooks Range (fig. IV.C.3). Although both sequences have important petroleum source rocks, reservoir rocks, and oil deposits, all commercial oil comes from the older sequence. An important geologic distinction between the North Slope and the remainder of the Cordillera is an episode of rifting during Cretaceous time. The rift, which lies buried offshore beneath the continental terrace and parallels the coastline of northern Alaska east of longitude 156^{o} (fig. IV.C.1), marks the line of separation between the North Slope terrane and its undetermined parent landmass. Structures and stratigraphic relations that formed during and after rifting are critical to the occurrence of large oil and gas accumulations in this province; most of these accumulations occur in broad, low-relief, structural-stratigraphic traps located along the rift margin.

The southern part of the North Slope consists of a deep sediment-filled trough and the adjacent Brooks Range. The Brooks Range and the southern part of the trough are deformed by folding and faulting. Numerous small, subeconomic oil and gas accumulations in faulted, anticlinal traps are known in this region. The Kandik basin, located in east-central Alaska (fig. IV.C.1), is a segment of the Cordilleran thrust belt and has many similarities in structure and stratigraphy to the southern part of the North Slope basin. Petroleum source rocks and reservoir rocks are known to be present in the Kandik basin, but no accumulations of oil or gas have been found to date.

Cenozoic nonmarine basins.--These are the most numerous of Alaskan basins, but most are poorly known because they lie in alluviated lowlands with little subsurface data. Most of these basins occur in the interior parts of Alaska. The Cook Inlet basin is the best known example because of extensive oil and gas exploration. These basins are characterized by gravity lows, a basin fill consisting of nonmarine fluvial and coal-bearing sedimentary rocks deposited in cyclic fining-upward sequences, locations along or adjacent to major faults suggesting a genetic relationship between faulting and basin development, both extensional and compressional structures, and shifted depocenters indicating deformation during basin filling. These basins may partly overlie older flysch basins, which are considered to have negligible petroleum potential because of some combination of (1) poor reservoirs, (2) intense deformation, and (3) excessive heating. Source rocks may occur in some flysch basins, offering the possibility of oil generation and migration from the flysch basin into traps in the overlying Cenozoic nonmarine basin. The Cook Inlet oil fields (fig. IV.C.3) are believed to have originated in this manner from marine Middle Jurassic source rocks. For most Alaskan Cenozoic nonmarine basins, gas is the expected hydrocarbon resource.

Cenozoic marine basins.--These basins are found on the periphery of Alaska and lie mostly offshore. These include the Bristol Bay and Gulf of Alaska basins. The Bristol Bay basin lies in a backarc setting to which sediments were supplied from both the Alaska Peninsula and the interior of Alaska. Basin fill, as much as 15,000 ft thick, is composed of generally undeformed mid- to-late Tertiary volcaniclastic sandstones deposited in nonmarine to nearshore marine conditions. The southwestern part of the basin

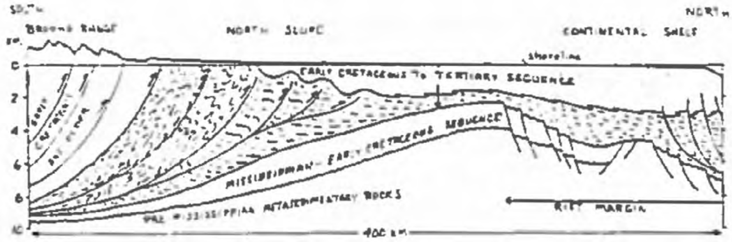

Figure IV.C.3a. Geologic cross section of the North Slope (modified from Bird and Bader, 1987). See figure IV.C.1 for location of section.

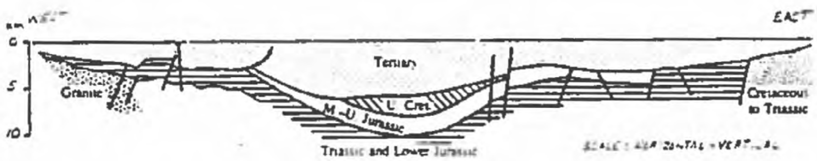

Figure IV.C.3b. Geologic cross section of the Cook Inlet basin (modified from Boss and others, 1976). See figure IV.C.1 for location of section.

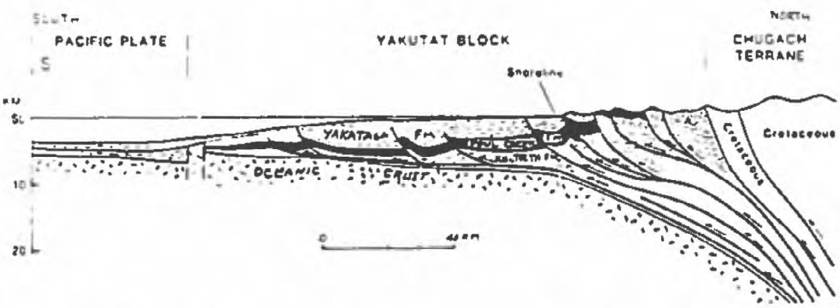

Figure IV.C.3c. Geologic cross section of the Gulf of Alaska basin (modified from Bruns, 1985). See figure IV.C.1 for location of section.

Figure IV.C.3. Geologic cross sections, Alaska.

overlies a continuation of the same Jurassic flysch basin which is believed to be the source for Cook Inlet oil.

The Gulf of Alaska basin lies on the Yakutat block, the most recently accreted terrane in Alaska. This basin developed on a composite oceanic and continental terrane that is postulated to have been sliced off of the North American continental margin at the latitude of northern California and transported by plate motion into the Gulf of Alaska where collision is now occurring. The basin records Eocene to Holocene marine and nonmarine clastic sedimentation. Potential reservoirs are sandstones in the Eocene Kulthieth Formation and Plio-Pleistocene Yakataga Formation. Potential source rocks are marine shales in the Oligo-Miocene Poul Creek Formation. The leading (northern) part of the block is deformed by the collision into a fold and thrust belt. Most of the block south of the fold and thrust belt is undeformed, and its trailing (southern) edge is a passive margin developed over a fossil fracture zone (fig. IV.C.3).

Petroleum Geology

On the North Slope, most reservoir rocks are known to be oil- or gas-bearing somewhere in the province, although all commercial oil is produced from Late Paleozoic and Mesozoic reservoirs. Large volumes of gas are present in Triassic sandstones in the Prudhoe Bay field, the largest oil field in North America, but at present the gas is not economic. The most important source rocks are of Triassic, Jurassic, and Cretaceous age.

In Cook Inlet basin, most oil occurs in Paleogene conglomeratic sandstone reservoirs, whereas most gas occurs in Neogene sandstone reservoirs. The oil is believed to originate from Jurassic source rocks underlying the basin, whereas the gas is believed to be of biogenic origin derived from the coal-bearing basin-filling sediments.

Alaska has produced 6.1 billion barrels of oil and 3.8 trillion cubic feet of gas and has measured reserves of 6.9 billion barrels of oil and 32.7 trillion cubic feet of gas as of January, 1987 (table IV.C.1). Most of the reserves are located on the North Slope, an area that contributes nearly 25 percent of daily U.S. oil production.

Petroleum exploration in Alaska dates from the late 1880's when surface oil seepages were investigated. Alaska's first oil field, Katalla, was found in the Gulf of Alaska province by drilling on a surface seepage. Between 1902 and 1933, a total of about 154,000 barrels of oil were produced from this field. Exploration of the Naval Petroleum Reserve and adjacent areas on the North Slope was conducted by the U.S. Navy from 1944 to 1953. This, the first oil exploration in an arctic region, resulted in the discovery of three oil and five gas accumulations, all of which were uneconomic; the Barrow gas fields, however, are currently produced for local consumption. Commercial oil was discovered in Cook Inlet in 1957 and on the North Slope in 1968. Government exploration of the petroleum reserve on the North Slope was reactivated from 1974 to 1981. Several encouraging shows and two subcommercial gas accumulations were discovered. During the 1980's the primary focus of Alaskan exploration has been offshore. Outside of those areas of Alaska where commercial oil and gas is produced, the exploration density is moderate to light. For example, only 12 wells have been drilled in all of interior Alaska north of the Cook Inlet and south of the Brooks Range.

Petroleum Potential

The petroleum potential of this region is estimated to be considerable (table IV.C.1) because of its favorable geology, exploration history, and the light to moderate exploration density. The largest remaining undiscovered petroleum resources in Alaska are estimated to occur in the North Slope basin. These resources are estimated to be about equally distributed between the coastal plain and foothills provinces. The foothills and coastal plain area of the Arctic National Wildlife Refuge (ANWR), an area presently closed to exploration, is considered the most promising part of the North Slope. The coastal plain west of ANWR is considered prospective for oil and gas in combination structural/ stratigraphic traps similar to Prudhoe Bay and in Cretaceous and Tertiary turbidite and deltaic reservoirs. In the foothills provinces, almost 40 separate structures have been tested resulting in one oil and six gas accumulations, all subeconomic. Several times as many structures remain to be tested. These are faulted anticlinal structures with Cretaceous and(or) Tertiary sandstone reservoirs in the northern part of the foothills and carbonate reservoirs of Carboniferous age in the southern part of the province.

Natural gas from the North Slope is presently uneconomic. Large volumes of gas have been discovered, and we estimate that equally large amounts remain to be discovered.

The economics of oil development on the North Slope are sensitive to the proximity of the pipeline system. A 5 trillion ft^3 gas field with 350 million barrels of recoverable condensate and oil (Point Thomson field), located 55 miles from the pipeline, is presently uneconomic; whereas a 58-million-barrel field (Niakuk), located within a few miles of the pipeline, has been announced for development by Standard Oil Production Company. When developed, this will be the smallest producing field on the North Slope.

Table IV.C.1.--Cumulative production, estimated reserves and undiscovered recoverable resources in Region 1.

	Cum. Production	Measured Reserves	Inferred + Indicated Reserves
Oil (BBO)	6.1	6.9	6.4
Gas (TCF)	3.8	32.7	3.0

Petroleum Provinces
Estimates of Undiscovered Recoverable Resources*

	Crude Oil (Billion Barrels)			Gas (Trillion Cubic Feet)		
	F95	F5	Mean	F95	F5	Mean
<u>Region 1 - Alaska</u>						
Arctic Coastal Plain	1.50	14.80	6.00	4.66	58.24	22.11
Northern Foothills	0.67	5.12	2.24	4.03	24.31	11.49
Southern Foothills	0.58	13.18	4.35	2.85	61.56	20.49
Kandik	0.00	0.49	0.11	0.00	0.49	0.11
Alaska Interior	0.00	0.00	0.00	0.45	2.85	1.33
Inter. Lowlands (Incl. in 062)						
Bristol basin	0.00	0.00	0.0	0.11	0.67	0.32
Hope basin	-	-	-	-	-	-
Copper River (Inc. in 062)						
Cook Inlet	0.09	0.64	0.29	0.35	3.91	1.53
Alaska Peninsula (Incl. in 062)						
Gulf of Alaska	0.03	0.58	0.19	0.03	2.00	0.56
Kodiak	-	-	-	-	-	-
SE Alaska	-	-	-	-	-	-
Total	3.6	31.3	13.2	15.6	138.6	57.9

Mean value totals may not be equal to the sums of the constituent means due to independent rounding.

Fractile values are not additive.

*Estimates of undiscovered economically recoverable resources are given in Table VIII.B.3.

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D. REGION 2, WASHINGTON, OREGON, AND CALIFORNIA
by K.J. Bird and L.B. Magoon

Geologic Framework

Region 2 includes all of onshore Washington, Oregon, and California and the submerged State offshore lands (fig. IV.D.1). This region includes the Pacific margin provinces and small parts of the Rocky Mountain and Basin and Range provinces. The geology of this region is varied and complex, the consequence of a geologic history that includes accretion of crustal blocks to the North American cratonic margin, subduction, arc-related volcanism and plutonism, large-scale horizontal translations, block rotations, eruption of flood basalts, and formation of numerous small, deep basins, some of which are prolific oil producers.

Because of the active tectonic history of this region, during which older basins have been destroyed and new ones created, petroleum-prospective rocks are limited mostly to the younger basins that formed during latest Mesozoic and Cenozoic time. In summarizing the framework geology as it relates to petroleum, the region can be subdivided into four parts: (1) western Washington and Oregon, (2) eastern Washington and Oregon, (3) Great Valley of California, and (4) coastal basins of California (fig. IV.D.1).

Western Oregon and Washington.--Most of western Oregon and Washington and the offshore continental margin is the site of a forearc sedimentary basin (fig. IV.D.1). This basin, composed of more than 20,000 ft of sedimentary and igneous rocks of Cenozoic age, was shaped by episodes of underthrusting, transcurrent faulting, and extension as a result of interaction between oceanic plates and the North American plate. The basin is bounded by pre-Tertiary igneous and metamorphic rocks of the Klamath Mountains on the south and the northern Cascade Range and Vancouver Island on the north. Its eastern limit is concealed beneath the Neogene Cascade volcanic rocks. The Olympic Mountains, near the northern end of the basin, are a large, non-petroleum-prospective mass of broken formations and melange. Clastic sedimentation punctuated by episodes of volcanism was essentially continuous in this basin, the poorly defined axis of which lies along the present inner continental shelf. Most, but not all, of the basin is floored by Paleocene to lower Eocene oceanic crust that includes volcanic ridges and chains of seamounts. Basin-filling sediments, which generally have a significant detrital volcanic component, consist of a complex assemblage of deep-marine turbidites, slope shales, marine shelf deposits, and coal-bearing fluvial-deltaic deposits. These sediments range in age from Paleogene to Neogene. Accretionary wedges of melange and broken formation were formed during periods of more direct plate convergence (fig. IV.D.2). These tectonically complex strata, which crop out along the western Washington coastline and beneath the adjacent shelf, are postulated to be the source rocks for gas seeps and oil and gas shows in exploratory wells in this area. The onshore part of the basin is prospective mainly for gas.

Eastern Oregon and Washington.--Most of eastern Oregon and Washington and northeastern California is a high plateau bordered on the west by a chain of Plio-Pleistocene stratovolcanoes, the Cascade Range (fig. IV.D.1). The plateau is composed of Neogene volcanic rocks, many thousands of feet thick, interbedded with nonmarine volcaniclastic sediments. Because the

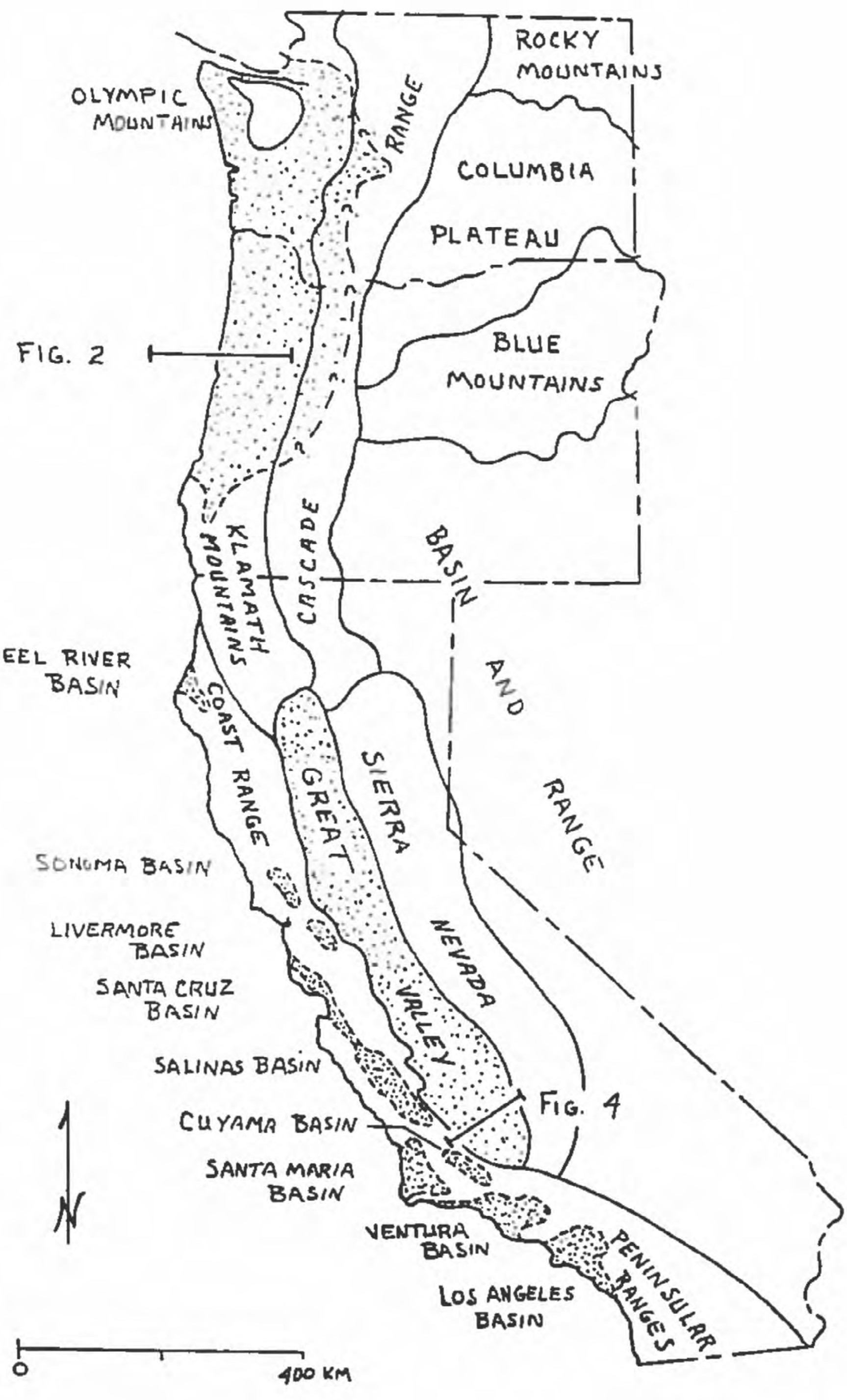

Figure IV.D.1. Petroleum region 2 (Washington, Oregon, California) showing petroleum-prospective basins (stippled) and areas discussed.

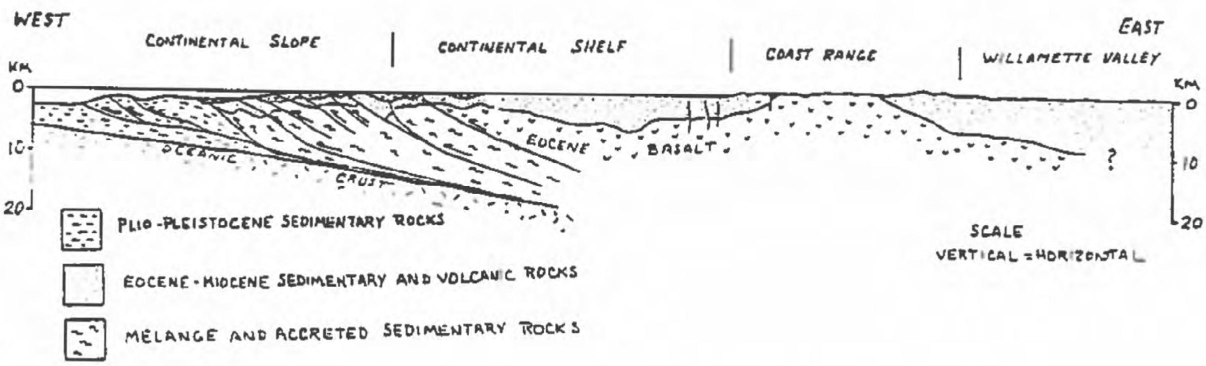

Figure IV.D.2. Geologic cross section of western Oregon (modified from Niem and Niem 1984). See figure IV.D.1 for location of section.

thick volcanic cover cannot be penetrated by reflection seismic methods, basins are poorly defined and pre-volcanic rocks poorly understood. Regional relations and pre-volcanic exposures in the Blue Mountains uplift record a complex history of terrane accretion followed by marine and nonmarine sedimentation and volcanic activity (fig. IV.D.3). The accreted terranes comprise a variety of igneous and marine sedimentary rocks that were formed in various structural settings. Overlap relations of marine strata indicate suturing of the terranes to the North American continent in about mid-Cretaceous time.

Since latest Cretaceous time, continental sedimentation and volcanism characterize the geologic record of this area. The sediments, interbedded with volcanic rocks, include fluvial lithic-rich sandstones and variable amounts of coaly material and tuffaceous lacustrine shales. Locally, more mature quartzose-feldspathic sandstones suggest periods of intense weathering, reworking of older sediments, or unroofing of batholithic rocks. Sediment thickness is variable but locally may be greater than 10,000 ft in grabens. Volcanic eruptions from dike swarms began in Miocene time (about 17 Ma). Flood basalts, interbedded with fluvial and lacustrine sediments, covered much of this area and accumulated to thicknesses as great as 11,000 ft. In later Neogene time, east-trending anticlines with high-angle faults developed in northern Oregon and Washington, and mostly north-trending normal faults developed in southeastern Oregon and northeastern California as part of the Basin and Range province. Although both oil and gas indications are found in this part of Region 2, it is considered prospective mainly for gas.

Great Valley of California.--The Great Valley is a forearc basin with marine and nonmarine clastic sediments ranging in age from Late Jurassic to Holocene (fig. IV.D.4). The basin is asymmetric. Basin depocenters with more than 25,000 ft of strata are located along the west side and at the very south end of the valley. Strata along the east side of the basin dip gently westward and strata along the west side generally dip eastward and are variously deformed and faulted. The northern part of the basin, the Sacramento Valley, is filled mostly with Upper Cretaceous and Paleogene strata. These include turbidite and deltaic deposits grading upward into nonmarine fluvial deposits. Paleogene strata are characterized by several episodes of canyon cutting and filling. The Sacramento Valley part of the forearc basin is predominantly gas productive.

The southern part of the forearc basin lies beneath the San Joaquin Valley and mainly produces oil. Similar to the northern part of the basin, its sedimentary fill ranges in age from Jurassic to Holocene, but it differs from the northern part in that Neogene strata comprise most of the basin fill, a large part of which is marine. The Neogene sediments were deposited during periods of major basin subsidence and rapid sedimentation related to basin-margin uplift. In this respect, the basin is similar to the California coastal basins. During Paleogene and Neogene time, conditions developed that were conducive to preservation of organic carbon and thus the development of important petroleum source rocks.

Movement on the San Andreas fault system, which bounds the basin on the southwest, and related or unrelated east-west compression subsequently produced many large anticlinal structures that trap oil in Pliocene and

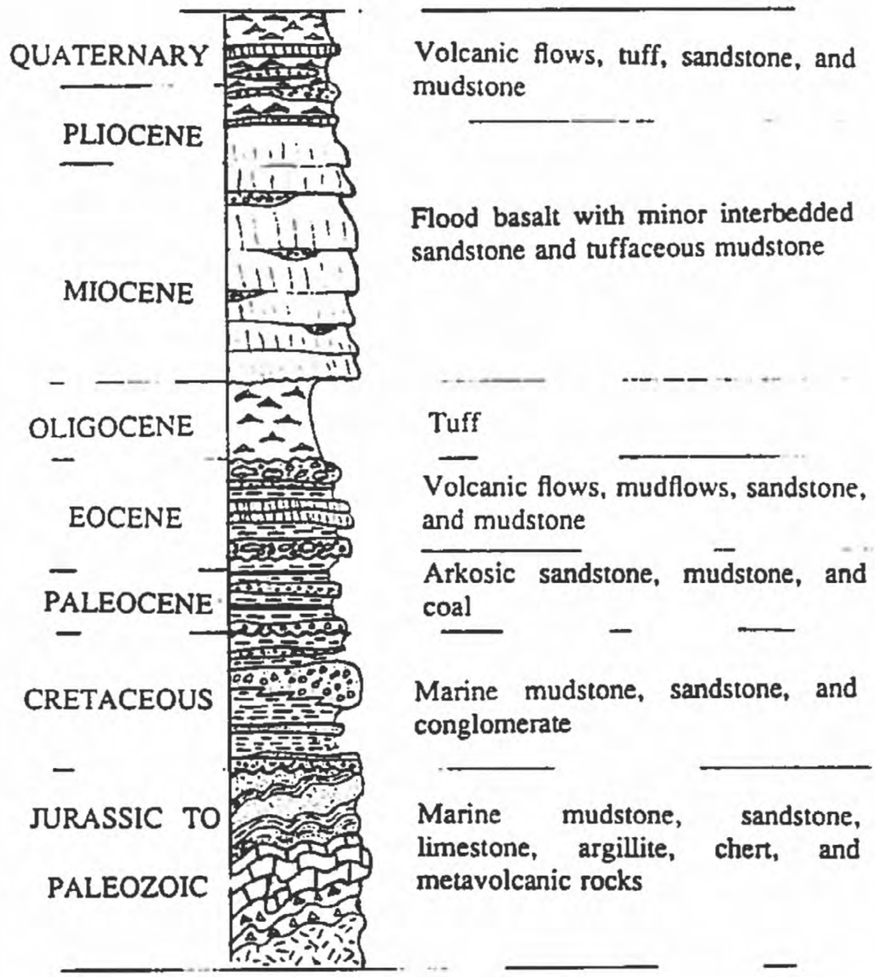

Figure IV.D.3. Generalized geologic column for eastern Oregon and Washington.

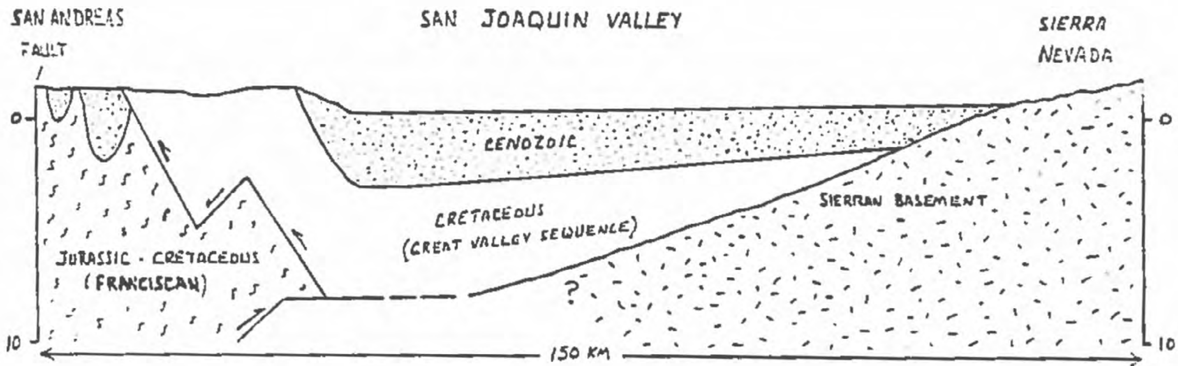

Figure IV.D.4. Geologic cross section of the southern San Joaquin Valley (modified from Namson and Davis, 1988). See figure IV.D.1 for location of section.

older strata along the west side of the basin. Normal faults trap oil along the east side of the basin, and cross-basin arches also form traps. The Bakersfield arch, an example of the latter, is the site of many oil accumulations.

California Coastal Basins.--These basins are located south and west of the Great Valley along the coast of California where many of them extend offshore (fig. IV.D.1). They are generally small and have very thick Neogene sedimentary fill. Most are extensional basins that developed during the late Oligocene and Miocene along the San Andreas transform fault system. Although not all of the basins formed at the same time and some (e.g., Ventura) overlie deposits from pre-existing basins consisting of thick Mesozoic and Paleogene sedimentary rocks, their sedimentary fill shows a generally similar vertical sequence of lithologies (fig. IV.D.5). Typically this succession includes (1) volcanic, continental, and neritic marine clastic rocks, representing the initial stages of Neogene basin formation, (2) early and middle Miocene deep marine shale, mudstone, and diatomaceous strata, corresponding to rapid subsidence and the development of marginal and borderland basins, and (3) late Miocene to Recent clastic deposits, turbidite, marine, and nonmarine sandstone, representing the final stages of basin filling. Complex structures and multiple unconformities indicate ongoing tectonism and structural deformation during the Cenozoic, including large-scale block rotations in middle Miocene time. Most oil-bearing structures in these coastal basins have formed during the last 2 my. in a period of compressional tectonics.

Petroleum Geology

Throughout Oregon and Washington and the northeastern part of California, potential reservoir rocks are generally volcanic lithic-rich sandstones in which porosity and permeability were rapidly lost during burial and diagenesis. Better reservoirs composed of quartz- and feldspar-rich sandstones occur locally, the result of some combination of reduced volcanic input, increased cratonic input, weathering, and reworking of older sediments. Source rocks include coal and marine and nonmarine shale, including in eastern Oregon and Washington the possibility of marine shale from accreted terranes. Limited data suggest that shales average less than 1 percent organic carbon and contain mostly type III kerogen. These data indicate that the source rocks are capable of generating gas and little or no oil. Traps are mostly anticlinal but also include combination structural and stratigraphic traps related to stratigraphic pinchouts and faulting. Only one economic petroleum accumulation is known from this area, the Mist gas field of western Oregon. Oil shows are limited to wells on the Washington coast and in north-central Oregon, whereas gas shows are more numerous and regionally widespread.

In the northern part of the Great Valley of California, gas is the predominant hydrocarbon. Gas is produced from Upper Cretaceous and Paleogene deltaic and turbidite sandstone reservoirs. Source rocks are age-equivalent marine shales. Traps consist of broad faulted structures, mostly located along cross-basin arches or reservoir pinchouts and truncations against shale-filled canyons. In the southern Great Valley and in the California coastal basins, oil accumulations in Cenozoic reservoirs predominate. Reservoir rocks consist predominantly of sandstone, but fractured chert, procelanite, and siliceous shale are also important

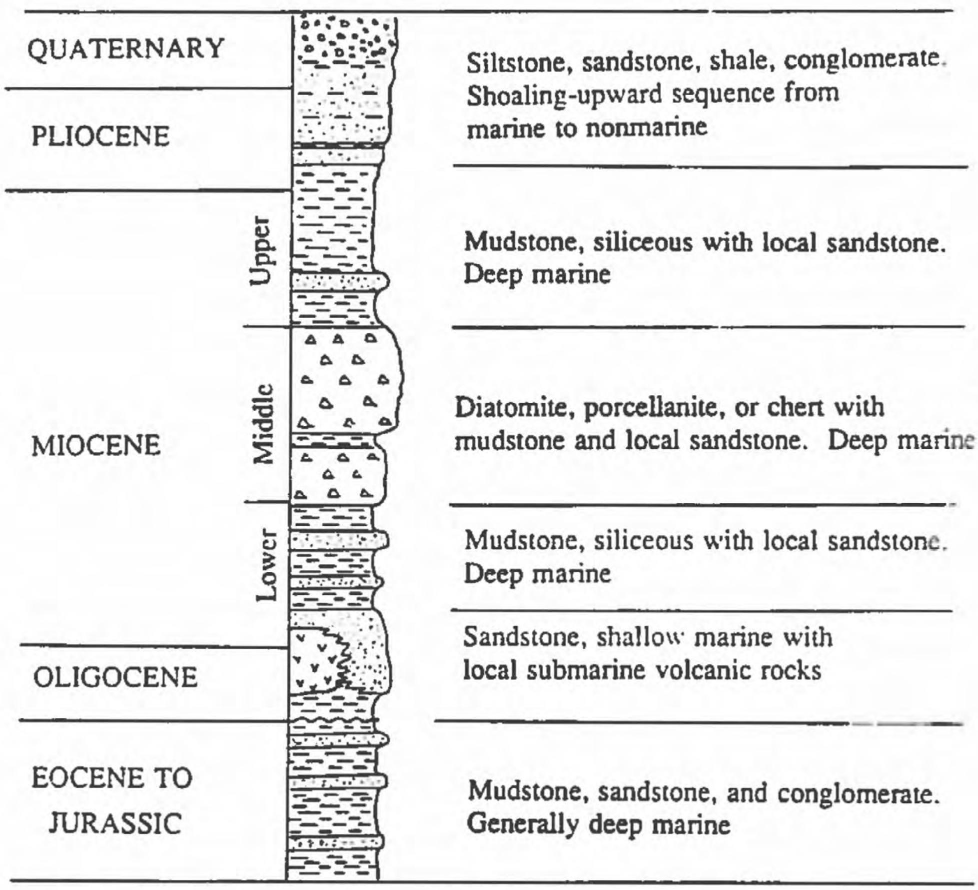

Figure IV.D.5. Generalized geologic column for California coastal basins.

reservoir rocks. The primary source rock is organic-carbon-rich Miocene marine shale, mudstone, and marl in the Monterey Formation and its equivalents. Traps consist of a variety of anticlinal structures of varying complexity, fault traps, and stratigraphic pinchouts related to structural noses or arches.

Region 2 has produced 20.3 billion barrels of oil and 33.2 trillion cubic feet of gas and has measured reserves of 4.7 billion barrels of oil and 3.9 trillion of cubic feet of gas as of January, 1987 (table IV.D.1). Essentially all reserves are located in California, an area that contributes about 13 percent of daily U.S. oil production.

Petroleum exploration in Region 2 dates from the mid-to-late 1800's when surface seepages of oil or gas were investigated and mined in some areas. Oil production was established during this time in California's Los Angeles and Ventura basins (fig. IV.D.1). Since then, tens of thousands of exploratory wells have been drilled. Most California basins are extensively drilled to depths less than 10,000 ft; two-thirds of the presently known total oil and gas in these basins was found before 1950. In contrast, Oregon and Washington is a lightly explored frontier with few hydrocarbon discoveries. Since exploratory drilling began in the early 1900's, almost 500 wells have been drilled. This amounts to a density of one well for each 100 mi^2 of area considered to have hydrocarbon potential; fewer than 80 wells are deeper than 5,000 ft. Oil was discovered in 1957 at Ocean City, Washington, and more than 12,000 barrels of 39-degree API gravity oil were produced before the well was abandoned in 1962. The only commercial hydrocarbon accumulation is the Mist gas field in northwest Oregon, discovered in 1979.

Petroleum Potential

The potential for finding additional hydrocarbons in this region is estimated to be modest (table IV.D.1). Most oil is expected to be found in those basins that have been major oil producers, the San Joaquin, Los Angeles, and Ventura basins. The undiscovered oil is postulated to be in deeper parts of the basins in subtle traps, in complex traps in producing trends, or in relatively unexplored areas such as military installations and State offshore waters.

Natural gas potential is estimated to be equally divided between associated and non-associated. Associated gas is expected to occur in those basins where the most oil is expected. Non-associated gas potential is expected mainly in Oregon, Washington, and the Sacramento Valley in small- to moderate-sized fields, similar to those already found.

Exploration in some areas of Region 2 may be severely restricted by high population densities and (or) governmental restrictions. Petroleum exploration and development in the Los Angeles basin is restricted by both. Other areas where restrictions apply are State waters and military installations.

Table IV.D.1.--Cumulative production, estimated reserves and undiscovered recoverable resources in Region 2.

	Cum. Production	Measured Reserves	Inferred + Indicated Reserves
Oil (BBO)	20.3	4.7	1.2
Gas (TCF)	33.2	3.9	2.6

Petroleum Provinces

Estimates of Undiscovered Recoverable Resources*

	Crude Oil (Billion Barrels)			Gas (Trillion Cubic Feet)		
	F95	F5	Mean	F95	F5	Mean
Region 2 - Pacific Coast						
W. Ore.-Washington	0.00	0.00	0.00	0.87	4.29	2.18
Sacramento	0.00	0.00	0.00	0.76	3.37	1.78
San Joaquin	0.55	3.22	1.53	1.23	6.69	3.27
Los Angeles	0.24	1.42	0.68	0.29	1.69	0.81
Ventura	0.20	1.63	0.70	0.40	2.93	1.30
Santa Maria	0.13	0.49	0.27	0.11	0.44	0.24
Central Coastal	0.05	0.72	0.27	0.04	0.58	0.21
Sonoma-Livermore	0.00	0.01	0.01	0.00	0.01	0.01
Humboldt	0.00	0.00	0.00	0.01	0.10	0.04
E. Ore.-Washington	0.00	0.00	0.00	0.43	2.39	1.16
E. California	-	-	-	-	-	-
Total	1.5	6.6	3.5	5.5	19.1	11.0

Mean value totals may not be equal to the sums of the constituent means due to independent rounding.

Fractile values are not additive.

*Estimates of undiscovered economically recoverable resources are given in Table VII.B.3.

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E. REGION 3, COLORADO PLATEAU - BASIN AND RANGE

by

R.B. Powers

Geologic Framework

Region 3 includes 12 geologic provinces within all or part of Nevada, Arizona, Utah, Idaho, New Mexico, Colorado, and Wyoming (fig. IV.E.1). The geology of the region is diverse and complex. Events that shaped the tectonic framework of this broad area include the Antler orogeny, the ancestral Rocky Mountain orogeny during Pennsylvanian-Permian time and the Jurassic Nevadan orogeny, and the Laramide orogeny of Cretaceous and early Tertiary time. Major present-day structural elements in the region mostly reflect Laramide and post-Laramide tectonism.

Most of the basins within the 12 assessed provinces are structural basins formed as a result of uplift and downwarp during the major orogenic episodes discussed above. However, there are exceptions to this style, including a mountain thrust belt, a portion of an extensive rift system, and a buried thrust belt with a surface tectonic overprint of Basin and Range block faulting, all of which have fair to good petroleum potential. The sedimentary sequence of these basins is dominated by marine carbonate rocks in the Early Paleozoic, marine and nonmarine clastics in Late Paleozoic time, and increasingly clastic rocks during Mesozoic and Tertiary time.

The Uinta-Piceance basin is characteristic of the Laramide intermontane basins of the region. It is a broad, asymmetric basin that formed in early Tertiary time and contains as much as 18,000 ft of lower Tertiary fluviatile and lacustrine deposits (Osmond, 1965). Older rocks in the basin productive of significant amounts of oil and gas include marine sandstone of Pennsylvanian-Permian age and marine to nonmarine sandstones of Jurassic age; Cretaceous sandstones are productive mainly of gas. Tertiary sedimentation was controlled by the high source area of the Uinta Mountains. Fluctuations in sediment supply from this source caused extensive and complex intertonguing of rich oil shale and sandstone in the Green River Formation and helped to create important stratigraphic traps for oil and gas accumulations. The lenticular nature of sandstones in the basin indicates that additional deposits would probably be in stratigraphic traps (fig. IV.E.2).

The Paradox basin is an example of one of the older Paleozoic basins in the region. It formed in Middle Pennsylvanian time as a large restricted basin in which a thick sequence of anhydrite, salt, limestone, and organic-rich black shale was deposited on a foundation of older Mississippian shelf carbonates. An additional 15,000 ft of coarse and fine clastic material was shed southwestward from the rising Uncompahgre Highland in Late Pennsylvanian-Early Permian time (Ohlen and McIntyre, 1965). More than 90 percent of oil and gas production is from stratigraphic traps (Aneth Field) formed by carbonate algal-mound reservoirs interbedded with rich black shale source rocks within the Paradox Formation (fig. IV.E.3). Additional important oil and gas in the basin is from Mississippian shelf-carbonate reservoirs in fault block traps (Lisbon field).

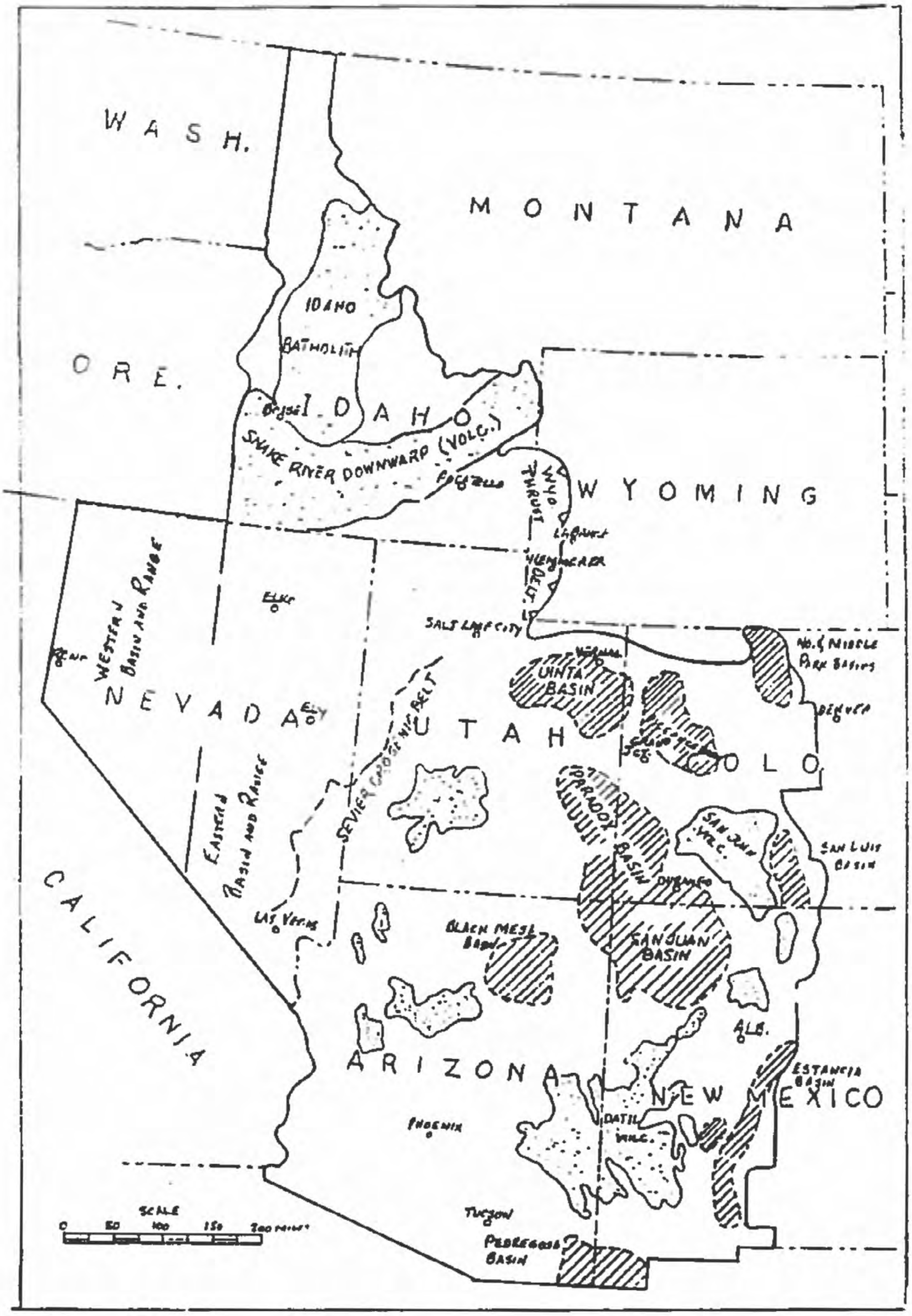

Figure IV.E.1. Index map of Region 3 showing basins, uplifts, and areas of igneous intrusives and volcanics (Modified from Lyth, 1971).

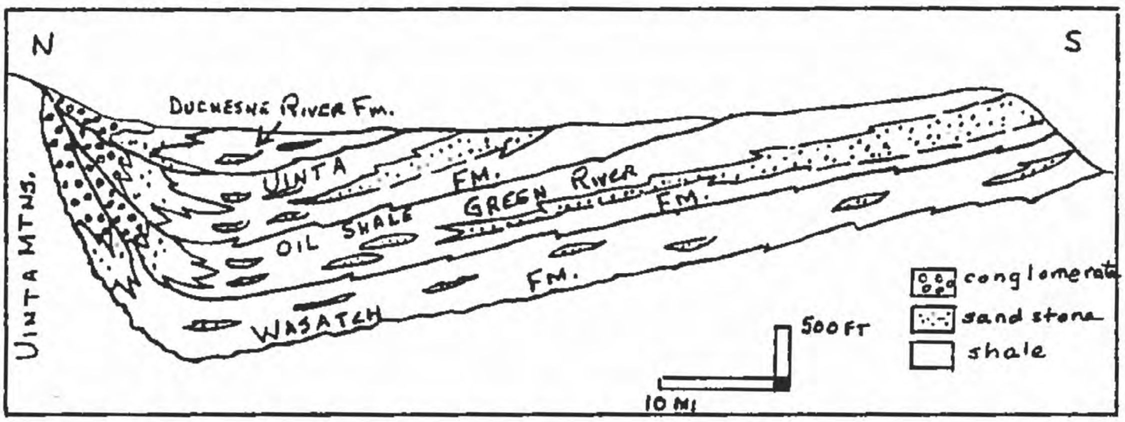

Figure IV.E.2. North-south diagrammatic cross section of Tertiary deposits in Uinta basin, showing complex intertonguing of sandstone reservoir rocks with lacustrine oil shales that create stratigraphic traps. (Modified from Osmond, 1965).

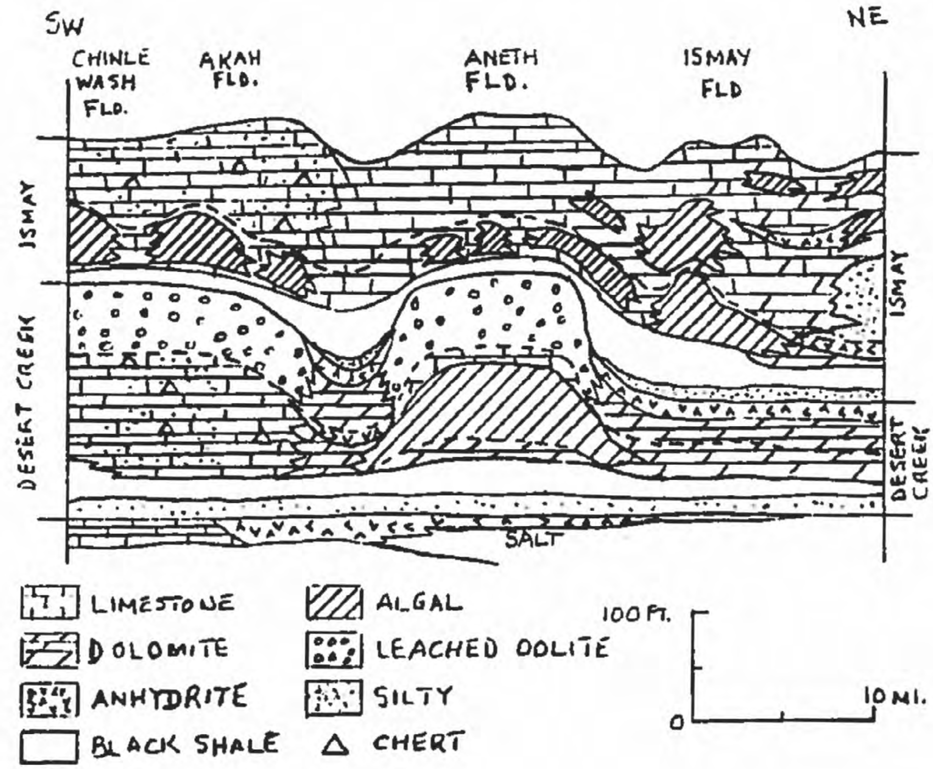

Figure IV.B.3. SW-NE cross section across Aneth Field Area, Paradox Basin, Utah, showing stratigraphic trap development in Pennsylvanian Desert Creek-Ismay plate-algal mounds. (Modified from Peterson and Hite, 1969).

Important oil and gas productive provinces in non-basin structural settings include the Wyoming-Utah-Idaho thrust belt and the Eastern Basin and Range province of eastern Nevada-western Utah. The thrust belt is located on what was a structural hinge line, or transition zone, between a shallow shelf to the east and a deep geosyncline to the west during Paleozoic and Mesozoic time. More than 50,000 ft of marine and continental sediments was deposited in the geosyncline in these two eras (Armstrong and Oriel, 1986). Between latest Jurassic and early Eocene time (Laramide orogeny), these sedimentary rocks were strongly folded and thrust eastward by compressional forces from the west, resulting in a terrain characterized by low-angle thrust faults and thrust-derived folds (Powers, 1984). Recently discovered oil and gas fields (24 since 1975) are located in hanging wall anticlines in Paleozoic carbonate and Triassic-Jurassic sandstone reservoirs (fig. IV.E.4 and IV.E.5). These are in communication with rich Cretaceous source rocks in the subthrust footwall (fig. IV.E.5). Depth of burial, maturation history, timing and generation were all favorable for migration of oil and gas from the footwall Cretaceous shales into the older reservoirs in the hanging wall.

The Eastern Basin and Range is a topographic terrain of mountain ranges (horsts) and broad valleys (grabens) with present-day interior drainage. Its tectonic development is complex, beginning with the Antler orogeny in Late Devonian-Early Mississippian time involving eastward thrusting of Early Paleozoic rocks. A second easterly thrusting event took place in Middle Mesozoic time and included emplacement of granitic plutons. Finally, in middle Miocene time, extensional faulting created deep grabens and elongate horst blocks and was accompanied by extrusive volcanic rocks and intrusive rocks. Only 10 small or medium size fields, 4 or 5 of which are commercial, have been found in these valleys during a sporadic 34-year drilling history since the first field discovery (Bortz, 1983). All accumulations are structural and associated with a major Tertiary unconformity. Known reservoirs range from fractured Tertiary volcanic rocks and lacustrine limestone to Mississippian and Devonian dolomites. Rich source rocks having varying maturation histories occur mainly in Tertiary lacustrine shales and Mississippian organic-rich black shale. Oil and gas probably are still being generated today from Paleozoic source rocks despite geothermal activity and previous leakage along older faults (Poole and others, 1979).

Petroleum Geology

Reservoirs productive of oil and gas are known in Paleozoic, Mesozoic, and Tertiary rocks in the region. Most of the oil production is from the Uinta-Piceance-Eagle basin and the bulk of gas produced is from Cretaceous sandstone reservoirs in the San Juan basin. The richest petroleum source rocks are in Pennsylvanian-Permian, Cretaceous, and Tertiary shales.

Seven of the twelve provinces within the region produce oil and gas; the most recently developed is the Wyoming-Utah-Idaho thrust belt. Major production is from reservoirs in the Permian-Pennsylvanian Weber Sandstone, Mississippian limestones, Triassic-Jurassic Nugget Sandstone, and various Pennsylvanian carbonate rocks.

Hydrocarbon seeps in various areas within the region were known to early explorers in the mid 1800's. However, actual exploration activity began in the late 1800's and was confined mostly to shallow drilling near

Geologic Age		Formation or Group	Oil or Gas	Thickness Range
Tertiary		Green River Fm.		0–8,000′
		Wasatch-Evanston Fms.		
Cretaceous	Late	Adaville Fm.		6,000′–16,000′
		Hilliard Fm.		
		Frontier Fm.	RS ●	
	Early	Aspen Shale	RS ●	10,000′
		Bear River Fm.	RS ✷	
		Gannett Group		
Jurassic		Stump Fm.	R ●	500′–1,000′
		Preuss Ss. < Salt[1]	R ✷	
		Twin Creek Ls.	RS ✷	1,200′–3,500′
		Gypsum Spring Mbr.		
Jurassic(?) and Triassic(?)		Nugget Ss.	R ✷	500′–2,000
Triassic		Ankareh Fm.	R ✷	2,000′–7,000′
Early Triassic		Thaynes Fm.	RS ☼	
		Woodside Fm.		
		Dinwoody Fm.	R ☼	
Permian		Phosphoria Fm.[2]	RS ☼c	400′–5,000′
Pennsylvanian		Weber Ss.	R ☼c	750′–4,000′
		Morgan-Amsden	R ☼	
Mississippian		Madison Group: Mission Canyon Ls.[3]	R ☼c	1,000′–7,000′
		Madison Group: Lodgepole Ls.	RS ☼c	
Devonian		Darby FM[4]: Three Forks Fm.	RS ☼c	500′–3,000
		Darby FM[4]: Jefferson Fm.		
Ordovician		Bighorn Dolomite	RS ☼c	250′–2,000′
Cambrian		Gallatin Fm.		1,500′–5,000′
		Gros Ventre Fm.		
		Flathead Ss.		
Precambrian				

● Oil productive
✷ Oil and gas productive
☼ Gas productive
☼c Gas with condensate productive
R- Known or potential reservoir rock
S- Known or potential source rock
[1] of Maher (1976)
[2] And equivalent strata
[3] Brazer limestone of some authors
[4] Locally in Wyoming

Figure IV.E.4. Example of a stratigraphic rock sequence (Wyoming-Utah-Idaho thrust belt province) showing productive formations and known, or potential reservoir and source rocks. After Powers (1984).

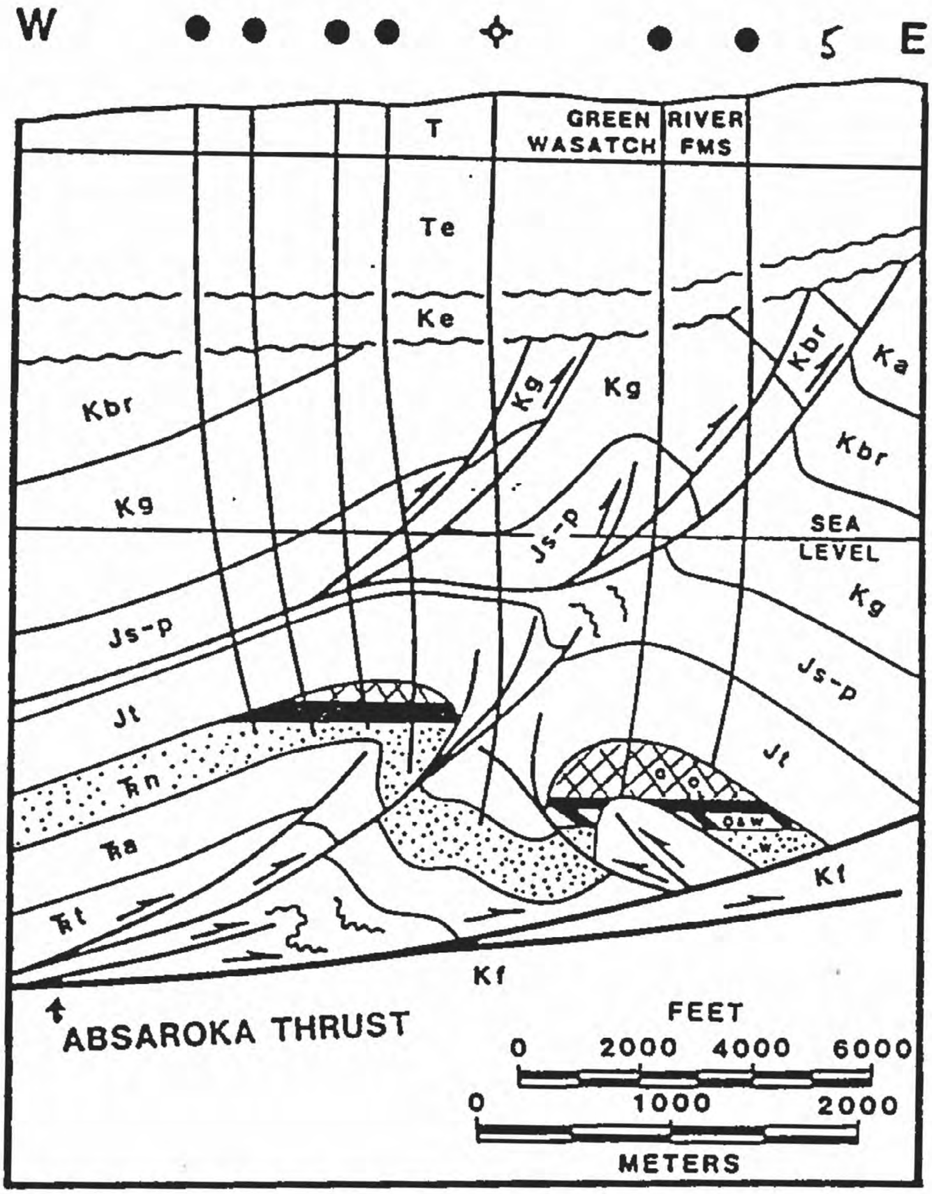

Figure IV.E.5. West-east structural cross section through Painter Reservoir and Painter Reservoir East fields in thrust belt province. Shows detail of anticlinal traps in Nugget Sandstone (Trn) in hanging wall and Cretaceous (Kf) source rocks in footwall of Absaroka thrust. (Modified from Lammerson, 1982).

known seeps and led to the discovery of the first oil field, Spring Valley, in the thrust belt in October, 1900. Production came from the Cretaceous Aspen Shale and Bear River Formation at depths of 100-2,000 ft. This discovery was followed closely by the first oil field in the Paradox Basin, Mexican Hat, in 1908, which produced about 60,000 barrels of oil before it was abandoned (Ohlen and McIntyre, 1965).

Approximately 3 billion barrels of oil and 24 trillion cubic feet (TCF) of gas have been produced in Region 3. Estimated ultimate reserves are 3.3 BBO and 38.1 TCF of gas (table IV.E.1). Greater than 98 percent of the reserves are concentrated in four provinces: the thrust belt, the Uinta-Piceance-Eagle, Paradox, and San Juan basins (table IV.E.1). At present, at least ten fields in the region are classified as "giants" (fields that will ultimately recover at least 100 million barrels of oil or equivalent gas).

Petroleum Potential

The potential for undiscovered oil and gas in the region varies considerably from province to province. The greatest amount of undiscovered conventional oil and gas resources is estimated to exist in the thrust belt (table IV.E.1). The Paradox, Uinta-Piceance-Eagle, and Juan basins are also viewed as having a high potential. It is believed that most of the future gas potential in the Uinta-Piceance-Eagle basin will be in unconventional tight gas sandstone reservoirs not included in this assessment, and that gas resource additions in the San Juan basin will be mainly through additions to known fields (inferred reserves).

Exploratory drilling in the Wyoming-Utah-Idaho thrust belt indicates that additional major or giant anticlinal oil and gas accumulations similar to those found may not exist throughout the remainder of the area, except in the area of the Moxa Arch extension beneath the thrust belt. A moderate potential may exist for future oil accumulations in stratigraphic traps in Cretaceous lenticular sandstones east of the Absaroka thrust fault.

Although a modest potential is indicated for the Eastern Basin and Range (table IV.E.1), exploratory drilling has actually tested only a very small part of the province, and wide gaps exist in the available geologic data on which assessment studies are based. Less than 300 wildcat wells have been drilled in the 110,000 mi^2 of the province, one of the lightest drilling densities in any of the areas where oil and gas is being produced. In addition, almost all of the drilling and current production is confined to two valleys southwest of Ely, Nevada, and two valleys southwest of Elko. In one of the newest fields discovered southwest of Ely (Grant Canyon, 1983), one well flowed an average of 4,065 barrels of oil per day (Duey and others, 1988). At least 15 surface seeps of oil or gas have been documented, as well as numerous shows of oil and gas in wildcat wells (Bortz, 1983). Geologic factors are favorable, but the most important drawback to finding new fields is that about 75 percent of the surface of the province consists of alluvium and volcanic rocks that effectively conceal the structural traps containing prospective reservoirs (Osmond and Elias, 1971) (fig. IV.E.6). Seismic reflection technology has been only partially successful in penetrating this cover and its associated unconformities.

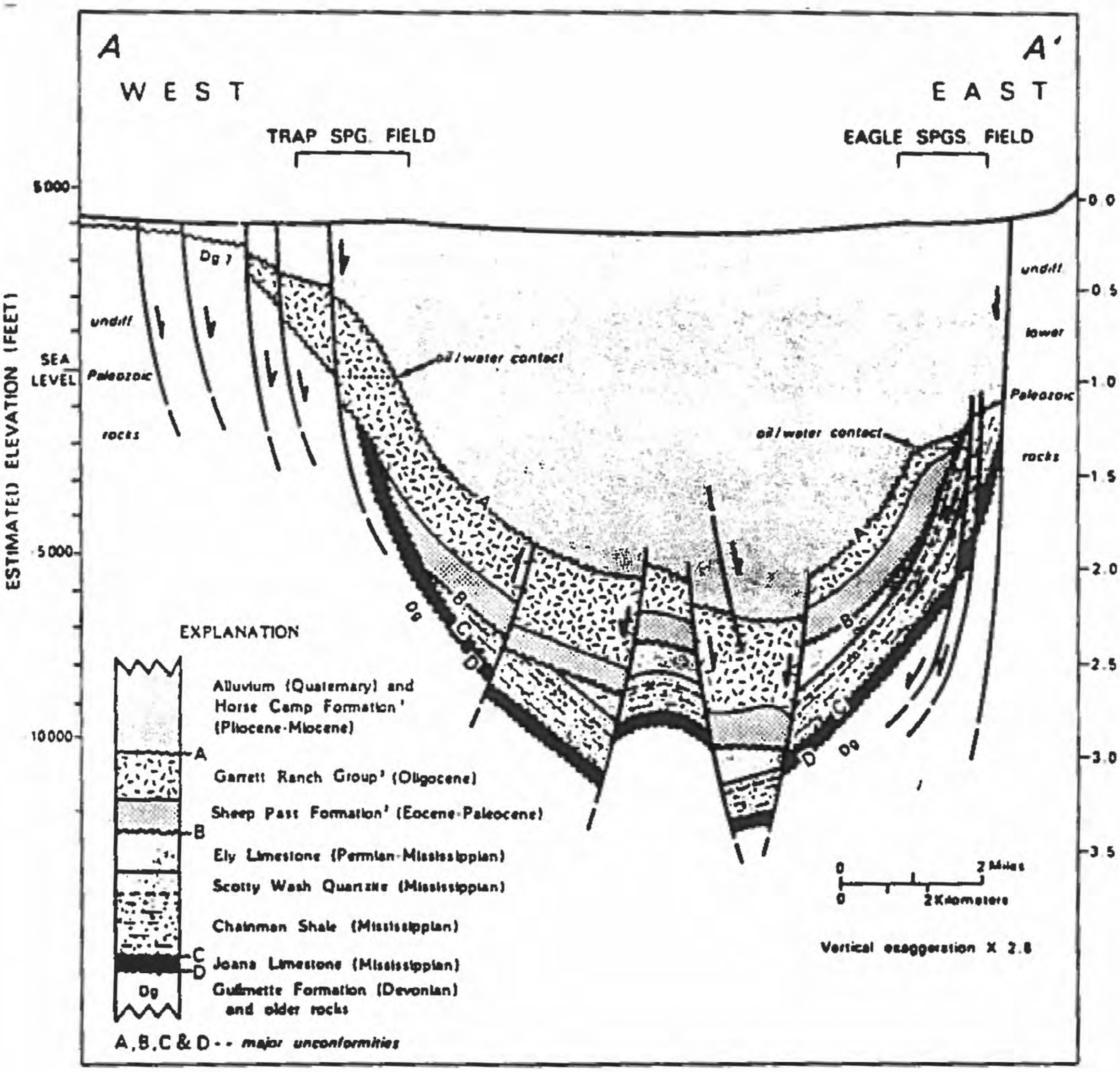

Figure IV.E.6. West-east cross section (based on seismic interpretation) across Railroad Valley graben southwest of Ely, Nevada, Eastern Basin and Range province. Shows relative positions of Chainman and Sheep Pass source rocks, fault zone conduits, structural and stratigraphic traps, reservoir rocks and seals below valley fill. (Modified from Poole and Claypool, 1984).

Table IV.E.1.--Cumulative production, estimated reserves and undiscovered recoverable resources in Region 3.

	Cum. Production	Measured Reserves	Inferred + Indicated Reserves
Oil (BBO)	3.1	0.6	0.4
Gas (TCF)	24.7	17.1	4.9

Petroleum Provinces

Estimates of Undiscovered Recoverable Resources*

	Crude Oil (Billion Barrels)			Gas (Trillion Cubic Feet)		
	F95	F5	Mean	F95	F5	Mean
Region 3 - Colorado Plateau and Basin & Range						
E. Basin & Range	0.09	0.65	0.29	0.03	0.47	0.17
W. Basin & Range	Negl.	0.06	0.02	Negl.	0.14	0.04
Idaho-Snake River	0.00	0.00	0.00	0.01	0.10	0.04
Paradox basin	0.01	0.72	0.20	0.04	1.26	0.38
Uinta-Piceance	0.04	0.55	0.20	1.11	3.76	2.19
Park basin	Negl.	0.03	0.01	0.01	0.05	0.02
San Juan basin	0.04	0.16	0.09	1.40	2.73	2.00
Albuquerque-Santa Fe	Negl.	0.07	0.02	0.06	0.63	0.25
Wyoming Thrust Belt	0.21	1.19	0.58	6.29	31.31	15.81
Northern Arizona	0.02	0.27	0.10	0.01	0.07	0.03
South-central New Mexico	Negl.	0.05	0.02	0.05	0.70	0.26
South Ariz.- SW New Mexico	Negl.	0.02	0.01	0.02	0.23	0.09
Total	0.5	3.4	1.5	9.6	39.3	21.3

Mean value totals may not be equal to the sums of the constituent means due to independent rounding.

Fractile values are not additive.

*Estimates of undiscovered economically recoverable resources are given in Table VIII.B.3.

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F. REGION 4, ROCKY MOUNTAINS-NORTHERN GREAT PLAINS
by
R.B. Powers

Geologic Framework

Region 4 includes all or part of 7 states; Montana, North Dakota, South Dakota, Wyoming, Colorado, Nebraska and New Mexico, an area of approximately 477,000 mi² (fig. IV.F.1). The general setting of the western, northern, and central sections is that of Laramide sedimentary intermontane basins, such as the Powder River and Bighorn basins, separated by major uplifts. Also included in the region is the broad, intracratonic Williston basin, a major Paleozoic paleostructural elements, and the narrow western Montana thrust belt of the Cordilleran System. The eastern parts of the region are composed of sedimentary basins along the eastern front of the Rocky Mountains (Curry, 1971). Most of the basin-uplift couplets are the result of tectonic events that occurred during the Late Cretaceous-Early Tertiary Laramide orogeny. The older Williston basin, however, has undergone mild tectonic subsidence since Late Cambrian or Ordovician time (Peterson, personal communication).

There are 19 sedimentary basins included within the 13 assessed provinces in the region. Rocks in most of these basins reflect the appreciable quantity of Upper Cretaceous and Tertiary clastic sediments deposited in association with the Laramide orogeny. Carbonate rocks of shallow marine origin are dominant, however, in Cambrian through Permian strata and are minor components in Triassic and Jurassic rocks (Fox and others, in press). The Williston basin shows an expanded sequence of Paleozoic carbonates related to early basin subsidence and a relatively thin Mesozoic sequence. The strongly folded thrust belt and the Sweetgrass, Las Animas and Sioux arches are the major subsurface positive features in addition to the Rocky Mountain uplifts.

Laramide intermontane basins.--These include, among many, the Powder River, Bighorn, and Wind River basins, have similar characteristics (fig. IV.F.1). They are bounded by Precambrian rocks emplaced in part by thrusting and have similar geometry and asymmetry, similar rock facies and ages, and structural and stratigraphic trap types (Fox and others, in press). The Denver basin is bounded only on its west side by the thrusted Precambrian of the Front and Laramie Ranges and its axis parallels these features.

The Powder River basin, largest of the Laramide intermontane basins in the northern Rocky Mountains of the United States, is strongly asymmetric, north-trending, and gently deformed and covers an area of approximately 35,000 mi² (fig. IV.F.1). It contains as much as 18,000 ft of sediments in its axial portion, which lies very close to its thrusted western margin. Almost half of the sediment thickness is composed of Late Cretaceous and early Tertiary clastics. Significant amounts of oil have been produced in the past from large structural traps (anticlines and plunging noses) around the basin margin, many of which have multiple pay zones (fig. IV.F.2). Equally significant production more recently has come from stratigraphic traps in Cretaceous deltaic and marine shelf and alluvial sandstones interbedded with organic-rich source rocks (fig. IV.F.3) and in Permian-Pennsylvanian paleotopographic highs or erosional remnants. Rich

Figure IV.F.1. Index map of Region 4 showing basins, uplifts, and areas of igneous intrusives and basement rocks. Contours are on top of Precambrian basement surface (modified from Curry, 1971).

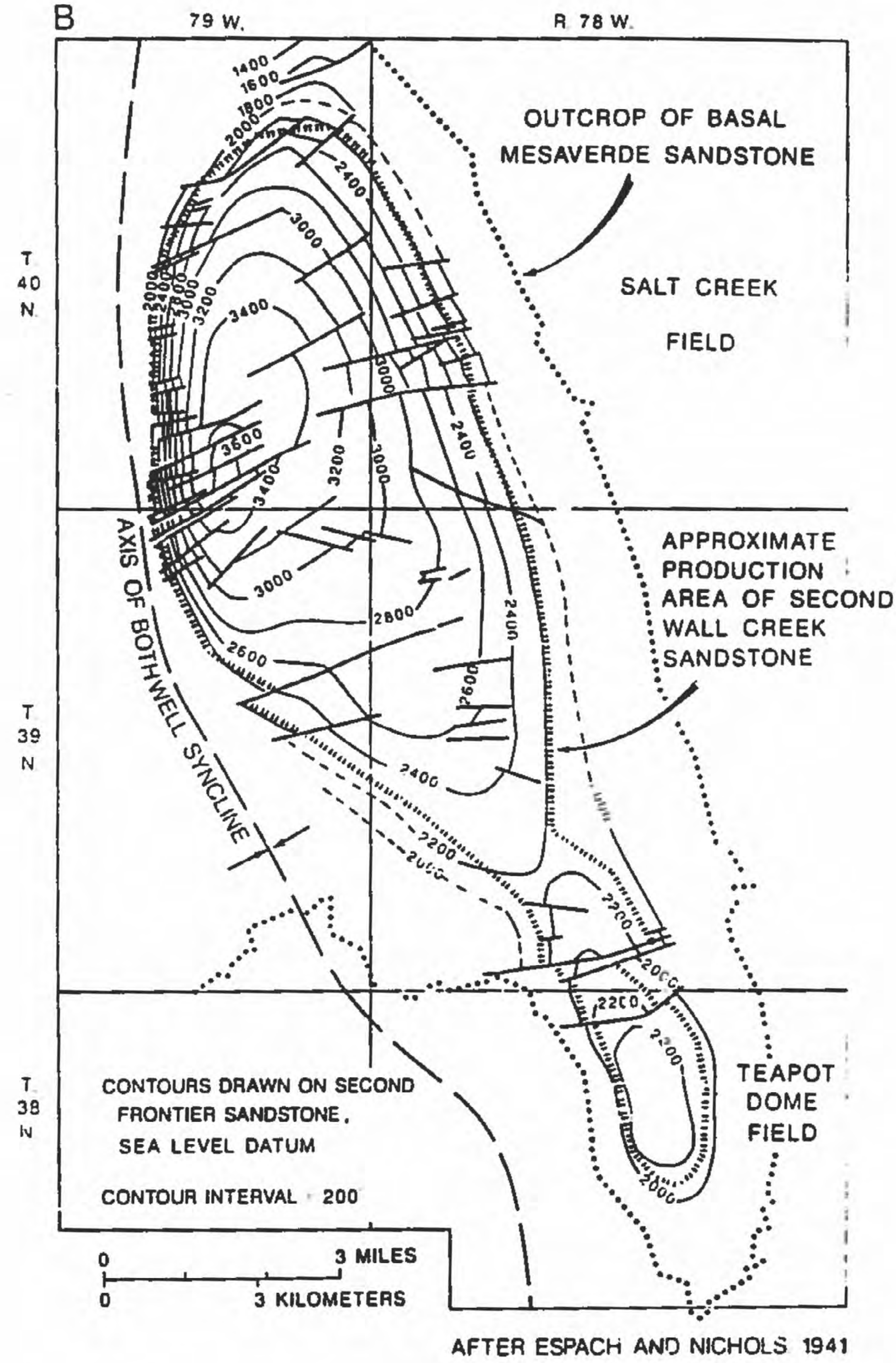

Figure IV.F.2. Structure map of Salt Creek anticline, western margin of the Powder River basin, Wyoming, largest oil field in Region 4. Contours on top of Second Frontier Sandstone after Espach and Nichols, 1941).

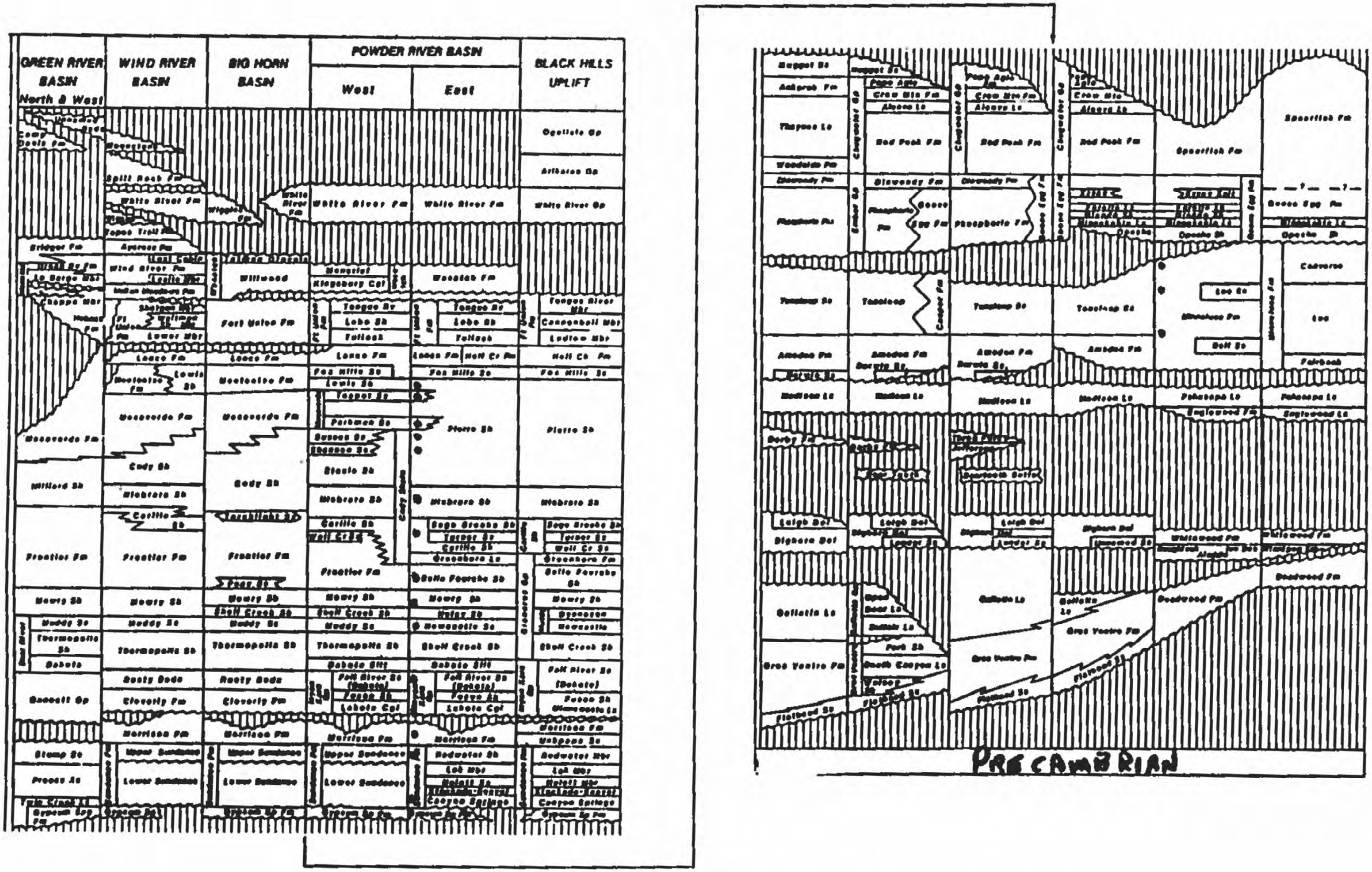

Figure IV.F.3. Example of stratigraphic rock sequence in four Wyoming intermontane basins showing producing formations in Powder River basin (modified from Miller, 1987).

oil-source rocks are present in Pennsylvanian shales as well as Cretaceous strata. The maturation history of the basin is related to burial beneath a thick, young sedimentary sequence and to an anomalously low geothermal gradient in parts of the basin, as indicated by the occurrence of oil, not gas, at depths of 15,000 ft in several fields. New fields will probably occur predominantly in stratigraphic traps.

The Williston basin is a intracratonic, almost saucer-shaped basin, which portion in the U.S. covers approximately 142,500 mi^2. It has a maximum sediment thickness of about 17,000 ft (fig. IV.F.1). Deposition of dominantly carbonate strata began in Late Cambrian time and continued, interrupted by varying periods of erosion, through early Tertiary time, clastic deposition was dominant starting in Late Jurassic time (fig. IV.F.4). Hydrocarbon accumulations are almost exclusively oil and associated-dissolved gas and occur primarily in combination structural-stratigraphic or wholly stratigraphic traps related to carbonate buildups. Many of the fields produce from three to four formations. Major reservoirs are mainly carbonate and of Mississippian, Devonian, and Ordovician age; secondary clastic reservoirs are in Pennsylvanian, Ordovician and Triassic strata. Organic-rich black shales have a favorable maturation history of Mississippian, Ordovician and Pennsylvanian-Mississippian age.

The basin is characterized by a great number of small fields (<5 million barrels of oil). However, the major part of the basin's reserves is in 15 percent of the nearly 700 fields discovered. Future oil discoveries will probably continue to be in subtle carbonate stratigraphic traps, and a possibility of gas exists in the deep center of the basin.

Contrasting structural settings in the region include the Montana Thrust Belt of the Cordilleran System and the southwestern Wyoming basins. The thrust belt is a southern continuation of the southern Alberta Foothills Thrust Belt. During Late Mesozoic and Early Tertiary time, strata deposited along a hingeline between an eastern shelf and a western geosyncline and younger rocks deposited in the western Interior Seaway during Cretaceous time were thrust eastward in complete stacked sheets, uplifted, and eroded (Gordy and others, 1977). The thrust belt is similar structurally to the Wyoming-Utah-Idaho thrust belt to the south, except that the total section of aggregate rock is thinner and the main oil and gas reservoirs are dominantly Mississippian and Devonian carbonates (with additional secondary reservoirs in Jurassic and Cretaceous rocks). Structure is characterized in the eastern part by multiple imbricate thrusts in Mesozoic clastics and in the western part by major thrust sheets stacked in broader imbricate fashion involving mainly Mississippian-Devonian carbonates (fig. IV.F.5). The most common trap types are thrust-faulted wedge-edges of Paleozoic reservoirs caught up in thrust sheets; additional traps are in drag folds associated with thrusting. Potential source rocks are shales of Mississippian-Devonian, Jurassic, and Cretaceous age. A high thermal history appears to favor the generation of gas than oil. Exploration mainly in the 1950's resulted in several small gas-condensate discoveries which were shut-in or abandoned because the area was remote and gas prices too low for profitable development.

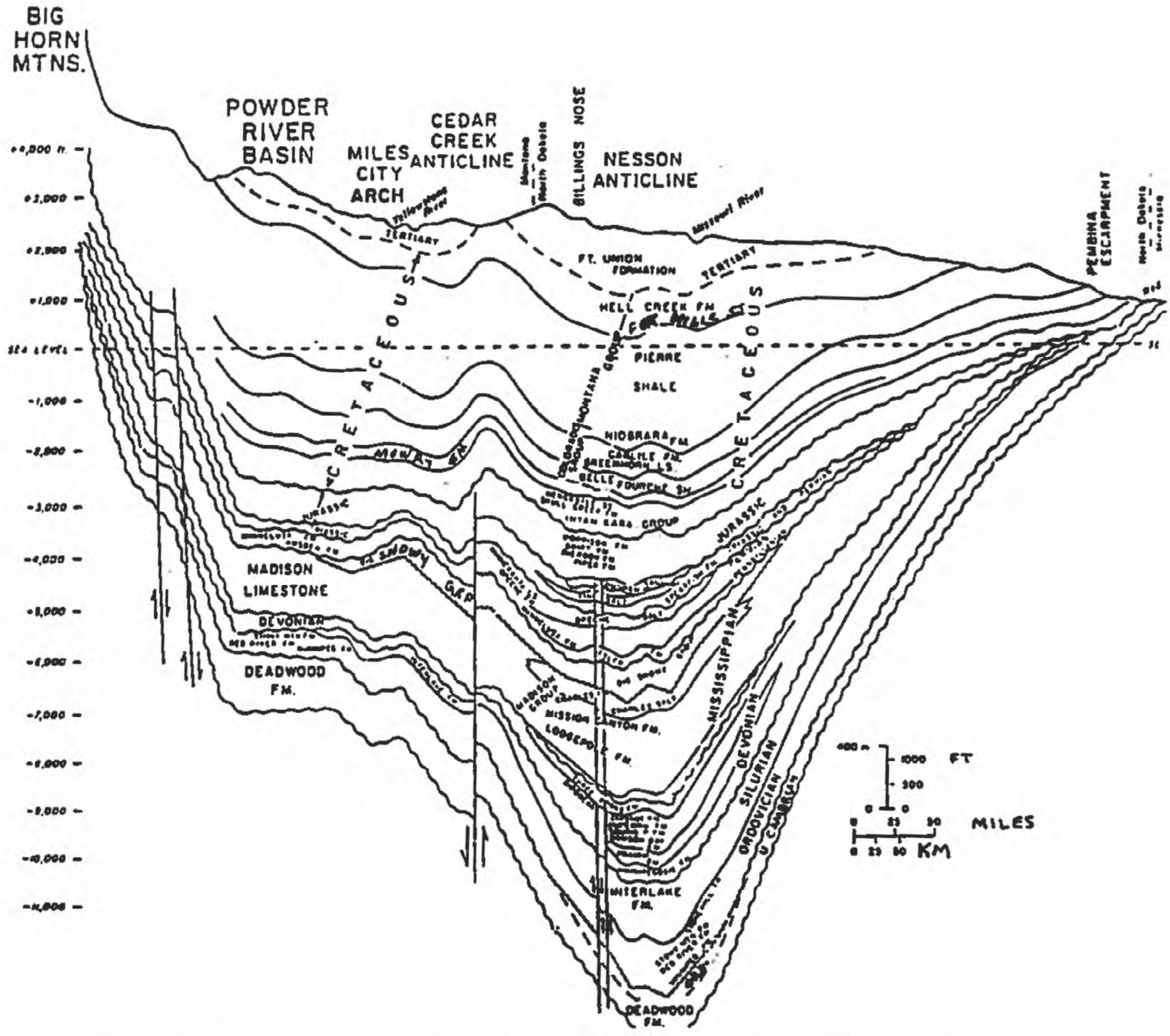

Figure IV.F.4. Generalized west-east structural-stratigraphic cross section from Bighorn Mountains, Wyoming, to northeastern North Dakota. Shows structural configuration of Williston basin and other features (after Peterson, J.A., personal communication).

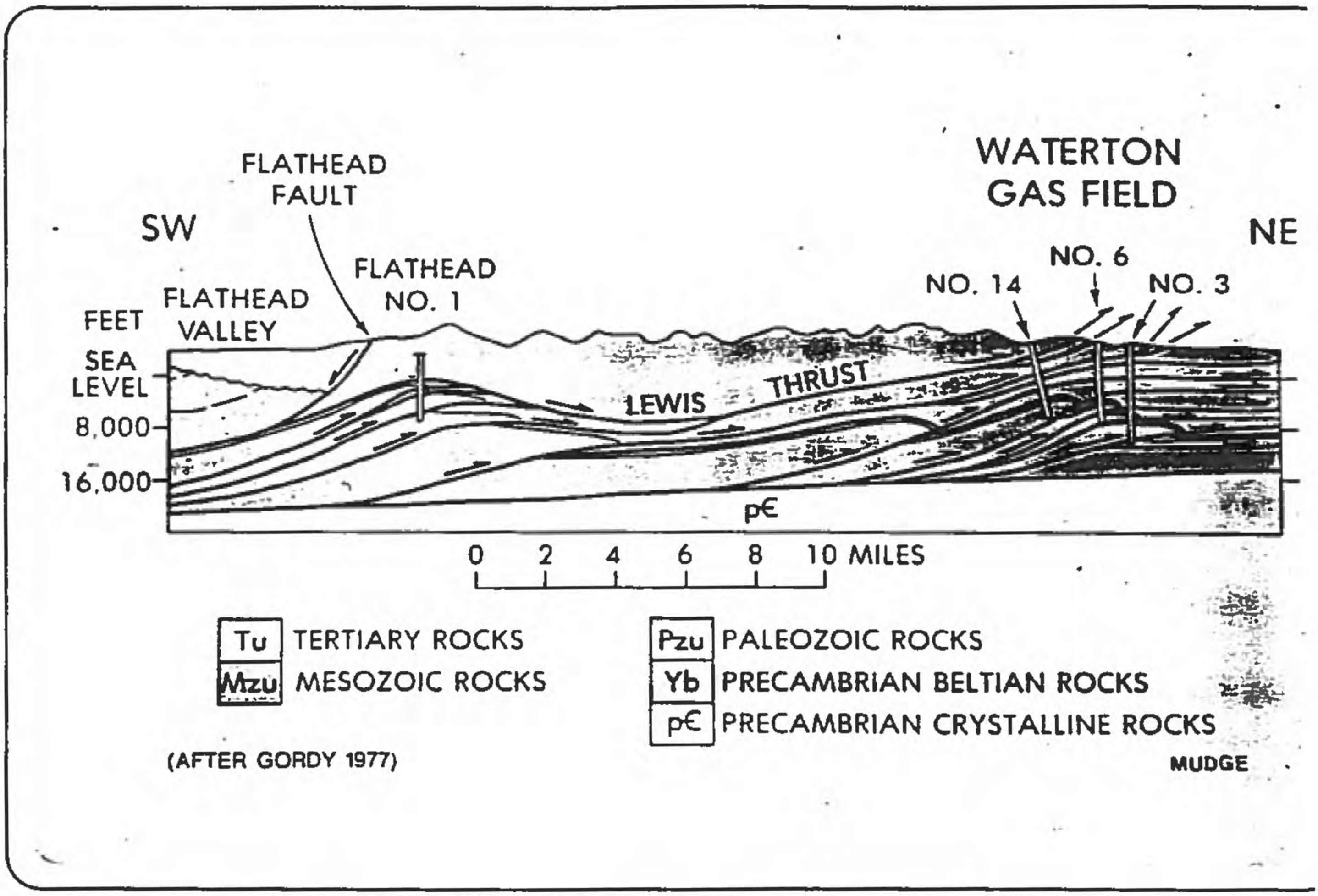

Figure IV.F.5. Regional west-east structural cross section in southern Alberta Foothills Thrust Belt showing styles of imbricate thrusting, and producing traps of two giant gas fields. Structural geometry of the Montana Thrust Belt is very similar to this setting (after Gordy and others, 1977).

Six individual Laramide basins are composited into the Southwestern Wyoming province. Each has a considerable thickness of Cretaceous and Tertiary rocks and all are bounded by adjacent uplifts and collectively bounded on the west by the Wyoming Thrust Belt. Approximately 60 oil and gas fields have been discovered in the southwestern Wyoming basins since the initial discovery in 1916. Accumulations are in traps that range from structural to purely stratigraphic, and reservoirs range in age from Paleozoic to Tertiary. Thermally mature source rocks, especially in the Cretaceous, are abundant and mainly gas prone. Additional source shales are in Late Paleozoic strata.

Petroleum Geology

Productive reservoirs in the region range from Paleozoic through Mesozoic and Tertiary in age. Oil production is concentrated mainly in five provinces (Bighorn, Powder River, Williston, and Denver basins and Southwestern Wyoming). The majority of gas production is in association (dissolved) with the oil in these provinces, and the bulk of non-associated gas is in southwestern Wyoming and the Wind River basin.

The first oil discovery in the region, and in the western United States, occurred in 1862 north of the Canyon City embayment, Colorado, at an oil seep at a depth of 50 ft in the Jurassic Morrison Formation. This discovery led to the finding of the Florence-Canyon City field in 1876, 7 miles south of the initial discovery, in the Cretaceous Pierre Shale (Powers and others, 1984). This was followed in 1889 by a discovery well on the north plunge of the Salt Creek anticline (Shannon field) on the western margin of the Powder River basin, but it was not until 1908 that the crest of the anticline was drilled to the Cretaceous Frontier Formation (McGregor, 1972). This was the discovery well for the giant Salt Creek field, which has an estimated >700 MMBO ultimately recoverable reserves (Powers, 1986), the largest field in the region (fig. IV.F.2). Between 1906 and 1918, five additional giant fields were discovered in the Bighorn basin alone (Weldon, 1972). There are presently at least 18 giant fields (>100 MBO, or oil-equivalent gas) in Region 4 that have been discovered in the past 126 years of exploration.

Of the 13 provinces in Region 4, 9 are productive of oil or gas in varying amounts. Seven of the provinces each have already produced greater than 100 million barrels of oil (MMBO) or 1 trillion cubic feet (TCF) of gas, led by the Bighorn basin and closely followed by the Powder River and Williston basins.

Cumulative production in the region is approximately 7.1 billion barrels of oil (BBO) and 13.1 TCF of gas (table IV.F.1). Estimated ultimately recoverable reserves are 9.6 BBO and 24.3 TCF of gas; more than 54 percent of the overall reserves is concentrated in seven provinces.

Petroleum Potential

Future undiscovered hydrocarbons in the region range widely from province to province. Given the long period of exploration, it is probable that most of the giant fields have already been found. Good oil potential exists, however, in the Powder River basin and large gas potential in the southwestern Wyoming basins; both the Williston and Denver basins have a modest oil potential and the Montana Thrust Belt and Wind River basin have a good potential for gas (table IV.F.1). Exploration density is fairly high in most areas in the Powder River, Williston and Denver basins and light to almost undrilled in much of the Wind River basin, Southwestern Wyoming and the thrust belt.

The great thickness of Cretaceous and Tertiary rocks in individual basins in the Southwestern Wyoming province have not been extensively tested and should have potential for gas in medium to large, stratigraphic or structural/stratigraphic traps (fig. IV.F.6). The probability of basin margin subthrust traps is highly speculative at present and this type of play, particularly along the north flank of the Uinta Mountains, may have good oil and gas potential. Unconventional gas resources in Cretaceous-Tertiary rocks in abnormally overpressured tight sandstones in the deep basins, although large, present serious problems of recoverability.

Good potential for gas and condensate exists in the Montana Thrust Belt. Reservoirs, source rocks, favorable maturation histories, and structural traps are a direct extension of the highly productive Southern Alberta Foothills thrust belt, where more than 30 fields have been discovered, 7 of which have produced greater than half a trillion cubic feet of gas each. Very few wells have been drilled in the Montana province in an attempt to find similar traps, and the thrust belt is still a frontier exploration province.

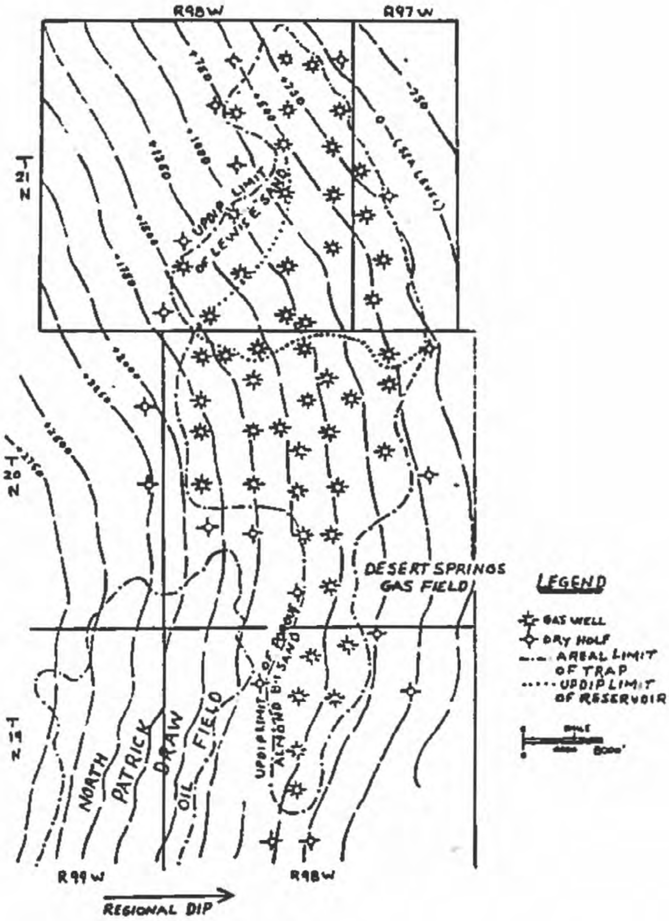

Figure IV.F.6. Desert Springs gas field and Patrick Draw oil and gas field, Green River basin, Wyoming. Examples of typical stratigraphic trapping in Cretaceous sandstones, showing westward updip pinchout of Lewis and Almond sandstones against east regional dip (modified from Mohl and Sasse, 1979).

Table IV.F.1.--Cumulative production, estimated reserves and undiscovered recoverable resources in Region 4.

	Cum. Production	Measured Reserves	Inferred + Indicated Reserves
Oil (BBO)	7.1	1.2	1.3
Gas (TCF)	13.1	7.6	3.6

Petroleum Provinces

Estimates of Undiscovered Recoverable Resources*

	Crude Oil (Billion Barrels)			Gas (Trillion Cubic Feet)		
	F95	F5	Mean	F95	F5	Mean
Region 4 - Rocky Mountains and Northern Great Plains						
Williston basin (incl. Sioux Arch)	0.49	1.15	0.78	0.49	1.07	0.74
Sweetgrass arch	0.05	0.18	0.10	0.31	0.95	0.57
Central Montana	0.01	0.06	0.03	0.01	0.02	0.01
Montana Overthrust Belt	Negl.	0.04	0.01	0.42	8.72	2.92
SW Montana	Negl.	0.06	0.02	0.07	1.07	0.38
Wind River basin	0.09	0.37	0.20	0.82	3.55	1.89
Powder River basin	1.16	3.82	2.25	1.38	4.78	2.76
SW Wyoming basins	0.06	0.47	0.21	1.32	6.76	3.38
Bighorn basin	0.10	0.48	0.25	0.18	1.59	0.66
Denver basin	0.37	0.87	0.59	0.96	2.76	1.71
Las Animas arch	0.02	0.07	0.04	0.04	0.15	0.09
Raton-Sierra Grande uplift	Negl.	0.02	0.01	0.02	0.36	0.13
Total	2.7	6.9	4.5	7.0	27.8	15.2

Mean value totals may not be equal to the sums of the constituent means due to independent rounding.

Fractile values are not additive.

*Estimates of undiscovered economically recoverable resources are given in Table VII.B.3.

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G. REGION 5, WEST TEXAS AND SOUTHEASTERN NEW MEXICO
by
M. Ball, G.L. Dolton, and K. Robinson

Geologic Framework

Region 5 (fig. IV.G.1) encompasses north, west and central Texas and southeastern New Mexico. The region is bounded on the south and east by the Marathon-Ouachita fold belt, on the north by the Amarillo-Wichita uplift, and on the west by the Pedernal uplift, and, in the extreme southwest, a portion of the Mexican Laramide thrust belt. The main structural elements of the area include the Permian basin in the west and the Bend Arch and Fort Worth Basin in the east (fig. IV.G.2, regional E-W cross section).

The Permian basin is a large asymmetric structural depression in the Precambrian basement of the southwestern margin of the North American craton that has been filled primarily with Paleozoic sediments and acquired its present form by Early Permian time. Rocks of all Paleozoic systems are present and attain a maximum combined thickness of 25,000 ft. Distinct tectonic subdivisions of the Permian basin include the Delaware and Midland basins, which are separated by the Central Basin platform, the Marfa and Val Verde basins, the northwestern and eastern shelves and the Diablo platform (fig. IV.G.1). The Bend arch to the east (fig. IV.G.2, cross-section) is the southern extension of the broad Precambrian basement swell known as the Transcontinental arch of the Mid-Continent Region that is traceable northward into the Precambrian outcrop on the Canadian Shield. Because this feature has been structurally high throughout its history, complete sequences of Paleozoic strata are typically absent on its crest as a result of erosion or nondeposition. On the easternmost extremity of Region 5, in the Fort Worth basin, the Paleozoic section is overthrust by the Ouachita fold belt and onlapped by Mesozoic section. Other structural elements of Region 5 include the Tucumcari and Palo Duro basins, and the Matador-Red River and Muenster arches (fig. IV.G.1).

From Cambrian through Mississippian time, the region was a broad relatively stable marine shelf area on which extensive carbonate sediments and an admixture of terrigenous clastics were deposited (fig. IV.G.3). Intense structural deformation from Early Pennsylvanian into Early Permian time resulted in development of the currently recognized tectonic elements (fig. IV.G.1). In Pennsylvanian time, coarse clastics were deposited on the shorelines of the Permian basin with limestones seaward of the quartz clastic shoals. Reef development was common on flooded shelves. Marine shales were deposited in the deeper sections of the Delaware and Midland basins. East of the transition from the eastern shelf to the Bend Arch, carbonates grade into thick accumulations of predominantly coarse quartz sand deposits. Regionwide unconformities can be traced throughout the area but are concentrated on the crest of the Bend arch where the Pennsylvanian Atokan-age Bend conglomerate directly overlies Lower Ordovician Ellenburger Limestone (fig. IV.G.3).

In Permian time, in the west, carbonate sedimentation continued to build upward with regional subsidence of the tectonic setting developed during the Pennsylvanian. Permian reefs expanded to become the most striking depositional features of the Permian basin. The reef rocks

Figure IV.G.1. Index map of west Texas and southeastern New Mexico showing structural elements and location of cross section Figure IV.G.2. (after Hartman and Woodard, 1971).

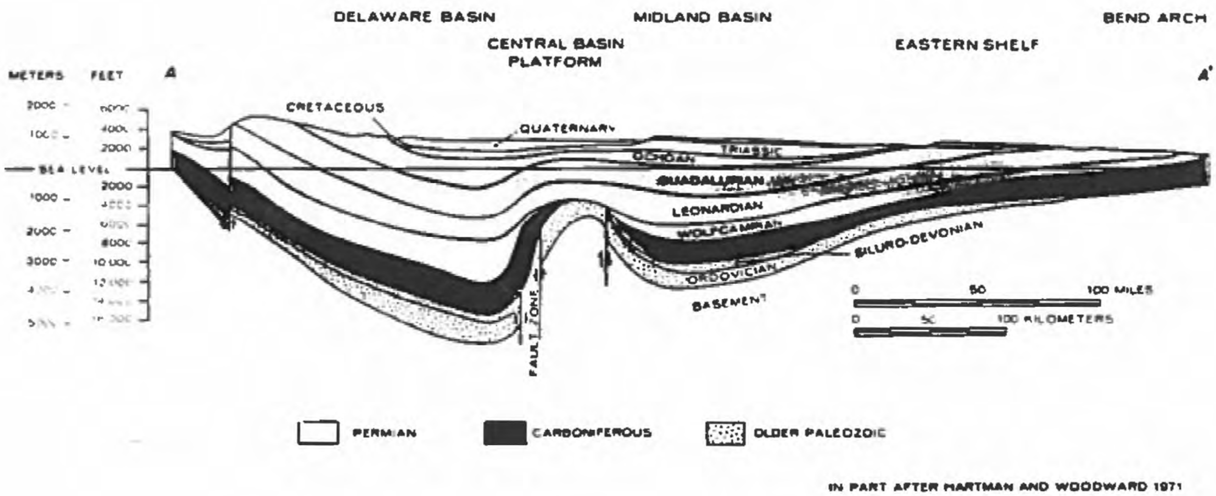

Figure IV.G.2. East-west cross section, west Texas-New Mexico. For location see figure IV.G.1.

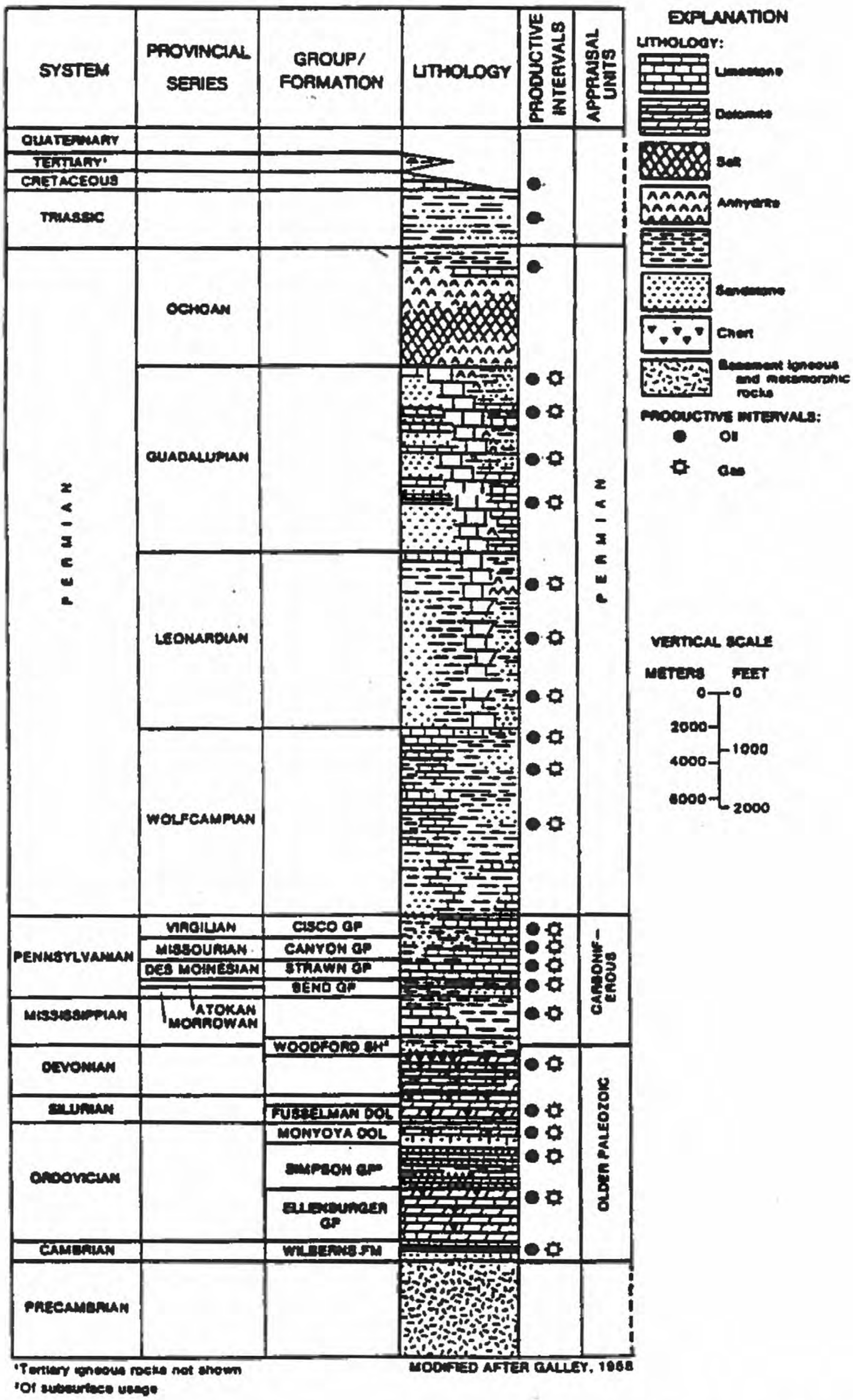

Figure IV.G.3. Generalized stratigraphic and lithologic column for the Permian basin showing productive intervals.

generally developed at basin hingelines and separated quartz clastic and thin carbonate deposition in the deeper basins from back-reef lagoonal facies of interfingering quartz sandstones, mudstones, carbonates, and anhydrites. To the east, on the west flank of the Bend arch, the entire Permian section is truncated by erosion and Pennsylvanian terrigenous clastics cropout.

Petroleum Geology

Region 5 (table IV.G.1) is second only to the Gulf Coastal Plain (Region 6) in cumulative production of onshore oil and gas. Roughly 75 percent of the region's production of oil and 85 percent of its production of gas have come from the Permian Basin province. It follows that the Permian basin is one of the most prolific petroleum provinces of North America. The Paleozoic reservoirs of the Permian basin produce oil from depths of less than 500 to 14,000 ft and produce gas from depths of less than 500 to 21,000 ft. Approximately 70 percent of the Permian basin oil and dissolved gas was found in the Permian section at relatively shallow depths of less than 10,000 ft. The Central Basin platform (fig. IV.G.1) is the major productive tectonic element for both oil and dissolved gas production mainly from the Permian Capitan Reef and back-reef complex and from lower Paleozoic reservoirs. The Midland basin is also an important oil- and gas-producing area, and the northwestern and eastern shelves produce oil and gas in smaller quantities. In the western part of the Permian basin (fig. IV.G.1), the Delaware and Val Verde basins and the western part of the northwestern shelf produce most of the non-associated gas.

The lower limits of reservoir depth in the Bend arch and Fort Worth basins of north-central Texas are 6,500 and 10,500 ft, respectively. Production from north-central Texas essentially rounds out the total production for Region 5.

Almost the entire Paleozoic section of the region is productive and virtually all the Paleozoic production of the states of Texas and New Mexico is contained in Region 5. The region's exploration history began with the recording of occurrences of gas in water wells drilled in north-central Texas in 1872 (Galley, 1971). The first commercial production of oil was from shallow Pennsylvanian reservoirs on the Bend arch in 1904 and commercial oil production in the Permian Basin province began in the 1920's (Galley, 1971). Approximately two-thirds of the Permian basin oil was discovered between 1930 and 1950. Both the Permian Basin province and Region 5 as a whole are now in a mature stage of petroleum exploration and development.

Petroleum Potential

Table IV.G.1 presents our estimates for undiscovered conventionally recoverable oil, natural gas, and natural gas liquids. The Permian basin province is, in our judgment, the most important for future oil exploration development with the Bend Arch-Fort Worth basin province in a distant second place. With respect to undiscovered recoverable gas resources, expectations for the Permian basin over the Bend Arch-Fort Worth province are even more pronounced. In a relative sense, prospects for the Palo Duro basin, Marathon fold belt and Pedernal uplift are considered insignificant.

Table IV.G.1.--Cumulative production, estimated reserves and undiscovered recoverable resources in Region 5.

	Cum. Production	Measured Reserves	Inferred + Indicated Reserves
Oil (BBO)	30.2	5.4	3.8
Gas (TCF)	82.2	16.7	12.9

Petroleum Provinces

Estimates of Undiscovered Recoverable Resources*

	Crude Oil (Billion Barrels)			Gas (Trillion Cubic Feet)		
	F95	F5	Mean	F95	F5	Mean
<u>Region 5 - West Texas and Eastern New Mexico</u>						
Permian basin	0.99	3.18	1.89	10.17	28.11	17.74
Palo Duro basin	0.05	0.24	0.13	0.02	0.11	0.05
Pedernal	-	-	-	-	-	-
Bend arch	0.37	0.76	0.54	1.00	2.31	1.57
Marathon	0.00	0.00	0.00	0.28	1.63	0.78
Total	1.5	4.0	2.6	11.9	31.3	20.1

Mean value totals may not be equal to the sums of the constituent means due to independent rounding.

Fractile values are not additive.

*Estimates of undiscovered economically recoverable resources are given in Table VIII.B.3.

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H. REGION 6, GULF COAST
by
R.Q. Foote

Geologic Framework

Region 6 extends from the Rio Grande to the Chattahoochee River and from the inner edge of the Gulf Coastal Plain to the seaward edge of the coastal state's territorial waters (fig. IV.H.1). In this appraisal, Region 6 is divided into three provinces: the Western Gulf province, the East Texas basin, and the Louisiana-Mississippi salt basins.

Geologic history.--The Gulf of Mexico is a relatively small ocean basin formed on the passive southern margin of the North American continent when the African and South American continents began to drift southeasterly during early Mesozoic time (Walper and Miller, 1985). The northern Gulf of Mexico basin (hereafter called northern Gulf basin) gained its present form from a combination of rifting and intrabasin sedimentary-tectonic processes during and after the Mesozoic Era (Murray and others, 1985).

During the early stage of continental separation in Triassic time, five complex systems of rhomb grabens or rift basins (Rio Grande embayment, East Texas basin, North Louisiana basin, Mississippi Interior basin, and the Apalachicola embayment) were formed on thinned continental crust and became the landward margin of the northern Gulf basin. Structurally positive elements which separate the rift basins are the San Marcos arch, the Sabine arch, the Monroe arch, and the northeast extension of the Wiggins arch (Martin, 1984).

A broad continental platform developed across the northern Gulf basin as a result of mid-Jurassic to Late Cretaceous subsidence. An early Cretaceous carbonate reef trend was deposited around the shelf edge of the continental platform from Mexico to offshore South Florida (Martin, 1978) and defines the Mesozoic shelf margin (fig. IV.H.2).

Basinward of the Mesozoic shelf edge, a massive influx of clastic sediments was deposited in depocenters in the central and western parts of the northern Gulf basin during Cenozoic time. A gradual shift of the depocenters from south Texas to south-central Louisiana caused the southward-prograding continental shelf to be best developed in the northeast (Martin, 1978) (fig. IV.H.3).

Structure, stratigraphy, and traps.--The northern Gulf basin is a gently dipping regional homocline or geocline bounded on the northern rim by complex arcuate systems of normal faults (Balcones-Luling, Mexia-Talco, south Arkansas, and Pickens-Gilbertown-Pollard fault systems) that determine the structural and depositional strike from south Texas to the West Florida shelf (Murray, 1961). These fault systems are the updip limits of thick Louann Salt deposits (Bishop, 1973). A relatively thin section of Louann Salt-Late Jurassic sedimentary rocks extends landward of the fault system in the East Texas, north Louisiana, and Mississippi interior basins (Murray and others, 1985).

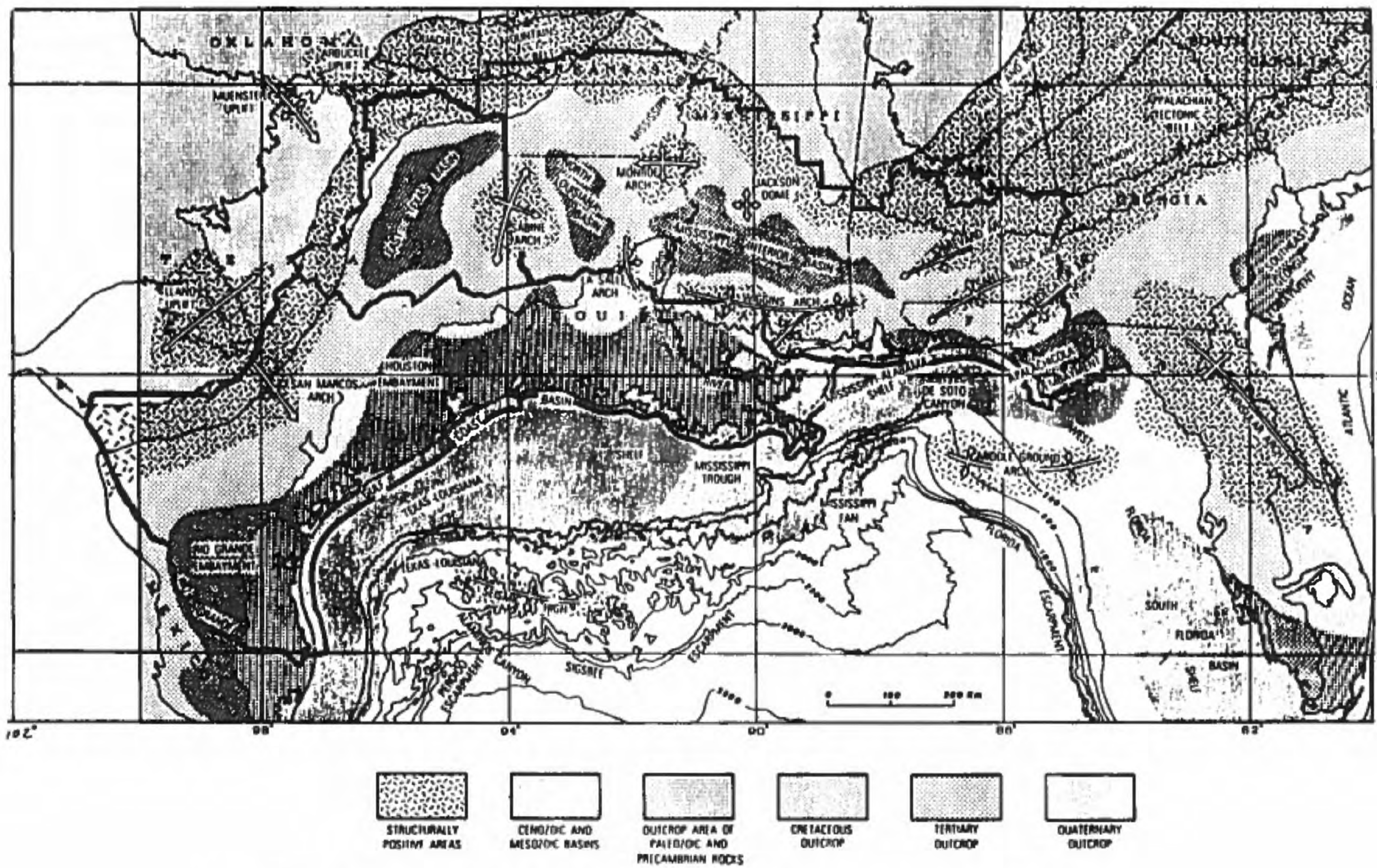

Figure IV.B.1. Generalized geologic map showing structurally positive areas, sedimentary basins, and subsea topography of northern and eastern Gulf of Mexico regions. Contour interval, 200 m. (from Martin, 1978).

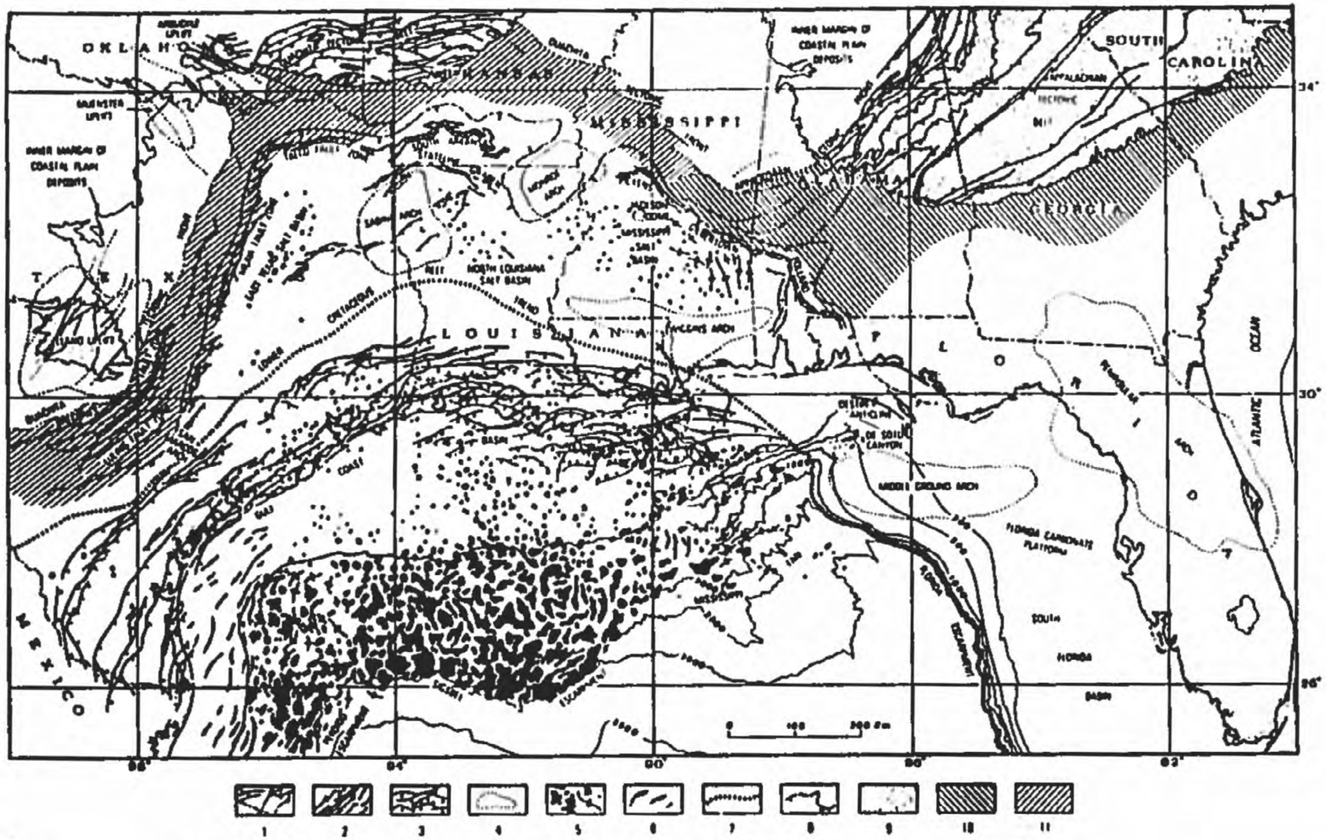

Figure IV.H.2. Tectonic map of northern Gulf of Mexico region. Compiled mainly from Flavn et al (1961), Bryant et al (1969), Hickey et al (1972), Braunstein et al (1973), Bebout and Loucks (1974), King and Beikman (1974), King (1975), and Thomas (1976), and unpublished U.S. Geological Survey data. Explanation of patterns and symbols: (1) Normal fault, hachures on downthrown side; (2) Reverse fault, sawteeth on overthrust plate; (3) Fault of undetermined movement; (4) Broad anticline, or arch, of regional extent; (5) Salt diapirs and massifs indicating relative size and shape; (6) Salt anticlines and swells (nondiapiric) showing general trend; (7) Shale domes and anticlines showing general size and trend; (8) Plutonic and volcanic rocks of Mesozoic ages exclusive of basement complexes and Triassic diabase sills; (9) Updip limits of Louann Salt; (10) Downdip limits of deep wells reaching rocks of Ouachita tectonic belt; (11) Uplifts of exposed Paleozoic strata and crystalline basement rocks; (12) Trend of Lower Cretaceous shelf-margin reef system; (13) Inner margin of Cretaceous and Tertiary Coastal Plain deposits. Scale: 1° lat. equals 110 km.

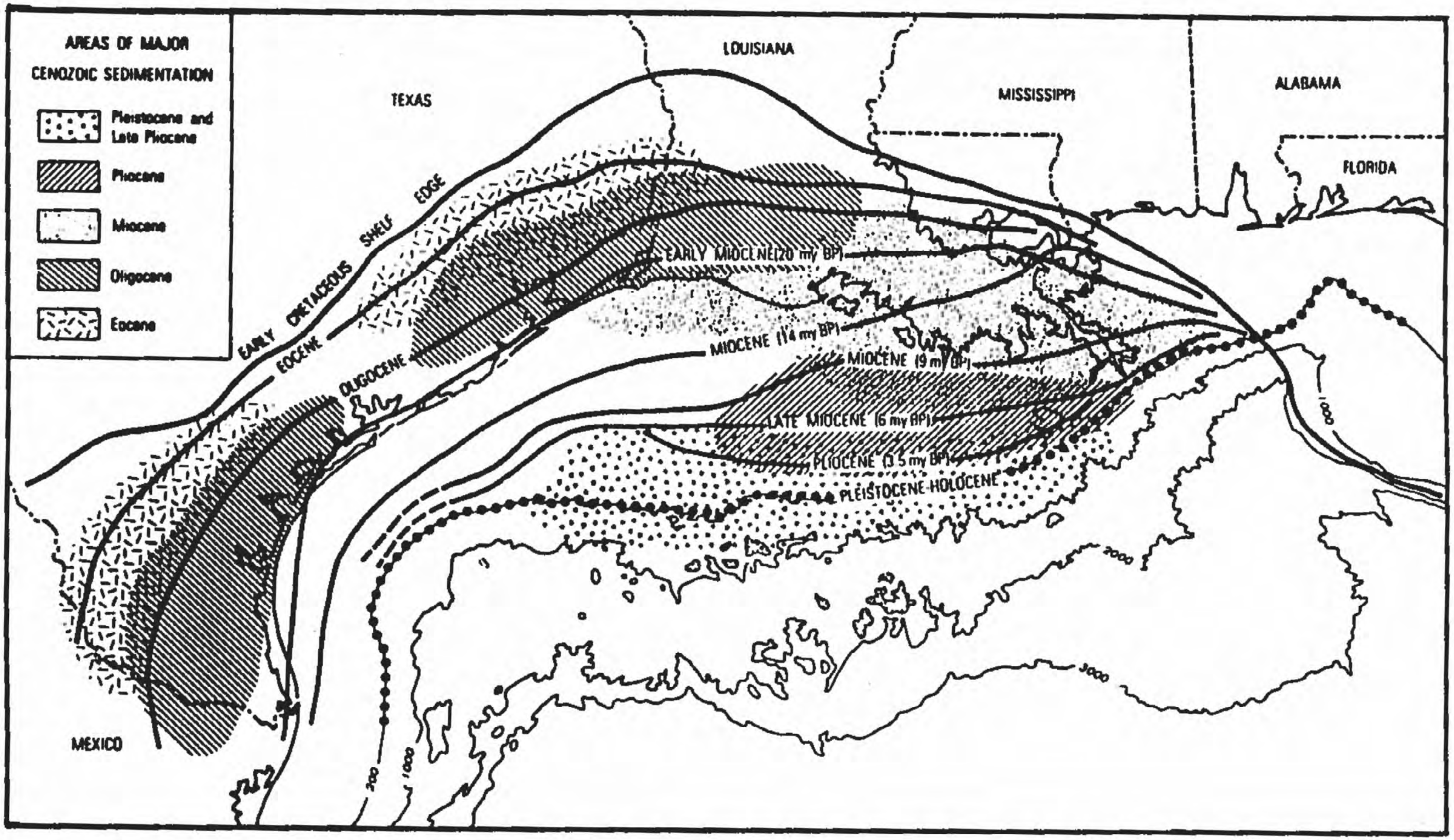

Figure IV.H.3. Sketch map showing paleoshelf edges in Gulf Coast basin and distribution of major Tertiary depocenters. Modified from Hardin (1962), Woodbury and others (1973), Caughey (1975), and McGookey (1975).

The continental margin of the northern Gulf basin has been deformed by uplift, folding, and faulting associated with plastic flowage of Middle Jurassic(?) Louann Salt deposits and masses of underconsolidated Cenozoic shale (fig. IV.H.4). Flowage of Louann Salt deposits has resulted in widespread fields of salt domes and diapir fields (Martin, 1984). Shale domes and ridges have formed across the Texas Lower Coastal Plain and offshore Texas and Louisiana (Bruce, 1973).

Basinward of the Mesozoic shelf edge, major systems of principally down-to-the-basin faults occur from the Rio Grande to the east side of the Mississippi Delta. These large faults, termed syndepositional faults by Shinn (1971) and growth faults by Hardin and Hardin (1961) and Ocamb (1961), formed contemporaneously with deposition.

The sedimentological history of the northern Gulf basin has been one of shelf progradation that began when Triassic clastic redbeds were deposited on an unconformable surface of Paleozoic and Precambrian sedimentary, igneous, and metamorphic rocks in the rift basins. The Early Jurassic was a period of limited deposition of anhydrites, shales, and sandstones. Throughout the Middle(?) Jurassic period, great thicknesses of Louann salt were deposited in the northern Gulf basin. Beginning in Late Jurassic time, clastic sequences were deposited in the rift basins, followed by formation of a carbonate ramp that controlled deposition of Late Jurassic formations from south Texas to south Florida (Budd and Loucks, 1981). Toward the end of the Late Jurassic period, the northern Gulf basin was flooded by open seas and clastic sediments are dominant in northeast Texas, northern Louisiana, southern Mississippi, and southwestern Alabama-Florida Panhandle (Murray and others, 1985).

Clastic sedimentation continued into Early Cretaceous time and extended across large areas of the northern Gulf basin, onlapping Late Jurassic terrigenous sediments. As subsidence slowed and the supply of terrigenous clastic materials waned, a shallow epicontinental sea covered the western coastal plain and regions to the south and west (Rainwater, 1970). A carbonate depositional regime prevailed around the periphery of the basin, and limestones, dolomites, and interbedded anhydrites were deposited on broad banks. Reef building and detrital carbonate accumulations developed on the seaward edges of the shallow banks (Budd and Loucks, 1981; Mitchell-Tapping, 1981). Early Cretaceous strata in south Texas consist mostly of shallow-marine carbonate rocks deposited over broad shelf areas (Bebout and others, 1981). Interbedded carbonate and silicate clastic rocks of neritic origin are predominant in the latter part of Early Cretaceous from northeast Texas to Alabama landward of the Mesozoic shelf margin (Rainwater, 1971).

Late Cretaceous seas expanded over the region and carbonates deposited in shallow-water environments transgress all older Mesozoic rocks (Holcomb, 1971). Late Cretaceous strata of the Gulfian Series are represented mainly by transgressive sands, shales, marls, and chalks. Locally, reeflike carbonate beds accumulated on the Monroe uplift and the Jackson dome, and around volcanic cores in south Texas (Murray and others, 1985).

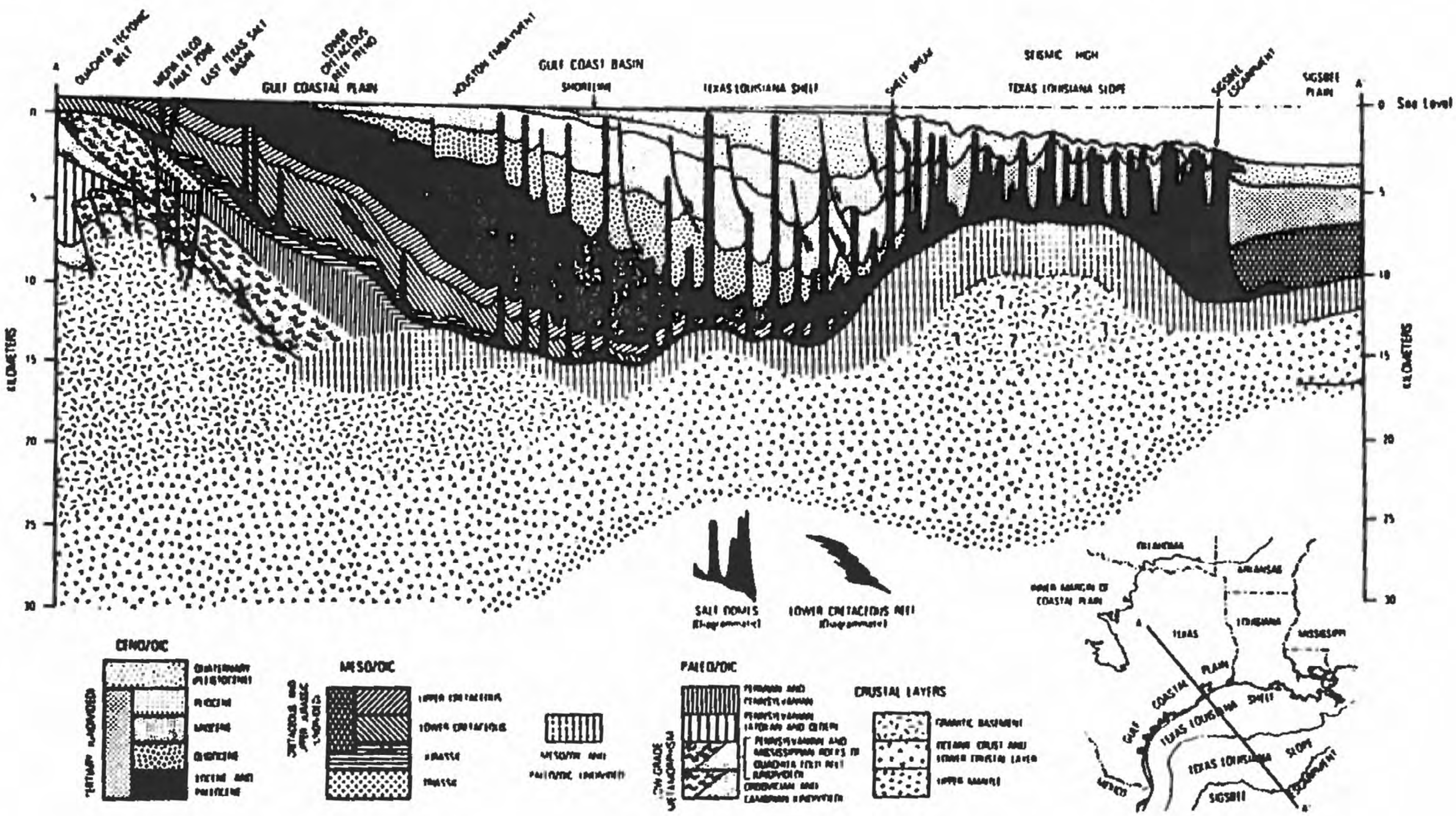

Figure IV.H.4. Generalized cross section of northern Gulf of Mexico margin. Modified from Lehner (1969, Dorman et al (1972), Antoine et al (1974), Martin and Cass (1975). (from Martin, 1984).

During early Cenozoic time, land-derived sands and muds from northern and western sources were deposited in the East Texas and Louisiana-Mississippi salt basins. Successively younger wedges of offlapping strata formed as the shelf margin prograded and the primary depocenters shifted seaward. Basinward of the Mesozoic shelf edge, thick deposits of alternating sandstones and shales were deposited as pulses in the rapidly subsiding basin, resulting in Cenozoic sequences prograding about 240 miles seaward and reaching cumulative sediment thicknesses of 50,000 ft or more on the Louisiana-Texas Continental Shelf (Martin, 1984). In the eastern Gulf, the carbonate environments that had prevailed during Mesozoic times persisted more or less during Cenozoic times. Land-derived clastic sediments from north and northwestern source areas were deposited on the northern end of the Florida platform as minor components of Tertiary carbonate environments (Rainwater, 1971; Winston, 1971).

Petroleum source rocks are present in basinal facies of the Mesozoic succession, and the thermal histories of Mesozoic strata in the northern Gulf basin are conducive to generating hydrocarbons. The oil-generation window for Paleocene to Oligocene sedimentary rocks ranges from about 8,700 to 13,000 ft, based upon studies by Dow (1978), with onset of thermal-gas generation by conversion of crude oil at greater depth (Dow, 1978; Galloway and others, 1984). Generally, Miocene hydrocarbon production in Louisiana is from thermally immature progradational facies, which overlie older thermally mature slope and rise facies. Galloway and others (1986) stated that indigenous oil and gas generation in the lower Miocene of Texas appears to be limited to the thermally mature lower Miocene expansion zone, basinward of the Oligocene shelf margin. The upper Miocene section of Texas appears to be above the oil-maturation interval and all hydrocarbons (except for biogenic gas) are probably derived either by upward migration from older formations or by lateral, updip migration from basinward time-equivalent marine units.

Oil and gas traps in the region are varied. Basement-related traps, generally associated with major basin boundary faults, produce oil and gas in northeast Texas, south Arkansas, and southwest Alabama. The hydrocarbons are in anticlinal closures, and stratigraphic traps formed by compaction over or onlap of the reservoir rocks on the flanks of horst blocks, Paleozoic cuestas and erosional remnant topography formed at the time of Late Jurassic transgression (Moore, 1984). Hydrocarbon production is from the Smackover Formation and other Upper Jurassic strata. Stratigraphic variations and diagenesis affect reservoir rock quality (Hardwood and Fontana, 1984).

Traps developed by faulting and folding account for significant quantities of hydrocarbons along the basin boundary fault systems (Balcones-Luling, the Mexia-Talco, south Arkansas fault zone, and Pickens-Pollard-Gilbertown fault systems) (Murray and others, 1985). Hydrocarbons are produced from closures on both upthrown and downthrown blocks. Reservoir rocks are primarily Upper Jurassic and Cretaceous carbonates and sandstones (Newkirk, 1971) and some sandstones of Tertiary (Eocene) age. Large quantities of oil and gas are associated with the down-to-the-basin growth faults across the Texas and Louisiana Lower Coastal Plain and their coastal waters. The reservoirs are in anticlinal closures on both upthrown and downthrown fault blocks and in traps against fault planes, antithetic faults, and up-to-the-basin normal faults. Production is from Paleocene- to Pliocene-age sandstones in which facies changes to siltstones and shales frequently affect the lateral extent and the quality of the reservoir rock. Significant quantities of natural gas have been discovered in anticlinal closures in deep Tuscaloosa Formation sandstones on the downthrown side of growth faults basinward of the Cretaceous shelf margin across south-central Louisiana.

Fracturing in reservoir rocks, in particular the Austin Chalk trend across the coastal plain, facilitates production in many oil and gas fields in the region. The foci of the fractures are in the hinge line of the basin, thereby producing the Austin Chalk-Buda Lime trends along paleo shelf edges (Scott, 1977; Stapp, 1977, Grabowski, 1981).

Salt-related structures in the region are productive as anticlines over piercement and deep-seated salt domes and ridges, as caprocks over piercement domes, as fault structures in crestal and flank positions, and between closely spaced salt masses, from termination of reservoir strata against salt domes, and from stratigraphic traps formed by reservoir sandstones onlapping salt shoulders (Halbouty, 1979). Salt structures in the Texas and Louisiana Lower Coastal Plain and their coastal waters produce hydrocarbons primarily from Cenozoic sandstone reservoirs. Salt structures in the East Texas and Louisiana-Mississippi Salt basins produce oil and gas from sandstones, limestones, and dolomites reservoirs ranging in age from Middle Jurassic in Alabama to Eocene in Louisiana (Jackson and Seni, 1984; Mancini and Mink, 1985).

Stratigraphic variations provide significant contributions to oil and gas entrapment throughout the region, the most notable of which is the super giant East Texas field, a classical stratigraphic trap located on the west flank of the Sabine uplift (Hudnall, 1951). Major gas accumulations on the Sabine uplift in east Texas-west Louisiana are in a series of individual stratigraphic traps caused by lateral porosity loss (Collins, 1980). Stratigraphic traps also occur in southwestern Alabama, where a trend of shallow, dry gas fields of Miocene age is produced by pinchouts of floodplain point-bar and reworked marine sandstones encased in shales; differential compaction has caused minor structural relief over the traps (Pfiester, 1983; Mancini and Mink, 1985).

Comparisons of trap types of giant oil and gas fields in the region reveal that 81 percent are structural, 17 percent are combination, and 2 percent are stratigraphic traps (Murray and others, 1985). Approximately 89 percent of producing zones in these giant oil fields are arenaceous rocks deposited in fluviatile-deltaic environments; however, more recent discoveries have been from prodeltaic and open marine facies. Multiple, stacked producing horizons are common (Murray and others, 1985). Limestone and limestone/sandstone reservoir rocks account for the remaining discovered hydrocarbons. Most are shallow-water, nearshore to shelf facies. Dolomitic rocks are significant reservoir rocks in east Texas, Alabama, and the Florida Panhandle, and substantial quantities of hydrocarbons have been found in salt-dome caprocks and in fractured chalks and limestones (Murray and others, 1985).

Two significant Mesozoic biohermal reservoirs (atop the Jackson Dome and Monroe Uplift) are productive, and biostromal carbonate reservoir rocks are relatively common from south Texas to the South Florida basin (Murray and others, 1985). Other reservoir rocks of less importance are waterlaid volcanics, altered igneous rocks, and volcanic rocks emplaced in sedimentary strata.

Exploration history.--Oil and gas exploration began in the northern Gulf basin in 1865 when a well was drilled in Alabama. The first successful oil well was completed in Nacogdoches County, Texas, in 1866 (Tyler and others, 1985) and the first significant oil field, the Corsicana field, was discovered along the Mexia fault zone in October, 1895. In 1901, the Spindletop Dome and the Saratoga Dome fields were found in southeast Texas, followed later that year by the Jennings field in Louisiana.

The number of giant fields found each decade since the turn of the century rose steadily from 7 fields in 1900-1909 to 53 fields in 1930-1939. The discovery rate dropped to 47 fields during 1940-1949 and then began a rapid decline to less than 5 giant fields in 1970-1979. These giants account for more than 75 percent of the discovered petroleum in the region.

Petroleum Potential

The estimated crude oil and natural gas resources are shown in table IV.H.1. The mean values of undiscovered recoverable conventional resources for the region are: crude oil, 4.2 BBO, and natural gas, 82.5 TCF.

The Western Gulf province is estimated to have most of the undiscovered crude oil and natural gas resources, with mean values of 3.05 BBO and 64.78 TCFG, respectively. The Louisiana-Mississippi Salt basins province, which is a smaller geographic area, remains promising for undiscovered resources of natural gas (mean value of 14.91 TCFG). The maturity of the East Texas basin is reflected in relatively small undiscovered resources.

Substantial areas and volumes of known and possible reservoir rocks remain to be explored in the region. Future discoveries can be expected from within and by extension of producing trends, from deeper plays within producing trends, and new plays in the lesser explored areas.

Large natural gas resources are estimated in deep-seated, salt-related traps and basement structures on the lower coastal plain and in coastal waters of Mississippi, Alabama, and western Florida; in fault-related traps on the lower coastal plain and coastal waters of Texas; and in deeper parts of the East Texas and Louisiana-Mississippi salt basins. Crude oil prospects are expected to be in the updip and thermally less mature areas. A south Texas equivalent of Upper Jurassic and Cretaceous traps on the west flank of the East Texas basin has not been found and the Smackover Formation and the lower part of the Buckner Formation are prospective (Budd and Loucks, 1981). In East Texas, the Gilmer shelf margin has potential in structural features and stratigraphic traps formed rapid lateral facies changes in a basinward direction (Moore, 1984). Reefs are possible future targets on the Gilmer shelf margin and in the centers of the interior salt basins.

Table IV.B.1.--Cumulative production, estimated reserves and undiscovered recoverable resources in Region 6.

	Cum. Production	Measured Reserves	Inferred + Indicated Reserves
Oil (BBO)	43.1	3.7	5.7
Gas (TCF)	285.6	33.6	42.3

Petroleum Provinces

Estimates of Undiscovered Recoverable Resources*

	Crude Oil (Billion Barrels)			Gas (Trillion Cubic Feet)		
	F95	F5	Mean	F95	F5	Mean
Region 6 - Gulf Coast						
Western Gulf basin	1.59	5.16	3.05	38.71	99.79	64.78
East Texas basin	0.18	0.80	0.42	1.51	4.59	2.78
La.-Miss. salt basins	0.48	1.16	0.77	8.06	24.59	14.91
Total	2.4	6.7	4.2	51.2	123.6	82.5

Mean value totals may not be equal to the sums of the constituent means due to independent rounding.

Fractile values are not additive.

*Estimates of undiscovered economically recoverable resources are given in Table VII.B.3.

Within the Late Cretaceous Gulfian series, large quantities of both oil and gas should be found in fractured chalks, limestones, and shales of the Austin Chalk-Eagle Ford Formations in the trend across south Texas and extending into south central Louisiana near the southern line of Mississippi. Possibilities for significant natural gas and oil discoveries are promising in sandstones of the Woodbine and Tuscaloosa Formations in the deeper parts and in the south end of the east Texas basin, south of the Sabine arch across southeast Texas and southwest Louisiana, in the deep Tuscaloosa gas trend across south-central Louisiana, and in shelf sandstone deposits in southern Mississippi.

Future discoveries of oil and gas in Cenozoic sedimentary rocks will be almost exclusively from sandstone reservoirs throughout the region. Significant discoveries are to be expected in the well-hidden traps in maturely explored areas, downdip extensions of plays (particularly natural gas) which have not been extensively explored, and new, deeper gas plays in downthrown blocks of regional growth faults and continental slope facies.

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I. REGION 7, MID-CONTINENT
by
M.M. Ball

Geologic Framework

The Mid-Continent Petroleum Region (fig. IV.I.1) includes the States of Iowa, Kansas and Minnesota; northwestern Arkansas; the southeastern corner of Colorado; Missouri, except for its southeasternmost corner; Nebraska, east of its panhandle; Oklahoma except for its southwesternmost three counties; and the northernmost part of the Texas panhandle. The limits of the region are based on a complex combination of political and geologic factors. Generally, State lines are followed by the region's boundaries. Local excursions are made in attempts to avoid dividing geologic entities that cross State lines.

From a geologic standpoint, this region is dominated by a broad, low-relief swell of Precambrian igneous rock that forms the core of the stable interior of the North American continent. This swell is sometimes referred to as the Transcontinent arch. The arch is overlain by a relatively thin cover of predominantly Paleozoic sedimentary rocks. This sedimentary rock cover thins northward on the gently rising Precambrian basement and pinches out in central Minnesota. North of this pinchout, Precambrian igneous rocks crop out and are referred to as the Canadian Shield.

The southern limit of the Mid-Continent region is marked by a major geologic boundary including the Amarillo-Wichita-Arbuckle uplifts in the southwest and the Ouachita Mountains in the southeast (fig. IV.I.2). The peak period of tectonic activity in these areas occurred in Late Paleozoic Pennsylvanian time. A tectonized zone resulted from an intercontinental collision accompanied by formation of compressional features such as thrust faults and overturned folds exposed in outcrop on uplifted blocks (fig. IV.I.2). The en echelon pattern of faulting in the Wichita and Arbuckle uplifts suggests some strike-slip motion.

Two deep basins, the Anadarko on the west and the Arkoma on the east, formed north of the uplifted area as a result of being overridden by the collision zone and loaded with sediments eroded from adjacent highs (fig. IV.I.2). These basins contain as much as 40,000 ft of Paleozoic sedimentary rock.

Elsewhere on the Transcontinental arch within the Mid-Continent petroleum region, relief on the basement surface is relatively gentle and divides the region into broad highs and shallow basins. Among the more prominent highs are the Cambridge-Arch-Central Kansas uplift, Ozark uplift and Nemaha uplift. The surrounding basins include the Hugoton embayment, Sedgwick basin, Salina-Central Nebraska basin, and Cherokee-Forest City basin. Most of the interior uplifts had their maximum expression during the Pennsylvania, and the underlying Mississippian section is often eroded off the crests of these highs.

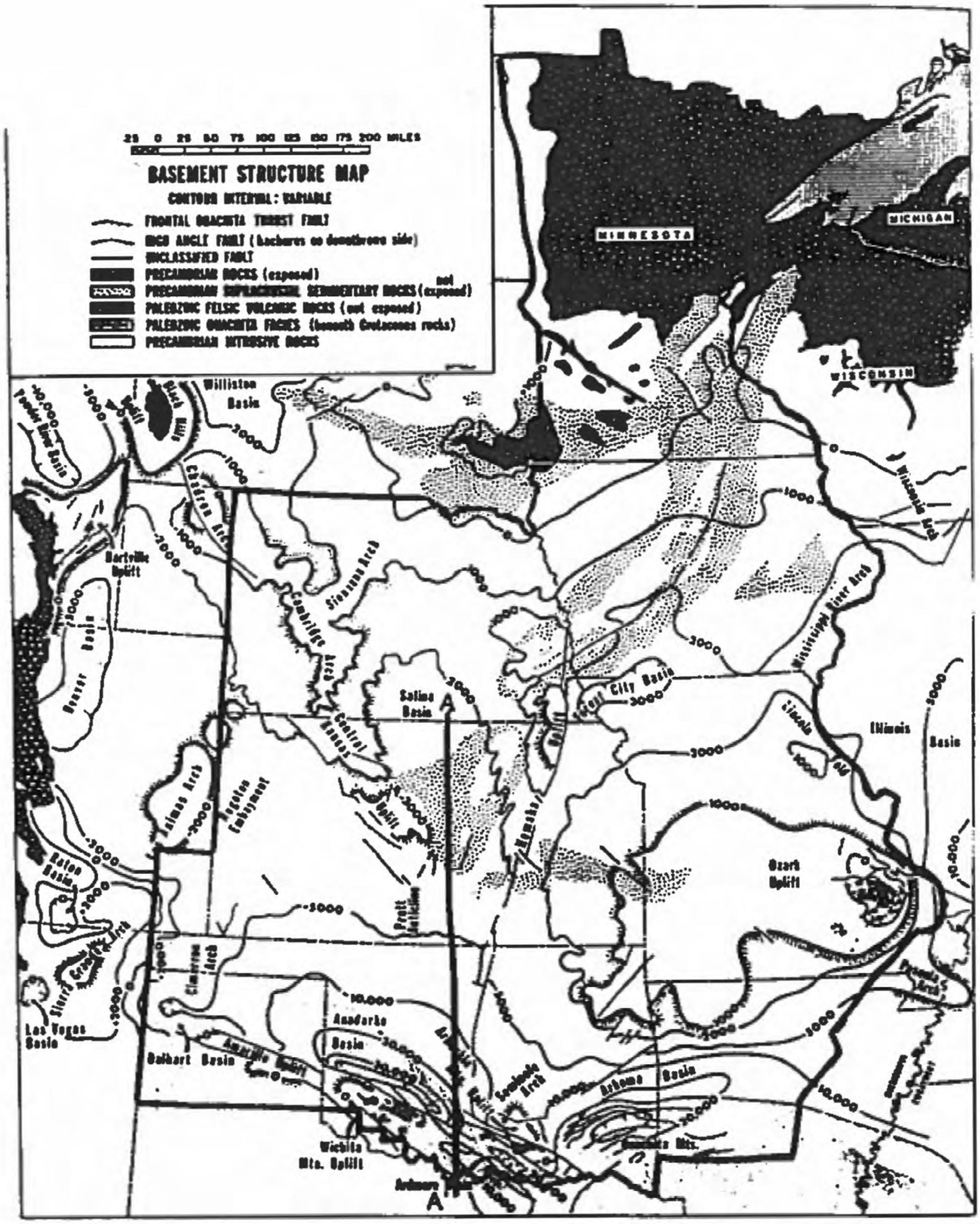

Figure IV.I.1. Regional boundary and basement structure map for the Mid-Continent petroleum region (after Adler, 1971).

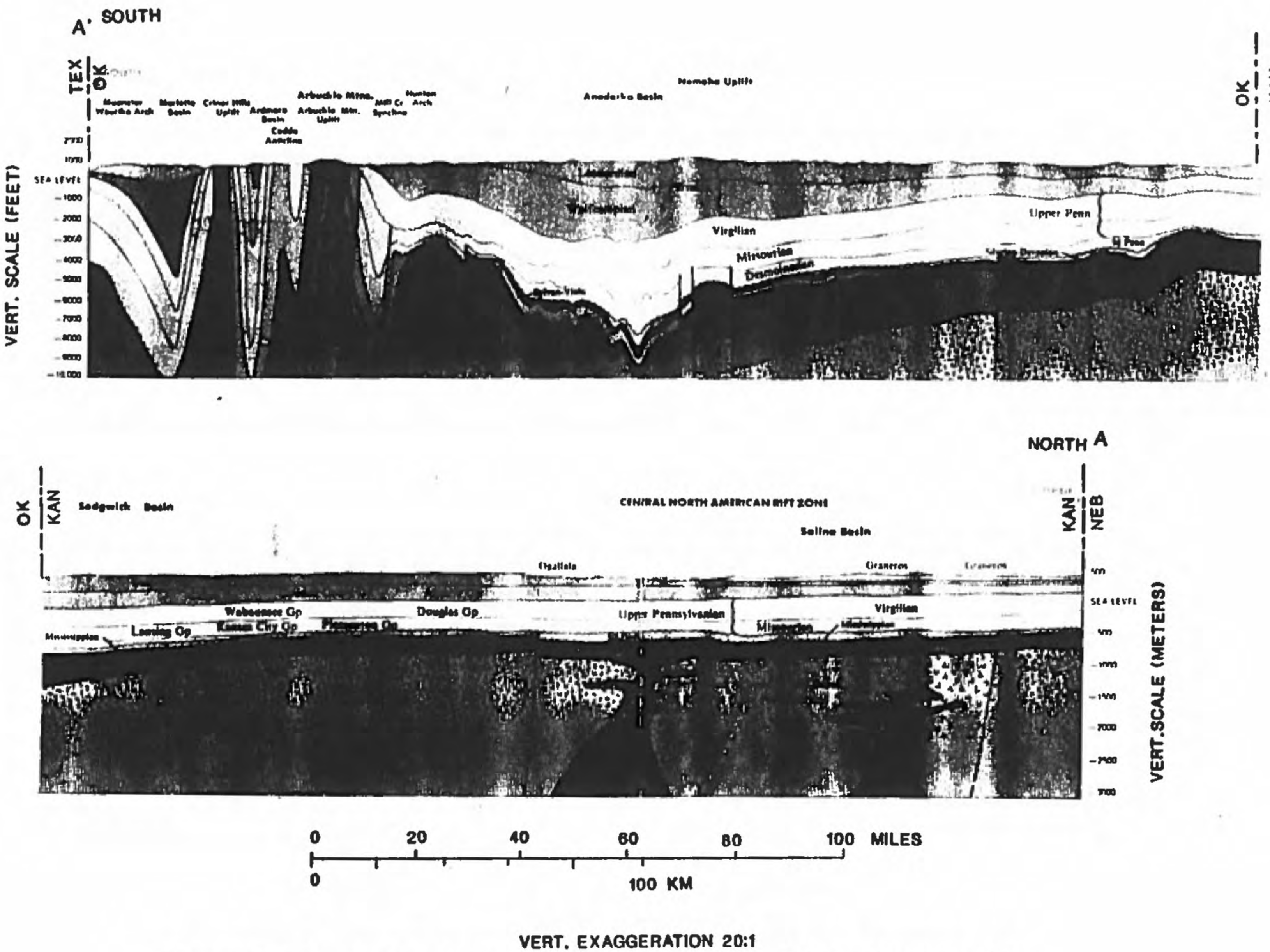

Figure IV.I.2. Regional north-south cross-section, Mid-Continent region. See figure IV.I.1 for location (after Oetking, P., Feray, D.E., and Renfro, H.B., 1966).

Paleozoic rocks of the Mid-Continent region (fig. IV.I.3) are generally predominantly carbonate, dolomite is common in Cambrian-Ordovician rocks, and chert as an admixture in carbonates occurs in Cambrian to Mississippian rocks and in Permian rocks. Sandstones and shales are interspersed throughout the Paleozoic section but are commonest in the lower Pennsylvanian rocks in closest proximity to the tectonized Amarillo-Wichita-Arbuckle-Ouachita zone (fig. IV.I.1) where terrigenous clastics are overwhelmingly the predominant rock type.

Petroleum Geology

Oil and gas production from the Mid-Continent Petroleum Region is concentrated in the states of Kansas and Oklahoma (table IV.I.1). The region's first production was established in 1860 in Pennsylvanian sandstones at a depth of only 100 ft near Paola, Kansas, in the Forest City basin (fig. IV.I.1). Traps in this basin are typically a combination structural and stratigraphic in origin. They continue to produce using secondary recovery methods but the entire basin's cumulative production is only 100 million barrels.

Over half of the cumulative oil production of Kansas (5 billion barrels) occurs on the Central Kansas uplift (fig. IV.I.1). This broad basement high on the Transcontinental arch has local proturbances over which Paleozoic sedimentary rocks are draped. Porosity related to subaerial exposure and leeching has created excellent reservoir rocks in Ordovician limestones and dolomites and in the Mississippian limestones on the Central Kansas uplift. Five of the six Kansas oil fields having ultimate reserves exceeding 100 million barrels are on the Central Kansas uplift. The sixth giant field and the largest field in Kansas (cumulative production of 280 million barrels) is Eldorado Dome. Its production comes from Pennsylvanian and Ordovician reservoirs at depths ranging between 630 and 2,600 ft. This field formed over a local high on the Nemaha uplift (fig. IV.I.1). Pennsylvanian quartz sandstones on the southwestern flank of the Ozark Uplift contain the tarry and heavy oil remnants of an accumulation whose volume is of the order of the ultimate reserves of the State of Kansas. Reservoirs holding this vast accumulation were breeched by erosion and now outcrop at the surface.

Almost 70 percent of Kansas gas production has come from the Hugoton field of the Hugoton Embayment in southwestern Kansas, Oklahoma, and Texas. The embayment is an updip extension of the Anadarko basin of western Oklahoma and the Texas Panhandle (fig. IV.I.1). The Hugoton field was discovered in the 1920's. Porous Permian carbonates pinch out updip to the north and west to form the traps for this gas accumulation. The ultimate reserves of Hugoton (approximately 40 trillion cubic ft) establish it as one of the world's great gas fields.

Oklahoma has cumulative oil production of approximately 12 billion barrels. Buried basement highs and stratigraphic traps similar to those in Kansas account for a significant portion of this accumulation, but traps associated with compressional folds related to the continental collision zone in the south are also important. Exploration more or less proceeded by using subsurface geologic techniques to follow the hydrocarbons southward from their shallower occurrences in Kansas, in the Forest City basin, into the Cherokee basin of Kansas and Oklahoma and finally into the Anadarko and

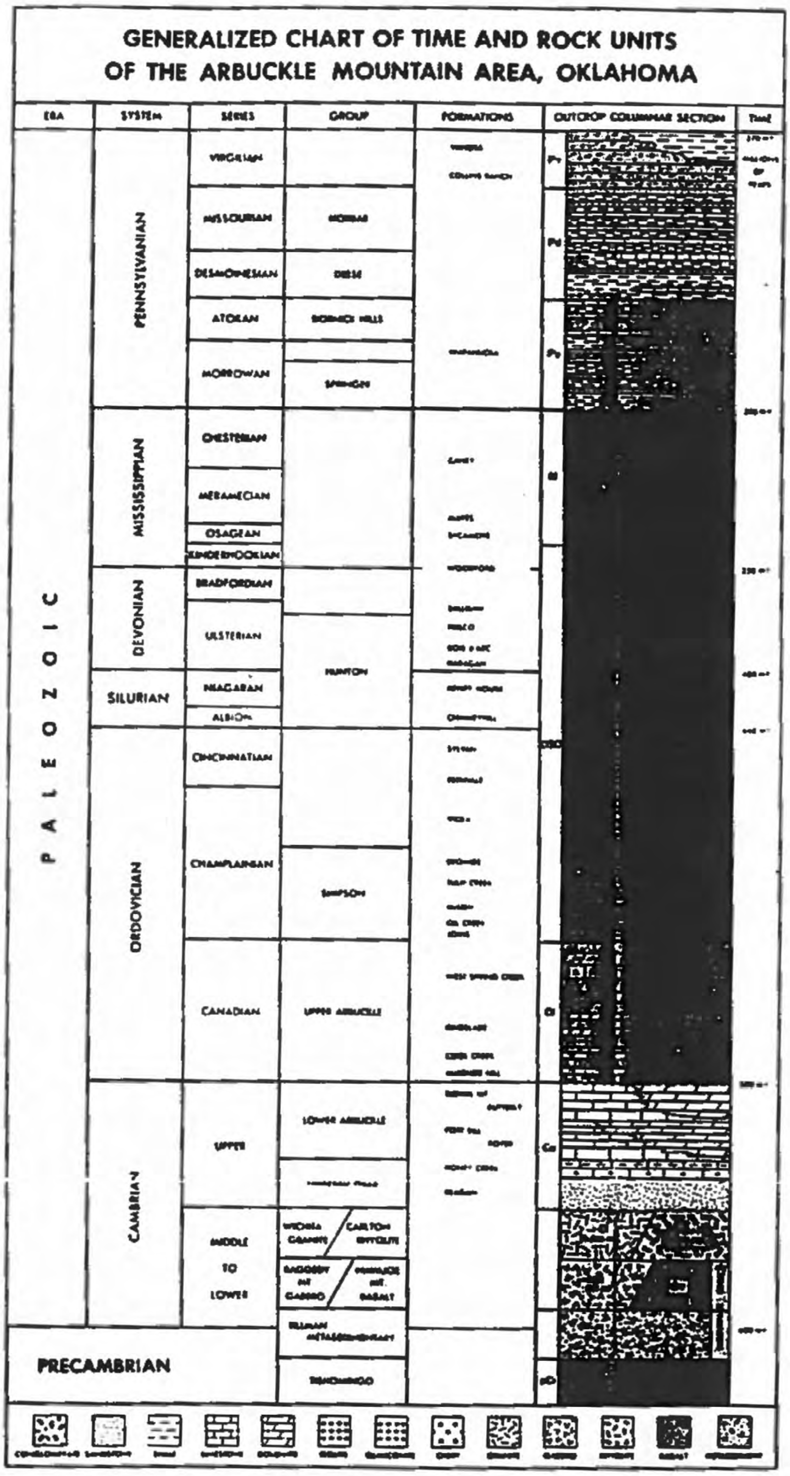

Figure IV.I.3. Generalized rock column for the southern Mid-Continent Petroleum Region (from Oetking, P., Feray, D.E., and Renfro, H.B., 1966).

Arkoma basins (fig. IV.I.1) of Oklahoma with their tremendous sediment thicknesses and structural complexities in the southern thrust-fold belt that includes overturned folds and section repeated in stacked sheets bounded by thrust faults (fig. IV.I.2).

Cumulative production and reserves for the Mid-Continent Petroleum Region 7 are shown in table IV.I.1.

The Forest City basin (fig. IV.I.1) serves as a typical example of the broad shallow basins of the Mid-Continent petroleum region. As previously mentioned, this basin contains the site of initial oil production in the region. Traps in the eastern part of the basin are a combination of structural and stratigraphic in origin. The Pennsylvanian quartz-sand reservoirs and seals of the Forest City basin are the same beds that hold the vast accumulations of tar just to the east on the flank of the Ozark Uplift (fig. IV.I.1). To some degree, the oil residues in the Missouri tar sands can be considered part of the seal for the Kansas accumulations.

Consideration of the source for this Kansas-Missouri oil and oil residue poses interesting questions. Strong arguments for some indigenous Forrest City basin source rocks were presented by Newell and others (1987). These rocks are related to quantitatively insignificant Ordovician accumulations in the west, along the east margin of the Nemaha uplift, and these Ordovician source rocks are marginally mature. It follows that the vast accumulation of the geochemically different oil in the Forest City basin and on the Ozark uplift flank probably reached its present position by long-range northward migration out of the deeper and richer Arkoma basin to the south. The prolific oil accumulations of the central Kansas uplift probably bear a similar relationship to the Anadarko basin (fig. IV.I.2).

Petroleum Potential

Undiscovered conventionally recoverable petroleum resources are shown by provinces within Region 7 in table IV.I.1. It is clear from table IV.I.1 that the Anadarko basin is judged to be far and away the most important province in the region for future petroleum resources.

Table IV.I.1.--Cumulative production, estimated reserves and undiscovered recoverable resources in Region 7.

	Cum. Production	Measured Reserves	Inferred + Indicated Reserves
Oil (BBO)	17.3	1.1	1.4
Gas (TCF)	145.4	37.5	18.3

Petroleum Provinces

Estimates of Undiscovered Recoverable Resources*

	Crude Oil (Billion Barrels)			Gas (Trillion Cubic Feet)		
	F95	F5	Mean	F95	F5	Mean
Region 7 - Mid-Continent						
Anadarko	0.49	1.53	0.92	13.77	41.04	25.12
Arkoma	Negl.	0.07	0.03	1.01	3.24	1.93
Central Kansas uplift	0.23	0.46	0.34	0.08	0.17	0.12
Cherokee Platform	0.18	0.37	0.27	0.36	0.74	0.53
Forest City	Negl.	Negl.	Negl.	0.01	0.02	0.01
Nemaha uplift	0.07	0.18	0.12	0.12	0.28	0.19
Salina	0.01	0.02	0.02	Negl.	0.01	Negl.
Sedgwick	0.06	0.11	0.08	0.32	0.66	0.47
So. Oklahoma	0.05	0.21	0.11	0.15	0.52	0.30
Iowa Shelf and Sioux uplift	0.00	0.00	0.00	0.00	0.31	0.06
Ozark uplift	0.00	0.00	0.00	0.00	0.00	0.00
Total	1.2	2.7	1.9	16.2	46.0	28.7

Mean value totals may not be equal to the sums of the constituent means due to independent rounding.

Fractile values are not additive.

*Estimates of undiscovered economically recoverable resources are given in Table VIII.B.3.

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J. REGION 8, THE EASTERN INTERIOR

by W. de Witt, Jr., R.T. Ryder, R. Charpentier,
and R.F. Mast

Introduction

The eastern petroliferous basins (fig. IV.J.1), which are filled predominantly with Paleozoic sedimentary rocks include the large elongate asymmetric Appalachian basin, the small deltoid Black Warrior basin, the medium-sized semielliptical Illinois basin, and the almost circular Michigan basin. The first two are foreland basins, and the others are intracratonic. The eastern basins are separated from each other by the Cincinnati arch or its ancillary elements. As a result of differing tectonics and sedimentation, each basin exhibits an individual sequence of source beds and reservoir rocks, which merit consideration, evaluation and discussion.

Geologic Framework

The Appalachian basin.--The asymmetric Appalachian basin is 75-350 miles wide and more than 1,000 miles long. It extends from Lakes Erie and Ontario south to central Alabama, where its Plateau segment melds with the Black Warrior basin and its Valley and Ridge segment is covered by Cretaceous and younger coastal plain rocks. The basin extends from the flank of the Cincinnati arch eastward to and under the Blue Ridge and Piedmont provinces (fig. IV.J.1). Rocks on the west flank of the basin dip gently to the east. In contrast, rocks of the eastern flank of the basin were greatly deformed by the Alleghany orogeny at the close of the Paleozoic Era as metamorphic and igneous rocks of the Blue Ridge and Piedmont were thrust more than 150 miles westward over a thick wedge of Lower Paleozoic sedimentary rocks (fig. IV.J.2). The basin contains 50,000 ft of sedimentary rock ranging in age from Cambrian to Early Permian (fig. IV.J.3). The great thickness of rock in the eastern overthrust belt contains several thrust sheets stacked one upon another.

Black Warrior basin.--The Black Warrior basin of Mississippi and Alabama is located in the major structural re-entrant between the Eastern and Ouachita overthrust belts (fig. IV.J.2). The northern margin of the basin is bounded by the Nashville dome. Most of the basin and the adjoining thrust-faulted margins are concealed beneath Cretaceous and younger rocks of the Gulf Coast.

Complexly faulted, southwest-dipping Precambrian basement rocks and overlying Paleozoic strata dominate the structure of the Black Warrior basin. The faults that cut the basement and cover rocks are extensional in origin and, in general, trend northwestward and exhibit a down-to-the-basin geometry. A northwest-trending, fault-controlled hinge zone is located in the south-central part of the basin and Pennsylvanian rocks thicken abruptly across it (fig. IV.J.4). The axis of the Black Warrior basin south of the hinge zone may in part be overridden by the Ouachita overthrust belt.

The thickness of the sedimentary rocks ranges from less than 5,000 ft along the northern margin to approximately 30,000 ft in the depocenter in the southern part. The deepest drill hole in the basin, the Exxon No. 1 Fulgham, reached Precambrian basement rocks at 21,340 ft. This hole, located between the hinge zone and basin axis, penetrated about 13,300 ft of

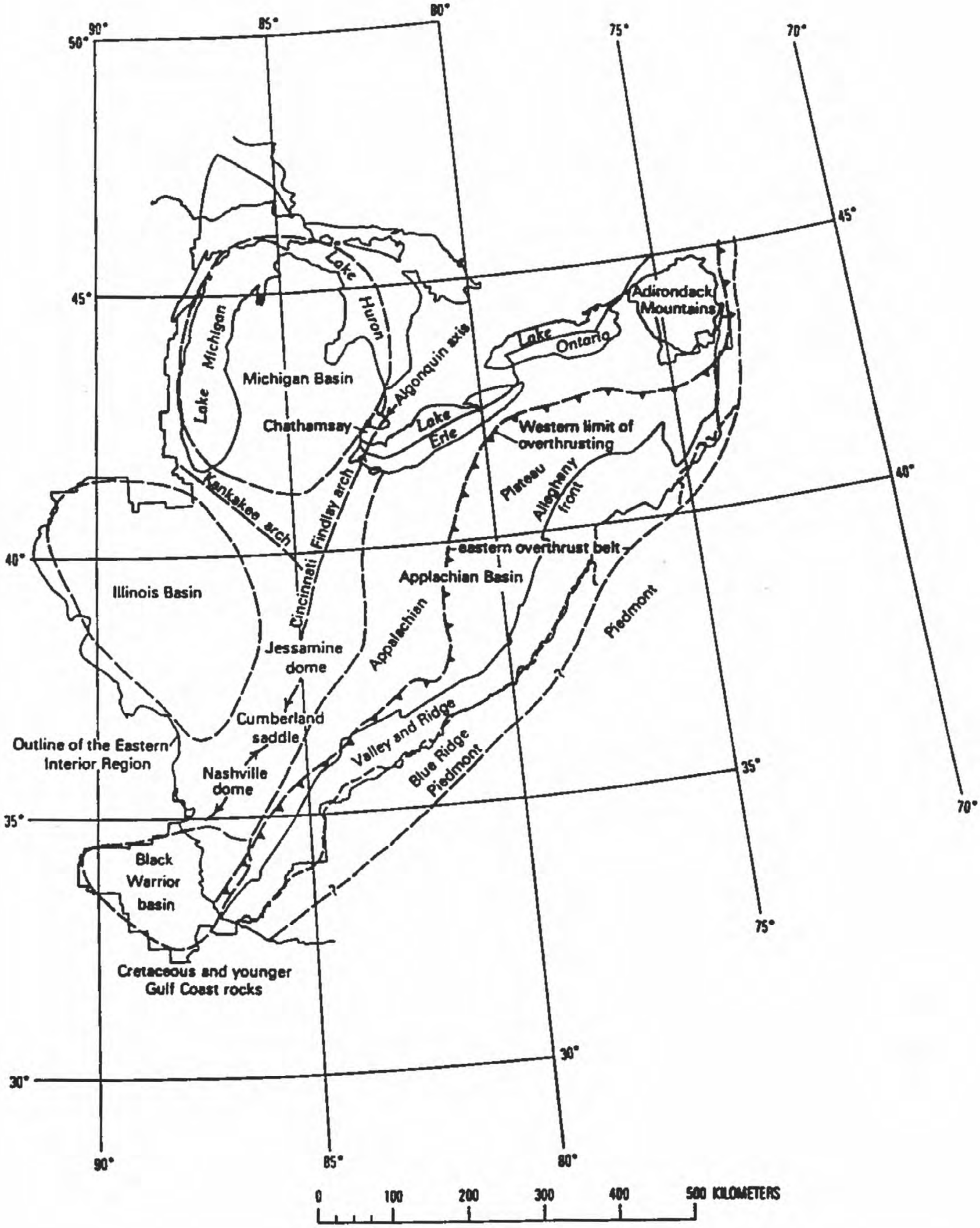

Figure IV.J.1. Eastern Paleozoic basins and some features mentioned in the text.

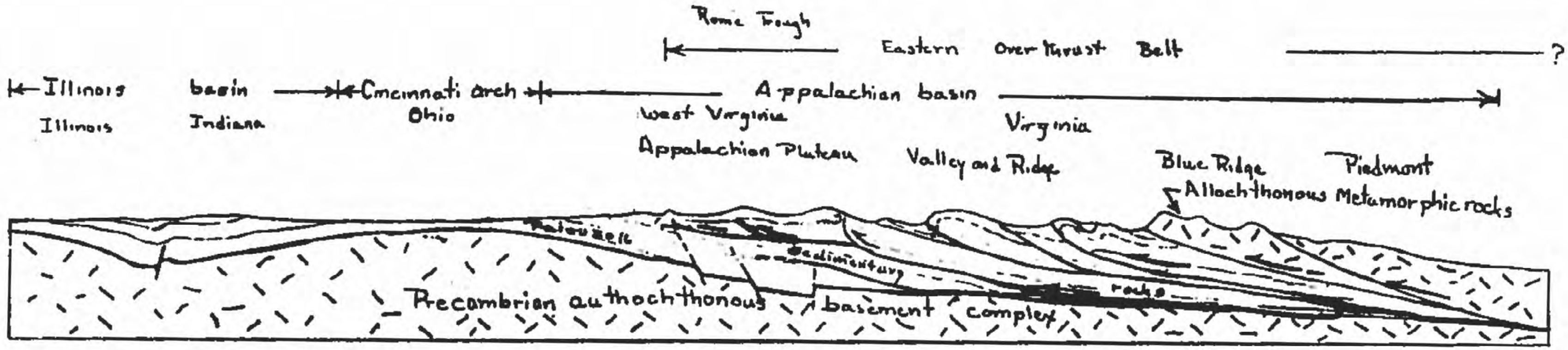

Figure IV.J.2. Generalized cross section from the Illinois basin east to the Appalachian Piedmont province. The Appalachian Basin is strongly asymmetric. Rocks on the west side dip gently toward the basin's center, whereas rocks on the east side have been faulted and folded during mountain building about 300 million years ago. The east side of the basin was telescoped as the metamorphic rocks of the Blue Ridge and Piedmont were thrust 150 miles westward over Paleozoic sedimentary rocks on the basin's east flank. Thrust faults shown by arrows. In contrast, the intracratonic Illinois Basin is symmetric. No vertical or horizontal scale.

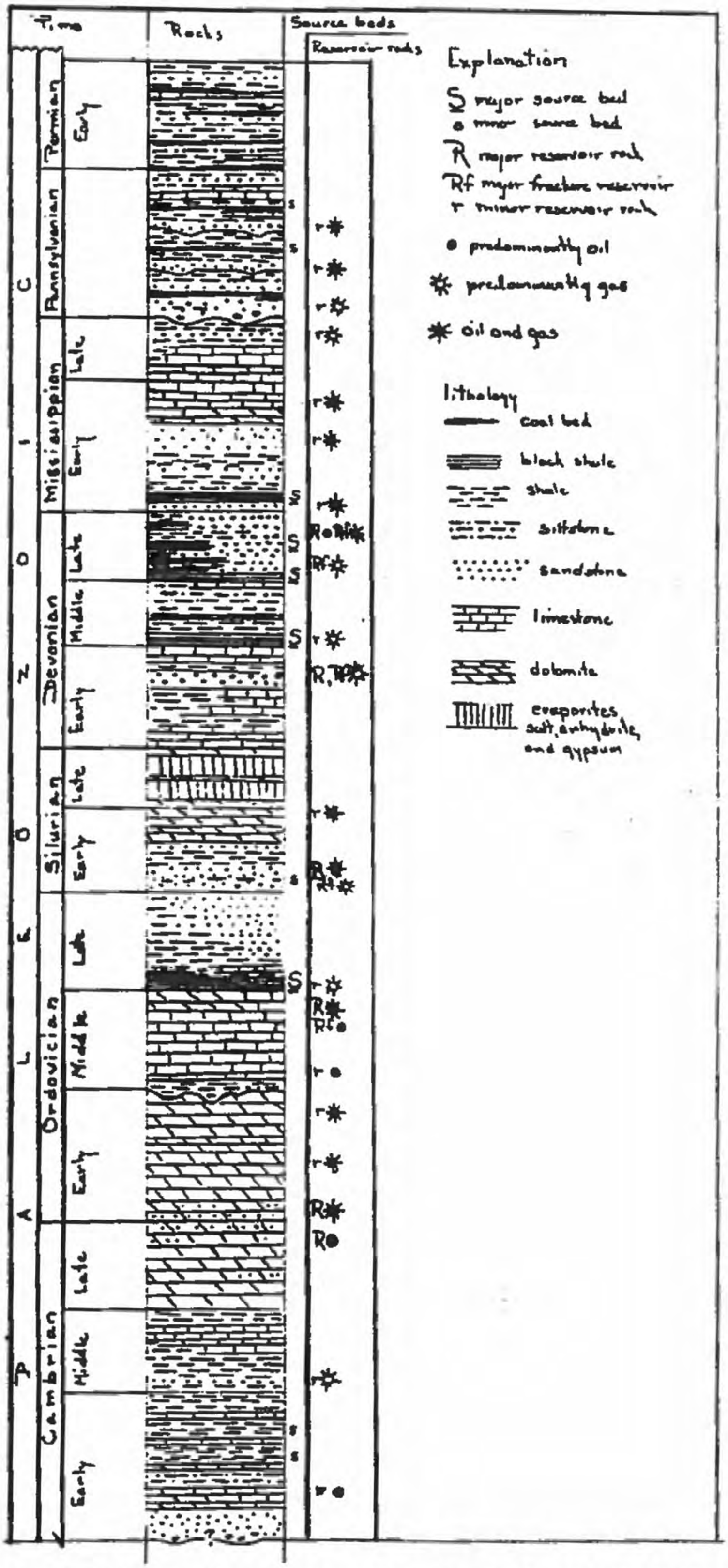

Figure IV.J.3. Position of principal source and reservoir rocks in the stratigraphic section of the Appalachian Basin.

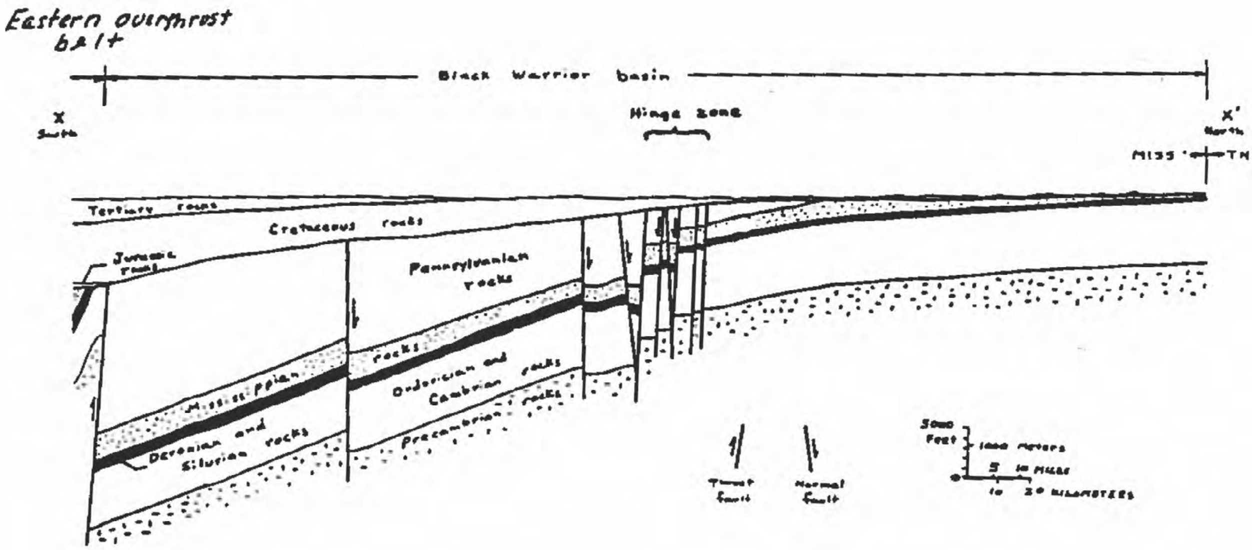

Figure IV.J.4. Geologic cross section through the eastern Mississippi part of the Black Warrior basin. The section is slightly modified from Williams (1969).

Paleozoic strata ranging from Pennsylvanian to Cambrian in age and about 8,000 ft of Tertiary and Cretaceous strata. The stratigraphy of the Black Warrior basin is summarized in figure IV.J.5.

The major oil and gas source rocks identified in the Black Warrior basin are coal beds in the Pottsville Formation, dark-gray to black marine shale in the Upper Mississippian Floyd and Neal Shales, dark-gray deltaic and interdeltaic shale in the Pennsylvanian and upper Mississippian Parkwood Formation, and dark-gray to black marine shale in the Chattanooga Shale (fig. IV.J.5). The dark shale beds in the Floyd Shale, Parkwood Formation, Neal Shale, and Chattanooga Shale are oil- and gas-prone source rocks, whereas the coal beds in the Pottsville Formation are gas-prone source rocks.

Hydrocarbon generation from the major source rocks probably was initiated in, and continued through, Pennsylvanian time when they were buried beneath a southwestward-thickening wedge of terrigenous clastic detritus.

Marked thickness variations in the Pottsville Formation across northeast-trending extension faults indicate that Pennsylvanian sedimentation was strongly controlled by penecontemporaneous faulting. Therefore, structural traps created by these growth faults had at least started to form at the time of oil and gas generation and migration. However, numerous heavy oil deposits in Pennsylvanian and Mississippian strata along the exposed northern margin of the basin suggest that significant amounts of oil and gas escaped from the basin.

Cincinnati arch.--The Cincinnati arch with its salients separates the basins of the Eastern Interior region. The arch is essentially bounded on the west by the Illinois basin and on the east by the Appalachian basin. On the north, the arch bifurcates with a western limb, the Kankakee arch, separating the Illinois and Michigan basins, and an eastern limb, the Findlay arch, separating the Appalachian and Michigan basins.

The entire sedimentary record on the Cincinnati arch is Paleozoic in age. These strata increase in thickness from about 2,800 ft on the Findlay arch, southward to about 3,500 ft on the Jessamine (Lexington) dome, to about 5,500 ft on the Nashville dome. The sedimentary cover thickens of the flanks of the arch to a maximum of about 8,800 ft in the eastern part of the Cumberland saddle.

The major oil and gas source rocks on the Cincinnati arch are the Upper and Middle Ordovician Utica Shale (Point Pleasant Formation) and the Upper Devonian Chattanooga Shale. The Utica Shale is confined to the Findlay arch, whereas the Chattanooga Shale is confined to the Cumberland saddle and Nashville dome. Time-temperature reconstructions and maturation indices suggest that the oil and gas on the Cincinnati arch was generated in the adjacent Appalachian basin and migrated to the arch in late Paleozoic time, where traps were available to accumulate the migrating oil and gas.

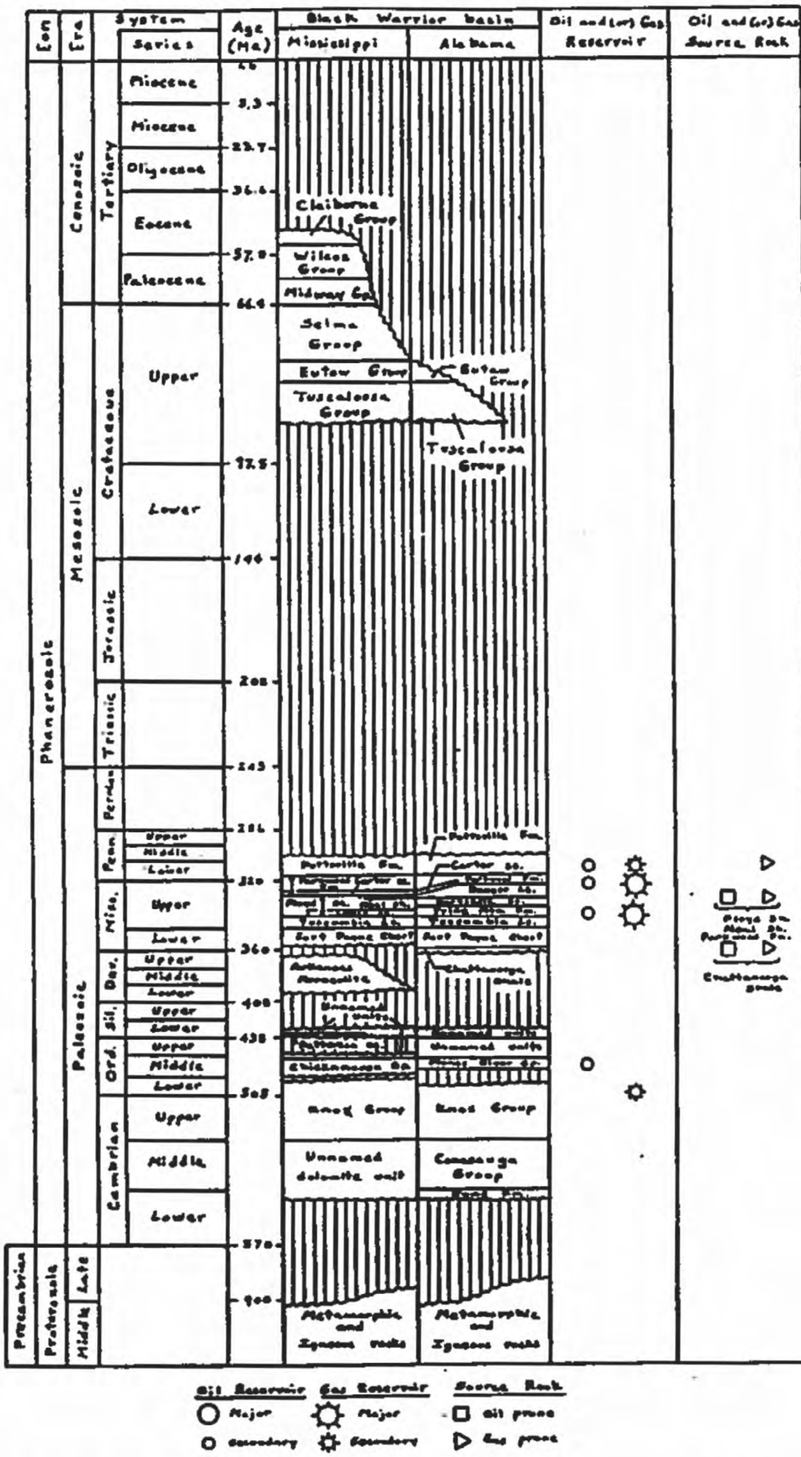

Figure IV.J.5. Stratigraphic correlation chart for Phanerozoic and Precambrian rocks of the Black Warrior basin. Also identified on the chart are the oil and gas reservoirs and source rocks in the basin. The chart is based on numerous publications.

Known oil and gas accumulations on the Cincinnati arch comprise the giant Lima-Indiana field on the Findlay and Kankakee arches, which produce from the dolomitized upper part of the Middle and Upper Ordovician Trenton Limestone, and numerous small fields in the Cumberland saddle, which produce from carbonate reservoirs ranging from Early Ordovician to Late Mississippian in age.

Michigan basin.--The Michigan basin (fig. IV.J.1) is an almost circular intracratonic basin, most of which is in Michigan where the sedimentary section reaches a thickness of about 17,000 ft. The Wisconsin portion of the basin has only a relatively thin sedimentary cover, the maximum thickness being slightly more than 2,000 ft. A secondary structural trend within the basin consists of northwest-trending anticlines. Other anticlinal features in the Michigan basin were formed over buried reefs, and others may be related to salt flowage.

Lying above the Precambrian crystalline basement, a series of Keweenawan (late Precambrian) clastic rocks is associated with central rifts and flanking basins. Paleozoic rocks begin with transgressive marine clastic rocks, mainly sandstones, of Cambrian and Lower Ordovician age. These are followed by marine carbonate rocks representing much of the rest of Ordovician through Devonian time. However, significant evaporite deposits, as much as 2,000 ft thick, are present in parts of the section. Lesser evaporite deposits, as much as 400 ft thick, are Middle Devonian age. The sequence is dominated by marine clastics again at the end of the Devonian time and through the Mississippian, during the Pennsylvanian the sequence became terrestrial. Above the Pennsylvanian rocks is a thin section of Jurassic terrestrial rock. The entire area is blanketed with Pleistocene glacial drift which reaches a thickness of about 1,000 ft.

Greatly conflicting thermal and burial history models of the Michigan basin have been reported in the literature. According to Nunn and others (1984), for example, only Ordovician and older rocks are mature as oil sources and only in the deep center of the basin. Cercone's (1984) calculations show maturity in rocks as young as Mississippian in the center of the basin. Regardless of these arguments, a significant amount of oil and gas has been produced from this basin.

The Illinois basin.--According to Barrows and Cluff (1984), the Illinois basin (fig. IV.J.6) is a broad intracratonic basin in Illinois, southwestern Indiana, and western Kentucky. The basin is bordered by the Mississippi River and Kankakee arches on the north, the Cincinnati arch on the east, the Pascola arch and Nashville Dome on the south and the Ozark Dome on the west. Major structural elements within the basin are the LaSalle anticline, the Duquoin monocline and the Rough Creek fault zone (Scalo, 1985).

In the Illinois basin proper, the maximum thickness of sedimentary rocks is 14,000 ft and is in the Fairfield basin of southern Illinois (fig. IV.J.6). However, the Moorman basin of western Kentucky contains sedimentary thicknesses probably in excess of 20,000 ft in a poorly dated sequence.

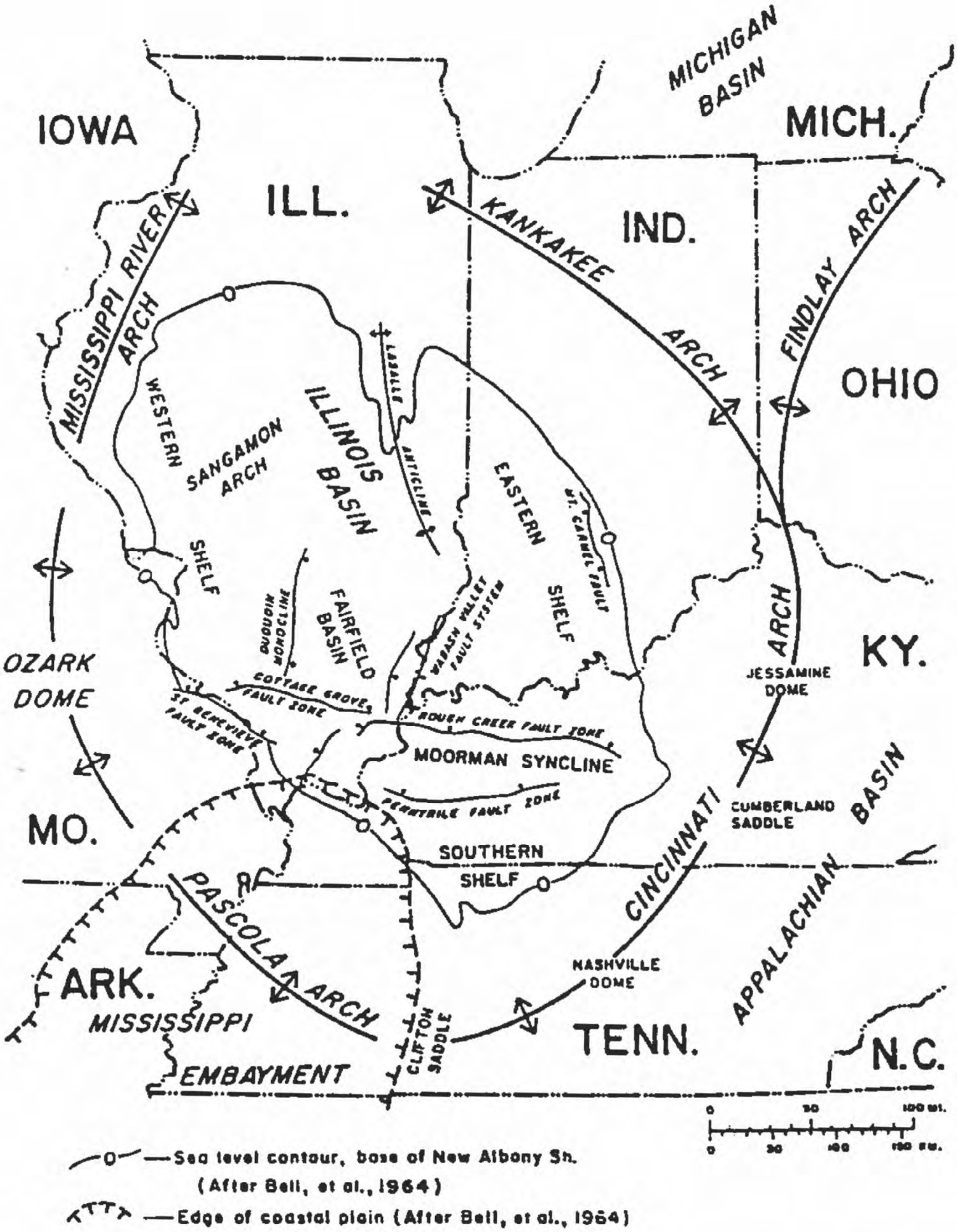

Figure IV.J.6. Map of east-central States showing regional structural features. (from Scalo, 1985).

The Paleozoic sedimentary section (fig. IV.J.7) ranges in age from Cambrian through Pennsylvanian. With the exception of basal Cambrian and possibly Precambrian rocks, the lower Paleozoic section is predominantly carbonate rocks. The black organic-rich Devonian-Mississippian New Albany Shale caps the predominantly carbonate older section. The Middle and Upper Mississippian section grades from predominantly carbonate at the base to a mixture of sandstones, shales, and limestones that carries upward into the Pennsylvanian section. The Pennsylvanian section contains sandstones, shales, coals, and limestones.

Petroleum Geology

The oil exploration history of the United States began in 1859 in the Appalachian basin with the Drake discovery well producing from Late Devonian and younger reservoirs in Pennsylvania. Oil and gas source and reservoir rocks are widespread; and gas and oil have been found in parts of the basin in rocks of all periods of the Paleozoic except the Permian (fig. IV.J.3). In general, porous clastic reservoir rocks yield oil and gas from primary porosity in stratigraphic traps in the western part of the basin. In contrast, to the east, especially in the thicker sequences in the Eastern Overthrust belt (fig. IV.J.1), original porosity has been destroyed by burial diagenesis and tectonics. Oil and gas occur in structural traps where faulting and folding have developed extensive zones of associated fracture porosity, and stratigraphic-trap accumulations are relatively scarce in the overthrust belt. The Appalachian basin cumulative production of oil exceeds 3 billion barrels and production of gas exceeds 35 TCF. Reserves are on the order of 150 million barrels of oil and 6 TCF of gas.

The first gas production in the Black Warrior basin was established in 1909 from a Pennsylvanian sandstone in Fayette County, Alabama at a depth of 1,400 ft. In 1926, gas was discovered in Monroe County, Mississippi from an Upper Mississippian sandstone at a depth of 2,400 ft. Exploration in the 1950's and early 1960's resulted in the discovery of several small gas fields and two noncommercial oil accumulations in Upper Mississippian sandstone reservoirs. The Pennsylvanian Pottsville Formation also produces small amounts of oil and gas in combination with or separate from the Upper Mississippian sandstone reservoirs. Most of the accumulations have been trapped by anticlines associated with normal faults and by the pinch-out of porous sandstone against anticlinal noses. The marked increase in drilling activity in the 1970's and 1980's resulted in the discovery of about 50 gas fields and about 10 small oil fields from Upper Mississippian sandstone reservoirs in the Alabama part of the basin. In Mississippi, several small- to medium-sized gas fields were discovered in this period. Cumulative production of oil and gas in the Black Warrior basin has been limited to less than 1 million barrels of oil and less than 1 billion cubic ft of gas.

In 1826, the Great American well in the Kentucky part of the Cumberland saddle produced the first "commercial" oil from the Cincinnati arch (Wilson and Sutton, 1973). This oil came from a Middle to Upper Ordovician limestone at a depth of about 171 ft m), followed by discoveries in Tennessee in 1866 (Born, 1943). Bond and others (1971) estimated that oil fields in the Cumberland saddle originally contained about 75 million barrels of recoverable oil, which has now mostly been produced. About three-fourths of the 75 million barrels of recoverable oil that existed on the Cumberland saddle resided in Lower Silurian and Middle Devonian dolomite

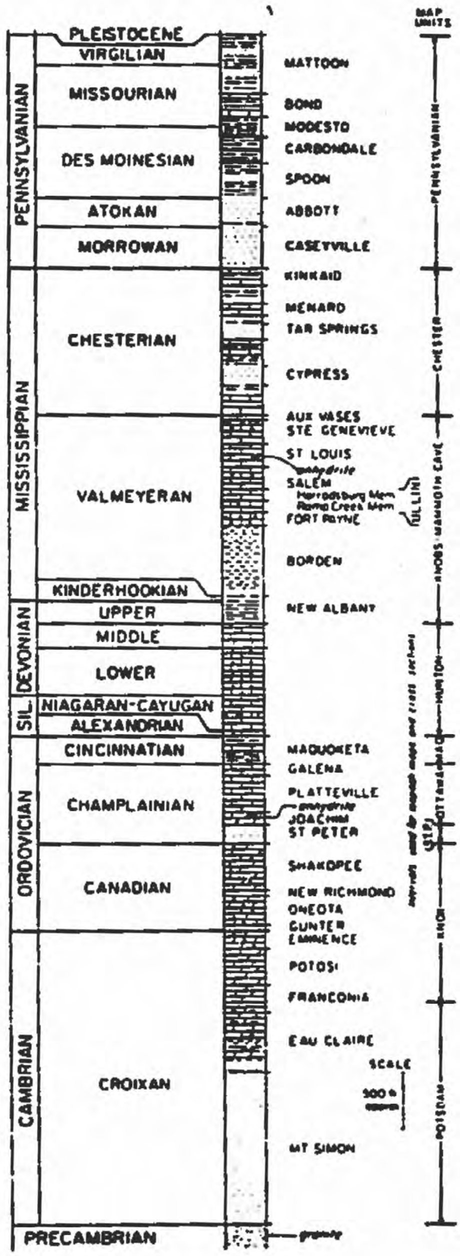

Figure IV.J.7. Stratigraphic column for the Illinois basin (from Bond, and others, 1971)

reservoirs. Commercial oil and gas in the giant Lima-Indiana field was discovered between 1884 and 1886 near Findlay, Ohio. Moody and others (1970) estimated that the field originally contained 514 million barrels of recoverable oil of which 482 million barrels have been produced as of January 1967. About 1 trillion cubic ft of gas has been produced from the Indiana part of the field (Keith, 1981). No estimates are available on gas produced from the Ohio part of the field.

The Michigan basin has cumulative production of oil of 769 million barrels and reserves approximately equal that number. Over one trillion cubic ft of gas have been produced and reserves are reckoned at approximately three times that amount. Possibilities may exist in the Precambrian rifts or in the thick (up to 2,600 ft) mostly sandstone Cambrian section, but at present there are no discoveries and little exploration in those units. The Ordovician Prairie du Chien Formation produces gas from deep (7,000 - over 11,000 ft) sandstone reservoirs in the center of the basin and is the most recently discovered major exploration play. The Trenton-Black River produces from stratigraphic traps in dolomitized Middle Ordovician limestones and includes the largest field in the basin: Scipio, in the south-central part of the basin, with ultimate recoverable reserves of approximately 200 million bbl. The reservoir at Scipio is a linear-shaped, fracture-associated dolomite. Oil and gas-producing pinnacle reefs of Niagaran (Silurian) age form a circular trend around the basin. Structural and structural/stratigraphic traps mainly associated with the northwest-southeast anticlinal trends produced from Devonian and Mississippian rocks. Small amounts of gas have also been found in the Pennsylvanian and in the glacial drift.

More than 150,000 wells have been drilled in the Illinois basin. All systems from Ordovician through Pennsylvanian produce with deepest production from the Devonian at depths less than 5,500 ft. The New Albany Shale (Devonian-Mississippian equivalent of the Chattanooga Shale) has been identified as the probable source for oil and gas contained in Mississippian and Pennsylvanian fields that make up 90 percent of the Illinois basin's production and reserves (Barrows and Cluff, 1984). Lack of significant hydrocarbon production below the Mississippian-Devonian New Albany Shale (fig. IV.J.7) may reflect lack of adequate source rocks in the pre-Devonian section. Despite this possibility and the fact that all major structures of this basin have been drilled into the Cambrian section, some exploration activity is focused on testing the Cambrian-Ordovician and Eo-Cambrian section. Cumulative production of oil approximates 4 billion barrels but reserves are limited to less than 200 million barrels. Combined production and reserves of gas approximate 1.7 TCF.

Petroleum Potential

It is apparent from table IV.J.1 that the Appalachian basin is in a very mature stage of exploration history. Our analysis indicates mean estimates for undiscovered recoverable oil and natural gas liquids and gas of approximately 300 million barrels and 6.5 TCF, respectively. Most of the new discoveries will probably be in the older Paleozoic section in deeper parts of the basin.

In the Black Warrior basin, Upper Mississippian sandstones in the deeper parts of the basin, south and west of the lobe of deltaic sandstones identified in figure IV.J.6, provide the most promise for undiscovered resources (mostly gas).

On the Cincinnati arch, undiscovered oil resources remain in vuggy dolomite near the top of the Lower Ordovician and Upper Cambrian Knox Group and in Middle to Lower Ordovician bioclastic limestone and fault-controlled vuggy dolomite.

According to our estimates, the Michigan basin is the brightest prospect for development of new resources in eastern Paleozoic basins. Estimates of undiscovered recoverable resources have means exceeding 500 million barrels for oil and 2 TCF for gas.

The Illinois basin is in the mature phase of its exploration history. Our estimates for undiscovered recoverable hydrocarbons for this basin (table IV.J.1) have means of 359 million barrels for oil, 152.1 BCF for non-associated gas and 462.1 BCF for associated-dissolved gas.

Table IV.J.1.—Cumulative production, estimated reserves and undiscovered recoverable resources in Region 8.

	Cum. Production	Measured Reserves	Inferred + Indicated Reserves
Oil (BBO)	8.4	0.5	0.7
Gas (TCF)	33.9	8.2	5.0

Petroleum Provinces

Estimates of Undiscovered Recoverable Resources*

	Crude Oil (Billion Barrels)			Gas (Trillion Cubic Feet)		
	F95	F5	Mean	F95	F5	Mean
Region 8 - Eastern Interior						
Michigan basin	0.63	1.62	1.05	3.92	13.40	7.78
Illinois basin	0.30	0.67	0.46	0.16	1.63	0.66
Cincinnati Arch	0.05	0.18	0.10	0.07	0.22	0.13
Black Warrior	Negl.	0.01	0.01	0.73	1.98	1.26
Appalachian basin	0.08	0.25	0.15	2.77	12.29	6.46
Blue Ridge overthrust & New England-Adirondack	0.00	0.00	0.00	0.22	1.93	0.81
Piedmont	0.01	0.09	0.04	0.05	0.27	0.13
Total	1.3	2.4	1.8	10.8	25.6	17.2

Mean value totals may not be equal to the sums of the constituent means due to independent rounding.

Fractile values are not additive.

*Estimates of undiscovered economically recoverable resources are given in Table VIII.B.3.

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K. REGION 9, ATLANTIC COASTAL PLAIN
by A.P. Schultz and M.M. Ball

Geologic Framework

The Atlantic Coastal Plain region contains Early Mesozoic rift basins and an overlying wedge of younger rocks which extend southward to peninsular Florida. The Early Mesozoic extensional basins (fig. IV.K.1) extend from Georgia to northern Massachusetts; they consist of the exposed basins of the Appalachian Piedmont and inferred basins below the coastal plain sediments. Rocks of the Coastal Plain that cover these basins include Late Mesozoic, Cenozoic and Holocene clastics and carbonates. Peninsular Florida is basically a thick carbonate buildup overlying subsided igneous and metamorphic continental crust.

The Early Mesozoic, Newark type (Manspeizer, 1981) extensional basins are a series of elongate, asymmetric, pull-apart or half-graben structures which contain thick, Late Triassic through Early Jurassic continental clastic, carbonate and volcanic rocks. The basin fill rocks rest unconformably on the crystalline rocks of older Acadian and Alleghanian orogenies (Manspeizer, 1981). Major sedimentary rock types are reddish-brown mudstones, course-grained polymict "border" conglomerates and fanglomerates, arkosic sandstones and siltstones, and gray to black lacustrine shales and carbonates with coal. Tholeitic lava flows are common in the northern basins and sills and dikes are concentrated in the southern basins. These igneous rocks are thought to have been generated and emplaced during sedimentation and immediately following major basin deposition (Manspeizer, 1981).

Within individual basins, rift related structures are complex (fig. IV.K.2). Models for the development of the basins (Manspeizer and Olsen, 1981; Ratcliffe and Burton, 1985) include a variety of normal faulting, strike-slip faulting and oblique normal faulting along pre-existing thrust faults in the crystalline basement rocks below the extensional basins. Structures within basins (fig. IV.K.2) consist of extensional border faults with some component of oblique slip and a domain of trans-tensional folds and faults within the basins. Ordinarily, rocks in a basin dip toward the border fault.

Sedimentation patterns within the evolving extensional basins involve complex continental facies distributions related to position in the basin (fig. IV.K.3). Coarse-grained conglomeratic debris flows, fanglomerates and alluvial fan deposits are characteristic of facies along the most tectonically active edge of the half graben. Clasts in the conglomerates are derived from Precambrian basement rocks and Paleozoic carbonate and clastic rocks uplifted along faults on the margin of the basin. These facies grade basinward into nearshore-lacustrine siltstones and mudstones which grade into lacustrine mudstones and carbonates in the basin center. Typically, the basin lake sediments grade into near-shore facies and alluvial fans along the opposite basin margin. This margin is less fault controlled and may consist of a gently dipping surface of eroded Precambrian rocks (fig. IV.K.3). Igneous rocks are both interbedded with and cross-cutting the basin-fill rocks (fig. IV.K.3).

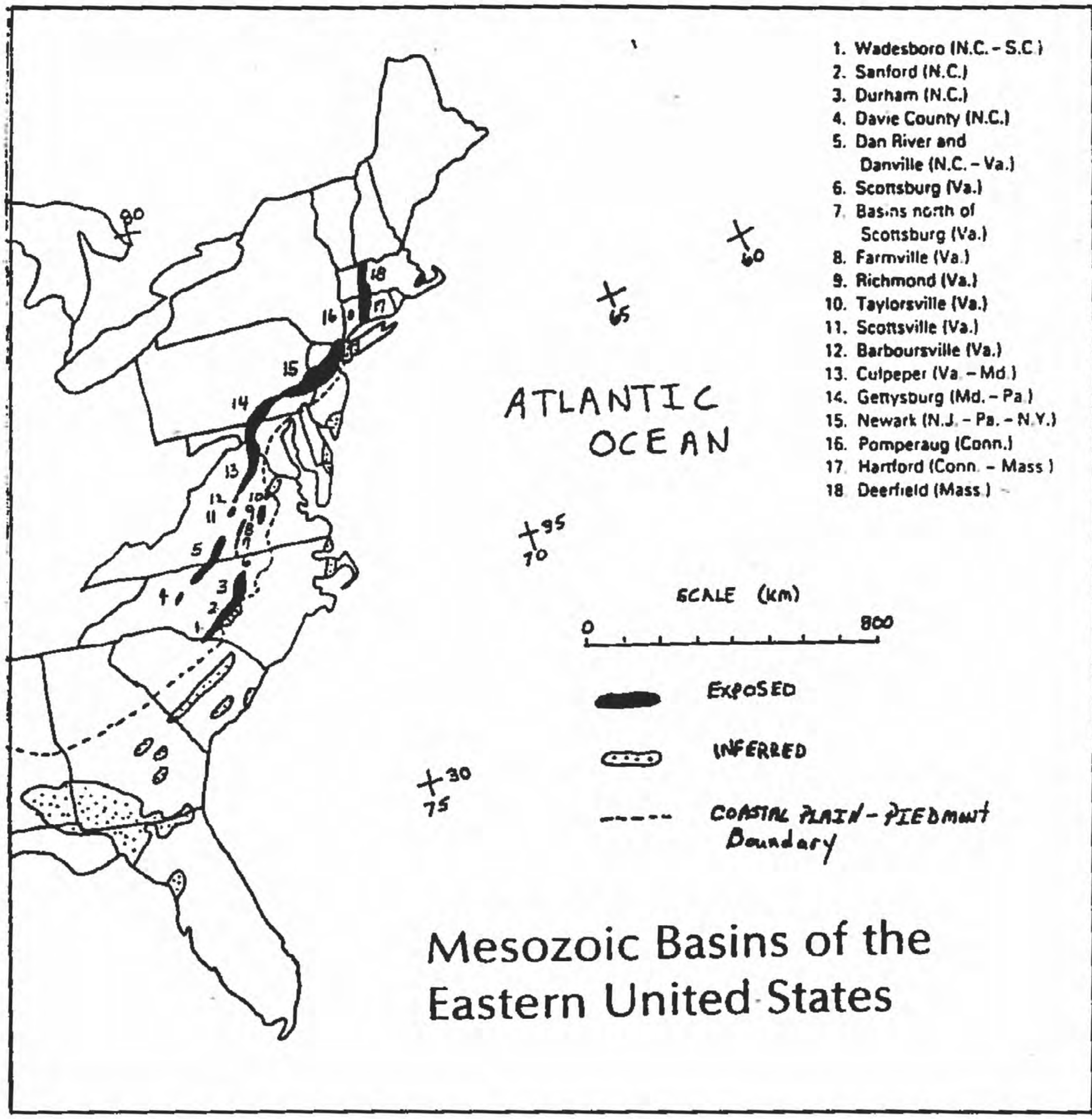

Figure IV.K.1. Index map of exposed and inferred Mesozoic basins of eastern North America and Coastal Plain-Piedmont boundary. Map is modified from Froelich and Olsen, 1985 and Manspeizer and Olsen, 1981.

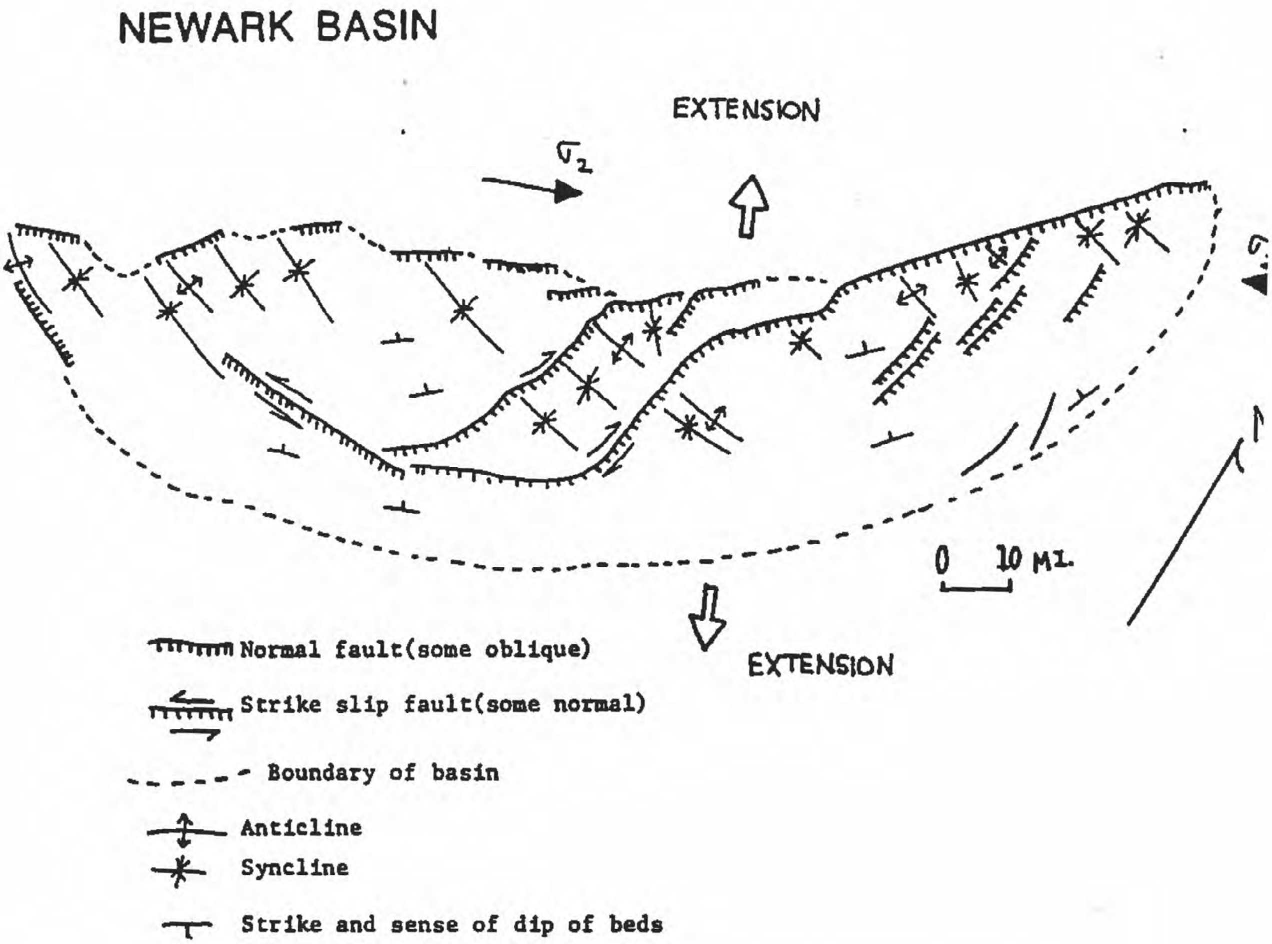

Figure IV.K.2. Typical rift basin structures showing inferred major extensional direction and location of intermediate principal stress direction sigma 2. Modified from Manspeizer, 1981 and Ratcliffe and Burton, 1985.

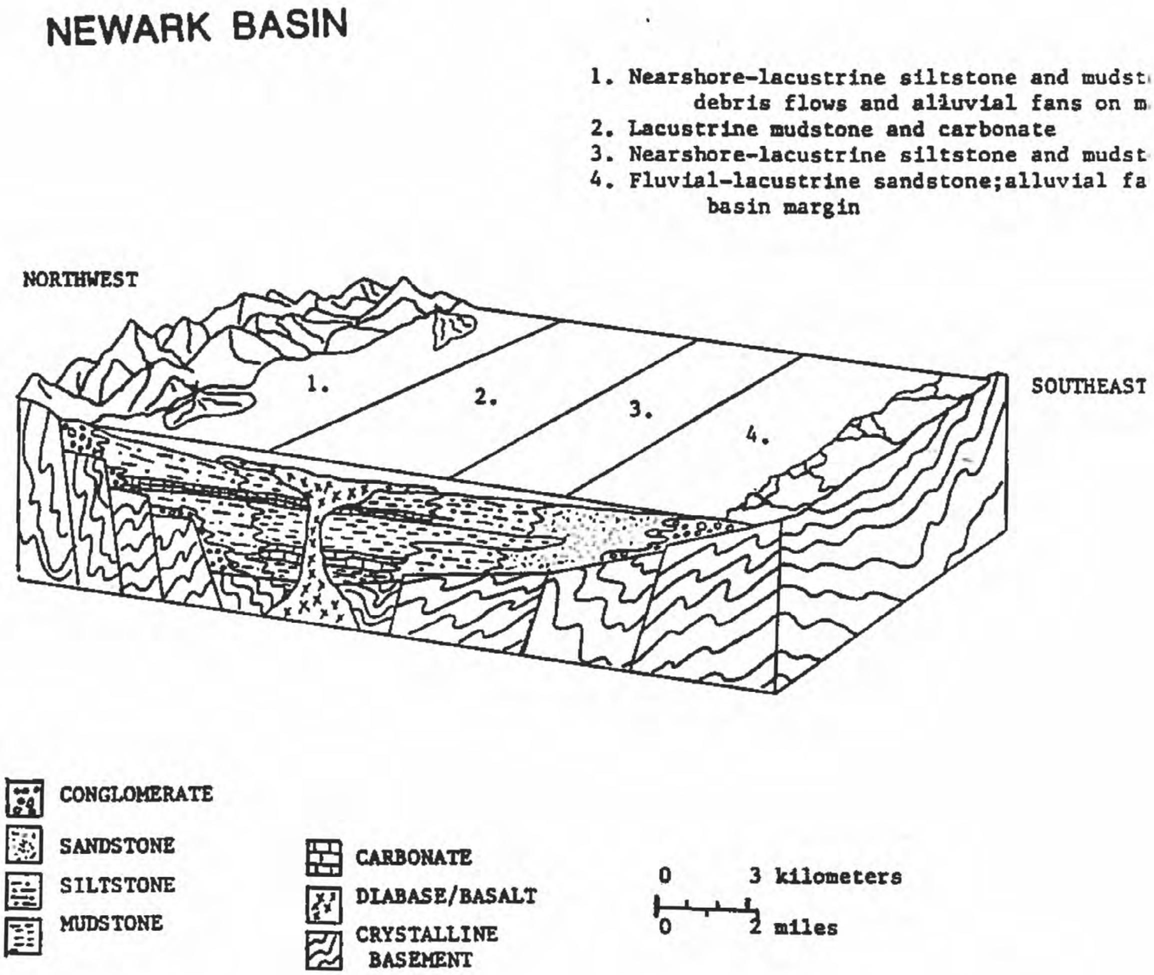

Figure IV.K.3. Generalized northwest-southeast block diagram showing distribution of facies in Newark basin (modified from Turner-Peterson and Smoot, 1985).

A transition in the younger rocks of the Coastal Plain occurs from north to south in peninsular Florida (fig. IV.K.4). In the region of the inferred Early Mesozoic fault-bounded Suwanee basin, a zone of mixed carbonate and clastic rocks of Cretaceous to Recent age overlie metamorphosed Paleozoic sedimentary rock and continental basement. South of the basement structure known as the Peninsular arch (fig. IV.K.4), the Cretaceous to Recent sediment wedge becomes exclusively carbonate and anhydrite and thickens dramatically into the South Florida basin where it attains thicknesses of as much as 20,000 ft.

Petroleum Geology

Source rocks are present in the majority of the exposed Mesozoic basins. Lacustrine black and gray shales and black siltstones and associated coal are typical source rocks. Total organic carbon (TOC) values for these rocks are more than one percent, which is considered to be minimum for oil generation (Tissot and Welte, 1984).

Thermal maturation patterns within individual basins, based on surface exposures, are highly variable. Extensive igneous activity has caused local changes in thermal maturation and has coked many of the coals in the southern basins (Reinemund, 1955). Pratt and others (1988) have shown that possible high heat flows were important in basin maturation. Bitumen has been associated with outcrops in several of the basins and usually occurs in sandstone fractures (Pratt and others, 1988). Oil and gas shows are evidence of continued migration of hydrocarbons.

Little is known concerning reservoir rock characteristics. General types of reservoirs found in the rift basins are marginal lacustrine-deltaic, shallow lacustrine, alluvial fan and fractured shales and sandstones (Ziegler, 1983). Sandstones with up to 20 percent porosity and permeabilities ranging from 0.01-14 millidarcies have been reported (Ziegler, 1983). Traps in the rift basins are faults, anticlines and stratigraphic pinchouts (fig. IV.K.3). In most of the exposed basins, reservoir rocks dip into the basin, thus the updip portions of the reservoir is exposed in outcrop. This is not a preferred orientation of a good reservoir. Rocks in the Mesozoic basins below the cover of the Coastal Plain may be better sealed.

In the south Florida basin, source rocks have been identified as dark limestones of lower Cretaceous age at depths of approximately 12,000 ft. Just updip from these source rocks, a fairway containing 10 oil fields produces the only hydrocarbons known in the Atlantic Coastal Region. The first oil was discovered in 1943. Table IV.K.1 shows cumulative production of 76 million barrels and 24 million barrels of reserves.

Petroleum Potential

Although exploration in the exposed and inferred Mesozoic rift basins has occurred for almost 70 years, no producing wells have been completed in them, and they are considered to have little petroleum potential. Analysis of cover rocks in the Coastal Plain (Libby-French, 1985) indicate they have no hydrocarbon potential. The South Florida basin is estimated to contain 210 million bbls of undiscovered recoverable oil.

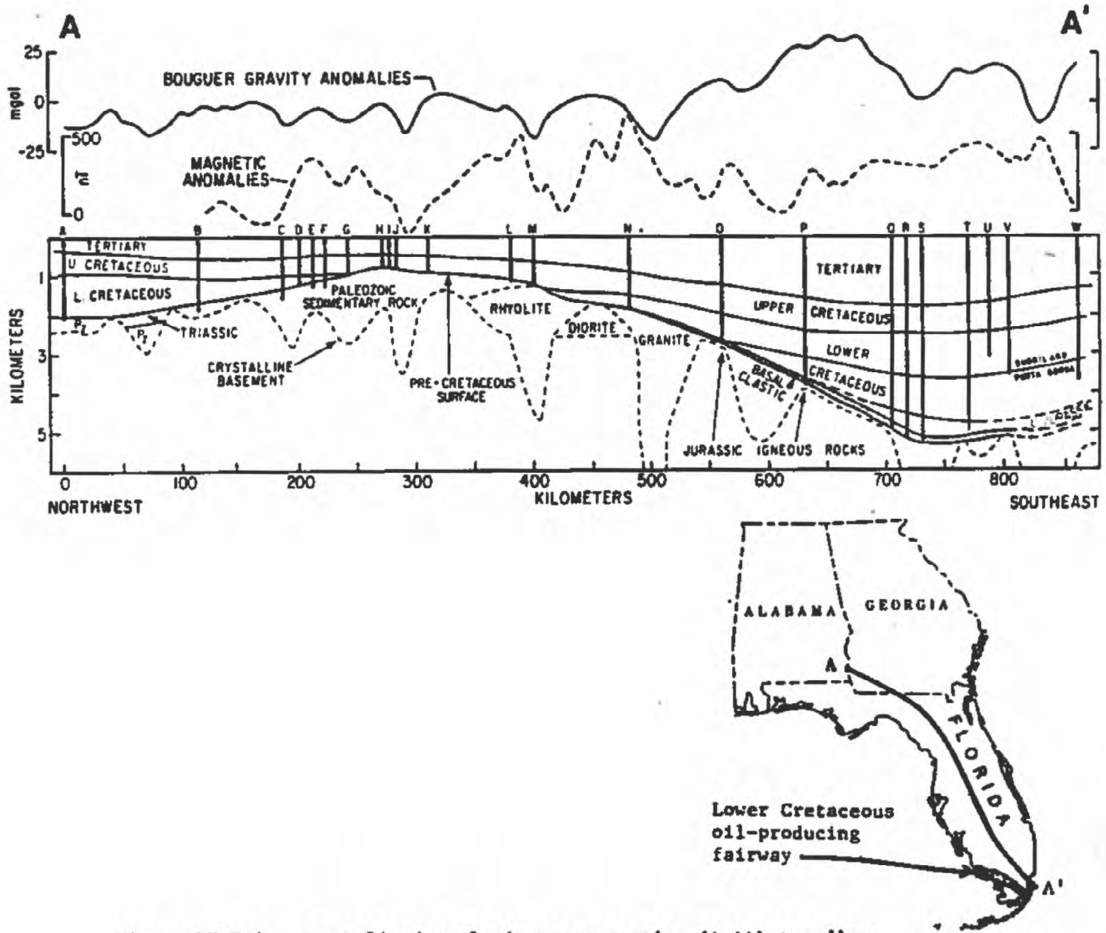

Figure IV.K.4. Generalized geologic cross section (A-A') trending northwest-southeast along peninsular Florida. (from Klitgord and others, 1984)

Table IV.K.1.--Cumulative production, estimated reserves and undiscovered recoverable resources in Region 9.

	Cum. Production	Measured Reserves	Inferred + Indicated Reserves
Oil (BBO)	0.1	<0.1	<0.1
Gas (TCF)	<0.1	<0.1	<0.1

Petroleum Provinces

Estimates of Undiscovered Recoverable Resources*

	Crude Oil (Billion Barrels)			Gas (Trillion Cubic Feet)		
	F95	F5	Mean	F95	F5	Mean
<u>Region 9 - Atlantic Coast</u>						
Atlantic Coastal Plain (incl. in Piedmont)						
So. Florida	0.06	0.50	0.21	0.01	0.04	0.02
Total	0.1	0.5	0.2	<0.1	<0.1	<0.1

Mean value totals may not be equal to the sums of the constituent means due to independent rounding.

Fractile values are not additive.

*Estimates of undiscovered economically recoverable resources are given in Table VIII.B.3.

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A. REGION 9A, ATLANTIC OCS

Introduction

The Atlantic region is bounded on the north by the Canadian maritime border, established in October 1984 by the World Court. Before 1984, resource estimates were based in part on an assessment of acreage now included within Canadian territorial waters (Dolton and others, 1981). The Atlantic region extends southward to the international Caribbean border and along the Straits of Florida westward to the Gulf of Mexico (GOM) to about 83° W., longitude. The region extends seaward from the 3-mile State-Federal boundary of the Outer Continental Shelf (OCS) to the edge of the Exclusive Economic Zone (EEZ) and in the mid-Atlantic area, beyond the EEZ. The Minerals Management Service (MMS) divides the OCS of the Atlantic region into four planning areas for lease sale and regulatory purposes. In this report, the OCS of the Atlantic region is further divided into seven provinces on the basis of common geologic characteristics within each province (fig. V.A.1).

Geologic Setting

The geologic setting of the Atlantic region is a tectonically quiescent, subsiding, continental shelf bounded near the continental rise by a transition to oceanic crust of Mesozoic and younger age. During the opening of the Atlantic Ocean through episodes of rift-faulting in Triassic and Lower Jurissic time, coarse-grained arkosic, evaporitic, lacustrine, and marginal marine sediments were deposited. Deposition occurred along linear rift-grabens and arid shoreline environments that transected the incipient Atlantic shelf margin. Rift-related tectonism ceased by Early to Middle Jurassic time along the shelf margin and widespread platform carbonates and sand units were deposited.

Ocean basin subsidence, relative to the continential margin, progressed in Late Jurassic and Early Cretaceous time with continued aggradation of

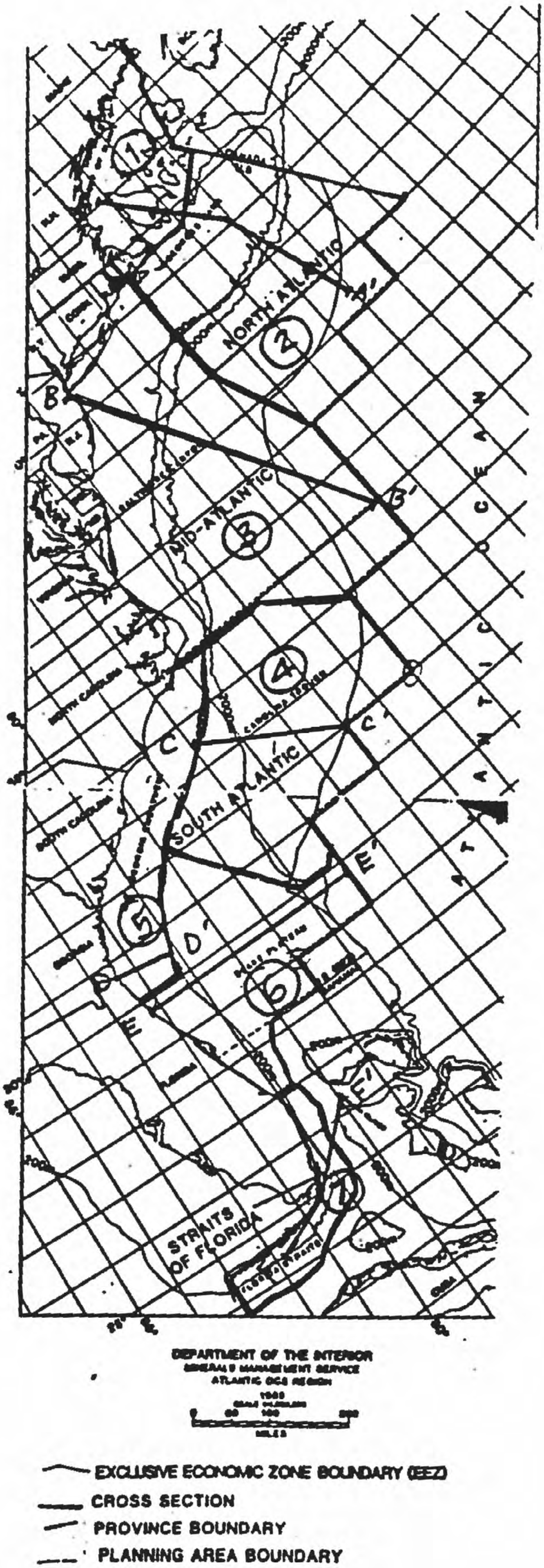

NORTH ATLANTIC
MID-ATLANTIC
SOUTH ATLANTIC
STRAITS OF FLORIDA
ATLANTIC OCEAN
DEPARTMENT OF THE INTERIOR
MINERALS MANAGEMENT SERVICE
ATLANTIC OCS REGION
EXCLUSIVE ECONOMIC ZONE BOUNDARY (EEZ)
CROSS SECTION
PROVINCE BOUNDARY
PLANNING AREA BOUNDARY

Fig. V. A. 1

platform and shelf edge carbonate buildups. Seismic data and information from a few boreholes are interpreted to indicate the upper part of the carbonate buildup is irregular in shape, perhaps representing local deposition of ecological reefs. By mid-Cretaceous time (Valanginian-Hauterivian ?), silty and sandy calcareous shales were deposited over the carbonate buildup as carbonate deposition failed to match rising sea level in the Baltimore Canyon Province (Edson, 1987, p. 26-27). Although carbonate deposition decreased in most of the region by the Late Cretaceous, carbonates continued to be deposited in the southern Atlantic region through Cenozoic time. Elsewhere in the region, Cenozoic sediments are mostly comprised of poorly indurated and consolidated sandstone, mudstone, siltstone, and, in some areas, Paleogene marine skeletal lime mudstone grading shoreward to marls and clastic rocks. Surface sediment is mostly unconsolidated sand, mud, and lime mud of Quaternary age except for a few current-scoured and slumped areas of the south Atlantic.

Exploration and Development History

Some of the provinces of the Atlantic region have been moderately explored since restricted areas were made available for leasing by the Department of the Interior beginning in 1959. Through January 1, 1987, _______ tracts had been leased in the Georges Bank, Baltimore Canyon, Carolina Trough, Southeast Georgia Embayment, and the Florida Straits. Areas in the remaining provinces have not been leased or tested for hydrocarbons. A total of 49 exploration wells and 5 industry Continental Offshore Stratigraphic Test (COST) wells have been drilled in the region. Subeconomic quantities of natural gas were discovered in five of the wells in the Baltimore Canyon Province, but the gas reservoirs are believed to be areally restricted channel sands not common in the rest of the region. Subeconomic quantities of oil were tested in 1959 from a well in State waters directly adjacent to the OCS of the Florida Straits Province (Applegate and Lloyd, 1985).

The OCS of the Baltimore Canyon Province is the most completely explored, with a total of 32 wells. Limited acreage in the Georges Bank (eight exploratory wells), Southeast Georgia Embayment (six exploratory wells), and Florida Straits (three exploratory wells) provinces are the only other OCS areas to receive exploration at present. Some exploratory drilling may be expected during the next 5 years in the Carolina Trough Province where the industry has retained highly promising undrilled leased acreage. Additional, but sparse drilling may also be expected on the few remaining active leases in other provinces, or upon newly issued leases, if leases are offered in any of the provinces of the Atlantic region. Deterrents to more extensive exploratory drilling include high operating costs (deep-water drilling and fast oceanographic currents up to 5 knots associated with the Gulf Stream), political and environmental opposition to leasing, unfavorable future price projections, and unfavorable geologic data from previous exploratory wells. Therefore, without a significant discovery or extensive reinterpretation of known geologic data from previously explored provinces, future Atlantic region exploration activity is anticipated to be somewhat minimal during the next 5 years and directly related to the leasing pace and economic projections.

There were 105 leases and 597,784 acres remaining under lease on the Atlantic region OCS as of January 1, 1987. Minor interest in conducting seismic and geochemical surveys in the Atlantic provinces exists, and exploratory drilling ceased in 1984.

Reserves

Exploratory drilling on the Atlantic region OCS has yet to establish the presence of economic oil or gas reserves, although the Baltimore Canyon Province at least one significant noneconomic accumulation of natural gas. Therefore, the estimate of oil and gas reserves for the Atlantic region is zero.

Summary

The estimates of undiscovered recoverable resources of the Atlantic region indicate the possible existence of potentially large quantities of hydrocarbons, especially natural gas. The discovery of one significant natural gas accumulation tested by 5 of the 49 exploratory wells in the region, is highly promising since many dry holes are commonly drilled in frontier basins worldwide before any major hydrocarbon deposits are found. However, analysis of rocks so far encountered in the exploration and COST wells has lowered earlier appraisals of the region's potential. Source rocks to generate hydrocarbons have been found in these wells to be comparatively lean, with total organic carbon (TOC) mostly averaging less than 1 weight percent. The low TOC values are generally considered near or below the lower boundary for significant natural gas generation and expulsion and are not permissive of significant oil generation. Further, the geothermal gradient is comparatively low in the region, so hydrocarbons, if any, must be generated in the deeper parts of the stratigraphic column. Good quality reservoir rocks, particularly in the Georges Bank Province, have been encountered mostly at shallower depths where thermally mature source rocks are absent.

There are few faults and tight folds to permit petroleum migration from source rocks at great depths to shallow reservoirs, limiting the petroleum potential of the Atlantic region. It has been a passive margin since the Late Jurassic without major active tectonic activity to produce these migration routes.

The lack of adequate evaluation of diapiric trends, Triassic to Jurassic rift systems, and fluvial-deltaic depositional systems suggests that untested potential exists in shelf areas of the region. The continuation of Jurassic to Lower Cretaceous carbonate buildups from onshore Gulf of Mexico and western Florida into the Atlantic region indicates significant hydrocarbon potential exists along the Atlantic margin if thermally mature source rocks are found. Presently, three wells in deep water have tested traps of the carbonate buildup trend, but only minor shows were found. A forth well, near the trend, did not penetrate carbonates, but encountered continentally derived clastics; no shows were found.

Global resource studies of passive margins by the MMS (Weaver, N., unpublished data, 1986) have indicated potential for other plays represented by offshore Triassic to Jurassic rift systems that have a chance of significant reserves of natural gas/condensate as well as oil from marginal marine/lacustrine depositional settings. The rifts are sufficiently deep for some older sediments deposited in the rifts to be within the window of thermal maturity. Also, these strata could provide a hydrocarbon source to shallower overlying traps if migration pathways are present along rift-system boundary faults. Although a low marginal probability of success exists, the rift systems in the Atlantic OCS have never been tested and have continued to be areas of commercial interest, as indicated by nominations for lease sale by petroleum firms. Study of several analagous production regions (e.g., Africa, South America, and Australia) indicate that depositional environments in such rift systems change markedly seaward. Therefore, what has been so far found onshore in these systems, does not necessarily predict what exists offshore.

Georges Bank Province

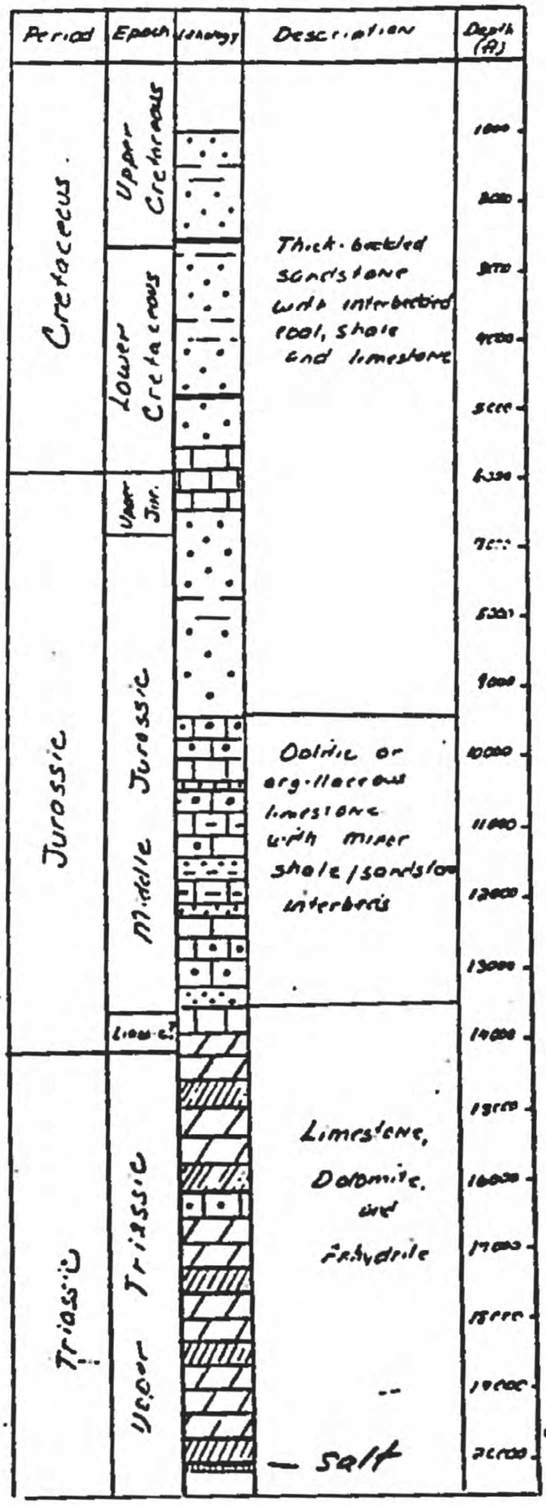
The province extends from the Gulf of Maine Province seaward to the continental rise and covers about of 76,065 square miles. Water depth ranges from 87 to 13,900 feet. The major feature of the province is the northeast trending Georges Bank Basin, a depocenter approximately 350 miles long and 120 miles wide. The province also includes five rift-grabens with up to 20,000 feet of sediment fill.

Geologic Setting

Continental sediments deposited below a regional "prerift" unconformity are overlain by Upper Triassic coastal deposits and shallow marine limestone, dolostone, and evaporites, which have been identified in boreholes in the Georges Bank Province (fig. IV.A.2). The zone of thickest sediment accumulation also includes some diapiric deformation, which trends southwest from the Canadian border. An Upper Jurassic to Lower Cretaceous carbonate buildup or bank, inferred from seismic data, is discontinuously distributed in the subsurface, trending parallel to the present shelf break throughout the province. The total sedimentary section in places is up to 30,000 feet thick.

Drilling History

Exploration of the province began in 1976 when the first of two COST wells was spudded (fig. IV.A.2). Eight exploratory wells were drilled by industry in 1981-82, all of which were dry. The two most prospective areas of the province, the Georges Bank (60-meter-bathymetric high) and deep-water carbonate buildup trend along the Mesozoic paleoshelf, have never been drilled. As of 1987, over 89 percent of the province is under a congressional moratorium on drilling or has been deferred from leasing under the Department's 5-year leasing plan.



Province 2
Georges Bank Basin

Generalized Lithologic column of the COST G-2 well. Time stratigraphic units are from the paleontologic analyses of H.L. Cousminer and W.E. Steinkraus.

[redacted]

Abernathy 8/4/87

V.A.

Figure 12

Source Rocks

Potential source rocks from the 10 boreholes drilled on the shelf of the province have been analyzed and found to contain hydrocarbon precursors (kerogen) of terrestrial, gas-prone types. Average total organic carbon from Upper, Middle, and Lower Jurassic shales and limestones ranges from 0.11 to 0.73 weight percent. Depth range of thermal maturity for oil and gas is 9,000 to 17,000 feet below the sediment-water interface (Carpenter and Amato, 1984).

Reservoir Rocks

Reservoir sandstones in the thermally mature interval tend to have low permeability, with porosities ordinarily less than 5 percent. Sandstone, as a distinct stratigraphic horizon, is largely absent in the thermally mature section. Across the shelf, limestones become a more dominate component of the sedimentary section. Carbonates of the inferred Upper Jurassic to Lower Cretaceous paleoshelf edge, rift sediments in grabens, and other prospective intervals have not been tested for reservoir potential by boreholes.

Undiscovered Potential

Identified plays that are mapped in the Georges Bank Province include structural cloosures within or overlying grabens, shelf anticlines, and anticlines seaward of the Upper Jurassic to Lower Cretaceous carbonate paleoshelf edge. Hypothetical and speculative plays include stratigraphic plays within grabens, clastic stratigraphic pinchouts against the outer platform carbonate buildup, and localized high porosity along the carbonate buildup and paleoshelf edge.

Table - Resource Estimates - Georges Bank Province

	Condl. Mean Oil Bbbl	Condl. Mean Gas Tcf	MP_{hc}	Risked Mean Oil Bbbl	Risked Mean Gas Tcf
Economically recoverable at $18/barrel	0.11	2.51	0.39	0.04	0.98
Undiscovered resource base	0.21	3.88	0.50	0.10	1.94

Gulf of Maine Province

The province extends seaward from the State-Federal boundary to the Georges Bank, covering about 22,063 square miles. Water depth in the OCS portion of the province ranges from 105 to 820 feet.

Geologic Setting

The Gulf of Maine Province is underlain by approximately 17 grabens, encompassing an about 2,368,000 acres. Total sediment fill in the grabens is up to 6,000 feet. Potential hydrocarbon traps include stratigraphic pinchouts against basement, combination stratigraphic-fault closures, and subunconformity plays.

Drilling History

None

Source Rocks

Lacustrine, evaporitic, and shallow marine source rocks are inferred from analogous basins.

Reservoir Rocks

Fault-bounded clastic wedges are inferred to be a possible reservoir sequence.

Undiscovered Potential -

Speculative potential exists within the graben-fill based on analog data. Limited seismic coverage indicates several rift systems that appear as half-grabens, perhaps represented rejuvenated thrust-fault systems. Thin sediment fill in the rifts limits the petroleum potential compared with other rift systems in the Georges Bank, Baltimore Canyon and Carolina Trough Provinces.

Table - Resource Estimates - Gulf of Main Province

	Condl. Mean Oil Bbbl	Condl. Mean Gas Tcf	MP_{hc}	Risked Mean Oil Bbbl	Risked Mean Gas Tcf
Economically recoverable at $18/barrel	0.04	1.09	0.02	Negl.	0.02
Undiscovered resource base	0.04	1.02	0.02	Negl.	Negl.

Baltimore Canyon Province

The province is named after its most prominent geologic feature, the Baltimore Canyon Basin. The basin is an elongate depocenter averaging 125 miles in width and extending from the Cape Fear Arch of offshore North Carolina about 400 miles to the northeast to the Long Island platform (Dellagiarino, 1986). The province also includes six identified rift-grabens which, in places, have deposits of over 15,000 feet of sediment fill. Water depth ranges from about 600 to 15,000 feet.

Geologic Setting

The continental shelf and upper slope seaward of about 1,000 feet water depth are underlain by relatively undeformed sediments, which thicken from less than 10,000 feet in the western half of the shelf to over 16,500 feet in the east. The sedimentary section underlying the western half of the shelf is interpreted from seismic and onshore data to be composed of thermally immature Cretaceous and Tertiary clastic sediments deposited in coastal-plain and shallow marine depositional environments (Carpenter and Amato, 1984). The seaward (eastern) half of the area has been described as ranging in age from Triassic to Tertiary, with most of the stratigraphic section being of Early to Middle Jurassic age (Dellagiarino, 1986). The sedimentary section thickens substantially to over 50,000 feet, in the Baltimore Canyon Basin near the outermost continental shelf and slope (Dellagiarino, 1986). Within the basin, rocks encountered so far are dominantly of terrigenous clastic origin, representing sediments shed into coastal and shelfal marine environments from the west of the basin (fig. IV.A.3). This stratigraphic section includes sands deposited by channels or delta lobes

II.A.-24
Figure 3
32

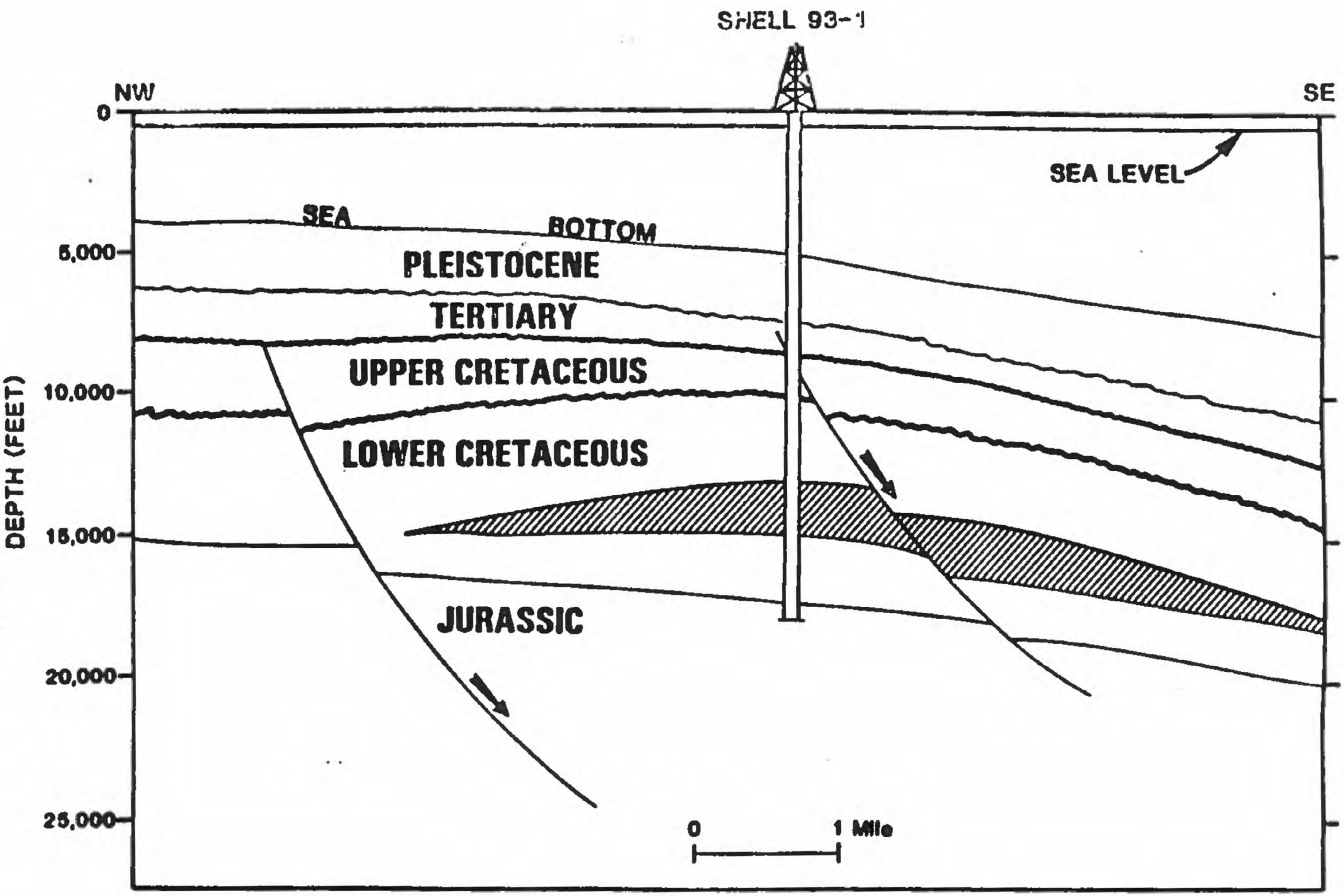


Figure --Schematic dip section through the Shell 93-1 well site showing ~~the relationships of the major geologic units and geologic structures. Shaded area represents the thickened Valanginian-Berriasian section deposited by channels or delta lobes and~~ the delta-growth fault play. ~~and a thickened Cretaceous [illegible]~~

~~Figure 4~~

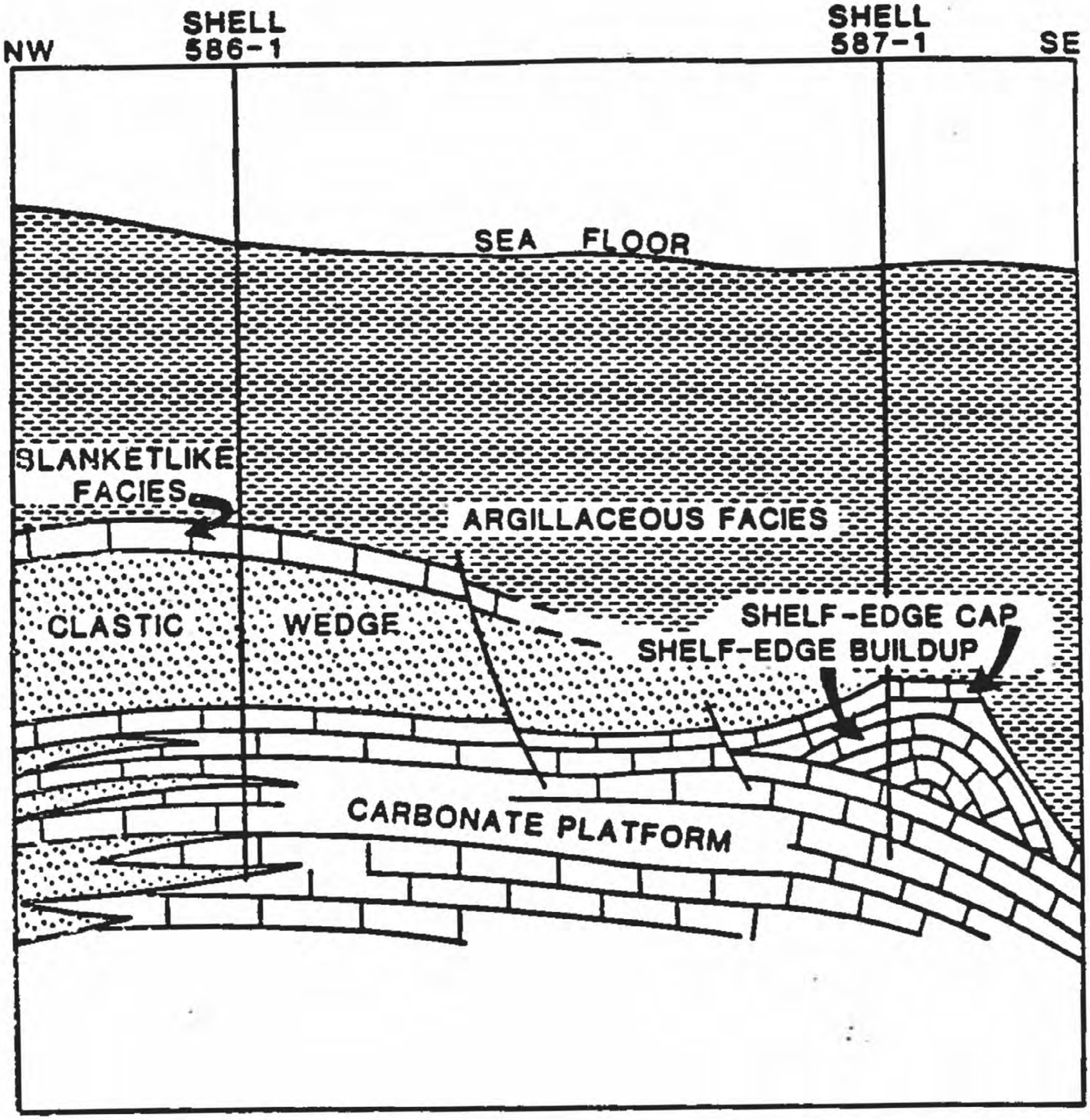
in Cretaceous time (Amato, 1987 b). A transition zone from dominantly clastic sediments to calcareous rocks, deposited along the Upper Jurassic to Lower Cretaceous paleoshelf edge, has been encountered in one borehole. The borehole drilled a clastic wedge directly shoreward of a carbonate buildup in the region (fig. IV.A.4). The province is the only part of the Atlantic OCS north of Florida where the carbonate buildup has been drilled and sampled by boreholes, confirming geophysical interpretations of its existence along the Atlantic margin (fig. IV.A.5). Wells that have drilled into the buildup have shown bank carbonate and blanket-facies carbonate rocks with an onlapping clastic wedge having fine- to medium-grained sandstone (Edson, 1986).

Drilling History

Exploration of the province began in 1976 when the first of two COST wells was spudded. A total of 32 exploratory wells were drilled between 1978 and 1984. Eight of the wells drilled a single faulted structure ("Texaco-Tenneco structure"), which may be structurally related to deep diapirism. Five wells tested gas. Significant quantities of gas and minor amounts of condensate are assessed in this structure, but these resources are considered noncommercial in the absence of a preexisting pipeline and gas transportation system.

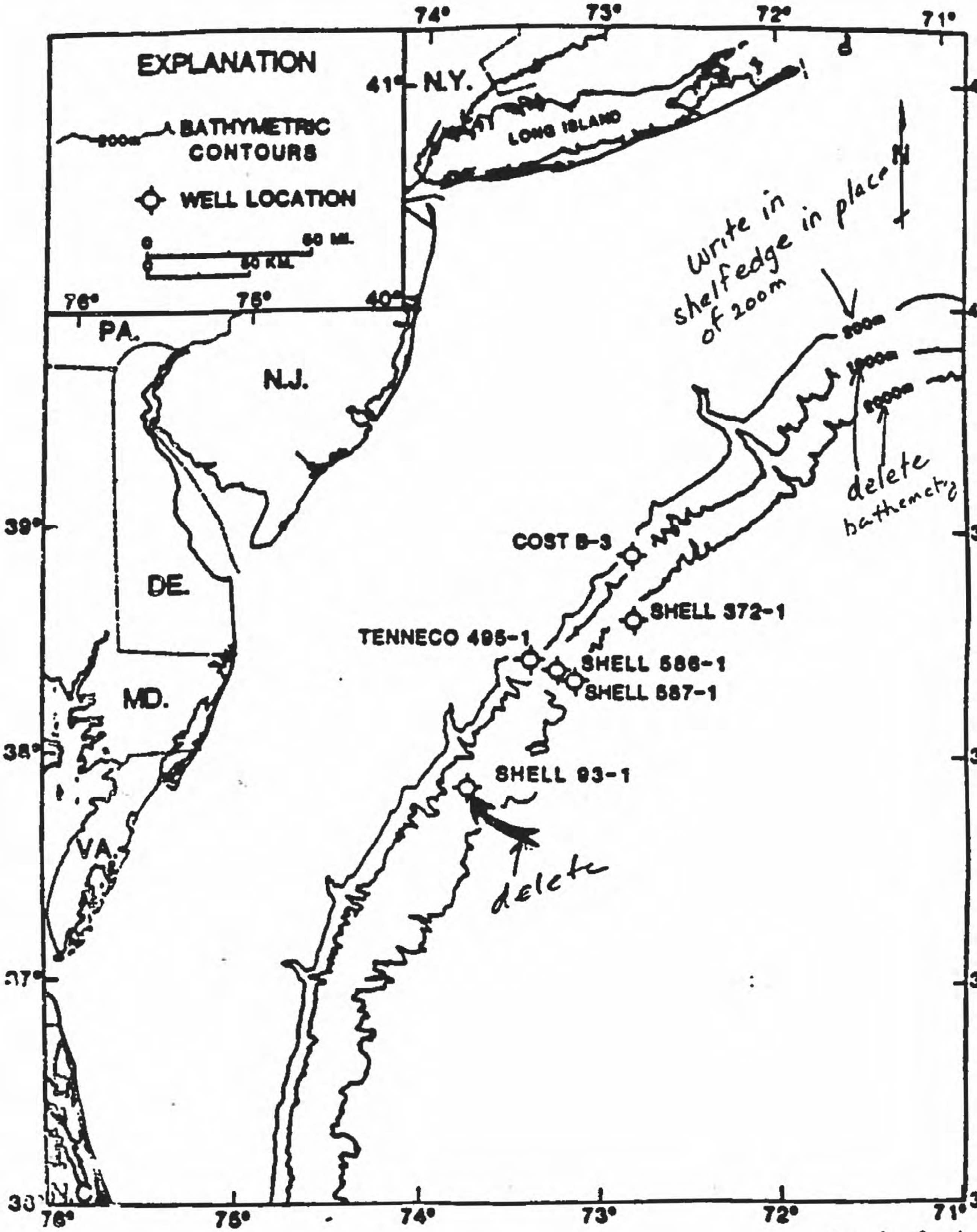
Source Rocks

Geochemical data from a COST well drilled near the carbonate buildup indicate that the threshold of intense oil generation occurs at a depth of about 8,775 feet and may be slightly shallower (8,125 feet) shoreward near a batholith ("Stone Dome"), which was the center of some drilling activity (Carpenter and Amato, 1984). Shales within the thermally mature section are thick (2,000 feet) in some areas, but have a low concentration (<0.5 percent) of total organic carbon. Kerogen types are of terrestrial origin and gas prone.



~~Figure 3.—Diagrammatic cross section through the Shell 586-1 and 587-1 wells.~~

V.A.
Figure 4



and waterdepth

~~Figure 1.—Map of a portion of the Mid-Atlantic offshore area showing the location of the Shell 93-1 well and selected other wells.~~ location of wells used in figures 3 and 4)

Fig. I.A.5

Reservoir Rocks

Interpretations of well log data show that only a small fraction of the total sand thickness below 10,000 feet has porosities greater than 5 percent (Dellagiarino, 1986). Most limestone beds in the carbonate buildup have low effective porosity (Edson, 1987, p. 31). The best reservoir sands of the "Texaco-Tenneco" structure were found in the Upper Jurassic between 12,000 and 14,500 feet.

Undiscovered Potential

Identified plays that are mapped in the Baltimore Canyon Province include shelf anticlines, the "Texaco-Tenneco" trend, the "Stone Dome," a delta growth-fault complex (fig. IV.A.3), wedge structures, and deep-water forebank anticlines. Hypothetical and speculative plays include stratigraphic plays within Triassic grabens, combination stratigraphic/structural potential of the carbonate buildup, and stratigraphic pinchouts along the carbonate buildup.

Table - Resource Estimates - Baltimore Canyon Province

	Condl. Mean Oil Bbbl	Condl. Mean Gas Tcf	MP_{hc}	Risked Mean Oil Bbbl	Risked Mean Gas Tcf
Economically recoverable at $18/barrel	0.22	5.35	0.44	0.10	2.36
Undiscovered resource base	0.48	9.72	1.00	0.48	9.72

Carolina Trough Province

The province is offshore of North and South Carolina and covers about 79,000 square miles. The major geologic feature of the province is the Carolina Trough, an elongate depocenter trending northeast along the outer shelf and continental slope. Water depth ranges from about 600 to about 15,000 feet.

Geologic Setting

The geologic setting of the Carolina Trough differs from other depocenters of the Atlantic region in several aspects. A few diapirs, generally considered to be salt, have been reported in the Baltimore Canyon (Grow, 1980) and Georges Bank, but the Carolina Trough has a comparatively denser concentration of these features (fig. IV.A.6). If the inference that the diapirs are salt-cored is correct (Dillon, 1983), then the areal distribution of diapirs indicates that a substantial volume of evaporites were deposited in Jurassic time along the length of the trough. There would then be a possibility in the Carolina Trough for better hydrocarbon source potential than in adjacent basins because of the interrelationship among evaporites, euxinic basins, rich source rocks, and petroleum generation (e.g., the rich petroleum source beds and evaporites offshore Angola and Niger area, south Atlantic, Mascle and others, 1973; Campos Basin, south Atlantic, Petrobras, 1983; Jeanne d'Arc Basin, north Atlantic, Tankard and Welsink, 1987).

The structural setting of the Carolina Trough is somewhat unique in that it is a comparatively linear depocenter bounded by a regional zone of growth faults along the landward side (fig. IV.A.6). The faults apparently involve downthrown basement blocks. Continental crust has been interpreted as thinner than other basins

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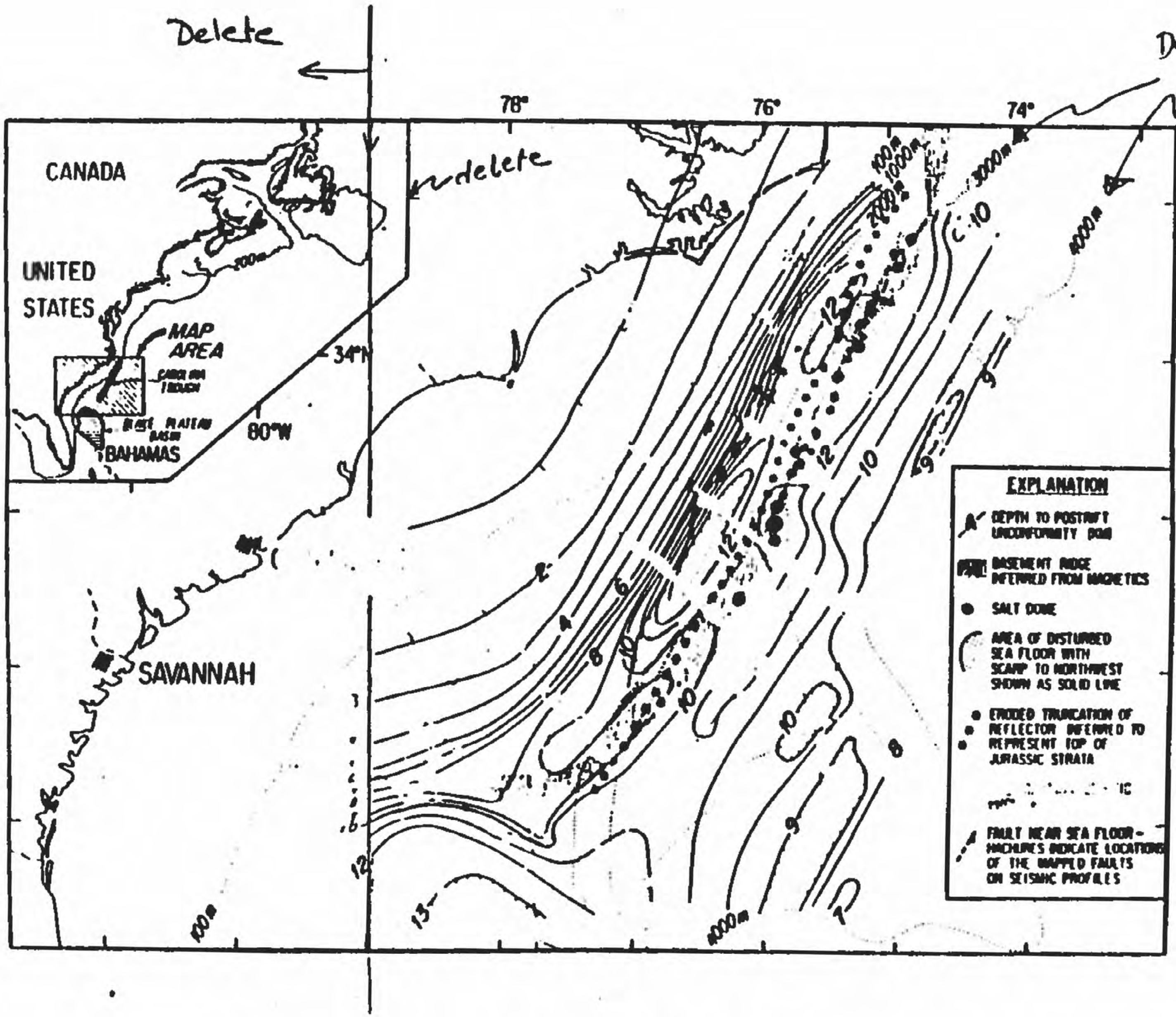


328 II.A. Figure 6

Figure .--Structural features of the Carolina Trough.

of the Atlantic region (Dillon, 1983, p. 14). More extensive rift-faulting, or thinner continental crust related to higher heat flow, may affect the threshold of thermal maturity of hydrocarbon-generating sediments in the trough.

Although somewhat different than other basins in the region, the Carolina Trough does share some common characteristics. Seismic data have been interpreted to show that a trend of carbonate buildups continues into the province from the Baltimore Canyon Province. Like the Baltimore Canyon Province, the stratigraphic section is considered to be dominantly Jurassic to Lower Cretaceous limestones and dolomites grading shoreward to more clastic lithologies. Younger sediments are believed to be dominantly clastic (Dellagiarino, 1986), with the carbonate component becoming more significant to the south.

Drilling History

There has been no drilling in the province, although a substantial amount of bonus money has been spent acquiring OCS leases that remain active. The main deterrent to drilling is the fast oceanic currents that cause vibration and stress to the drill string, particularly along the riser. The nearest well to the province is the Esso Hatteras Lighthouse, which was completed as a dry hole onshore at Cape Hatteras.

Source Rocks

There is no direct evidence of source potential from boreholes. The inferred presence of evaporites, the extreme linearity of the trough, and the possibility of higher heat flow indirectly reflect potential for good source rocks.

Reservoir Rocks

There is no direct evidence for reservoir from boreholes. Potential reservoir rocks include reefal buildups and clastic wedges shed into a deep trough with active growth faulting in Jurassic time.

Undiscovered Potential

The Carolina Trough has undiscovered potential represented by mapped plays, including fault-related anticlines, growth-fault structures, deep-water anticlines, and diapirs. Speculative and hypothetical plays include stratigraphic pinchouts against the carbonate bank and zones of enhanced porosity along the carbonate buildup at the paleoshelf edge.

Table - Resource Estimates - Carolina Trough Province

	Condl. Mean Oil Bbbl	Condl. Mean Gas Tcf	MP_{hc}	Risked Mean Oil Bbbl	Risked Mean Gas Tcf
Economically recoverable at $18/barrel	0.15	3.53	0.22	0.03	0.77
Undiscovered resource base	0.37	16.25	0.55	0.20	3.57

Southeast Georgia Embayment Province

The province extends from the onshore Atlantic Coastal Plain near Savannah, Georgia, seaward where sediments overlying Devonian metasedimentary basement rocks increase in thickness to as much as 14,000 feet. The province circumscribes the Southeast Georgia Embayment Basin, an east-plunging depression about 120 miles long and 80 miles wide (Dellagiarino, 1986). Water depths in the OCS portion of the province range from 66 to 157 feet.

Geologic Setting

The Southeast Georgia Embayment Basin is a minor sag of continental basement overlain by Cretaceous continental clastic sediments with poor source rock characteristics (Dellagiarino, 1986). These sediments are overlain by Cretaceous and younger flat-lying strata, mostly deposited in shallow marine environments (Dillon, 1983, p. 29-30).

Drilling History

Drilling in the OCS portion of the province includes one COST well completed in 1977 and six exploratory wells drilled in 1979. No hydrocarbon accumulations were discovered.

Source Rocks

Geochemical data from the wells drilled in the province indicate that the threshold of thermal maturity begins about 10,000 feet below the sediment-water interface. Total organic carbon values from shales in this interval are low, ranging from 0.10 to 0.27 weight percent. The richest potential source rocks in the COST well were encountered at depths of less than the threshold of hydrocarbon generation and are described as alternating shales, claystone, and lime mud (Amato and Bebout, 1978).

Reservoir Rocks

Sandstones with good porosity and permeability were penetrated by boreholes, but the reservoirs contained only formation water. The best potential reservoir section in the COST well was between 5,700 feet and approximately 11,000 feet.

Undiscovered Hydrocarbon Potential

Identified plays that are mapped in the province are related to low-relief folds and drape structures. The comparatively low resource estimate of the province reflects the absence of both large traps and a significantly thick, thermally mature, stratigraphic section. In addition, the Jurassic section, the most prospective of the Atlantic OCS exploration targets, is missing in this basin.

Table - Resource Estimates - SE Georgia Embayment

	Condl. Mean Oil Bbbl	Condl. Mean Gas Tcf	MP_{hc}	Risked Mean Oil Bbbl	Risked Mean Gas Tcf
Economically recoverable at $18/barrel	Not economic				
Undiscovered resource base	0.05	0.67	0.03	Negl.	0.02

Blake Plateau

The Blake Plateau Province encompasses about 48,500 square miles in the southern Atlantic region. Water depth ranges from 100 to 16,400 feet.

Geologic Setting

The Blake Plateau Basin is the dominant geologic feature of the province. The sedimentary section is over 30,000 feet thick in places and sediments are mostly flat lying with broad, extremely low relief, fold and drape structures. Most of the sedimentary section is thought to be Jurassic and Cretaceous in age (Dellagiarino, 1986).

Drilling History

None

Source Rocks

There is no direct evidence for source potential from boreholes. Potential exists for interbedded marine shale and limestone to have source rock characteristics according Deep Sea Drilling Project (DSDP) data obtained near the edge of the basin. Deeply buried Triassic source rocks, if present, would be below the threshold of thermal maturity.

Reservoir Rocks

There is no direct evidence for reservoir potential from boreholes. Speculations regarding the probable lithologies are based on seismic facies analyses and peripheral DSDP well data. Sediments above acoustic basement are interpreted as mostly carbonates that might have reservoir characteristics if deposited in reefal or other favorable settings.

Undiscovered Hydrocarbon Potential

Identified plays in the province are related to broad, low-relief folds.

Speculative and hypothetical plays include stratigraphic accumulations.

Table - Resource Estimates - Blake Plateau Province

	Condl. Mean Oil Bbbl	Condl. Mean Gas Tcf	MP_{hc}	Risked Mean Oil Bbbl	Risked Mean Gas Tcf
Economically recoverable at $18/barrel	0.31	4.67	0.06	0.02	0.30
Undiscovered resource base	0.34	5.56	0.25	0.08	1.38

Florida Straits Province

The province extends southward from the Pennisula Arch of central Florida to the international border with the Bahamas and Cuba. The province includes rocks of the South Florida/Bahama Basin, which are up to 35,000 feet thick. Water depths range from 30 to 3,600 feet.

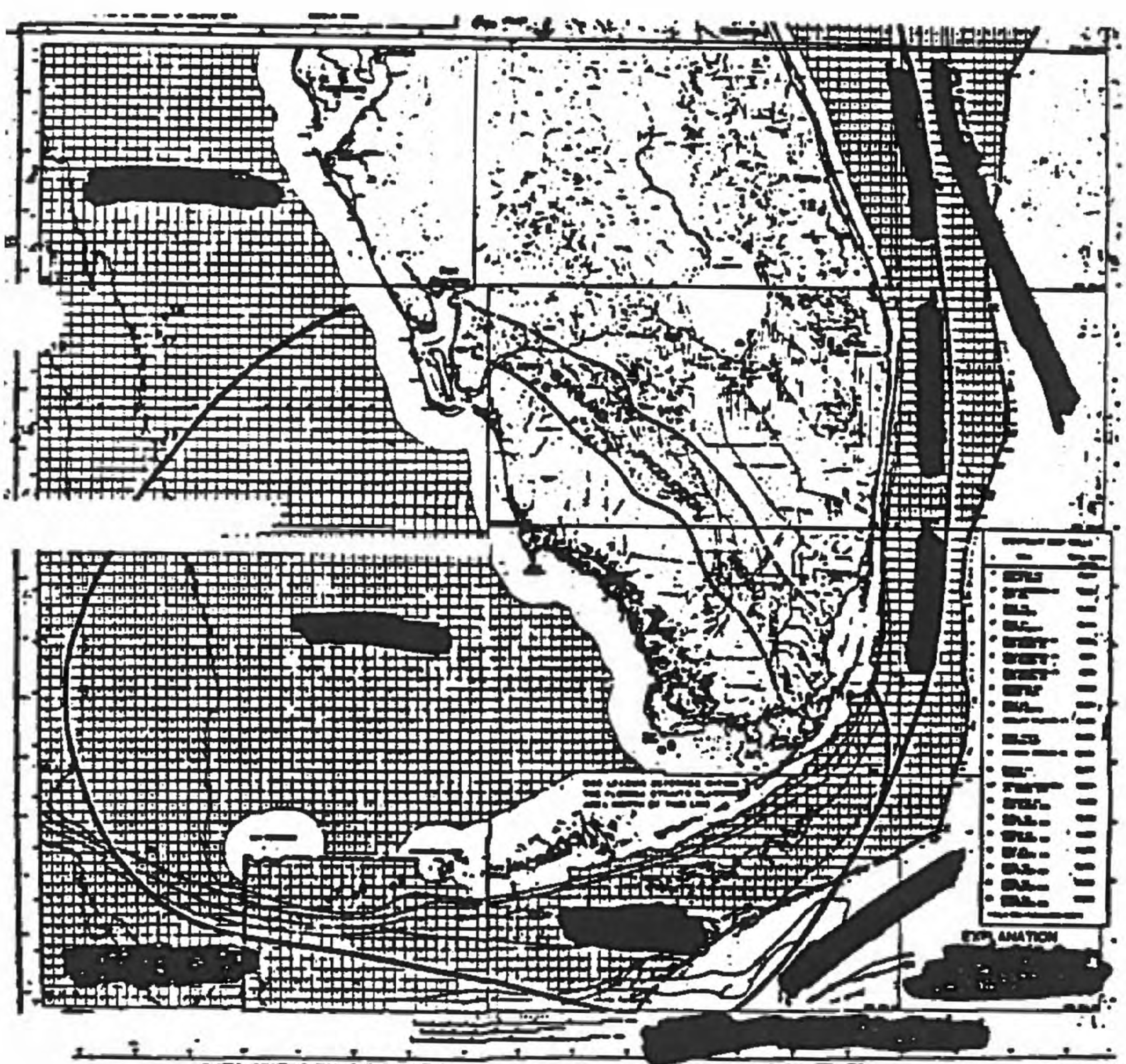
Geologic Setting

Regional structural features include the Pennisula Arch to the north and the Pine Key Arch paralleling and just south of the Florida Keys (Amato, 1987a). The South Florida/Bahamas Basin contains Jurassic age and younger limestone, dolostone, anhydrite, and salt overlying an unknown thickness of Triassic rift-stage clastic rocks. The Lower Cretaceous rocks of the basin are as much as 9,300 feet thick and include the Sunniland Formation, which is productive onshore in a northwest-southeast trend near the center of the basin (fig. IV.A 7).

Drilling History

Three wells have been drilled within the OCS portion of the province within and south of the Florida Keys by Gulf Oil Company (Chevron) and The California Company (Chevron) in 1960 and 1961. Leases for drilling were obtained in OCS Sale 5 in 1959, in which 23 blocks were leased in the Straits of Florida. Two of the three wells were abandoned before the target depth because of drilling problems in the Paleocene and Upper Cretaceous-aged Rebecca Shoals Reef. The third well, Gulf No. 1 Marquesas OCS Block 28, encountered oil staining in thick porous dolomite intervals below 12,336 feet.

Other wells have been drilled adjacent to or near the OCS portion of the province in the Florida Keys (fig. IV.A 7). Hydrocarbon shows were noted in some of these wells with the Gulf Oil State Lease 826-A testing 15 barrels of 22° API gravity oil over a 14-hour period (Applegate and Lloyd, 1985).



V. A.
FIG. 7

Source Rocks

Significant shows have been encountered in rocks that are correlative with the Sunniland and Lehigh Acres Formations of Lower Cretaceous age. Onshore, source rocks for Sunniland reservoirs appear to be in the lower part of the formation.

Reservoir Rocks

Porous carbonate reservoir rocks have been drilled in many wells of the province. Dolostone and limestone of Lower Cretaceous age have porosities commonly ranging from 5 to 30 percent in intervals as thick as 300 feet. Dolostone beds with pinpoint to vugular porosity and limestones with porous zones composed of rudistid bioclasts have reservoir potential in the Lower Cretaceous and Upper Jurassic sections.

Undiscovered Potential

Stratigraphic and reefal traps are modeled as speculative and hypothetical plays in the province. Minor production occurs in areas peripheral to the province (northwest Cuba and onshore Sunniland Formation in Florida) from carbonate reservoirs.

Table - Resource Estimates - Florida Straits Province

	Condl. Mean Oil Bbbl	Condl. Mean Gas Tcf	MP_{hc}	Risked Mean Oil Bbbl	Risked Mean Gas Tcf
Economically recoverable at $18/barrel	0.35	0.44	0.18	0.06	0.08
Undiscovered resource base	0.26	1.20	0.32	0.08	0.38

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Figure Captions

Figure 1 - Atlantic region province and planning area boundaries.

Figure 2 - Generalized Lithologic column based on the COST G-2 well, Georges Bank Province.

Figure 3 - Diagrammatic cross section through the Shell 93-1 well site showing plays associated with channel or delta lobe sands, Baltimore Canyon Province.

Figure 4 - Diagrammatic cross section through the Shell 586-1 and 587-1 wells showing plays along the paleoshelf-edge in the Baltimore Canyon Province.

Figure 5 - Map of the Mid-Atlantic offshore areas showing the location and water depths of plays and wells illustrated in figures 3 and 4.

Figure 6 - Sketch map showing structural features of the Carolina Trough Province (after Dillon, 1983).

Figure 7 - Map of the south Florida area showing major geologic features and exploratory wells.

B. REGION 6A,
GULF OF MEXICO ~~REGION~~ OCS

Introduction

The Gulf of Mexico (GOM) region extends from the Florida Keys westward around the Gulf to the Mexican border (fig. II.B.1). The areal limits of the region are defined by Federal-State boundaries and by the 200 mile Exclusive Economic Zone (EEZ) limit to seaward. The region includes nearly 160 million acres of Federal submerged lands.

Geologic Setting

The GOM is an enclosed marginal sea with a high sedimentation rate (Ewing and others, 1973). Its general geologic setting is that of a stable, slowly subsiding, passive continental margin mantled by great thicknesses of Mesozoic to Recent sediments. Mesozoic sedimentation in the basin and its periphery was largely limited to carbonate deposition as platform deposits, reefs, and banks. During the Jurassic, an extensive salt horizon (Louann Salt) was deposited during a period of restricted interbasin circulation. This evaporite deposit forms the core of the large number of salt diapirs, pillows, and swells found throughout the GOM (Foote and others, 1981).

A distinct change in sedimentation, resulting from continental uplift, occurred in the late Cretaceous and early Cenozoic when major river systems began to depositing large volumes of terrigenous clastics into the basin. These sediments were deposited in the western part of the basin by the ancestral Colorado, Rio Grande, and Brazos rivers starting in the Paleocene. By the Miocene, the principal sediment supply had shifted northeastward to the Mississippi river system (Foote and others, 1981). The eastern portion of the GOM basin did not accumulate significant volumes of clastics; sediments are largely Mesozoic

Fig. IV.B.1

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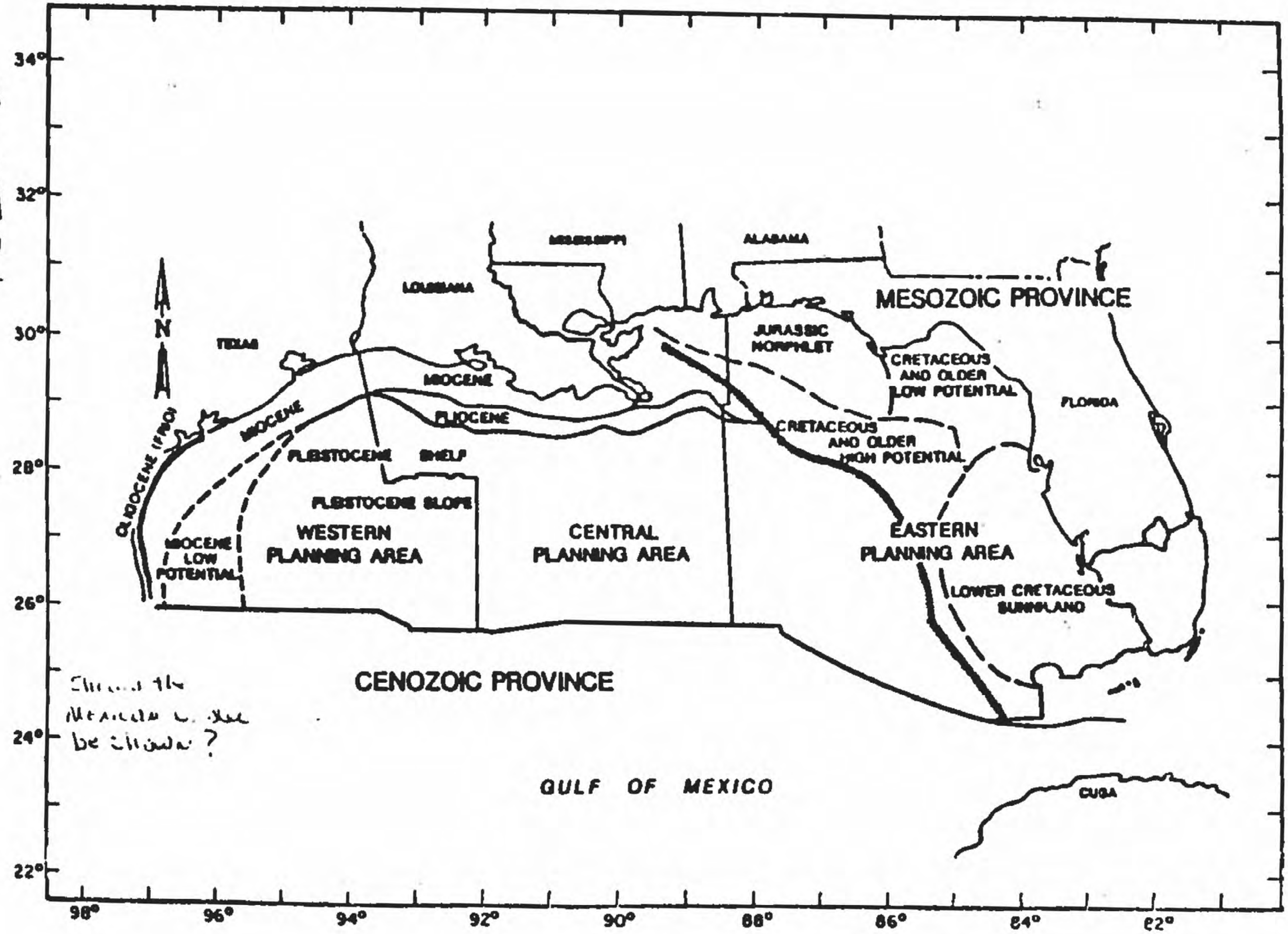

Should the Mexican coast be shown?

carbonates. Because of this change in sedimentation, the GOM is logically divisible into two distinctly different geologic provinces, a Mesozoic primarily carbonate province in the east and a Cenozoic clastic province occupying roughly the western two-thirds of the basin. The two provinces are separated by a Cretaceous reef trend.

The influx of large volumes of clastics in the western province resulted in overburden pressures high enough to induce plastic flow in the Louann Salt. Salt tectonics has produced most of the diapiric structures in the Cenozoic province. These structures and their associated faulting are the focus of most exploratory efforts.

Clastic sedimentation during the Cenozoic has exceeded the rate of basin subsidence, resulting in a series of progressively younger seaward migrating depocenters ending with deposition of large volumes of Pleistocene clastics on the present shelf-slope break off the coast of Louisiana. These depocenters, particularly those of Miocene to Pleistocene age, form the major petroleum producing areas of the offshore GOM.

Exploration and Development History

The first offshore well in the GOM was spudded in 1938. In 1947, the first well in what are now Federal waters was drilled out of sight of land about 12 miles off the Louisiana coast. Thousands of wells have since been drilled, the vast majority of which are located on the continental shelf. The drilling effort has resulted in the discovery of enormous quantities of oil and natural gas. As of December 31, 1986, there were 697 active fields in the federally regulated portion of the GOM. Average daily production from these fields for 1986 amounted to nearly 1 million barrels of oil and condensate and over 11 billion cubic feet of natural gas (Hewitt and others, 1987). There were 4,291 active leases in the GOM as of December 31, 1986, more than at any other time.

Exploration and development activity is concentrated in the Cenozoic province. Exploration has progressed seaward to the point where leasing interest in recent sales has focused on the Pleistocene slope (Flexure trend) play, which is located beyond the shelf break in deep water. Possibilities for large field discoveries have been exhausted for most of the continental shelf because most areas in shallow water have either been developed, leased, and relinquished, or are still under lease, leaving little to explore.

The Mesozoic Province has not been as well tested as the rest of the GOM. Fewer than 100 exploratory wells have been drilled throughout the province. Although no production has yet occurred, a number of economic deposits have apparently been discovered in clastic plays in the Mesozoic Province. The most promising of these are in the Jurassic Norphlet off Mobile Bay. Good production rates of gas below 20,000 feet have been found in many wells in this formation. Several producible gas fields have also been discovered in a trend of Miocene age terrigenous sands in the Pensacola clay in Alabama. Some Miocene gas has been found offshore. Although not prolific, the reservoirs are shallow and relatively inexpensive to produce.

Reserves

The Table below shows the various categories of remaining reserves in the GOM.

	BBO/TCFG
Demonstrated reserves (remaining recoverable)	3.88/45.8
Reserves in insufficiently developed fields	0.07/1.24
Undiscovered resources in known fields	0.4-0.6/4.6-6.9
Cumulative production	6.93/75.2

Summary

The GOM is the most productive OCS region. It has considerable remaining potential, and it is the lowest cost offshore operating area. It is also climatically and oceanographically benign and, in most cases, the oil business is politically acceptable to local residents.

An analysis of resource estimates for the GOM indicates that the best remaining potential for large discoveries is in deep water beyond the shelf break. The Pleistocene slope play is currently seen as having the most promise, with estimated conditional mean economically recoverable resources of 6.51 billion barrels of oil and 42.11 trillion cubic feet of gas. Development is operationally difficult because of the water depth, but novel solutions, as in the case of the Green Canyon field, show that commercial oil can be produced from the play.

Cenozoic Province

The Cenozoic province extends from a point just west of Biloxi, Mississippi, west and south to the Mexican border (fig. V.B.1). The seaward limit of the province is arbitrarily defined by the southern boundaries of the central and western GOM planning areas. Water depths range from less than 30 feet near the Federal-State boundaries to over 10,000 feet at the seaward limit of the province.

Geologic Setting

Total thickness of sedimentary rocks near the axis of the principal depocenter exceeds 50,000 feet. The lithology of the producing interval (Cenozoic) is primarily clastics deposited mostly as deltaic sequences over a passive, subsiding continental margin (fig. V.B.2).

Drilling History

Since 1938, thousands of wells have been drilled in the province; it is the most extensively drilled offshore area in the world. The exploration front has gradually moved seaward to the point where a substantial number of production wells have been drilled in water depths greater than 1,000 feet. This trend is expected to continue.

Source Rocks

No specific source rock lithology in the province is apparent, although a sequence of Miocene shales and mudstones is thought to be of particular importance (Bouma and others, 1978). Multiple completions are standard in most wells, and the producing intervals are thought to be sourced by

V. B. 2

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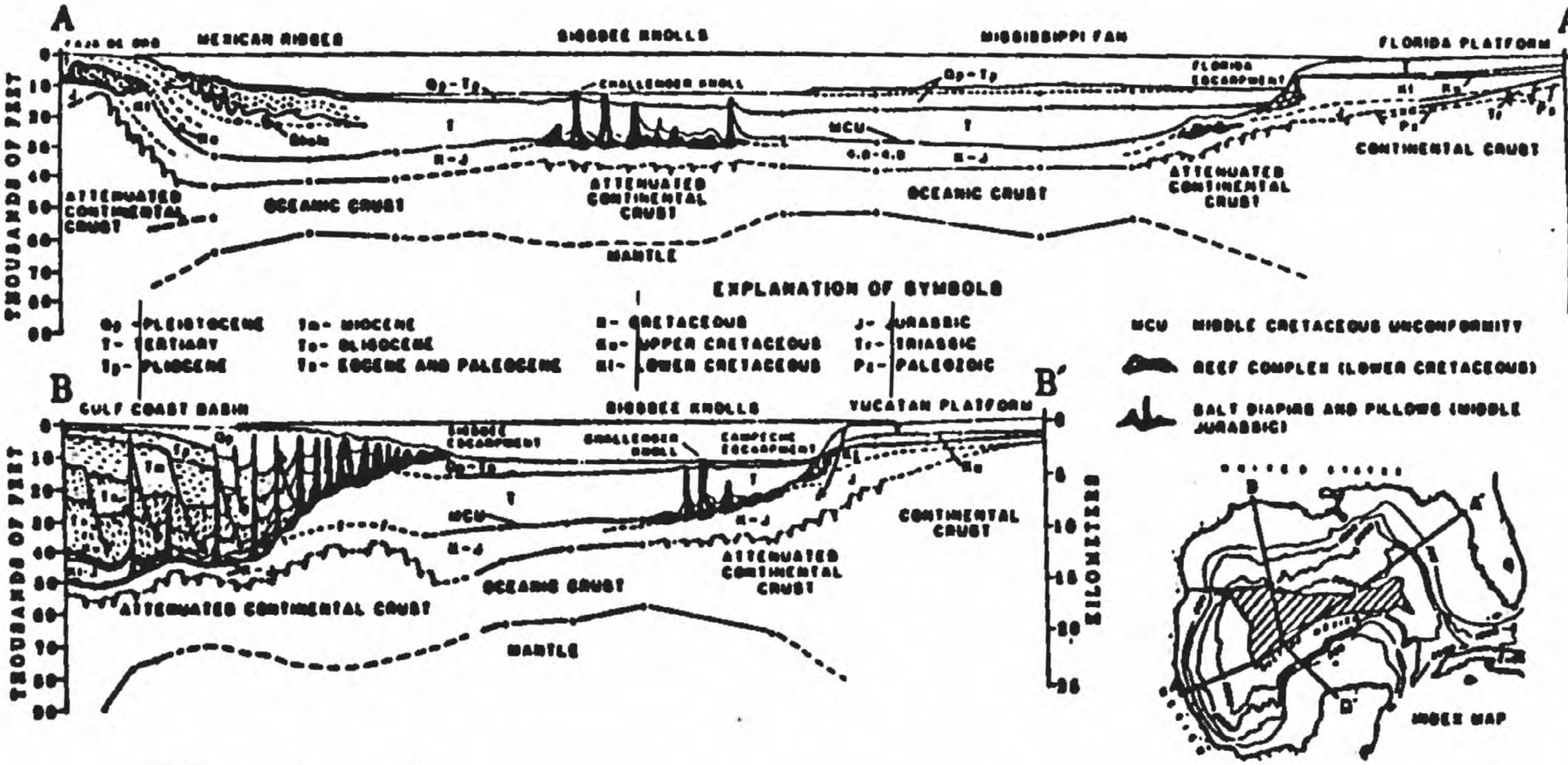

Figure ~~I-8. Diagrammatic~~ IVB2 Schematic crustal sections across continental margin and deep ocean basin regions of the Gulf of Mexico. Based on: (1) published cross-sections (Lehner, 1969; Dorman and others, 1972; Antoine and others, 1974; Martin and Case, 1975; Martin, 1978); (2) interpretation of seismic-reflection profiles; (3) seismic-refraction data (Crane, 1961; Ewing and others, 1962; Antoine and Ewing, 1963; Hales and others, 1970; Dorman and others, 1972, Buffler and others, 1980; Ibrahim and others, 1981); (4) drill-hole information from Florida, Yucatan, and Faja de Oro (Maher and Applin, 1968; Lopez-Ramos, 1975; Vinegra O. and Castillo-Tejero, 1970).

shales and mudstones that interfinger with reservoir sands. Source rocks are especially rich, ranging up to 10 percent weight of convertible organic matter (Foote and others, 1981). Amorphous, oil-prone kerogens predominate in the eastern part of the province, whereas greater percentages of humic, structured, gas-prone kerogens are found to the west.

Reservoir Rocks

Reservoir rocks are mostly well sorted Oligocene to Pleistocene deltaic and turbidite sands. The rocks in the upper portion of the section are virtually unconsolidated so that little primary porosity is lost. Porosity values of 35 percent are common and permeability tends to be high.

Undiscovered Potential

The Cenozoic Province has produced well over 7 billion barrels of oil and condensate and 70 trillion cubic feet of natural gas. Although the area is a mature petroleum province, considerable potential remains, particularly in deeper water. The province includes approximately 60 million acres of leasable land, encompassing a number of highly prospective areas.

The area generally considered to have the best remaining potential is the Pleistocene slope play. This play is the youngest of a series of progressively younger, seaward migrating depocenters ranging in age from Oligocene to Pleistocene. Pleistocene shelf edge and slope sediments are over 20,000 feet thick, with excellent source and reservoir characteristics. Reservoir sands accumulate in subsurface lows between salt ridges, which generally parallel the margin. The ridges function as barriers to prograding sands, which are deposited as thick sequences behind them. The deeper water of this area has favored preservation of the organic component of fine-grained sediments. Sands derived from the shelf interfinger with deeper water shales and mudstones in this area, providing an excellent ratio of source rock to reservoir rock. The Flexure trend has been partially explored with encouraging results. Older plays (Oligocene, Miocene, and Pliocene) have been well explored, but may have remaining potential deeper in the sedimentary section. Smaller accumulations may come into production as the economic climate improves.

Table - Resource Estimates, Cenozoic Province

	Condl. Mean Oil Bbl	Condl. Mean Gas Tcf	MP_{hc}	Risked Mean Oil Bbl	Risked Mean Gas Tcf
Economically recoverable at $18/barrel	5.36	62.10	1	5.36	62.10
Undiscovered resource base	9.27	100.34	1	9.27	100.34

Mesozoic Province

The shoreward boundary of the Mesozoic Province extends from a point slightly west of Biloxi, Mississippi, east and south to the Florida Keys. For the purposes of this report, the seaward boundary of the province is defined by the southern edge of the eastern GOM planning area and by the EEZ boundary, whichever is furthest seaward (fig. V.B.1). Water depths range from 30 feet near State waters to over 10,000 feet. The total area of the province is approximately 81,000 square miles.

Geology

The dominant lithology is composed of Cretaceous and older carbonate rocks which are over 35,000 feet thick in some areas (Foote and Martin,, 1981). Some sand is present, particularly in the northern part of the province where terrigenous clastics compare a significant fraction of the deeper part of the sedimentary section (fig. V.B.2). These clastics extend from onshore Alabama and Florida and are separated from the rest of the carbonate platform by the Middle Ground Arch. Except for local deltaic accumulations, Cenozoic clastics are largely absent (Bouma and others, 1978).

Roughly the northwestern quarter of the Mesozoic province is underlain by a massive salt horizon that has formed a number of diapirs and salt swells. Structures resulting from salt tectonics are less common than in the Cenozoic Province, presumably because of reduced thicknesses of overburden.

The sedimentary section in the eastern part of the province is primarily carbonates, with only a minor terrigenous component. These sediments form a part of the Florida Platform.

Drilling History

Exploratory drilling commenced in 1974 and continues to the present. Approximately 45 wells have been drilled, but no commercial accumulations have been found in the carbonate province. Most exploratory effort has focused on the offshore extensions of onshore trends, for example, Norphlet and Sunniland.

Source Rocks

Marine shales and organic-rich carbonates of Cretaceous to Jurassic age probably provide the best source rocks in the province. Thin, scattered Tertiary rocks generally do not appear to have source rock potential. Kerogens in terrigenous clastic rocks, such as those in the northern part of the province, are structured and thus gas prone. Marine shales and carbonates are more likely to contain amorphous, oil-prone kerogen.

Reservoir Rocks

Reservoir rocks in Jurassic sediments are mostly grain-supported sandstones and dolomitized carbonates. Cretaceous reservoir rocks are largely turbidite sandstones, shelly zones, and patch reefs.

Undiscovered Potential

Results of recent deep drilling off Alabama and western Florida have been extremely encouraging. The presence of commercial reserves has been established and several gas fields are expected to produce shortly. Industry interest is centered on the deep (>20,000 feet) Norphlet, a Jurassic sandstone. This formation has also been tested on the Destin Dome, but was found to be dry. However, the Norphlet on Destin Dome had good reservoir qualities and thus perhaps some remaining potential for discoveries elsewhere on the structure.

The Sunniland, a minor producing formation in south central Florida, may extend some distance seaward of the west Florida coast. The formation is a Cretaceous carbonate that produces oil from thin zones of secondary porosity (Pontigo and others, 1979). The source rocks are probably limestones in the lower part of the formation which include algal kerogens. Sunniland fields tend to be small, averaging 10-15 million barrels, with none larger than about 50 million barrels. There is no compelling reason to assume that the field size distribution for a hypothetical offshore Sunniland trend would be any different.

The Cretaceous and older low potential play (fig. V.B.I) appears to have only limited prospects for the occurrence of hydrocarbons. Sediments are thin, thermally immature, and have poor source and reservoir characteristics.

The Cretaceous and older high potential play (fig. V.B.I) has not been drilled, but shows probable reef structures as well as some evidence for sands. Hydrocarbons would presumably be derived from algal kerogens (oil prone) in carbonate rocks.

Table - Resource Estimates, Mesozoic Province

	Condl. Mean Oil Bbl	Condl. Mean Gas Tcf	MP_{hc}	Risked Mean Oil Bbl	Risked Mean Gas Tcf
Economically recoverable at $18/barrel	0.28	2.32	.96	0.27	2.22
Undiscovered resource base	0.30	3.00	1	0.30	3.00

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C. REGION 2A

PACIFIC ~~REGION~~ OCS

Introduction

The Outer Continental Shelf (OCS) of the Pacific region extends from the Canadian maritime border southward to the provisional maritime border with Mexico. Hydrocarbon resources of the Pacific region OCS are assessed seaward from the 3-statute-mile State-Federal boundary to the outer edge of the Minerals Management Service (MMS) planning areas, including the Exclusive Economic Zone (EEZ). The MMS divides the region into four planning areas for lease sale and regulatory purposes. In this report, the planning areas are subdivided into eight provinces on the basis of common geologic characteristics within each province. Six of the provinces extend onshore crossing State and other administrative boundaries (fig. V.C. 1). The provinces are comprised of 26 major geologic basins or depocenters in the OCS (Dellagiarino, 1986, plate 1) with additional minor fault-bounded subbasins.

Because of the Pacific Region's size and geologic complexity, the eight geologic provinces of the Pacific OCS are discussed in three groups for ease of discussion. The groups are (1) the Northern California-Southern Oregon Coastal Province and Western Oregon-Washington Province; (2) the Central California Coastal Province and Santa Maria Basin Province; and (3) the Santa Barbara Channel-Ventura Basin Province, Inner Banks and Basins Province, Los Angeles Basin Province, and Outer Banks and Basins Province, all in southern California. An assessment of the hydrocarbon potential of each province follows the general description of the Pacific region.

Geologic Setting

The Pacific OCS is a tectonically active, complexly folded and faulted, active plate margin. In Washington, Oregon, and northernmost California, geologic provinces are bounded on the west near the continental rise by sub-

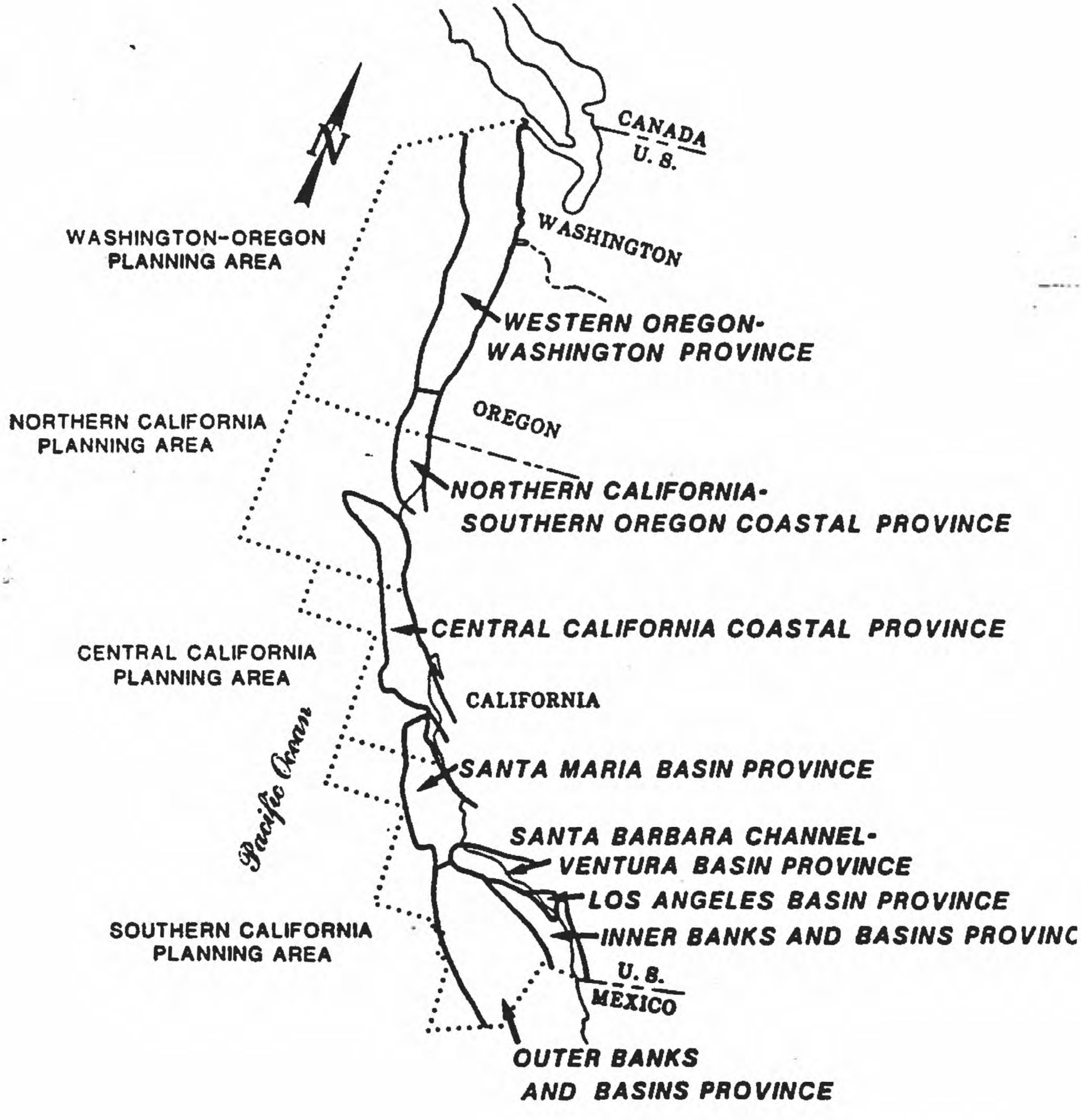
N
CANADA
U.S.
WASHINGTON
WASHINGTON-OREGON
PLANNING AREA
WESTERN OREGON-
WASHINGTON PROVINCE
OREGON
NORTHERN CALIFORNIA
PLANNING AREA
NORTHERN CALIFORNIA-
SOUTHERN OREGON COASTAL PROVINCE
CENTRAL CALIFORNIA COASTAL PROVINCE
CENTRAL CALIFORNIA
PLANNING AREA
CALIFORNIA
Pacific Ocean
SANTA MARIA BASIN PROVINCE
SANTA BARBARA CHANNEL-
VENTURA BASIN PROVINCE
LOS ANGELES BASIN PROVINCE
INNER BANKS AND BASINS PROVINC
SOUTHERN CALIFORNIA
PLANNING AREA
U.S.
MEXICO
OUTER BANKS
AND BASINS PROVINCE

Figure V C. 1

ducting oceanic crust and on the east by the Coast Ranges uplift. South of the Mendocino fracture zone, the OCS of the Pacific region is underlain by a complexly folded and fault-imbricated zone of oceanic crust, metasediments, and allochthonous continental crystaline basement.

Continental rocks of the Northern California-Southern Oregon Coastal Province and Western Oregon-Washington Province north of the Mendocino fracture zone override the subducting Pacific oceanic plate (Juan de Fuca and Gorda oceanic plates of Clarke and others, 1985). A volcanic belt is thought to have extended along the continental plate margin and shelf in middle to late Eocene time (Armentrout and Suek, 1985, fig. 11). Volcaniclastic and feldspathic-quartzose sands were shed from this belt and deposited in coastal plain and forearc basin depositional settings. The dimensions of the coastal plain and depositional basins in the region changed through time as oceanic and metasedimentary rocks accreted to the North American continent, volcanism episodically continued, and uplifts occurred. During Late Paleogene and Neogene volcanic episodes, dominantly lithic sandstones with clay minerals were deposited. The deposition created sandstone reservoir rocks with mostly low porosity and permeability since allogenic clays clogged pore space. Also, diagenetic minerals formed during burial, lowering the porosity and permeability of reservoir rocks which could potentially contain hydrocarbons. Generally, effective porosity is lost in reservoir rocks which were buried deeper than 8 to 10 thousand feet in the northern Pacific Ocean north of the Mendocino fracture zone. Subduction and arc volcanism continuing to the present created six major slope or modified forearc basins in the OCS. These basins are from north to south Cape Flattery, Willapa, Astoria, Newport, Coos Bay, and Eel River. (See province discussions for basin locations, fig. V. C. 9.)

The Central California Coastal Province and Santa Maria Basin Province, south of the Mendocino fracture zone, are not undergoing active subduction. The two provinces are comprised of five major OCS basins, which are from north to south Point Arena, Bodega, La Honda, Ano Nuevo, and offshore Santa Maria ~~(fig.)~~ (See province discussions for basin locations, fig. V.C.7.). Although differing in detail, the basins have a similar tectonic setting and have a similar depositional history. They are all west of the San Andreas Fault, and, except for the Santa Maria Basin, they share at least some similar Sierran-type basement rocks of the "Salinian" province of Reed and Hollister (1936). Basement rocks of the Santa Maria Basin are erosional remnants of an arc-trench system developed in Late Jurassic time.

Deposition and structural style in the five basins of the two provinces reflect a major change in mid-Tertiary time from an oblique subduction zone, somewhat similar to present day offshore Washington and Oregon, to a right-lateral transitional shear boundary marked by the San Andreas Fault and related fault systems. Some related right-lateral fault systems found in the two provinces include the Rinconada, Nacimiento, Palo Colorado-San Gregorio-Seal Cove, and Hosgri faults. Displacement along regional faults has produced a network of fault-bounded ridge and basin structures trending northwest-southeast. The general northwest-southeast structural grain of the provinces terminates on the south along the younger east-west trending Transverse Ranges.

The common stratigraphic characteristic of all of the basins in these two provinces is the presence of a thick section of Miocene shales mostly assigned to the Monterey Formation. In the Point Arena Basin in the north, however, these shales are called Point Arena Formation ~~(see fig. 10).~~ See province discussions for stratigraphic chart and lithology descrip. The presence of the Monterey Formation and similar rocks is significant because these strata are the primary reservoir and source rocks in the leased areas of the southern Santa Maria Basin Province and western Santa Barbara Channel-Ventura Basin Province. These strata contain about 1.2 billion barrels of the total oil equivalent reserves in the Pacific region OCS. Although there is no current production in the OCS of the Central California Coastal Province or northern Santa Maria Province, the similarity of the Miocene stratigraphic sequence between the southern Santa Maria Basin Province and basins farther to the north results in a substantial estimate of undiscovered recoverable hydrocarbons and a low basin exploration risk.

Provinces in the Federal OCS south of the Santa Ynez Mountains in southern California reflect deposition in wrench-faulted structural basins in an east-west trend in the Santa Barbara Channel-Ventura Basin Province and in a northwest-southeast trend farther to the south. Hydrocarbon traps in the area are related mainly to rejuvenated downfaulted blocks, uplifted in Pliocene and later time along regional northwest and east-west wrench faults and conjugate shears.

The distinguishing stratigraphic feature of the provinces in the southern area is that, except for the western Santa Barbara Channel, the primary exploration targets and productive reservoirs are sandstone rather than fractured shales of the Monterey Formation, although this formation is considered to have some potential. In Tertiary time, a tectonically controlled topographic and paleobathymetric setting in the southern area profoundly affected the distribution and origin of these clastic reservoir rocks. At times, high coastal mountains adjacent to deep offshore basins created a geologic setting where quartzose sediments were eroded from mountains and subsequently deposited as canyon fill or deep-water submarine fan systems within shale sequences deposited in euxinic basinal settings. The short transport distance of clastic grains has limited porosity because of angularity and poor sorting of grains, but extraordinarily thick sequences of stacked reservoirs have resulted in zones productive of hydrocarbons many hundreds of feet thick in some fields.

In general, there were three major orogenic-depositional cycles in the southern provinces. The reservoir quality of sandstones improves overall in the younger cycles because sediments were recycled by younger uplifts, sorting of grains by minor transgressive-regressive episodes, and uproofing of plutonic rocks exposing more granitic provenance terrains. Also, diagenetic minerals are less likely to clog pore space in the shallower stratigraphic sequences. Source rocks were deposited in each of the depositional cycles, with the Miocene stratigraphic sequence being the most significant in terms of thickness, richness in lipids, total organic carbon content, and other source rock characteristics.

Exploration and Development History in the Pacific Region

The OCS of the Western Oregon-Washington Province and Northern California-Southern Oregon Coastal Province was moderately explored when the Department of the Interior made areas available by two lease sales in 1963 and 1964. A total of 17 tracts (97,920 acres) were leased in the OCS of the Northern California-Southern Oregon Coastal Province in 1963. A total of 101 tracts (580,853 acres) were leased in the Western Oregon-Washington Province in 1964. All leases were relinquished between November 1966 and November 1969. No leasing, exploration, or development has occurred in Federal waters in either of these provinces since the Santa Barbara oil spill in 1969. However, large scale regional seismic operations have been carried out, which allows the quantification of hydrocarbon resource potential represented in this study.

A total of 12 exploratory wells (11 original wells and 1 redrill) were drilled in the OCS of the Western Oregon-Washington Province between 1965 and 1967. Hydrocarbon shows were encountered in some wells, but none were considered for commercial development. A total of four exploratory wells were drilled in 1964 and 1965 on the OCS of the Northern California-Southern Oregon Coastal Province. No significant shows of gas or oil were encountered in the four wells.

The OCS of the Central California Coastal Province and Santa Maria Basin Province underwent sparce drilling activity after limited acreage was made available for lease in the first OCS oil and gas lease sale in the Pacific OCS in May 1963. A total of 40 tracts (215,026 acres) were leased in the two provinces, and all leases were relinquished by June 1968. Since that time, leases have not been offered in any area except the southern Santa Maria Basin Province. Here, major discoveries resulted after lease sales in 1979 (Sale 48) and 1981 (Sale 53).

A total of 16 exploration wells were drilled in the two provinces on leases acquired in the 1963 lease sale, and hydrocarbon shows were encountered in the Miocene shales in most wells. In 1978, 14 oil companies participated in the drilling of the Continental Offshore Stratigraphic Test (COST) well, OCS-CAL 78-164 No. 1 in the offshore Santa Maria Basin. Sale 48 resulted in the drilling of lease P-0316 held by Chevron, Phillips, and Champlin and the discovery of the giant Point Arguello Field. Sale 53 resulted in the largest bonus bid ever received by the Federal Government for an OCS tract ($333.6 million) and the discovery of eight additional fields as of January 1, 1987.

The provinces of offshore southern California, south of the Santa Maria Basin Province, have been explored and developed for hydrocarbons since 1896, starting in offshore State tidelands of Santa Barbara County. Since the 1966 OCS sale of a drainage tract in the Santa Barbara Channel-Ventura Basin Province, there have been five sales in the OCS portion of these provinces. A total of 298 exploratory wells, exclusive of core holes, have been drilled in the area, and 105 tracts were active as of January 1, 1987. No discoveries have been made in the Outer Banks and Basins Province, where nine exploratory wells and one COST well have been drilled. No discoveries have been made in the Inner Banks and Basins Province, where only three core holes have been drilled near the 3-mile State-Federal boundary off San Clemente, Oceanside, and San Diego. A total of 24 OCS fields have been developed in the provinces of southern California, mostly in the Santa Barbara Channel and southern Santa Maria Basin.

Reserves

Estimated oil and gas reserves as of January 1, 1987, are 1,302 million barrels of oil and 2,135 billion cubic feet of gas. Estimated ultimate recovery (reserves plus production) from the fields is 1,670 million barrels of oil and 2,460 billion cubic feet of gas. Reserves have been estimated for only the Federal portion of fields that cover both State and Federal lands.

Reserves distributed by the plays used to model economically recoverable undiscovered hydrocarbon resources are summarized in the following table.

Table I.C.1. Pacific Region, discovered hydrocarbon resources

Reservoir Play	Formations	Reserves*	Estimated Ultimate Production*
Post-Monterey	Foxen, Pico, Repetto, Santa Margarita, Sisquoc, Upper Puente	264 MMBBLS	592 MMBBLS
Monterey	Monterey, Lower Puente	1,218 MMBBLS	1,304 MMBBLS
Pre-Monterey	Point Sal, Hueneme, Topanga, Vaqueros, Gaviota, Sespe/ Algeria, Camino Cielo, Matilija, Sacate, Jalama	176 MMBBLS	184 MMBBLS

(from Raftery and Wolfson, 1987, p. 12)

* Reserves are given in barrels of oil equivalent. An additional 5 to 10 percent of oil and gas reserves may yet be discovered in known fields. Ultimate production is proven reserves plus hydrocarbons already produced.

Summary

The estimates of the undiscovered, conventionally recoverable resources of the Pacific Region indicate the possible existence of potentially large quantities of hydrocarbons, especially oil (~~table 2~~). The discovery of 24 fields (with economically recoverable oil of 1,670 million barrels and gas of 2,460 billion cubic feet) is highly promising because currently over 1.2 billion barrels of oil equivalent reserves are economically recoverable from the Monterey Formation alone (table IIC 1). This formation and similar rocks are known from past drilling to be present in vast unleased areas of the northern Santa Maria Province and the Central California Coastal Province. The Monterey Formation and correlative rocks were found, at some locations, to be comparable in thickness and diagenetic grade to productive reservoirs in the southern Santa Maria Basin Province and western Santa Barbara Channel-Ventura Basin Province (~~see figures 4~~ ~~and 5~~). (See province discussions for figures showing thicknesses.)

Except for the southern part of the Santa Maria Basin Province, the OCS acreage of all of the provinces in central and northern California, as well as Washington and Oregon, has not been leased and explored since 1969. Only 26 exploration wells have been drilled in these areas, many concentrated in shallow water along the less promising edges of major basins. Some areas of the provinces in the OCS of southern California have been exhaustively leased and explored, but major areas remain excluded from exploration. Areas never offered for lease include the following: (1) the Federal Ecological Preserve and Buffer Zone, (2) Santa Monica Bay, (3) military use areas, the largest of which surrounds San Nicolas Island, and (4) a large area between Dana Point and San Diego. In addition, the Channel Island National Marine Sanctuary has been excluded from lease since 1980.

Outer Banks and Basins Province

The Outer Banks and Basins Province is part of the southern California borderland, lying between the Santa Cruz/Santa Catalina Ridge and the Patton Escarpment (fig. V.C. 2). Numerous basins and subbasins are separated by fault-bounded uplifts and banks in the province (Dellagiarino, 1986). The total area of the province is approximately 21,700 square miles. Water depth ranges from 60 to over 7,500 feet.

Geologic Setting

The stratigraphic sequence in the province is varied based on information from a few boreholes, seismic coverage, and bottom sampling. In the nearshore areas, some basins contain only Paleogene and lower Neogene sediments; others contain only middle and upper Neogene sediments overlying metamorphic basement. The banks farther from shore generally have Paleogene and Upper Cretaceous sandstone and shales overlying basement, and basin depocenters also appear to have onlapping Neogene strata. However, the outermost banks and basins have Neogene sediments lying directly on basement rocks.

The structural grain of the Outer Banks and Basins Province is generally northwest-southeast, with regional wrench fault systems controlling uplifts and depositional patterns. According to seismic interpretation, sediment thickness in certain basins could exceed 20,000 feet, although the stratigraphic section is mostly less than 15,000 feet.

Drilling History

Ten deep wells have been drilled in the province. One offshore COST well and eight exploratory wells were drilled on the Santa Rosa-Cortes Ridge and

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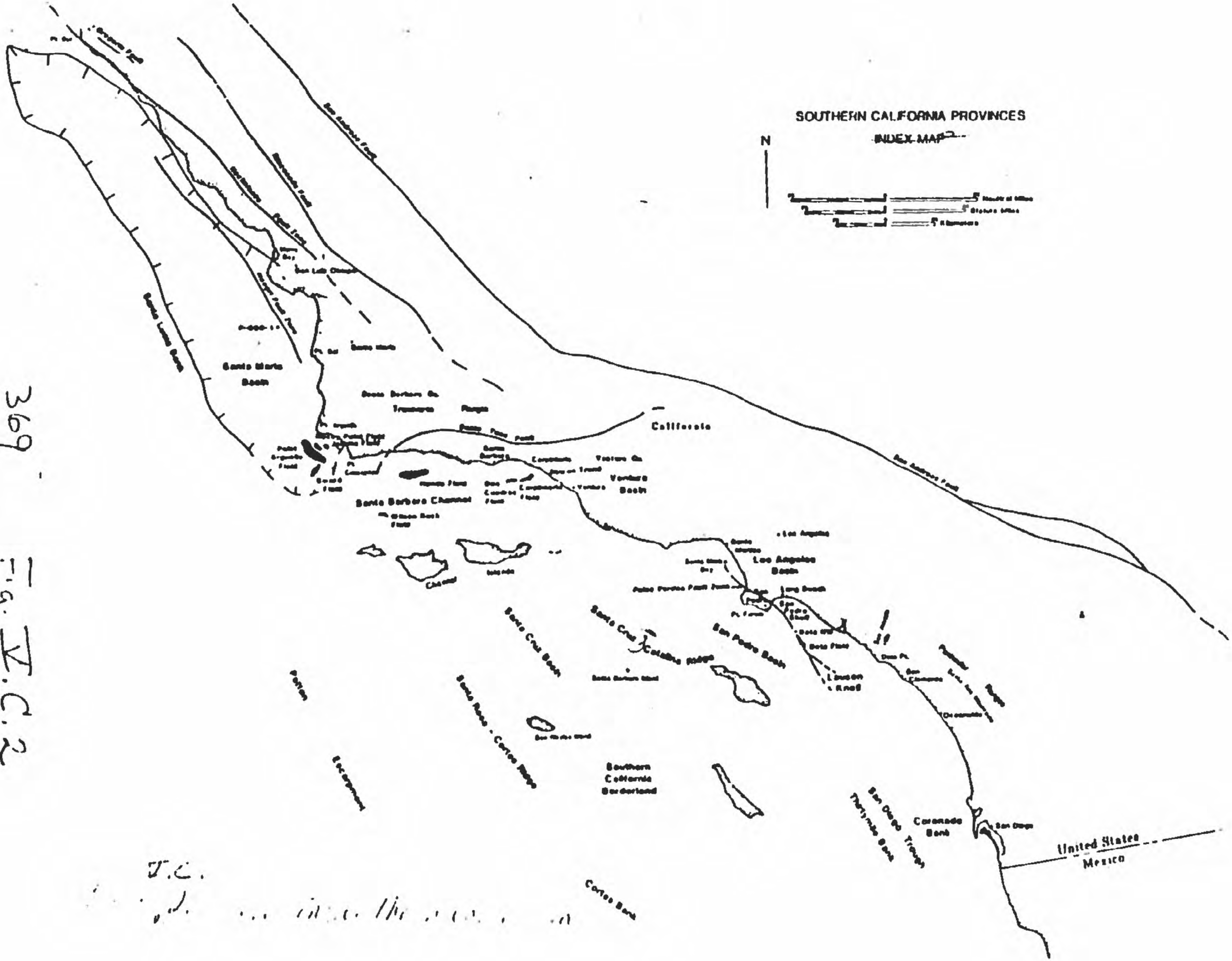
Fig. I.C.2



SOUTHERN CALIFORNIA PROVINCES
INDEX MAP
N
San Andreas Fault
Santa Maria Basin
Santa Barbara Channel
California
Ventura Basin
Los Angeles Basin
Long Beach
San Pedro Basin
Santa Cruz Basin
Lasuen Knoll
Southern California Borderland
Coronado Bank
San Diego
Cortes Bank
Escarpment
United States
Mexico

and Cortes Bank. A tenth well was drilled northwest of Santa Barbara Island on the eastern flank of the Santa Cruz Basin.

The COST well was spudded in August 1975 and drilled to a total depth of 10,920 feet in 348 feet of water. The well spudded in middle Miocene sands and shales and bottomed in Upper Cretaceous marlstone and clastics. The other wells drilled mostly Cretaceous, Paleogene, and Holocene sediments. Onlapping basinal Miocene sandstones and volcanic rocks were locally present on the flank of Santa Rosa-Cortes Ridge. Hydrocarbon staining, fluorescence, cuts, and cut fluorescence were noted in several wells.

Source Rocks

The limited drilling in the province has indicated the presence of source rocks in homotaxial equivalents of the Upper Eocene and Oligocene Gaviota and Cozy Dell Formations, with total organic carbon (TOC) averaging 2 to 3 weight percent and Type II kerogen. Shows of hydrocarbons were encountered in the Cretaceous section below a mid-Upper Cretaceous unconformity, and Paleogene rocks have had TOC analyses ranging from 0.5 to 5 weight percent, with Type I and II kerogen. A major limit to source rock potential, based on the limited data from the few wells, is that organically rich rocks above the mid-Upper Cretaceous unconformity were thermally immature. Below the unconformity, shales were mature, but organically lean. In areas of deeper burial, the younger organically rich shales may be thermally mature, but this inference has not been tested by drilling.

Reservoir Rocks

Rocks below the mid-Upper Cretaceous unconformity were highly cemented and have relatively low porosity in areas drilled. Extremely thick sandstone horizons were encountered above the mid-Upper Cretaceous unconformity in many wells and these rocks have moderately good porosity and permeability. Strata similar to Monterey Formation cherts and shales are also present and have potential as fractured shale reservoirs in the province.

Hydrocarbon Potential -

Three plays have potential in the province. Natural gas may be a possible hydrocarbon type in the older stratigraphic section or where young rocks are deeply buried. The Pre-Monterey Play includes sediments of Late Cretaceous to middle Miocene age which consist of marine sandstones, shales, mudstones, and volcanics. The Monterey Play is middle to late Miocene in age and is restricted to the northern part of the province. The Monterey Play is a generic term applying to all Monterey aged exploration targets. The Post-Monterey Play consists of sandstones, silts, and shales similar to those that were deposited in the Los Angeles Basin, but are not as thick or extensive.

Analog data used to model resource potential for this province were generated from the Ventura Basin (Miocene and older) and the Los Angeles Basin (Pliocene). Analog data are used in conjunction with directly obtained data because the province has not been widely tested by drilling.

Table - Resource Estimates - Outer Banks and Basins Province

	Condl. Mean Oil Bbbl	Condl. Mean Gas Tcf	MP_{hc}	Risked Mean Oil Bbbl	Risked Mean Gas Tcf
Economically recoverable at $18/barrel	0.50	2.39	0.47	0.23	1.11
Undiscovered resource base	0.66	3.10	0.50	0.33	1.55

Inner Banks and Basins Province

The Inner Banks and Basins Province includes the continental borderland south of the Channel Islands and westward from the mainland coast to the Santa Cruz-Santa Catalina Ridge and Thirtymile Bank (fig. V.C.2). The province includes the Santa Monica and San Pedro Basins, as well as the Dana Point and San Diego areas represented in part by the San Diego Trough and Coronado Bank (fig. V.C. 2). The area of the province west of the 3-mile State-Federal boundary is about 3,600 square miles. Water depths range from about 60 to 7,500 feet.

Geologic Setting

The Inner Banks and Basins Province in the OCS contains over 10,000 feet of Cretaceous and younger sediments deposited in areas of Santa Monica and San Pedro Basins, Coronado Bank, and San Diego Trough (fig. V.C. 2). These sediments overlie Catalina Schist, Coast Ranges ophiolites, and Great Valley sequence basement rocks (Webster and others, 1985).

The Cretaceous sedimentary sequence is incompletely known in the OCS part of the province. Onshore in the Santa Ana Mountains and San Joaquin Hills, Upper Cretaceous sediments include nonmarine clastics overlain by a transgressive-regressive sequence of conglomerate, shale, submarine channel sands, shallow-water sandstone, and siltstone. In the San Diego area, Upper Cretaceous sediments include claystones, shales, sandstones, and shallow-water conglomerates and deep-water turbidites. It is not known how far the Cretaceous sediments extend offshore, but boreholes and sampling have demonstrated these strata do not extend to Lasuen Knoll or to Thirtymile Bank.

Sedimentary rocks of Paleogene age crop out in the same onshore areas as the Upper Cretaceous sediments. They are similar to the Cretaceous section and include sandstones and conglomerates in part deposited as submarine channel fill. The stratigraphic sequence also includes shallow-water lagoonal claystones transgressive-regressive marine sequences (Webster and others, 1985). The Neogene stratigraphic sequence contains widespread volcanic rocks, most of which are believed to be Miocene in age (Webster and others, 1985). Sediments of middle Miocene and younger age include siliceous shale, diatomaceous shale, course clastic turbidites, and marine transgressive and regressive sandstone and shale which, in part, have an eastern provenance.

Structurally, the deposition and deformation of potential reservoir and hydrocarbon source rocks were controlled by uplift along the coast beginning in middle Miocene time. Periodic displacement along strike-slip faults has resulted in the uplift of clastic depocenters as anticlines which have the potential to act as traps for hydrocarbons in the province. Also, channel fill sands cutting marine shales are potential stratigraphic traps.

Drilling History

Large areas of the province have never been drilled or offered for lease. They include the following: (1) Santa Monica Bay, (2) military use areas, the largest of which is between Dana Point and offshore San Diego, and (3) areas deferred from leasing for ecological and environmental concerns. Several core holes have been drilled in State waters of the Los Angeles Basin Province and west of San Pedro Bay. Three core holes were drilled near the State-Federal 3-mile tidelands boundary near San Diego, Oceanside, and San Clemente. The offshore San Diego test well/hole penetrated only Pliocene sediments and bottomed in volcanics; the offshore Oceanside test was shallow and remained in Pliocene at total depth; the offshore San Clemente test bored into a highly promising thick section of Miocene sands, shales, and breccia. Four wildcat wells have been drilled in the Palos Verdes uplift west of the Palos Verdes fault. No wells have been drilled in the deeper portions of Santa Monica Basin, San Pedro Basin, or San Diego Trough. Gas shows were encountered in some coreholes.

Source Rocks

Data from nearshore wells, onshore outcroppings of source rocks, and seismic-stratigraphic interpretations suggest hydrocarbon source potential in the main depocenters of the province. Source rocks are inferred to be present in the Miocene section, most likely in shales that are the homotaxial equivalents of the Miocene Monterey and Puente Formations. Oil sand crops out in the Puente Formation at Point Fermin in the Palos Verdes Hills (Webster and others, 1985). Paleogene and Cretaceous strata, where present, may also have source potential. Owing to the overall thinness of the stratigraphic sequence, it is unlikely that a significant part of the Pliocene section is below the thermal window of maturity and has potential to generate hydrocarbons.

Reservoir Rocks -

Extremely thick sand sequences have been found in the few core holes drilled in the province. The potential for fractured shale reservoirs exists in temporal equivalents of the Monterey Formation. Sandstones found in nearshore core holes have reservoir potential if migration pathways for hydrocarbons generated by deeper seated hydrocarbon source rocks are present. Overall, reservoir rocks appear to have good quality and thickness.

Undiscovered Petroleum Potential

The Inner Banks and Basins Province has outstanding undiscovered potential. There are Pre-Monterey, Monterey, and Post-Monterey Plays in this province. The Pre-Monterey Play includes sediments of Late Cretaceous to middle Miocene in age and consists of marine sandstones, shales, mudstones, and volcanics. The Monterey Play is comprised of rocks of middle to upper Miocene in age and occurs over much of the province, especially Santa Monica and San Pedro Basins. The Monterey Play is a generic term applying to all Monterey aged exploration targets. The Post-Monterey Play consists of sandstones, silts, and shales similar to those deposited in the Los Angeles Basin, but not as thick or extensive. Analog data used to analyze this province were generated from direct data and the onshore Ventura Basin (Miocene and older) and the Los Angeles Basin (Pliocene).

Table - Resource Estimates - INNER Banks and Basins Province

	Condl. Mean Oil Bbbl	Condl. Mean Gas Tcf	MP_{hc}	Risked Mean Oil Bbbl	Risked Mean Gas Tcf
Economically recoverable at $18/barrel	0.42	0.72	0.95	0.40	0.69
Undiscovered resource base	0.47	0.82	0.95	0.45	0.78

Los Angeles Basin Province

The Los Angeles Basin Province encompasses mostly onshore lands. The Federal OCS portion of the province seaward of the State-Federal 3-mile boundary covers about 400 square miles in area along the western edge of the province. The province represents the structurally controlled Los Angeles Basin. The basin has as much as 8 miles of vertical relief between the peaks of faulted mountain ridges on its northern border and acoustic basement underlying over 30,000 feet of sedimentary fill in the basin depocenters (Henry, 1987, p. 1). The province includes San Pedro Bay and a portion of Santa Monica Bay. Water depth in the Federal OCS portion of the basin ranges from about 60 to over 7,500 feet.

Geologic Setting

The sedimentary section is comparatively thinner in the Federal OCS portion of the Los Angeles Basin than in State-regulated tidelands and onshore areas. Along the San Pedro shelf and Palos Verdes fault zone, sediments are mostly 9,000 to 15,000 feet thick, thinning or pinching out over short distances to the western boundary of the basin where basement has been drilled at depths of less than 2,000 feet (Henry, 1987). The depositional environments of the late Miocene aged and younger sediments, which make up most of the stratigraphic section in the basin, were controlled by divergent wrench-fault displacements (Harding, 1973) active in late Miocene through Pliocene time. In the basin deeps, organic shales and deep-water turbidite sandstone sequences were deposited during periods of geologically rapid subsidence at lower bathyal marine water depths.

The 62 Los Angeles Basin fields are mostly structurally controlled faulted anticlines, which follow major wrench-fault trends active through mid-Pleistocene time. The faulted structural closures of the Beta Field and Beta Northwest Field in the Federal OCS area are the result of uplift and folding along the Palos Verdes fault zone, one of these major wrench fault trends.

Drilling History

Commercial oil production developed in the Los Angeles Basin Province between 1860, when a commercial oil retort started producing along Wilshire Boulevard, and 1892, when the discovery of the Los Angeles City Oil Field triggered a drilling boom. As of 1986, approximately 25,800 wells have been drilled in the province (Henry, 1987). Drilling in the Federal OCS area of the province occurred after Lease Sale 35 in 1975, resulting in hydrocarbon production from the Beta Field in January 1981. Twenty-seven OCS wildcat wells in eight leases were drilled east of the Palos Verdes fault in San Pedro Bay and over 100 were drilled in the rest of the province.

Source Rocks

Source rocks in the Los Angeles Basin include Pliocene shales of the Pico and Repetto Formations, which have total organic carbon (TOC) ranging from 1 to 2 weight percent. The shales of the Miocene Puente Formation, in part correlative with the Monterey Formation, are a major source of hydrocarbons with TOC ranging up to 6 weight percent.

Reservoir Rocks

Reservoirs in the Beta Field and Beta Northwest Field are in upper Miocene sandstones that are the homotaxial equivalent to the upper Puente Formation, which is a major reservoir onshore (Webster and others, 1985, p.44). Younger reservoirs, such as the Pico, are not productive in the Federal OCS area. Cherty shales, similar to the shales of the Monterey Formation of the Santa Barbara Channel Basin, have been encountered in wells near San Pedro Bay (Webster and others, 1985, p. 45). Poorly sorted sandstone, phosphatic shales, and chert, probably correlative to the Monterey have been described from the "237" production zone in the Long Beach area (Henderson, 1987, p. 57, ~~See~~ fig. 5 of HENDERSON). ~~fig. 5~~). The shales, where present in the Federal OCS, possibly do not have the thickness or fracture permeability to be stand-alone commercial reservoirs or plays.

Undiscovered Petroleum Potential

Hydrocarbon potential is limited by the comparatively small amount of acreage available for leasing in the Federal OCS portion of the province. Also, the thin stratigraphic sequence in the OCS limits the potential for deep plays that are active onshore. Monterey, Pre-Monterey, and Post-Monterey Plays are present in the OCS part of the Los Angeles Basin.

The Pre-Monterey Play consists of middle Miocene silty and sandy shales, sandstones, and conglomerates. This zone is of minor importance, accounting for less than 1 percent of the oil produced from the basin. The Monterey Play (lower to middle Puente Formation equivalent) consists of middle and upper Miocene cherty shales. These shales are of unknown importance in this basin as a reservoir, but are very important as source rocks. The Post-Monterey Play is late Miocene to Pliocene in age and includes rocks equivalent to the upper Puente Formation, the lower Pliocene Repetto Formation, and the upper Pliocene Pico Formation. These sequences/plays consist of marine sands, silts, and shales.

Analogs for this province are derived from the fields within the basin, including OCS, State-water, and onshore fields.

Table - Resource Estimates - Los Angeles Basin Province

	Condl. Mean Oil Bbl	Condl. Mean Gas Tcf	MP_{hc}	Risked Mean Oil Bbl	Risked Mean Gas Tcf
Economically recoverable at $18/barrel	0.13	0.18	0.72	0.09	0.13
Undiscovered resource base	0.12	0.17	0.76	0.09	0.13

Santa Barbara Channel-Ventura Basin Province

The Santa Barbara Channel Basin is the offshore extension of the onshore Ventura Basin. The Santa Barbara Channel Basin in Federal waters extends about 80 miles along an east-west trend, is about 25 miles wide, and covers about 1,700 square miles. Water depths range from 150 to 2,300 feet in the Federal OCS outside the State-Federal 3-mile boundary.

Geologic Setting

The Santa Barbara Channel Basin in Federal waters contains as much as 45,000 feet of Cretaceous through Holocene sediments. These sediments were deposited over a structurally complex group of basement rocks, probably correlative to the melange of the Franciscan assemblege and pre-Cretaceous (?) diorites and schists, which crop out on islands and the nearby mainland. These basement rocks have been encountered in a few wells. Sediments deposited in the basin include a thick section of Cretaceous and Paleogene marine and nonmarine clastic rocks overlain by a sequence of Neogene sandstones, shales, volcanics, and siliceous shales and cherts. The late Neogene section of sandstones and shales thickens toward the northeast.

Structural trends in the basin are mostly east-west, subparallel with the Santa Ynez fault zone, north of the province. In the south, the basin is bounded by the east-west trending Channel Islands, which are cut by the Santa Cruz Island fault. Differential strike-slip and reverse displacements along these and other significant regional fault zones have resulted in numerous faulted, steep-limbed folds indicative of a history of intense and complex deformation. Beginning in early Pliocene time, and continuing with more intensity in mid-Pleistocene time, major tectonism produced most of the present structural and geomorphic features of the Santa Barbara Channel Basin.

Drilling History

Drilling in the Santa Barbara Channel-Ventura Basin Province began in 1866 with the successful completion of an onshore well by the California Petroleum Company near the town of Ojai. Offshore production in State tidelands began with the seaward extension of the Summerland Oil Field in the 1890's. Federal leases were first awarded in the offshore Santa Barbara Channel Basin with the 1966 sale of a drainage tract, OCS Lease P-0166, which was drilled in 1967. Since that time, over 140 expendable exploratory and delineation wells have been drilled, and over 400 total wells have been completed, including development holes. In the Federal portion of the province, a total of 13 fields capable of production have been discovered, of which 6 are currently producing hydrocarbons in commercial quantities (Webster and others, 1985, p. 42). Most of the rest are commercially viable and await permits and construction of platforms.

Source Rocks

The Santa Barbara Channel-Ventura Basin Province is world renowned for its rich source rocks that generate hydrocarbons naturally expelled at the surface in the form of deposits, seeps, and tar sands.

Veinlike hydrocarbon deposits have been observed in outcrops of fractured Monterey Formation (Dibblee, 1950) illustrating that the rich organic shale beds of the unit generated hydrocarbons before uplift. Boreholes in the Santa Barbara Channel Basin have drilled through up to 3,000 feet (stratigraphic thickness) of Monterey Formation which had total organic carbon content (TOC) ranging from 2 to 9 weight percent. Based on outcrop evidence of hydrocarbon expulsion, thermal subsidence history, and borehole data, the Monterey Formation appears to be the major source of hydrocarbons in the basin. Also, Eocene shales are interpreted to have source potential based on samples with TOC ranging from 0.5 to 4 weight percent.

Reservoir Rocks

Sandstone and shale sequences of the Neogene part of the stratigraphic section represent most of the productive reservoirs in the Santa Barbara Channel-Ventura Basin Province. Producing sandstone formations include the Pico, Repetto, Santa Margarita, and Vaqueros. Fractured shales of the Monterey Formation became a significant productive reservoir with the discovery of the giant Hondo Oil Field by Exxon Company, USA in 1969. The hydrocarbon potential of the Monterey increases in a westward direction and the unit may also have future potential as a deep exploration target in the eastern Santa Barbara Channel. Paleogene sandstone reservoirs are additional drilling targets in the western portion of the basin where these rocks have not lost all permeability due to deep burial as in the east and northeast areas of the basin. Gas and condensate are produced from upper Paleogene sandstones in the Hondo Field.

Undiscovered Petroleum Potential

Three plays in the province, both onshore and offshore, are producing. The most prolific play so far has been the Post-Monterey, but the greatest production in the future probably will be from the Monterey play.

The Pre-Monterey Play consists of nonmarine and marine sandstones and shales to Cretaceous to lower Miocene age. This play ranges from being gas prone and relatively tight in the lower part, to being oil prone with good permeability and porosity in the upper part. The Pre-Monterey Play is found in the western part of the Santa Barbara Channel; if present to the east, it is very deep (>30,000 feet) and probably overmature.

The Monterey Play occurs throughout the Santa Barbara Channel and is very deep in the northeastern Channel, as is the Pre-Monterey Play. The Monterey Formation varies from 1,000 to 3,000 feet thick and generally is of higher diagenetic grade (and, therefore, is a better reservoir) to the west.

Up to 15,000 feet of Post-Monterey age sediments are present in the Santa Barbara Channel, primarily in the eastern Channel. Extensive, thick turbidite sands are present, and this zone has been the most prolific in the province.

Table - Resource Estimates - Santa Barbara Channel/Ventura Basin Province

	Condl. Mean Oil Bbbl	Condl. Mean Gas Tcf	MP_{hc}	Risked Mean Oil Bbbl	Risked Mean Gas Tcf
Economically recoverable at $18/barrel	0.29	0.79	1.00	0.29	0.79
Undiscovered resource base	0.32	0.90	1.00	0.32	0.90

Santa Maria Basin Province

The Santa Maria Basin Province extends northward from Point Conception to approximate latitude 36°15' N. It is bounded by the Santa Lucia bank on the west and by Franciscan rocks elevated along major coastal faults on the northeast. The province includes areas of major hydrocarbon production both onshore and offshore. It is defined by the Santa Maria depositional basin, which is a Middle to Late Tertiary depocenter overlying a pre-Tertiary structurally high area. The Santa Maria Basin in the OCS is approximately 140 miles long and 25 miles wide and covers about 9,200 square miles. The Santa Maria Basin is divided from the Santa Barbara Channel Basin (Dellagiarino, 1986, plate 1) southwest of Point Conception by a ridge formed by the truncated edges of the thick Paleogene sedimentary section widely distributed in the Santa Barbara Channel Basin, but not in the Santa Maria Basin. Water depth in the Federal OCS portion of the province ranges from 90 to about 9,000 feet.

Geologic Setting

Basement rocks underlying the offshore Santa Maria Basin consist of Franciscan assemblage and unmetamorphosed Upper Cretaceous strata (Howell and others, 1978). Both groups of rocks are exposed on the adjoining mainland along the coast. Marine mudstone, silty shale, and sandstone beds of early Paleogene age are locally preserved on the Santa Lucia bank, but have been mostly truncated by a subsequent Paleogene erosion. During Paleogene time, the Santa Maria Basin was a highland area uplifted along major wrench faults. Marine deposition occurred only in submarine valleys. Before Neogene time, the highlands were eroded, leaving discontinuous remnants of lower Paleogene strata in the Santa Maria Basin. The oldest Neogene rocks in the offshore Santa Maria Basin

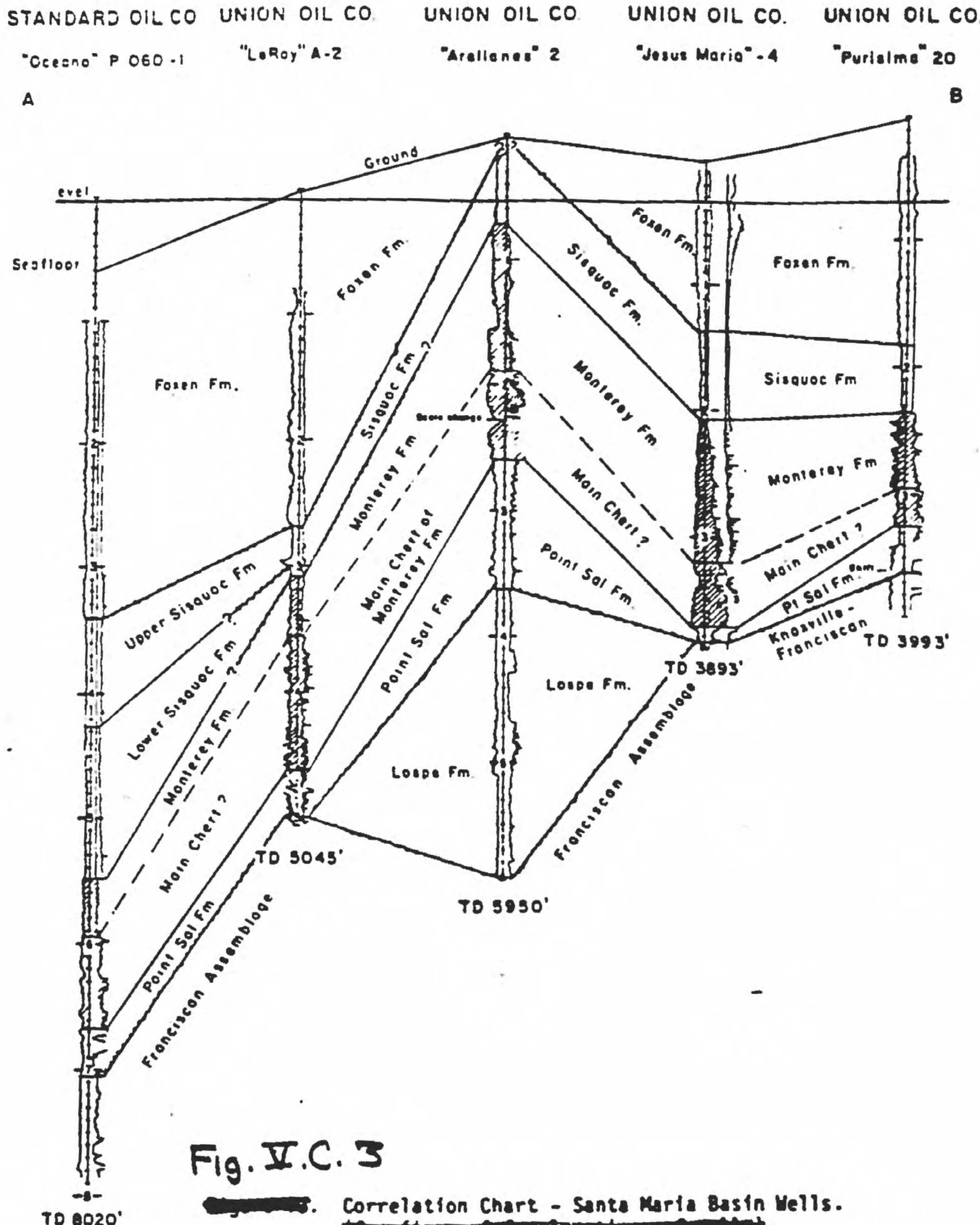


Fig. V.C. 3

[redacted]. Correlation Chart - Santa Maria Basin Wells.
[redacted].

are probably volcaniclastics and thin igneous flows (Howell and others, 1978). These rocks are covered by deposits of the transgressing middle Miocene sea. The uneven fault-controlled seafloor bathymetry controlled the amount of deposition and, as a consequence, the thickness of the Neogene sediments is highly variable, ranging from less than 3,000 feet to well over 10,000 feet.

In some portions of the basin, nonmarine sands and shales no more than a few hundred feet thick were deposited in early Miocene time. This deposition was followed in early middle Miocene time by the deposition of organic marine siltstone, mudstone, and sandstone beds ranging in thickness from a few feet up to 3,000 feet. The Monterey Formation, rich in organic material as well as silica and calcium carbonate, was deposited during the latter part of middle Miocene through the early part of late Miocene time over most of the area. The formation ranges in thickness from less than 100 feet to over 3,000 feet. The Monterey Formation is overlain by organic, diatomaceous sediments and nearshore sands of the Sisquoc Formation. A late Neogene depositional cycle began with the deposition of the Foxen Formation, which reaches a thickness of several thousand feet in some areas and consists dominately of organic mudstone of early to late Pliocene age. The youngest sediments are sands and silts of late Tertiary and Quaternary age.

Drilling History

The onshore Santa Maria Basin is one of the most productive basins per volume of sediments in the Pacific Region, with the first wells drilled during the 19th century. Initial daily oil production rates from wells drilled in the basin varied from 90 barrels to as high as 12,000 barrels, and rates of 2,500 barrels were common (Regan and Hughes, 1949). Following the first offshore lease sale in the Santa Maria Basin in 1963, Standard Oil Company of California (now Chevron USA, Inc.) drilled an exploratory well OCS-P 060 "Oceano" No. 1 about 15 miles northwest of Point Sal. The Monterey Formation in this well was 1,200 feet thick and contained shows of bleeding and fluoresent oil from top to bottom. A few indications of oil and tar were also logged in Miocene and Pliocene beds above the Monterey as well as tar in fractures in the volcanics encountered below the Monterey. At the conclusion of drilling the operator decided that it was not economically feasible at that time to produce the well, and the hole was plugged and abandoned without testing. The six leases granted in the 1963 OCS lease sale were relinquished by June 14, 1968.

In the latter part of 1978, 14 oil companies participated in the drilling of a COST well, OCS-CAL 78-164 No. 1, at a location approximately 10 miles southwest of Point Arguello. The well reached a total depth of 10,571 feet in lower Cretaceous or uppermost Jurassic sediments. Oil shows were encountered in the Pliocene and Miocene sections.

Lease Sale 48 was held in June 1979. It primarily included tracts in Santa Barbara Channel Basin and south of the Channel Islands and also some tracts along the southern edge of the Santa Maria offshore basin. The Point Arguello, Rocky Point, Jalama, and Sword fields were discovered during the drilling of some of these Sale 48 leases.

Lease Sale 53, covering the offshore southern Santa Maria Basin, was held in 1981. Commercial interest was high because of discoveries along the southern edge of the offshore Santa Maria Basin, as well as the favorable results of the COST well. Subsequent drilling on leases acquired in Sale 53 resulted in the discovery of five new oil fields. The highest bonus for a single tract in Federal leasing history was the $333,596,200 bid for lease OCS P0450 in the offshore Santa Maria Basin in Sale 53. The first well on this lease tested 2,778 barrels of oil per day from two zones in the Monterey Formation. Gravity of the oil was surprisingly high, ranging from 29.3° API to 34.4° API. This well is a delineation well of the Point Arguello oil field, which the operator estimated to have recoverable reserves ranging from 300 million to 500 million barrels of oil (Crain and others, 1985, p. 5-5). The field is also estimated to be capable of producing up to 225,000 barrels of oil per day.

Source Rocks

The primary source rocks of the province are fractured shales and carbonates of the Monterey Formation. Total organic carbon from these strata have been measured at 2 to 9 weight percent. Thermal maturity studies have so far shown that the hydrocarbons in productive fields of the basin are sourced from deeply buried Monterey Formation rocks. The oil and gas apparently migrates up faults and fractures in the formation to be trapped in structures enclosing shallower units of the same formation.

Reservoir Rocks

Over 95 percent of all productive reservoirs in the province occur in fractured shales of the Miocene Monterey Formation. Productivity appears related to diagenetic grade and silica content with the most cherty units being the most productive. Other reservoirs include clastic stratigraphic sequences of the lower Miocene to Pliocene Foxen and Siquoc Formations and the lower Miocene Point Sal Formation.

Undiscovered Hydrocarbon Potential

In general, hydrocarbon bearing rocks become thinner in a northern direction in the province, and reservoir rocks have been erosionally removed from some faulted anticlines in the northernmost part of the province. However, basins to the north of the Santa Maria Basin Province are known from past drilling to contain thicker and higher quality Monterey Formation rocks in some locations. (See discussion of Central California Coastal Province.)

Table - Resource Estimates - Santa Maria Basin

	Condl. Mean Oil Bbbl	Condl. Mean Gas Tcf	MP_{hc}	Risked Mean Oil Bbbl	Risked Mean Gas Tcf
Economically recoverable at $18/barrel	0.27	0.26	0.95	0.26	0.25
Undiscovered resource base	0.62	0.57	0.95	0.59	0.54

Central California Coastal Province

The Central California Coastal Province extends northwest along the Coast Ranges of California. The Federal OCS portion of the province covers about 12,800 square miles. Water depths in the OCS range from 60 to over 9,000 feet. The Federal OCS portion of the province includes four major basins which are from north to south, Point Arena, Bodega, La Honda, and Ano Nuevo ([redacted]).

Geologic Setting

Distribution of Paleogene and older sediments in the basins of the province varies considerably. In the Ano Nuevo Basin, Paleogene sediments appear to be absent (fig. V.C.4). The Miocene strata overlie Upper Cretaceous rocks with angular unconformity. The onshore La Honda and Bodega Basins, however, contain Paleogene sediments (fig. V.C.5). Upper Paleogene sediments in the Bodega Basin are absent because of erosion. Upper Paleogene sediments in the Point Arena Basin have been partially removed by erosion.

In contrast to the variable Paleogene sediment distribution, Neogene sediments are widely distributed over the basins included in the province ([redacted] compare figures V.C.4, V.C.5, and V.C.6). The Monterey Formation overlies lower Neogene sediments and volcanics, which are present throughout the Ano Nuevo, La Honda, and Bodega Basins. The Monterey Formation, in some locations, is as thick as productive reservoirs found in southern California (fig. V.C.4), although late Miocene erosion removed much of the Monterey Formation in portions of the Bodega Basin (fig. V.C.5). The Miocene Point Arena Formation is found in the Point Arena Basin in place of the Monterey Formation. The Point Arena Formation is the homotaxial equivalent

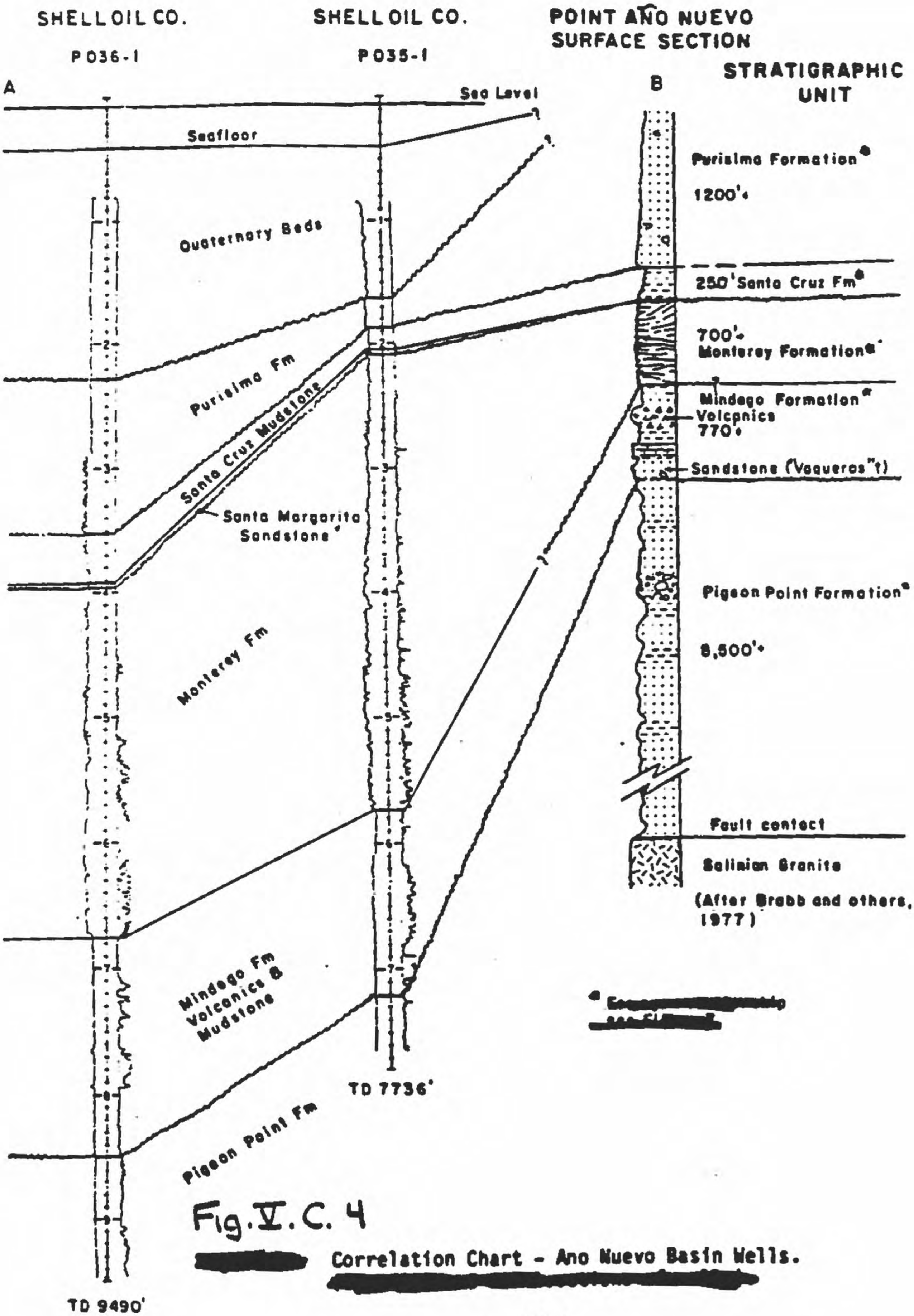
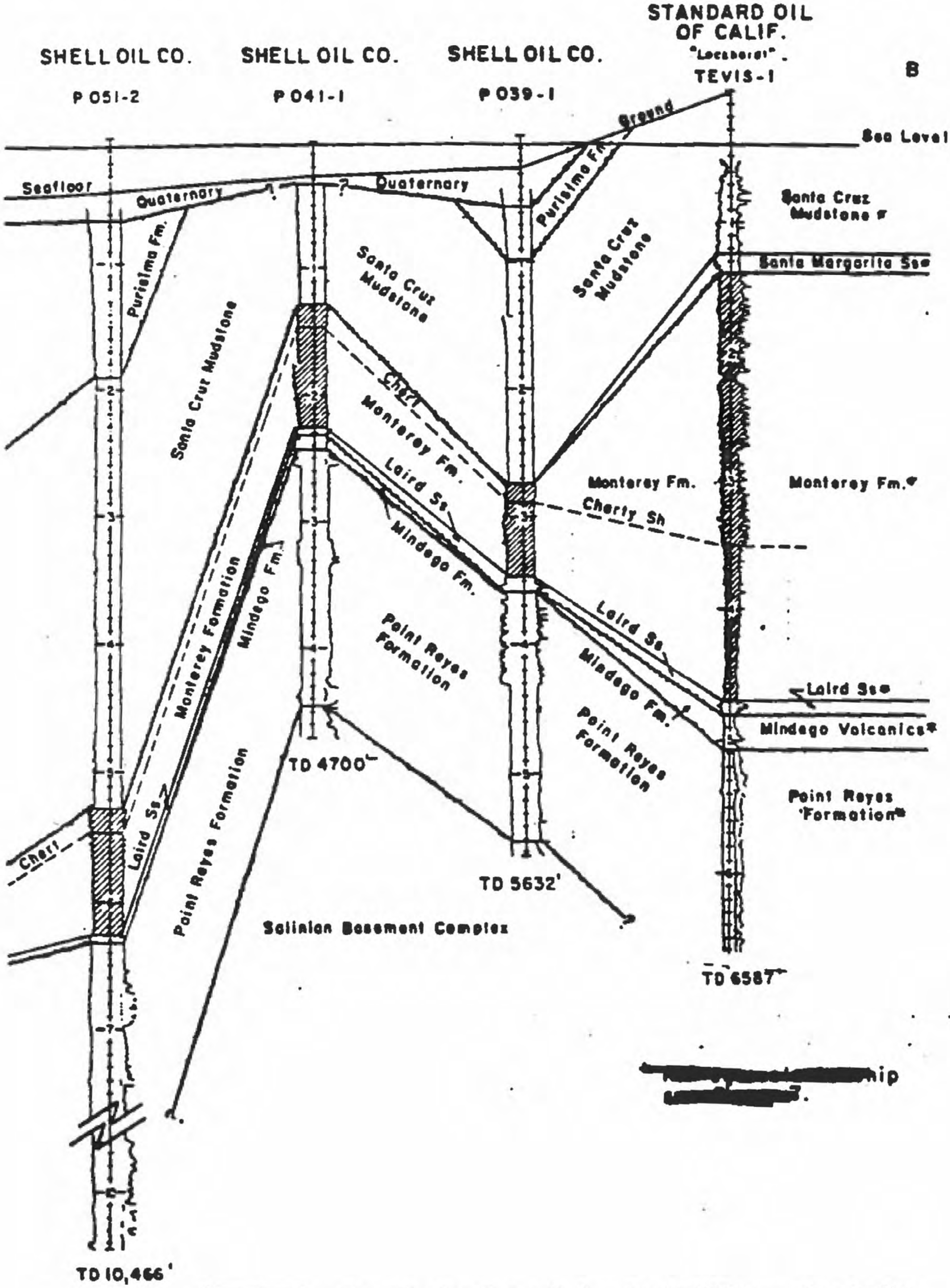


Fig. V. C. 4

[redacted] Correlation Chart - Ano Nuevo Basin Wells.
[redacted]

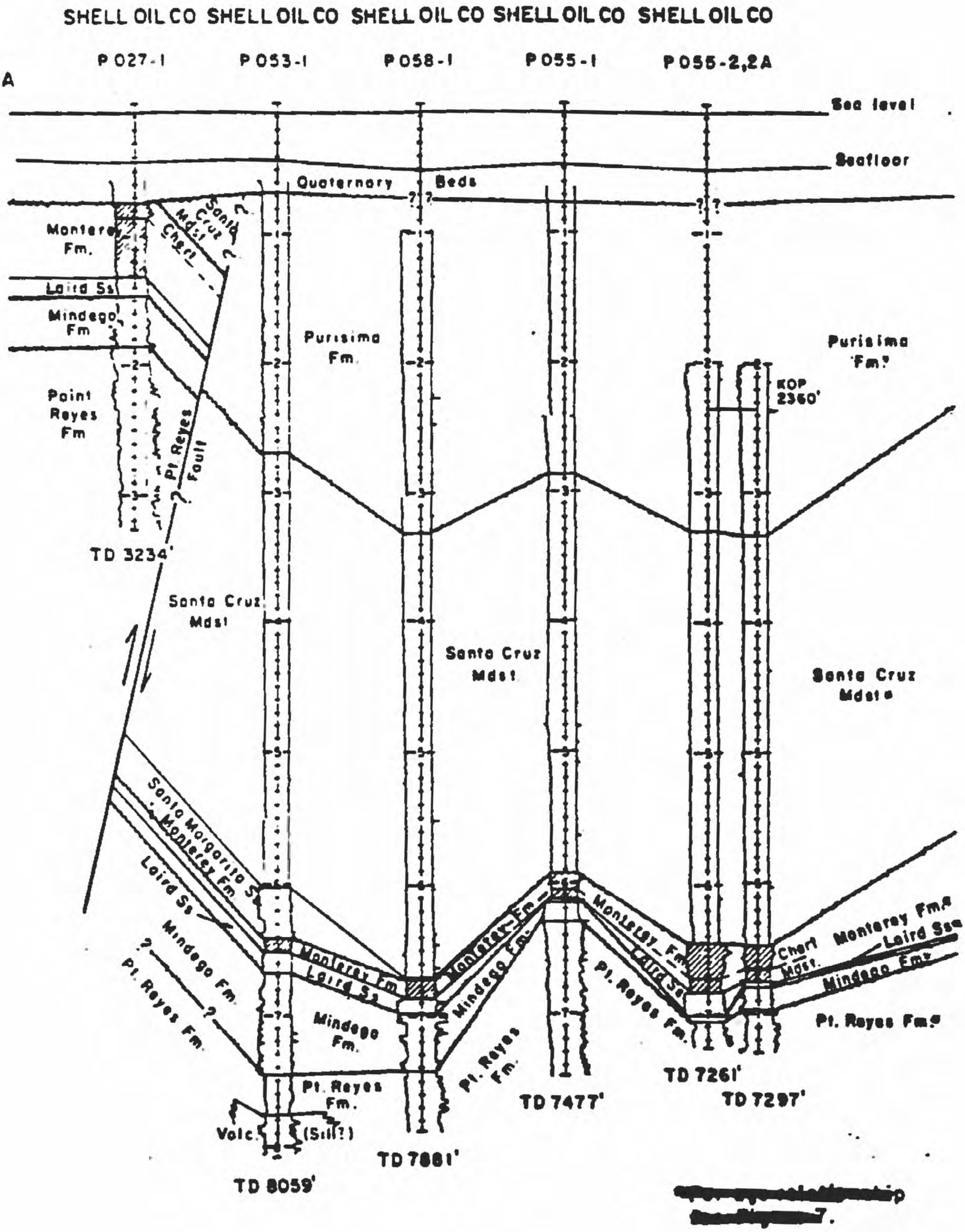


[redacted]. Correlation Chart-Bodega Basin Wells --[redacted]

[redacted]

Fig. V.C.5A
(part 1)

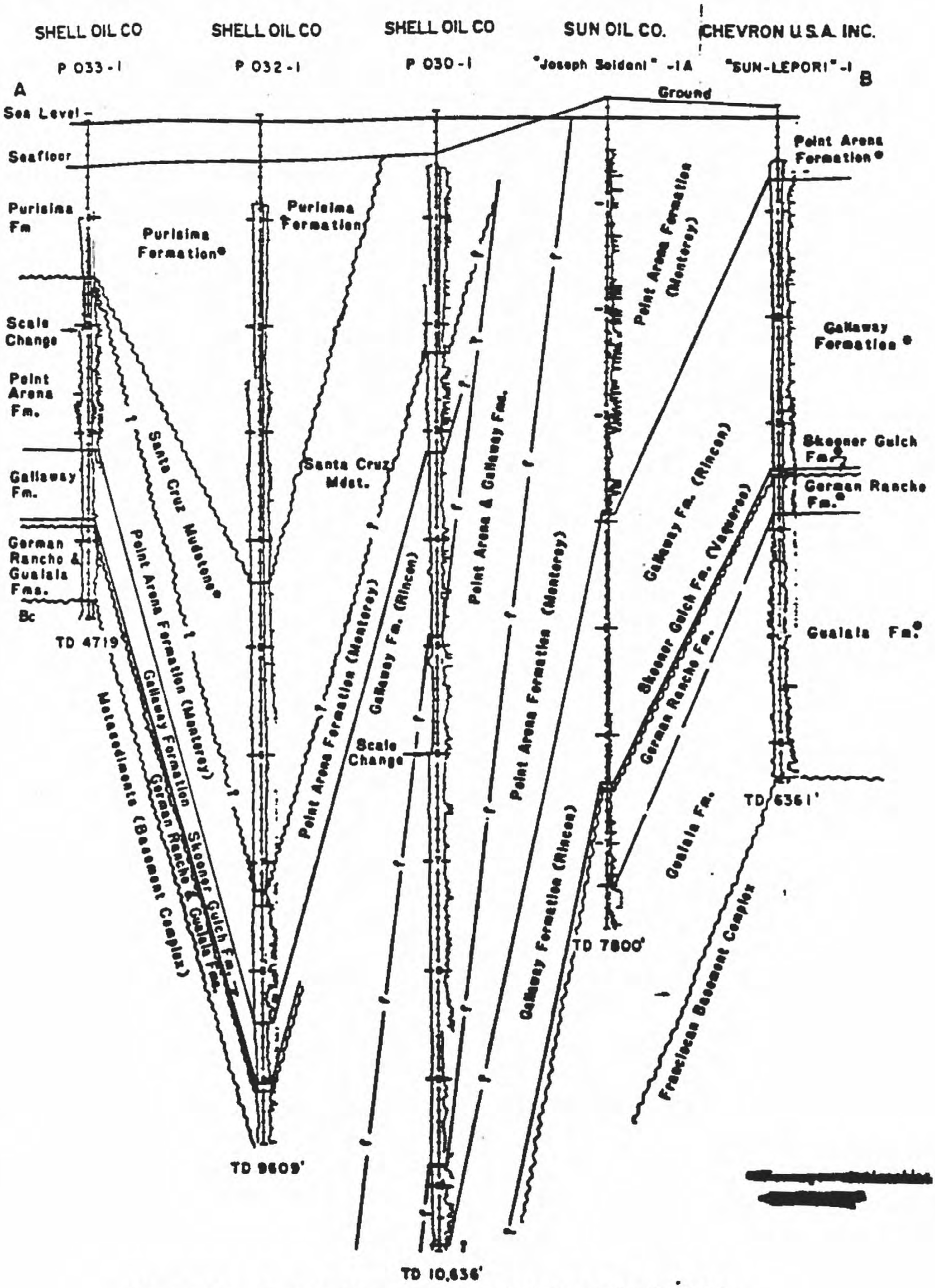
[redacted] 397



[redacted]. Correlation Chart - Bodega Basin Wells.

Fig. V.C.5B
(part 2)

[redacted]



[redacted]. Correlation Chart - Point Arena Basin Wells.
[redacted].

Fig. V.C.6

to the Monterey Formation. A homotaxial equivalent formation is a rock-stratigraphic unit with the same order, composition, or arrangement but is in a different location, and is not necessarily of contemporaneous age. Miocene rocks are overalin by varying thicknesses of late Neogene mudstone, shale, and minor amounts of sandstone in all of the basins.

The structural setting of the province is dominated by northwest-trending wrench faults and conjugate shear sets associated with the San Andreas transcurrent fault zone. The Pacific Plate-North American Plate boundary is approximately defined by this zone (Field and others, 1980). Stike-slip displacement has moved Sierran-type basement rocks northwestward, perhaps as much as 370 miles in some areas. Recurrent stike-slip displacement has produced many faulted anticlinal structures subparallel to regional wrench faults in each of the basins of the province. These types of anticlinal structures represent the primary exploration targets and productive oil and gas fields in provinces of southern California.

Drilling History

Some of the earliest oil and gas production in California (circa 1880) occurred in onshore fields of the province (Webster and Yenne, 1987). The size and number of the fields discovered, however, proved to be small, and the ultimate production from them will probably be less than 10 million barrels of oil and 10 billion cubic feet of gas. Production occurred in reservoirs of Eocene through Pleistocene age.

Ten wells were drilled in the OCS of the Bodega Basin, beginning in 1963, and two wells were drilled in the Ano Nuevo Basin, beginning in 1967 (see fig II.C.7. for well locations). These wells were drilled on leases issued in the 1963 Pacific OCS lease sale. Oil shows were encountered in six of the Bodega Basin wells, one of which was

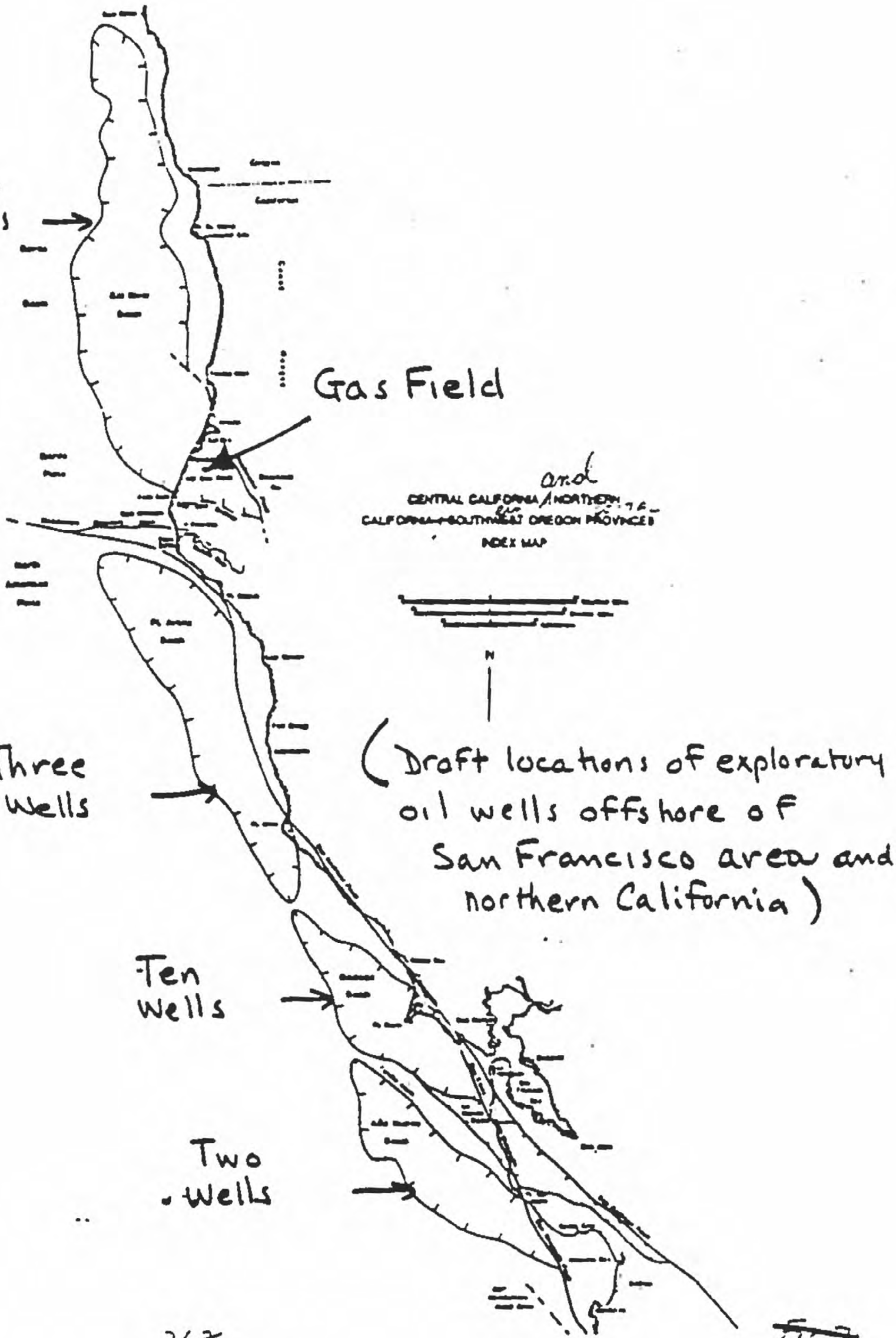


Figure I.C.17

~~Fig 7~~ 8

tested, resulting in the recovery of only drilling mud and water (Webster and Yenne, 1987). In both Ano Nuevo wells, drill cuttings throughout the nearly 3,000 feet of Monterey Formation were coated with free tarry oil, but no drill stem tests were run. Three wells were drilled by Shell in 1965-1966 in the southernmost Point Arena Basin following the 1963 OCS lease sale (Webster and others, 1987), as much as 90 percent of the cuttings were coated with free tarry oil. In the first of these wells, cherty limestone beds were encountered, and 29° API gravity oil was recovered with formation water in one test. The other wells also encountered shows of tar and visible hydrocarbon cuts and/or cut fluorescence.

Source Rocks

Hydrocarbon source rocks within the Point Arena Basin are within the Neogene section. The Point Arena Formation had indications of oil throughout in OCS exploratory wells and source rock potential is indicated onshore in wells and outcrops. The Gallaway Formation, the homotaxial equivalent of the Rincon Formation, underlies the Point Arena Formation, and indications of light oil were also noted in wells in this formation also. The main hydrocarbon source rocks in the Bodega, La Honda, and Ano Nuevo Basins are inferred to be the Monterey Formation and perhaps some Paleogene strata in La Honda Basin, which showed minor production from rocks of this age onshore.

Reservoir Rocks

There is significant potential for reservoir quality rocks in the Point Arena Basin. Porous sandstones, in addition to fractured shales, occur in the Point Arena, Gallaway, and Skooner Gulch Formations of Neogene age and possibly in the younger units of the Paleogene. Fractured cherts and other brittle rocks of the Point Arena Formation may be the primary reservoirs. The primary reservoir rocks in the basins south of the Point Arena area are thought to be fractured shales of the Monterey Formation. Potential reservoirs also exist in Pre-Monterey and Post-Monterey clastic sediments.

Undiscovered Hydrocarbon Potential

Pre-Monterey, Monterey, and Post-Monterey Plays are all present in this province. The Monterey Play is by far the most important and is found in all of the basins. Monterey Play is a generic term applying to all Monterey aged exploration targets, including the Point Arena Formation. The other plays are more restricted in extent. Pre-Monterey potential is found in Bodega, La Honda, and possibly Ano Nuevo Basins, whereas the Post-Monterey Play is restricted to the Bodega and La Honda Basins. Data for this province were derived from direct drilling information and from analog information from the Santa Maria Province for the Monterey and Post-Monterey and the Santa Barbara Channel-Ventura Basin Province for the Pre-Monterey Plays.

Table - Resource Estimates - Central Central California Coastal Province

	Condl. Mean Oil Bbbl	Condl. Mean Gas Tcf	MP_{hc}	Risked Mean Oil Bbbl	Risked Mean Gas Tcf
Economically recoverable at $18/barrel	0.77	1.10	0.95	0.74	1.05
Undiscovered resource base	1.63	2.03	0.95	1.55	1.93

Northern California-Southern Oregon Coastal Province

The province extends northward about 130 miles from False Cape (south of Eureka) on the south to Cape Blanco in Oregon. The Eel River Basin has been the main area of hydrocarbon exploratory interest in the province (fig. I.C.7). The Eel River Basin onshore yielded commercial quantities of gas (about 95 bill cubic feet of reserves), and minor amounts of oil were produced in the Petrolia area onshore. Water depth in the Federal OCS portion of the province ranges from 60 to about 9,000 feet.

Geologic Setting

The Mendocino fracture zone separates the Central California Coastal Province from the Northern California-Southern Oregon Coastal Province (fig. I.C.7). The Eel River Basin is the major depocenter of the province and lies north of the fracture zone, reflecting in part subduction and transform faulting. The Along the western boundary of the province near the continental slope, oceanic rocks are being subducted beneath continental rocks of North America. The structural configuration of the Eel River Basin was defined in late middle Miocene time, and structural features are generally parallel with the long axis of the basin (west-northwest onshore to north-south offshore). Basement rock is probably accretionary metasedimentary and igneous rocks of Cretaceous and Jurassic age. Paleogene sediments exist only as scattered erosional remnants.

Three major depositional/orogenic cycles, the Paleogene, early Neogene, and late Neogene comprise the Tertiary stratigraphic section of the province. Deposition of the Paleogene cycle began in Latest Cretaceous time and ended, because of regional uplift and erosion, in Oligocene time during which most of the Paleogene section was removed. Two minor periods of possible uplift and local erosion occurred within the Paleogene cycle during Paleocene and middle Eocene times. Landward transgression of the sea in early Miocene time instigated the early Neogene depositional cycle, remnants of which are preserved onshore. The Eel River Basin contains more than 15,000 feet of Neogene marine sediments offshore (Hoskins and Griffiths, 1971). The basin is the primary area of deposition of Wildcat Group sediments of late Neogene age [redacted]. Along the southern edge of the province, beds of upper Miocene age unconformably overlie the Yager Formation of early Paleogene age. Erosional remnants of lower and middle Miocene strata of the lower Neogene depositional cycle, informally named the "Bear River Beds" (Hopps and Horan, 1983), are present to the south onshore in the Bear River drainage. All of these stratigraphic units have sandstones with a significant component of lithic fragments and clays, which affects the reservoir quality of the units. However, at some locations, the porosity and permeability are of excellent to good quality. The nature of the stratigraphic section in the main part of the offshore southern basin is uncertain due to the lack of any drill holes, and the potential source and reservoir rocks can only be inferred.

Higher than normal geopressure fluid gradients have been encountered at depths generally below 5,000 feet in wells drilled onshore exceeding 0.7 psi/feet in some areas (Hopps and Horan, 1983). Although no abnormal geopressures were encountered in the few wells drilled offshore, abnormally high geopressures have caused shale flowage in deeply buried sediments. This caused the growth of many shale diapir structures. These structures intrude upward into the younger beds, in some cases breaching the seafloor, and in most cases, creating seafloor relief (Field and others, 1980).

Drilling History

The first commercial production of petroleum in the Northern California-Southern Oregon Coastal Province from oil wells, rather than from mining, and the first commercial sale of this oil came from the Petrolia region during the short-lived oil boom of 1864-1865 (Hopps and Horan, 1983). Petrolia is on the Mattole River in Humboldt County in an area of numerous oil and gas seeps. Production came from highly deformed fault blocks of Cretaceous rocks. In the following 85 years, over 50 wells were drilled in the Bear River, Mattole River, and Briceland areas. Some were temporary producers of high-gravity oil, some of gas. Most were located near seeps, many in shear zone rocks (Ogle, 1953). In September 1937, The Texas Company (now Texaco, Inc.) drilled "Eureka" No. 2, the discovery well of the Tompkins Hill Gas Field. It was drilled to 7,708 feet total depth and produced 1,400 Mcf/D (thousand cubic feet per day) of gas from 4,010-5,350 feet in the Rio Dell Formation (FG. V.C.8, & Ogle, 1953). Production came from thin sandstone beds of Pliocene (Venturian) age.

On May 14, 1963, the first OCS oil and gas lease sale on the Pacific OCS was held resulting in seventeen tracts being leased. The offshore area west of gas production of the onshore Eel River Basin was withheld from the sale because of the shipping lanes into Eureka (Hoskins and Griffiths, 1971). Four exploratory tests were drilled in the northernmost part of the offshore Eel River Basin from July 1964 to July 1965. They were located on the shelf between Trinidad Head and Crescent City. Two wells encountered Franciscan basement rocks at shallow depths, overlain by Quaternary sediments, and gained no useful geologic information. Two others were farther offshore and penetrated sediments of the Wildcat Group before encountering pre-Neogene rocks. No

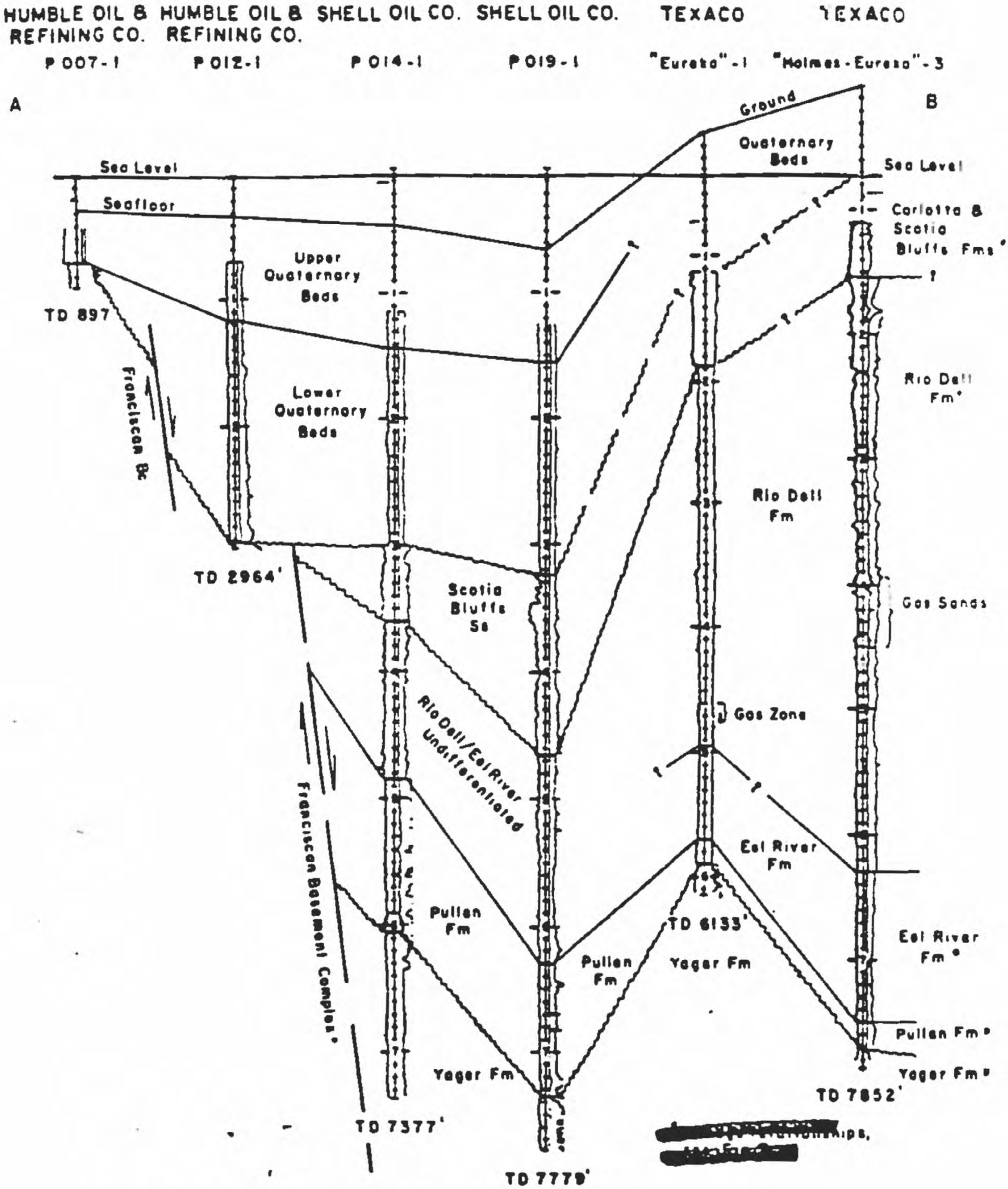


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Figure [redacted].

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Fig. I-8

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hydrocarbon shows were encountered in any of the four drill holes (Webster and others, 1986). However, hydrocarbons were recovered offshore from a gravity core in unconsolidated sediments ponded within a depression on the surface of a shale diapir. The hydrocarbons contained high concentrations of ethane through butane (C_2-C_4). Gasoline-range hydrocarbons (C_5-C_{-10}) and a complex mixture of heavy hydrocarbons (C_{15+}) were also present. This gas/liquid mixture may have originated deep within the basin and migrated to the surface through fractures and faults associated with the diapir (Kvenholden and Field, 1981), although the data set is too small to be conclusive as to origin (Abrams, 1987).

Source Rocks

Yager strata are the most likely source beds for hydrocarbons within the Eel River Basin. Type III kerogen, which generates mostly gas, is dominant, and the organic carbon content and hydrocarbon yield of the beds are relatively low. The thermal maturity of Yager shales is within the window of peak hydrocarbon generation. This maturity is attributable to a combination of middle Tertiary thrust faulting and subsequent depositional burial of the Yager strata beneath the Neogene Wildcat Group sediments (Underwood, 1985).

Most of the numerous onshore oil shows are within the pre-Neogene section and at the unconformity at the top of the pre-Neogene sediments (MacGinitie, 1943). These locations indicate that the source of the oil in the seeps and wells is the black organic shales of the pre-Neogene rocks. This oil has a paraffin base (MacGinitie, 1943).

The Monterey-equivalent "Bear River Beds" contain sandstone beds as well as siliceous shales and may be more organic and cherty if present at the same depth offshore. Oil seeps are associated with the Bear River/Yager contact onshore as well as with the Pullen-Yager contact. Fractured siliceous rocks in the "Bear River Beds," if present offshore, may provide additional source rocks. Middle Eocene to Cretaceous organic shales are already known to occur in offshore wells.

Reservoir Rocks

Electrical logs in the Yager Formation in onshore wells have shown low values on the self-potential curve and high values on the resistivity curves, indicative of poor reservoir potential. However, porosities of the basal sandstones of the Pullen Formation were about 25 percent with permeabilities exceeding 300 millidarcies, as measured from offshore well cores. Some of the thin turbidite sandstone beds of the Eel River Formation were also of reservoir quality in onshore wells (Hopps and Horan, 1983). The primary reservoirs are inferred to be sandstone units of the Rio Dell Formation of the Wildcat Group.

Undiscovered Petroleum Potential

The Northern California-Southern Oregon Coastal Province has low to moderate potential for oil, gas, and condensate production. Oceanic rocks of the Exclusive Economic Zone, comprised in part by the subducting basaltic Pacific Plate, are assessed as having zero long-term potential for economically recoverable hydrocarbons due to the thin veneer of source beds and reservoir rocks as well as very low heat flow and thermal maturity. The southern province is favorably located adjacent to existing onshore natural gas pipelines, and most of the OCS shelf area is in shallow-water depths favoring commercial. production. As with other offshore OCS Pacific provinces along a subduction zone setting, all boreholes have so far been dry, encountered lean source rocks, and found reservoir rocks with clay cementation filling and lowering effective porosity. The most prospective play in this province is the Post-Monterey sediments of the Wildcat Group. The Wildcat Group consists of up to 10,000 feet of marine sandstones and shales. Commercial gas production in the Eel River Basin is from this zone. Analogs used to develop the parameters for this province are derived from the onshore Eel River Basin, as well as from reservoirs in similar-aged rocks.

Table - Resource Estimates - Northern California and Southwestern Oregon Province

	Condl. Mean Oil Bbbl	Condl. Mean Gas Tcf	MP_{hc}	Risked Mean Oil Bbbl	Risked Mean Gas Tcf
Economically recoverable at $18/barrel	0.11	1.92	0.36	0.04	0.69
Undiscovered resource base	0.36	4.47	0.36	0.13	1.61

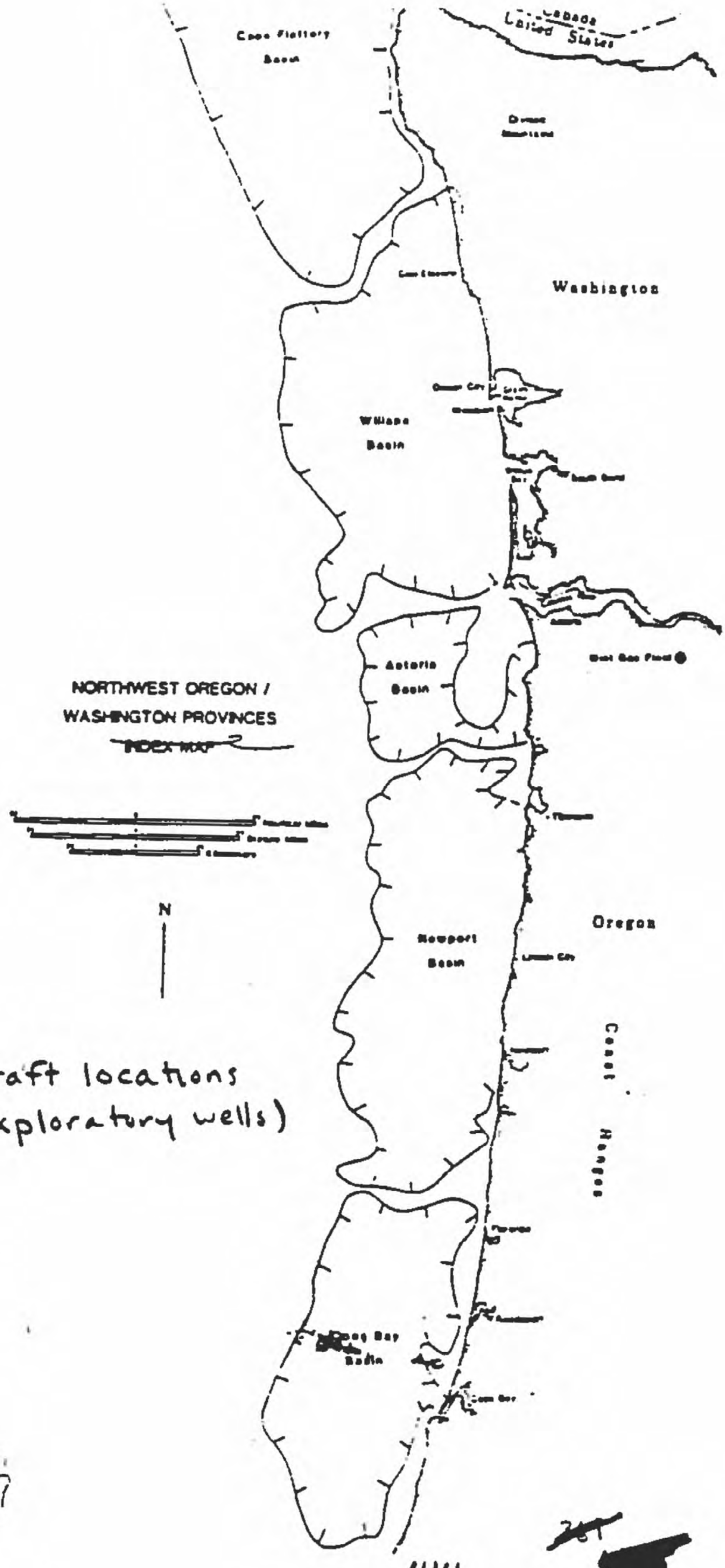
Western Oregon-Washington Province

The province extends from Cape Blanco, Oregon, northward to the Canadian border along the Oregon and Washington Coast Ranges and Olympic Mountains. The province in the Federal OCS includes five Neogene depositional basins, which are from north to south Cape Flattery, Willapa, Astoria, Newport, and Coos Bay (fig. II.C 9). The province in the Federal OCS covers 24,800 square miles, and water depth ranges from 60 to about 7,500 feet. Most areas of the Exclusive Economic Zone (EEZ) in the province have thin sediments deposited over oceanic basaltic crust, and these were assessed as being too thin to generate or trap recoverable volumes of hydrocarbons at any price/cost scenario in the foreseeable future.

Geologic Setting

The geologic setting of the Western Oregon-Washington Province is controlled by subduction of Pacific Oceanic Plate beneath slope-type basins deposited over accretionary crust seaward of a volcanic belt. The Tertiary basins, whose dimensions have changed over time, are part of a series of slope basins that developed in forearc tectonic settings around the northern Pacific Ocean.

There were four cycles of deposition and orogeny in the province in Eocene to Pliocene time before the Cascadian Orogeny. The first cycle occurred in early and middle Eocene time; the second in late Eocene and Oligocene time; the third began in early Miocene and ended in late Miocene time; and the forth cycle began in late Miocene and ended in late Pliocene/Pleistocene time (Webster, 1985). Deposition of dominantly lithic sandstones, shales, and volcanic rocks during each cycle was interspaced by deformation and also local erosion at the close of each cycle.



(Draft locations of exploratory wells)

I.C
Figure 7

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[redacted]

Drilling History

The second OCS oil and gas lease sale for the Pacific region was held on October 1, 1964, for the Federal area off the States of Oregon and Washington. It followed the first sale, off central and northern California, by about 18 months. Bids were received and accepted on 101 tracts (580,853 acres). Seventy-four of the tracts (425,433 acres) were off Oregon and 27 tracts (155,420 acres) were off Washington. Tracts off northern Washington were not offered at this lease sale because of the disputed international boundary with Canada. All leases were relinquished between November 21, 1966, and November 30, 1969.

Between April 1965 and August 1967, 12 exploratory wells (11 original wells and 1 redrill) were drilled on Oregon and Washington OCS leases. Hydrocarbon shows were encountered in some of the wells, but none were considered at that time to be anywhere near commercial quantity.

Source Rocks

Source rocks are known to exist in coastal Oregon and Washington Tertiary sediments, but rocks equivalent in age and composition to California's Monterey Formation have not been found, although their presence offshore cannot be discounted. Paleogene and Neogene source rocks, although not as rich as those of the Monterey Formation, have the potential for generating commercial hydrocarbons. Onshore volcanism, widespread in each depositional cycle, may be related to elevated geothermal gradients permitting the maturation of source rocks at shallow-to-moderate burial depths. Offshore, the low geothermal gradient related to the relatively cool subducting Pacific plate migrates this trend. Gas production in the Mist Field in onshore northern Oregon is from late Paleogene sandstone.

Trivial short-lived production of 38.9° API gravity oil from middle Tertiary rocks onshore at Ocean City, Washington, indicates that source rocks could also be present in adjacent basins offshore if similar conditions exist to those onshore. The presence of rocks capable of generating significant quantities of hydrocarbons on the Washington and Oregon OCS has not yet been established, but future production is possible.

Reservoir Rocks

The lower Paleogene rocks offshore are primarily volcanics and distal mudstones, not likely to contain reservoir rocks. Deep-water turbidite sandstones of the late Paleogene and Neogene depositional cycles are most likely found offshore and may provide reservoirs for hydrocarbons.

Undiscovered Hydrocarbon Potential

The few wells drilled offshore encountered numerous hydrocarbon indications and shows, including tests of natural gas at 10-20 and 50-70 Mcf/day. Hydrocarbon fluorescence indicating high-gravity oil was noted. Both Pre- and Post-Monterey Plays are modeled in this province. It appears that Monterey lithologies and age-equivalent rocks were not deposited in this province, although they may occur offshore. The regional nature and scarcity of seismic lines available makes defining individual traps impossible in this province, so all prospects are modeled as prospect-distributions using analog data from other basins. The Post-Monterey Play is modeled on that of the nearby Eel River Basin, whereas the Pre-Monterey Play data uses western Santa Barbara Channel, Santa Cruz Basin, and directly obtained well information as analogs.

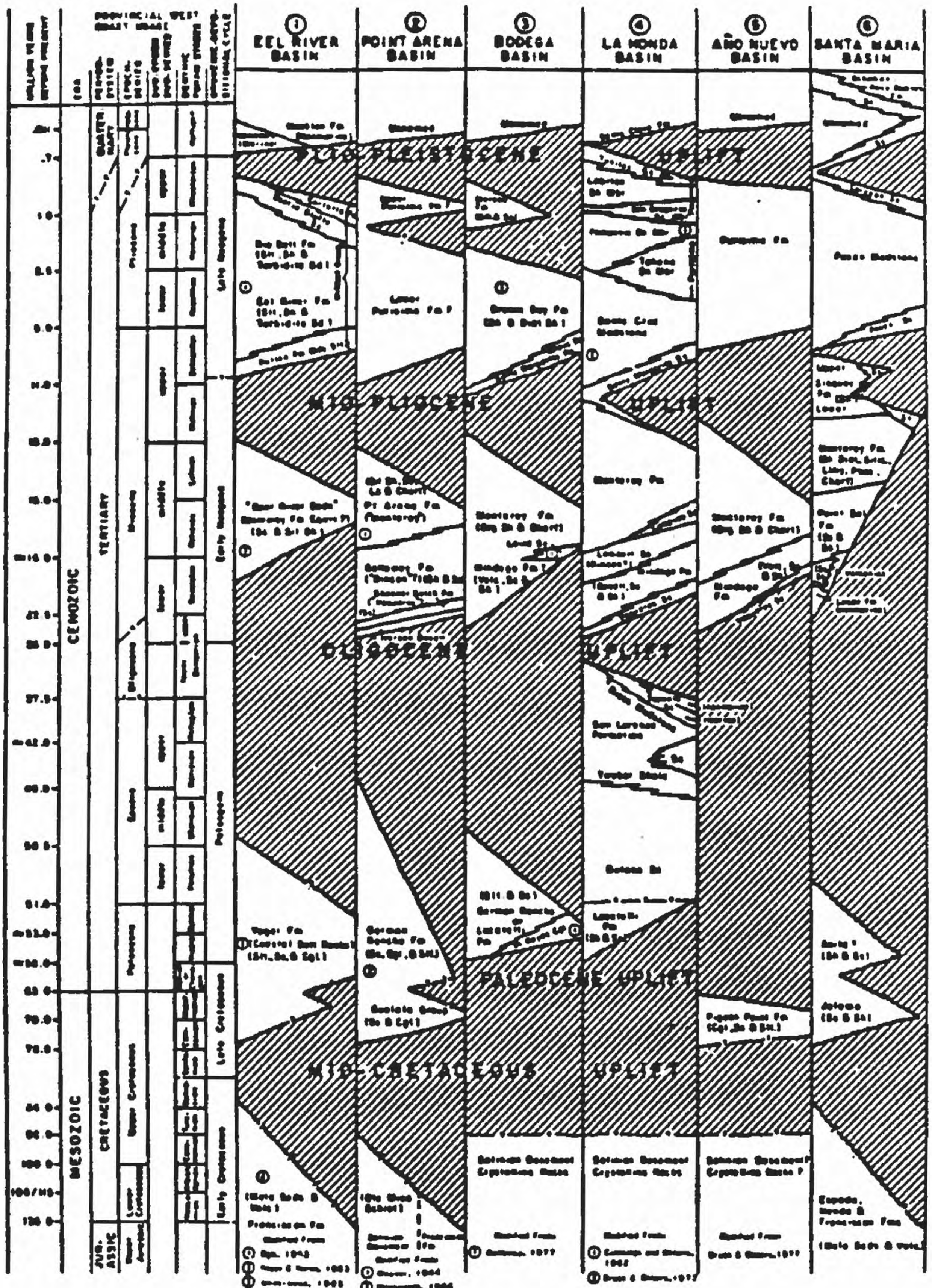

Figure 5. Stratigraphic correlation chart for central and northern California.

OCs Report 86-0025

Suggest using the Strat chart from OCS Report 87-0108 P.N Fig 7 (enclosed)

also for So. Calif. reduce plate I into 2 parts OCS RAMS 85-0042 (enclosed)

417

Regional Chart I.C FIG. 10

Table - Resource Estimates - Western Oregon - Washington Province

	Condl. Mean Oil Bbbl	Condl. Mean Gas Tcf	MP_{hc}	Risked Mean Oil Bbbl	Risked Mean Gas Tcf
Economically recoverable at $18/barrel	0.18	1.84	0.25	0.04	0.46
Undiscovered resource base	0.22	2.28	0.25	0.06	0.57

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Figure Captions

Figure 1 - Pacific region province and planning area boundaries.

Figure 2 - Geologic and physiographic features of provinces in southern California.

Figure 3 - Correlation chart of selected exploratory wells in the onshore and offshore Santa Maria Basin Province.

Figure 4 - Correlation chart of onshore stratigraphic section and two exploratory wells offshore Monterey Bay, Ano Nuevo Basin, Central California Coastal Province.

Figure 5 - Correlation chart of an onshore exploratory well just north of San Francisco and 10 exploratory wells drilled offshore near Point Reyes and Bodega Bay, Bodega Basin, Central California Coastal Province.

Figure 6 - Correlation chart of two onshore exploratory wells drilled near Point Arena and three wells offshore Point Arena Basin, Central California Coastal Province.

Figure 7 - Geologic and physiographic features of Central California Coastal Province, and Northern California-Southern Oregon Coastal Province showing approximate location of illustrated exploratory wells.

Figure 8 - Correlation chart showing productive onshore gas well and four offshore wells, Eel River Basin, Northern California-Southern Oregon Coastal Province.

Figure 9 - Geologic and physiographic features of Western Oregon-Washington Province.

Figure 10 - Stratigraphic columns, Pacific region.

D. REGION 1 A

ALASKA ~~REGION~~ OCS

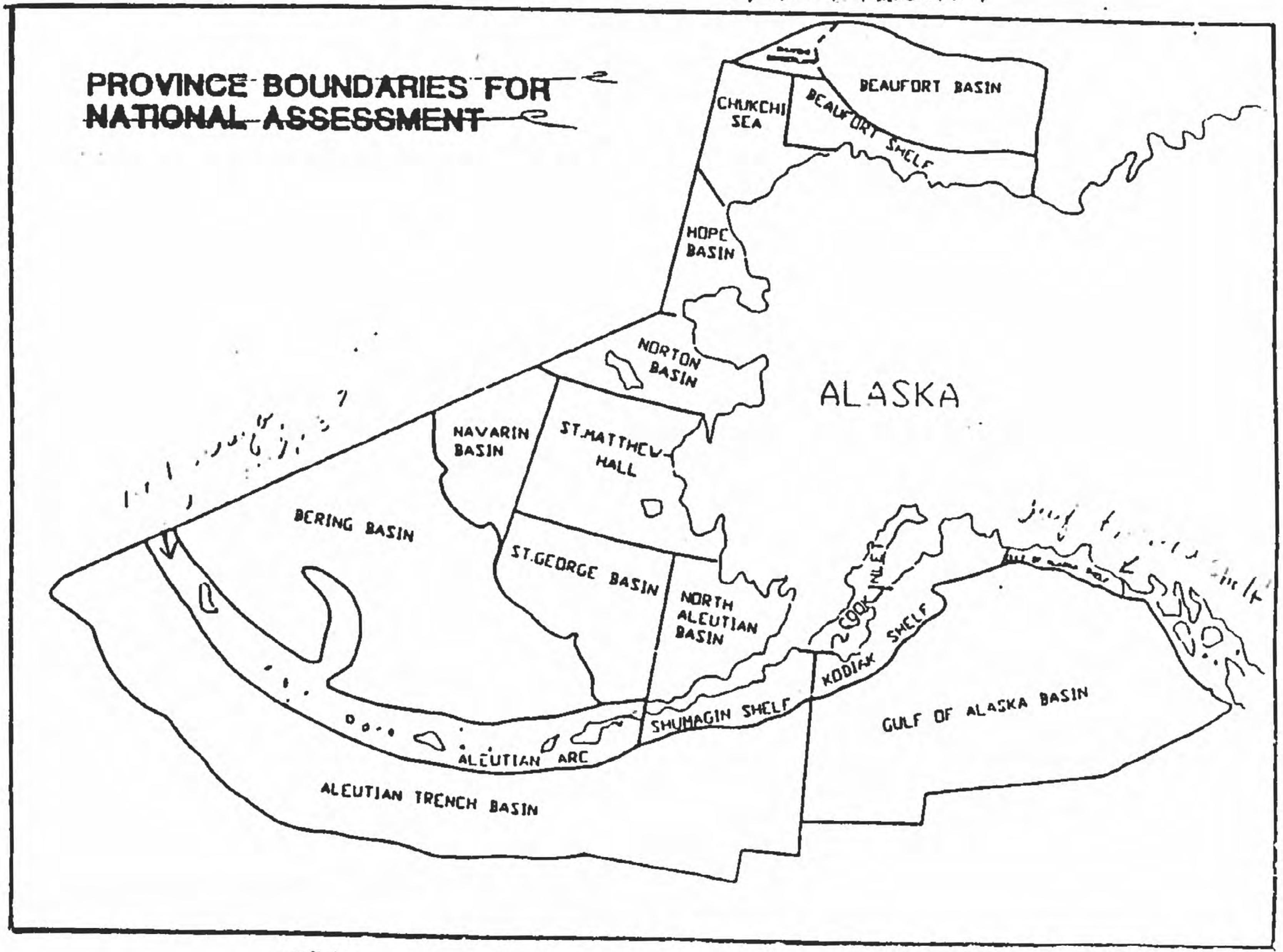
Introduction

The Alaska region includes all Federal OCS lands off the State of Alaska to the 200-mile EEZ limit, except where constrained by the Russian and Canadian V.D.1. international boundaries (fig. A). It is the largest OCS region, comprising 74 percent of total U.S. offshore lands. Because of its size and geologic complexity, the region is divided into three major areas--northern, Bering Sea, and southern to simplify the geology discussion. Each of these areas includes a number of distinct geologic provinces, which are discussed in some detail.

Geologic Setting

The northern area includes the Beaufort Basin, Beaufort Shelf, Chukchi Borderland, Chukchi Sea, and Hope Basin Provinces (fig. V.D.1. A). The area is geologically complex due to rift related compressional/extensional tectonics which resulted in widespread structural deformation. Major geologic formation groupings found in the area are the Franklinian, Ellesmerian, and Brookian sequences. At least one of these sequences occurs in each geologic province in the area. Franklinian rocks are deformed low-grade metamorphics, which constitute economic basement throughout much of the northern area. The sequence is Middle Devonian to Cambrian in age and is not considered prospective.

Ellesmerian rocks range in age from Middle Devonian to Early Cretaceous. With the exception of a locally restricted carbonate unit near the sequence base, Ellesmerian lithologies are clastics derived from the Franklinian sequence (Craig and others, 1985).


PROVINCE BOUNDARIES FOR NATIONAL ASSESSMENT
BEAUFORT BASIN
CHUKCHI SEA
BEAUFORT SHELF
HOPE BASIN
NORTON BASIN
ALASKA
NAVARIN BASIN
ST. MATTHEW-HALL
BERING BASIN
ST. GEORGE BASIN
NORTH ALEUTIAN BASIN
COOK INLET
KODIAK SHELF
SHUMAGIN SHELF
GULF OF ALASKA BASIN
ALEUTIAN ARC
ALEUTIAN TRENCH BASIN

IV.D.
Figure 1.

The Ellesmerian is capped by a sequence of coarse clastics of Cretaceous age related to a Mesozic episode of rifting. This sequence of rocks is sometimes broken out as a separate grouping ("Rift Sequence"), but here is included within the Ellesmerian.

Brookian rocks range in age from Early Cretaceous to Pliocene and are the thickest and most widespread lithologic sequence in the northern area. The rocks are clastics derived from the Brooks Range orogenic belt and were deposited as seaward prograding sedimentary wedges. The sequence is geologically complex and contains large numbers of structural closures (Craig and others, 1985).

The northernmost part of the area (Beaufort Sea) can be divided into an older landward portion (the Arctic Platform) and a younger portion consisting largely of Brookian sequence rocks deposited seaward of a rifted zone that forms the boundary (Hinge Line) between the two. Sediments landward of the Hinge Line are mostly Ellesmerian rocks deposited on Franklinian basement. It is in this zone that the major North Slope oil and gas fields (Prudhoe, Kuparuk, Point Thomson) are found (Dellagiarino, 1986).

Sedimentary sequences in the Beaufort Sea are also present westward in the Chukchi Sea. Brookian and Ellesmerian strata overlie, for the most part, Franklinian basement. The Chukchi area is generally structurally complex, with structural overprinting resulting from a number of successive orogenies. Wrench faulting has generated large numbers of complicated flower structures, "snake heads," etc. The combined thickness of Brookian and Ellesmerian sediments exceeds 40,000 feet at certain sites near the principal depocenters.

Hope Basin to the south is a Late Cretaceous-Tertiary basin containing less than 20,000 feet of terrigenous clastic sediments. Economic basement is largely Mesozoic clastics which are faulted into an east-west trending horst and graben. Basin fill is largely Brookian equivalent marine and fluvial shales, mudstones, siltstones, and sandstones.

The Bering Sea area includes the Norton, Navarin, Bering, St. Matthew-Hall, St. George, and North Aleutian Basins and the Aleutian Archipelago. The area includes a diverse suite of lithologies and structural styles and covers a wide range of water depths. For purposes of discussion, the Bering Sea area is divided into three subareas: the continental shelf, the Bering deep sea basin, and the Aleutian Archipelago.

The general structure of the continental shelf consists of a series of Tertiary basins filled with terrigenous clastics and volcaniclastics unconformably overlying volcanic or metasedimentary basement rocks. A number of transgressive-regressive episodes resulted in several regional unconformities as well as widespread interfingered marine and nonmarine deposits. Coal measures are found throughout the area (Turner, 1985; Comer et al., 1987).

The present continental margin was the focus of strike-slip motion between an oceanic plate and the continent in early Tertiary time. This motion produced a number of extensional basins along the margin, which rapidly filled with Teritary clastics. The plates subsequently locked and subduction shifted to its present location south of the Aleutian Archipelago. The intervening section of oceanic crust was stranded and became the Bering Sea Basin.

The Bering deep sea basin is underlain by basaltic (oceanic) crust of Cretaceous age. The geology is poorly known because of a lack of well control data, but generally consists of fine-grained hemipelagic sediments interspersed with volcaniclastics. Seismic data show the sedimentary section to be well stratified, parallel bedded, and evenly draped over preexisting topography. Postdepositional deformation of the sediments by tectonic processes is apparently absent. Maximum thickness of the sedimentary section is approximately 10,000 feet, except near the continental margin where the section thins.

The Aleutian Archipelago was formed by back arc volcanism resulting from subduction in the Aleutian Trench beginning in the early Tertiary. A few small extensional basins, generally with less than 10,000 feet of fill, occur in the area. Sediments in them are thought to consist largely of volcaniclastics with fine-grained hemipelagic clays and coarser turbidites as minor components.

The southern area includes the Gulf of Alaska and Aleutian Trench Basins, Cook Inlet and the Shumagin, Kodiak, and Gulf of Alaska Shelf Provinces. The area covers a wide range of depositional environments and water depths.

The continental shelf (excluding Lower Cook Inlet) portion of the southern area includes a series of extensional Tertiary basins overlying Tertiary volcanics and metasedimentary rocks (Plafker and others, 1975). The stratigraphy and general structural style of the continental shelf result from the subduction of the Pacific plate under the continent (Fisher, 1980). Postsubduction sedimentation consists of flat-lying, relatively undisturbed Miocene (?) to Recent terrigenous clastics with volcaniclastics as an important second order-component. Synsubduction sediments are largely Oligocene and older flysch and mafic volcanic rocks, which form economic basement throughout the area. The younger part of the section is up to 25,000 feet in thickness.

Lower Cook Inlet/Shelikoff Strait sediments include a maximum of 35,000 feet of Mesozic rocks and up to 25,000 feet of Cenozoic rocks deposited in an arcuate northeast-southwest trending basin (Dellagiarino, 1986). Jurassic and older Mesozic rocks are largely shallow water marine shales, siltstones, and sandstones. The Cenozoic section consists of shale, siltstone, sandstone, and conglomerates composed of volcanic, plutonic, and metamorphic clasts (Wills and others, 1978). Coal and dispersed tuffaceous zones are minor stratigraphic components.

Gulf of Alaska Basin sediments are largely poorly consolidated hemipelagic muds and oozes conformably deposited on oceanic crust. The section tends to be quite thin (<10,000 feet) except near the continental rise, where the influx of terrigenous clastics has developed a relatively thick prograding wedge greater than 10,000 feet thick.

Sediments in the Aleutian Trench Basin are deep-water shales, carbonates, and siliceous oozes. Strata within the trench axis are thick and highly deformed as a result of subduction (Moore, 1973). Seaward of the trench, sediments are thin and comformably overlie oceanic igneous crust.

Drilling History

Seventy-eight test and exploratory wells have been drilled in Alaskan Federal offshore waters as of December 31, 1987. Exploration of Federal offshore lands began in 1975 with the drilling of a continental offshore stratigraphic test (COST) well on the continental shelf of the Gulf of Alaska. Drilling in the Beaufort Sea, generally considered the most promising area on the Alaska Federal OCS, began in 1981 on lands leased in OCS Lease Sale BF (Craig and others, 1985). Eighteen wells have been completed in the area since that time, resulting in one as yet undeveloped discovery (the extension of the Seal Island field into Federal waters) and a number of subeconomic accumulations of oil and gas.

Drilling in the remainder of the Alaska Region in Federal waters has not resulted in commercial production, but has revealed a number of promising leads. All wells outside the Beaufort Sea area have been plugged and abandoned.

Reserves

The only "reserves" on the Alaska Federal OCS are subeconomic discovered resources contained within the Federal extension of the Seal Island structure, discovered in 1984. Total (State and Federal) recoverable hydrocarbons for Seal Island are estimated to be 300 million barrels of oil (Rogers, Golden, and Halprin, 1986). Gas associated with the field is not considered economic.

Summary

Results of drilling 78 exploratory and COST wells reveal a number of significant facts about the potential for future oil and gas production from the Alaska Region OCS. Despite world-class discoveries onshore, the OCS does not appear as promising as it once did. This shift is reflected in the change in economically recoverable resource estimates between a 1985 MMS study (Cooke, 1985) and this resource assessment study. Cooke (1985) provided risked economically recoverable estimates of 3.3 billion barrels of oil (BBO) and 13.9 trillion cubic feet (TFC) of gas for the Alaska OCS.

Gas is considered subeconomic throughout the Alaska Region and is not reported as an economically recoverable resource at current prices. The change in estimates is partially a reflection of deteriorating economics in the oil and gas industry, but it is mostly a result of disappointing drilling and the consequent reevaluation of the region's potential.

Drilling results show that most hydrocarbons will be gas or condensate, particularly on the Bering Sea continental shelf (Turner and others, 1986). Gas-prone kerogens predominate in the Gulf of Alaska continental shelf as well. The best potential for significant oil accumulations is on the North Slope where oil-prone, mature Ellesmerian Sequence rocks occur. However, this sequence has been explored on the OCS with little success so far, Mukluk being perhaps the biggest disappointment.

The most promising undrilled province in the region is the Chuckchi Sea. Ellesmerian rocks occur in at least part of the province and sediment thicknesses are great enough (>40,000+ feet) to ensure thermal maturity (Thurston and Theiss, 1987). Wrench faulting has generated large numbers of complex structures.

The following sections provide a province-by-province assessment of the potential for commercial hydrocarbon accumulations in Alaska. Eighteen distinct oil and gas provinces have been identified which are partially or wholly offshore. Of the 18, only 11 are judged to have significant potential for hydrocarbon generation and retention.

The Aleutian Trench, Bering Basin, and Gulf of Alaska Basin Provinces were eliminated from the assessment because they are oceanic areas with great water depths. Sediments in them are largely fine-grained hemipelagic clays, siliceous oozes, and volcaniclastics with poor source/reservoir characteristics.

Beaufort Basin and Chukchi Borderland Provinces were not assessed. Although the thick sedimentary section in part of these provinces has attractive potential for hydrocarbons, the water depth and year-round ice cover preclude development in any reasonably forseeable period of time. The collection of geophysical data, on which a resource assessment is based, is severely constrained by the harsh environmental conditions as well.

The Aleutian Arc Province was not considered because sediments tend to be thin and consist almost entirely of Tertiary volcaniclastics. Such rocks contain virtually no convertible organic matter and tend to be impermeable because of solution and compaction effects.

St. Matthew-Hall Province was eliminated from the assessment because the generally thin (<6,000 feet) Tertiary section is above the thermal generation window for hydrocarbons. The underlying Mesozoic sequence is believed to be composed of nonprospective metamorphics.

Beaufort Shelf Province

The province extends seaward from the State-Federal boundary to the edge of the continental shelf. It is bordered on the east by the United States-Canadian border and on the west by the Chukchi Sea Planning Area boundary.

Geologic Setting

The province is the seaward extension of the geology of the North Slope and includes Ellesmerian rocks. Identified Ellesmerian hydrocarbon deposits onshore are trapped by faults, dip, and truncation by unconformities (Craig and others, 1985). Traps in the offshore extension of the trend are expected to be similar in both type and distribution.

Brookian Sequence rocks are found in the province and are considered highly prospective. Brookian equivalent rocks in the Canadian Mackenzie Delta contain over one BBO of recoverable oil. Most identified Brookian structures appear to be anticlines, faulted anticlines, and rotated fault blocks (Craig and others, 1985). Figure ID2. shows the structural and stratigraphic relationships of the province.

Drilling History

A total of 18 exploratory wells have been drilled in the province through December 31, 1987. Fifteen were drilled to test prospects in Ellesmerian rocks and three to explore Brookian potential. Most of the wells encountered minor to significant shows of oil and gas, but the only significant find was the subcommercial Seal Island extension.

Source Rocks

Source rocks in the Ellesmerian Sequence include rich (up to 7.5 percent total organic carbon (TOC)) sapropelic oil-prone kerogens within the thermal oil window.

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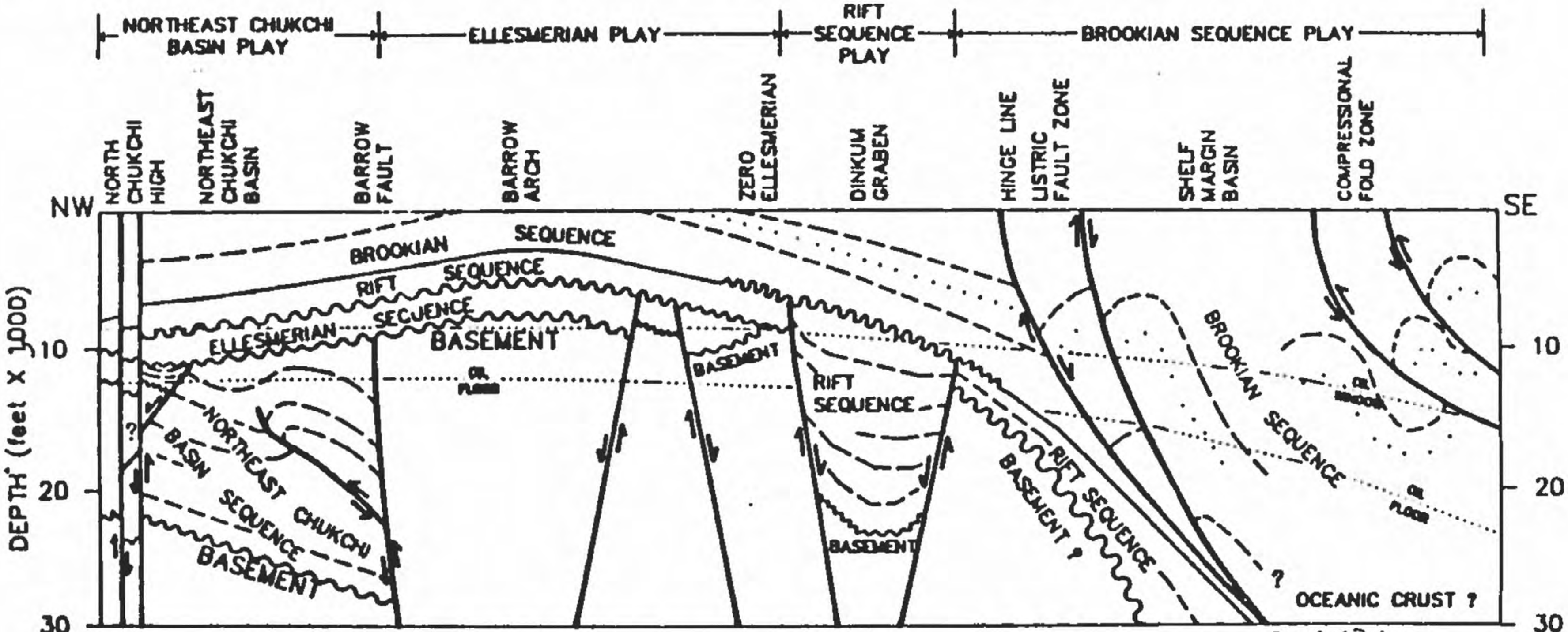
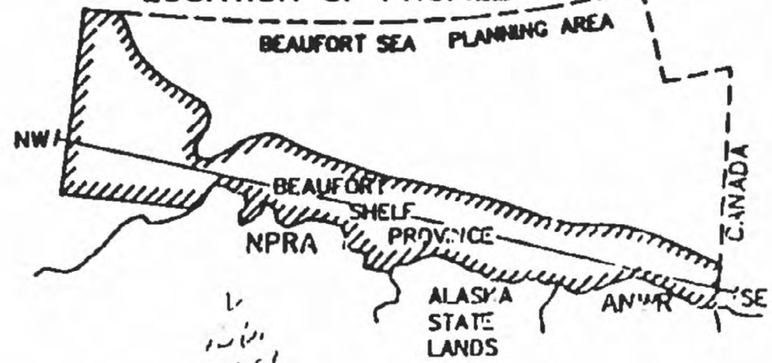
BEAUFORT SHELF PROVINCE



LOCATION OF ~~PROFILE~~ DIAGRAM



SCHEMATIC CROSS SECTON ~~ILLUSTRATING~~ PRINCIPAL PLAYS AND GEOLOGICAL ELEMENTS OF THE BEAUFORT SHELF PROVINCE

Figure V.D.2

Shales predominate in the upper portions of the sequence with more shales and carbonates deeper in the section. Total thickness of potential source rock in the Ellesmerian is about 2,000 feet.

Source rocks in the Brookian Sequence tend to be shales with about 1 percent TOC. Kerogens are terrestrial and thus gas prone, but much of the sequence is thermally immature for gas.

Reservoir Rocks

Reservoir rocks in the Ellesmerian are sandstones and, to some extent, carbonates in the lower part of the section. Porosity in good quality reservoir rock ranges around 20 percent, but can be locally higher.

Brookian reservoir sands have good porosity in the range of 10-15 percent, but permeability is often low due to contamination by clay-silt size particulates. Individual sandstone beds can be up to 700 feet thick (Craig and others, 1985). Figure VD3. shows the distribution of sands throughout formations found on the Beaufort continental shelf.

Undiscovered Potential

Since much of the offshore Ellesmerian has been drilled with little commercial success and since few remaining large prospects remain to be drilled, the Brookian Sequence is thought to offer the best potential for future discoveries. Significant shows and subeconomic accumulations of oil and gas occur in Brookian rocks, both onshore and offshore. The largest known deposit in Alaska (West Sak), with 40 BBO in place, is in Brookian rocks west of Prudhoe Bay.

~~BEAUFORT SHELF PROVINCE~~

~~STRATIGRAPHIC COLUMN~~

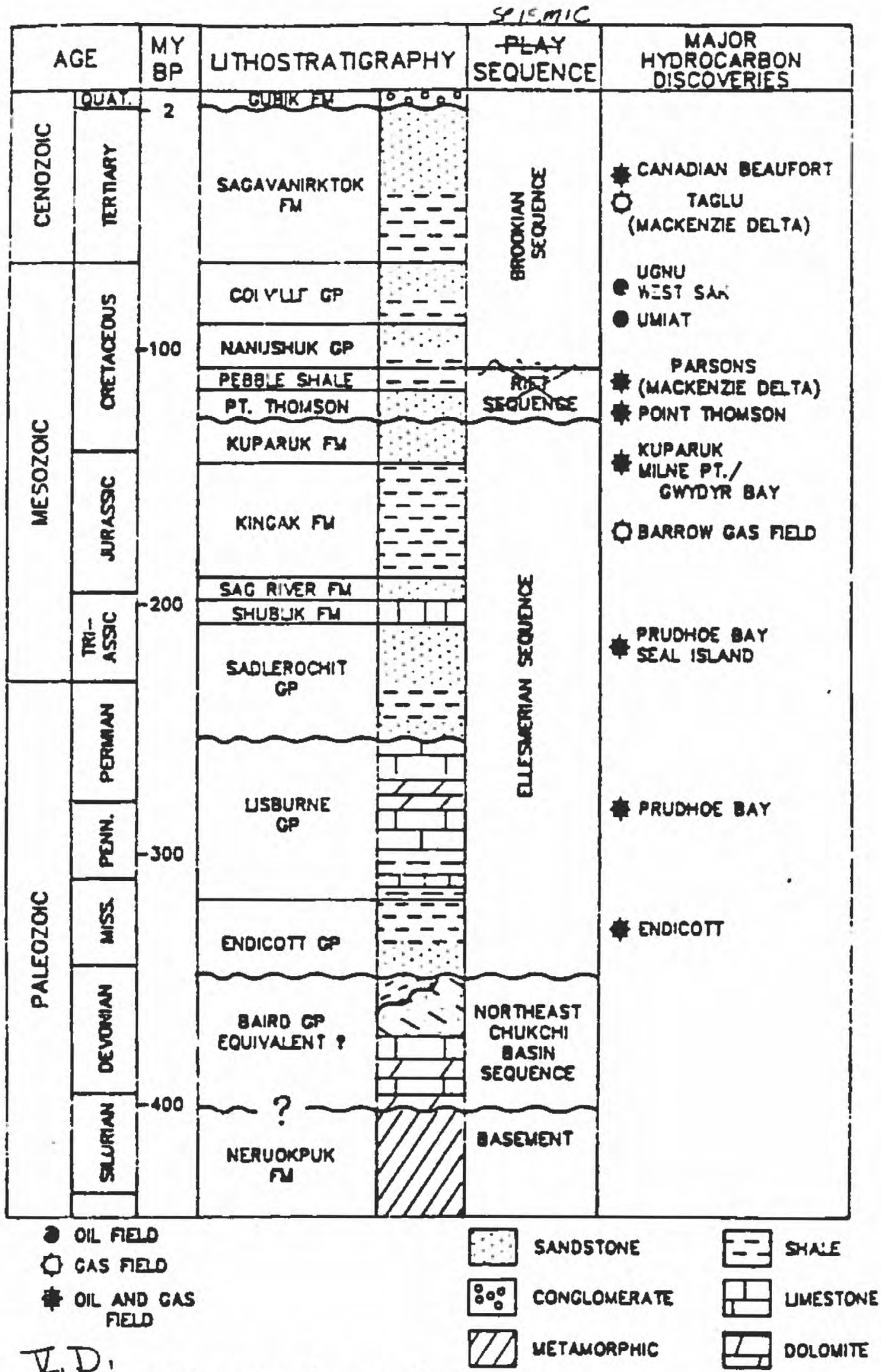


Figure V.D.3. Stratigraphic column of Beaufort Shelf Province

Actively subsiding depocenters seaward of the Hinge Line may have accumulated great thicknesses of sand on the downthrown blocks of growth faults. Since this mechanism also produces structurally sealed traps, Brookian rocks seaward of the Hinge Line may be particularly prospective.

Table - Resource Estimates, Beaufort Shelf Province

	Condl. Mean Oil Bbbl	Condl. Mean Gas Tcf	MP_{hc}	Risked Mean Oil Bbbl	Risked Mean Gas Tcf
Economically recoverable at $18/barrel	1.44	0	0.14	0.21	0
Undiscovered resource base	1.27	12.66	1	1.27	12.66

Chukchi Sea Province

The province extends seaward from the State-Federal boundary to the 200-mile EEZ limit. It is bounded on the east by the western edge of the Beaufort Sea Planning Area and extends southwestward to Point Hope.

Geologic Setting

The tectonic and depositional history of the Chukchi Sea Province has been complicated by a number of distinct orogenic events starting in the Devonian (?) and continuing to the present. Ellesmerian Sequence rocks accumulated in the basin during a long and erratic period of regional subsidence beginning in the Devonian (?) and ending in Early Cretaceous. Brookian Sequence terrigenous clastics were deposited over older rocks as the Brooks Range to the south began to uplift in Early Cretaceous. Cenozoic strike-slip shear motion along deep seated faults subsequently developed a number of distinct structural styles related to wrench faulting (Thurston and Theiss, 1987). The intense tectonism in the area has resulted in structural overprinting and the formation of large numbers of complex (if small) structures favorable to hydrocarbon accumulation and retention (fig. ID.4.).

Drilling History

None

Source Rocks

Although there is no direct evidence from drilling, inferences regarding likely source rocks can be made. Ellesmerian rocks appear to be present throughout much of the basin, with perhaps the same excellent oil source characteristics

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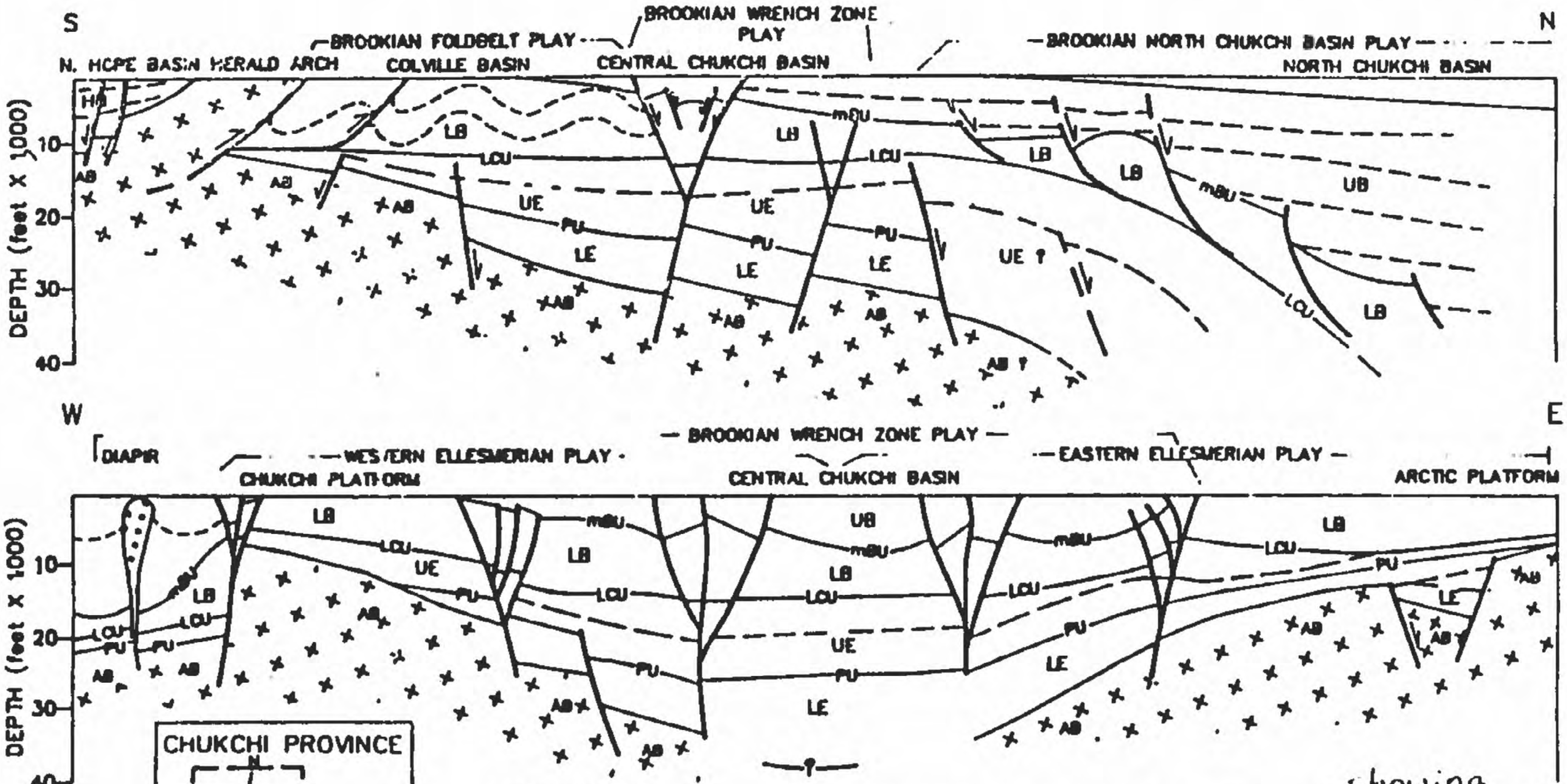
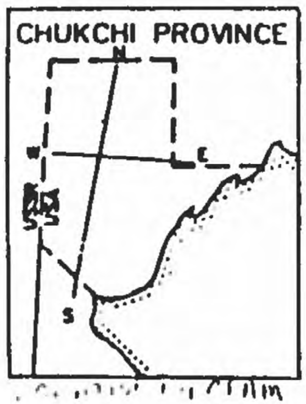




EXPLANATION

- HB Hope Basin Sequence
- UB Upper Brookian Sequence
- mBU mid-Brookian Unconformity
- LB Lower Brookian Sequence
- LCU Lower Cretaceous Unconformity
- UE Upper Ellesmerian Sequence
- PU Permian Unconformity
- LE Lower Ellesmerian Sequence
- AB Acoustic Basement

SCHEMATIC CROSS SECTIONS ~~ILLUSTRATING~~ showing PRINCIPAL PLAYS AND GEOLOGICAL ELEMENTS OF THE CHUKCHI Sea ? PROVINCE

IV.D.
Figure 4.

as this sequence shows onshore and in the Beaufort offshore. Brookian Sequence source lithologies are assumed to occur in much of the Chukchi, and they are expected to be gas prone with relatively low percentages of convertible kerogens, as they are in drilled areas to the east. Figure V.D.5. A shows the distribution of potential source and reservoir rocks in the stratigraphic section.

Reservoir Rocks

Ellesmerian sandstones, and to some extent carbonates in which secondary porosity has developed, would be likely reservoirs in the deeper part of the section (Thurston and Theiss, 1987). These rocks often show porosities in the range of 20-30 percent with correspondingly good permeability in drilled areas in the Beaufort Sea. Brookian rocks, where drilled, show locally good porosity, but permeability is often low because of intergranular contamination by fine-grained particulates.

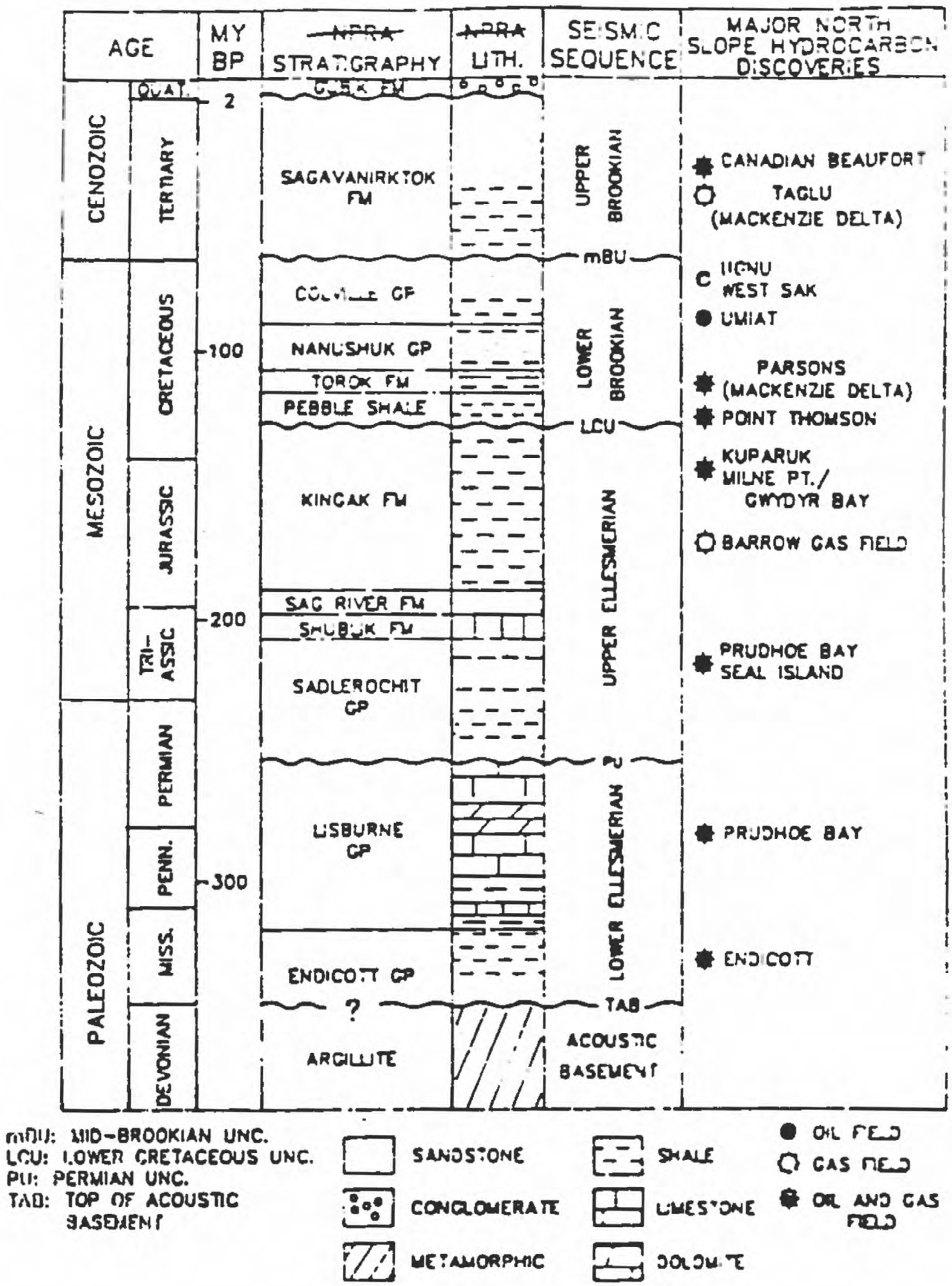
Undiscovered Potential

The structural geology of the Chukchi Province is distinctly different from other areas on the North Slope. The province contains a great diversity of potential hydrocarbon bearing structures that are unlike others in the region and thus may have considerable promise.

The best potential for future discoveries in the Chukchi Province is probably on the Chukchi Platform and in the North Chukchi Basin. The Chukchi Platform is a structural high, overlain by Ellesmerian Sequence rocks that are apparently thermally mature. Faulting occurred before Brookian sedimentation so traps existed before thermal heating and subsequent hydrocarbon expulsion. Potential traps related to diapirism and wrench faulting are also present on the platform.

~~CHUKCHI PROVINCE~~

~~STRATIGRAPHIC COLUMN~~



V.D.

Figure 5. Stratigraphic column of [illegible]

North Chukchi Basin fill is apparently Brookian Sequence rocks that are thermally mature. Timing of trap formation relative to hydrocarbon migration is inferred to be good. However, hydrocarbons generated in Brookian rocks are more likely to be gas rather than oil.

Table - Resource Estimates, Chukchi Sea Province

	Condl. Mean Oil Bbbl	Condl. Mean Gas Tcf	MP_{hc}	Risked Mean Oil Bbbl	Risked Mean Gas Tcf
Economically recoverable at $18/barrel	2.73	0	0.22	0.59	0
Undiscovered resource base	4.44	12.66	0.50	2.22	6.33

Hope Basin Province

The province extends seaward from the State/Federal boundary to the U.S.-U.S.S.R. international border. The northern boundary is the Herald Arch, which physiographically separates this province from the Chukchi Province. The southern boundary is near Cape Prince of Wales on the Seward Peninsula.

Geologic Setting

Hope Basin Province is a Late Cretaceous to Tertiary sedimentary basin. Late Cretaceous and older basement rocks are faulted into a ridge/trough configuration, which has generated most of the traps in the overlying Brookian equivalent strata (Dellagiarino, 1986). Sediments in the basin are generally less than 15,000 feet thick and probably thermally mature only near the axis of the principal depocenter. Figure VD.6. shows the stratigraphy and general structural outline of the province.

Drilling History

None

Source Rocks

No information.

Reservoir Rocks

No information.

Undiscovered Potential

The potential for significant economic accumulations of hydrocarbons is low. Late Cretaceous and older basement rocks have unknown (but probably poor) source rock characteristics, and overlying Tertiary rocks are, for the most part, thermally immature. Adjacent onshore drilling in a somewhat similar geologic setting revealed high quality reservoir rocks with good porosity (>25 percent) and permeability, but these may not be an appropriate analogue.

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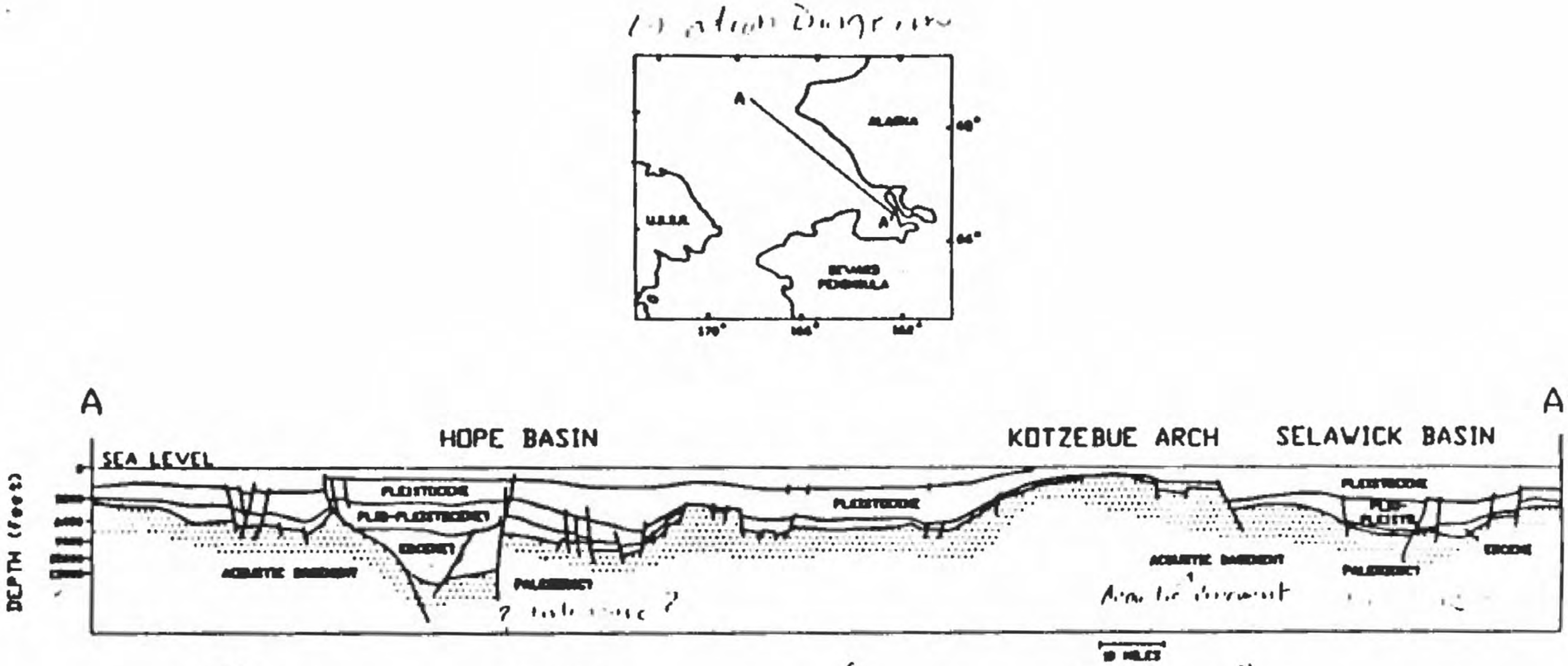

IV.D. Figure 6. SCHEMATIC [STRUCTURE] Cross SECTION of HOPE BASIN [~~PLANNING AREA~~] Province

Table - Resource Estimates, Hope Basin Province

	Condl. Mean Oil Bbbl	Condl. Mean Gas Tcf	MP_{hc}	Risked Mean Oil Bbbl	Risked Mean Gas Tcf
Economically recoverable at $18/barrel	0.66	0	0.01	Negl.	0
Undiscovered resource base	0.32	5.22	0.05	0.02	0.26

Norton Basin Province

The province is bounded on the north by the Seward Peninsula and on the south by the 63° N. latitude line. The U.S.-U.S.S.R. boundary (disputed) defines its seaward edge.

Geologic Setting

The thickest sediments in the province are found in Norton Basin, which is approximately coincident with Norton Sound. It contains an average thickness of about 15,000 feet of Tertiary sediments, mostly terrigenous clastics. These sediments unconformably overlie Paleozoic and older metamorphic basement (Turner and others, 1986).

The basin is divided into two subbasins, which are separated by the Eocene north-south trending Yukon horst. The western subbasin includes mostly deep-water clastics, while the eastern part contains a sequence of shallower water silt and sandstones. In mid-Oligocene, the sill was breached and shallow-water siltstones, sandstones, and coal were deposited in both subbasins. A schematic cross section of the province is shown in figure V.D.7.

Drilling History

Two COST wells were drilled in 1980 and 1982. Six exploratory wells were drilled in 1984-1985 on land leased in OCS Lease Sale 57. The wells yielded only minor shows of oil and gas, and all were plugged and abandoned.

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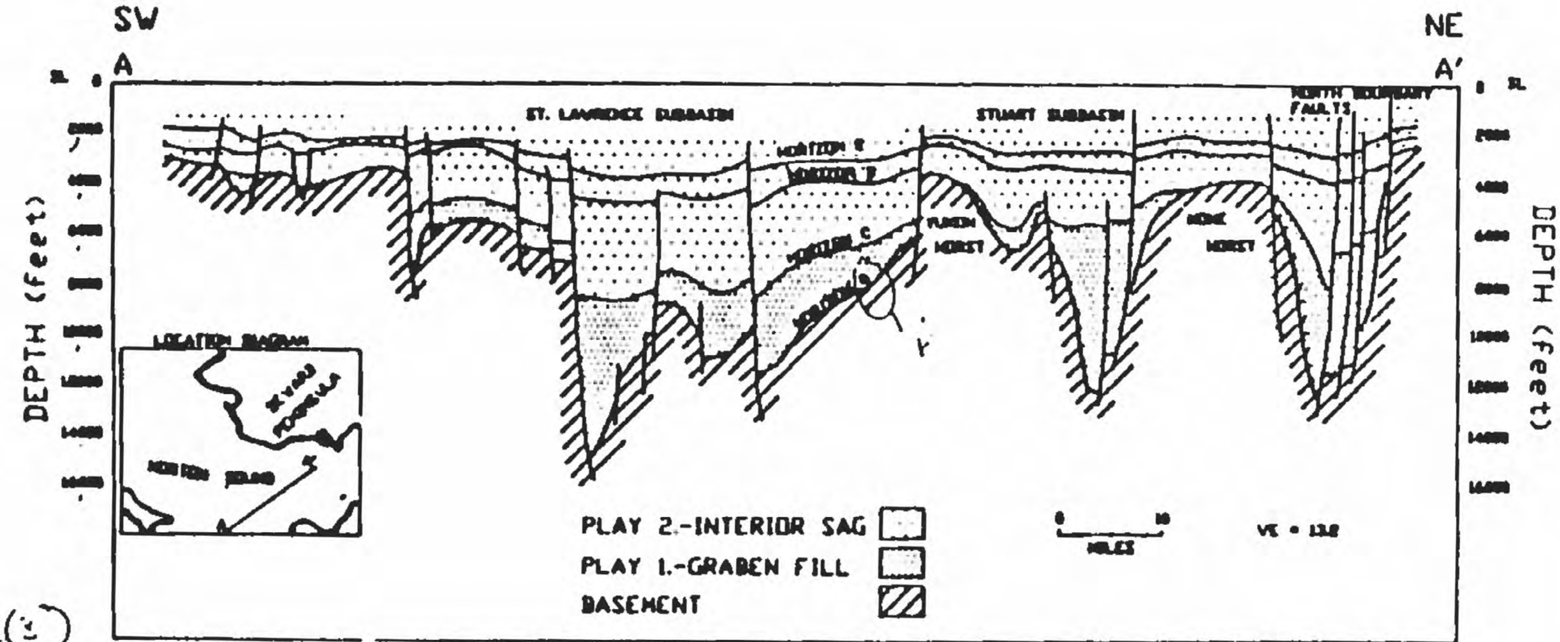

see note (3)

I.D.
Figure 7. GENERALIZED STRATIGRAPHIC CROSS SECTION ACROSS ~~NORTON~~ BASIN SHOWING MAJOR STRUCTURAL FEATURES. of Norton Basin Province

1

Source Rocks

Structured terrigenous kerogens predominate in potential source rocks in the basin indicating that most hydrocarbons will be gas and possibly condensate. Weight percentages of convertible kerogen tend to be low, ordinarily less than 1 percent.

Reservoir Rocks

Sandstones in most of the Norton Basin are locally derived metamorphic detritus eroded from topographic highs in and around the basin. Volcanics and volcaniclastics are important second order components. Porosity and permeability decline rapidly with depth largely because of solution effects and contamination by clay and silt size intergranular particulates. The best sandstones appear to be in Oligocene strata when deposition in a relatively high-energy environment has winnowed out the fines (Turner and others, 1986).

Undiscovered Potential

Sediments in the province tend to be thin and, therefore, thermally mature only in the deepest parts of the basin. The little amorphous (oil-prone) kerogen that exists in the area also tends to be concentrated in the deeper parts of the basin. The best possibilities for oil would seem to be restricted to deeply buried prospects near the axis of the principal depocenters.

Table - Resource Estimates, Norton Basin Province

	Condl. Mean Oil	Condl. Mean Gas	MP_{hc}	Risked Mean Oil	Risked Mean Gas
Economically recoverable at $18/barrel	0.58	0	0.01	Negl.	0
Undiscovered resource base	0.19	2.70	0.07	0.01	0.19

Navarin Basin Province

The Navarin Basin Province is bounded on the east by the 174° W. longitude line and on the west by the U.S.-U.S.S.R. disputed border. The continental shelf break forms the southern edge of the province.

Geologic Setting

The Navarin Basin Province is comprised of three extensional Tertiary subbasins filled with up to 36,000 feet of terrigenous clastic sediments. Figure V.D.9. is a generalized stratigraphic column showing the age relationships of lithologies present in the province. The depositional regimes of the three subbasins were unified in the Oligocene when a fall in sea level exposed the interbasinal topographic highs to erosion (Turner and others, 1985). The highs were beveled to roughly the same level, the lows filled and regional sedimentation followed. A subsequent 26,000 feet of Oligocene to Recent clastics were deposited in the area. An early Tertiary change in the seafloor spreading pattern resulted in subsidence of the basin which continues to the present, driven in part by isostatic loading. Intrastratal growth faults and basement-rooted faulting offset sediments as young as Pleistocene (fig. V.D.10). Thus, the timing of trap formation relative to hydrocarbon migration may be an important constraint to the accumulation of significant oil and gas deposits.

Drilling History

A COST well was drilled in 1983. In 1985, eight exploratory wells were drilled on tracts leased as a result of OCS Lease Sale 83. One well had a show of gas in Eocene sands, but it was assumed to be a small lenticular reservoir. The wells were all plugged and abandoned.

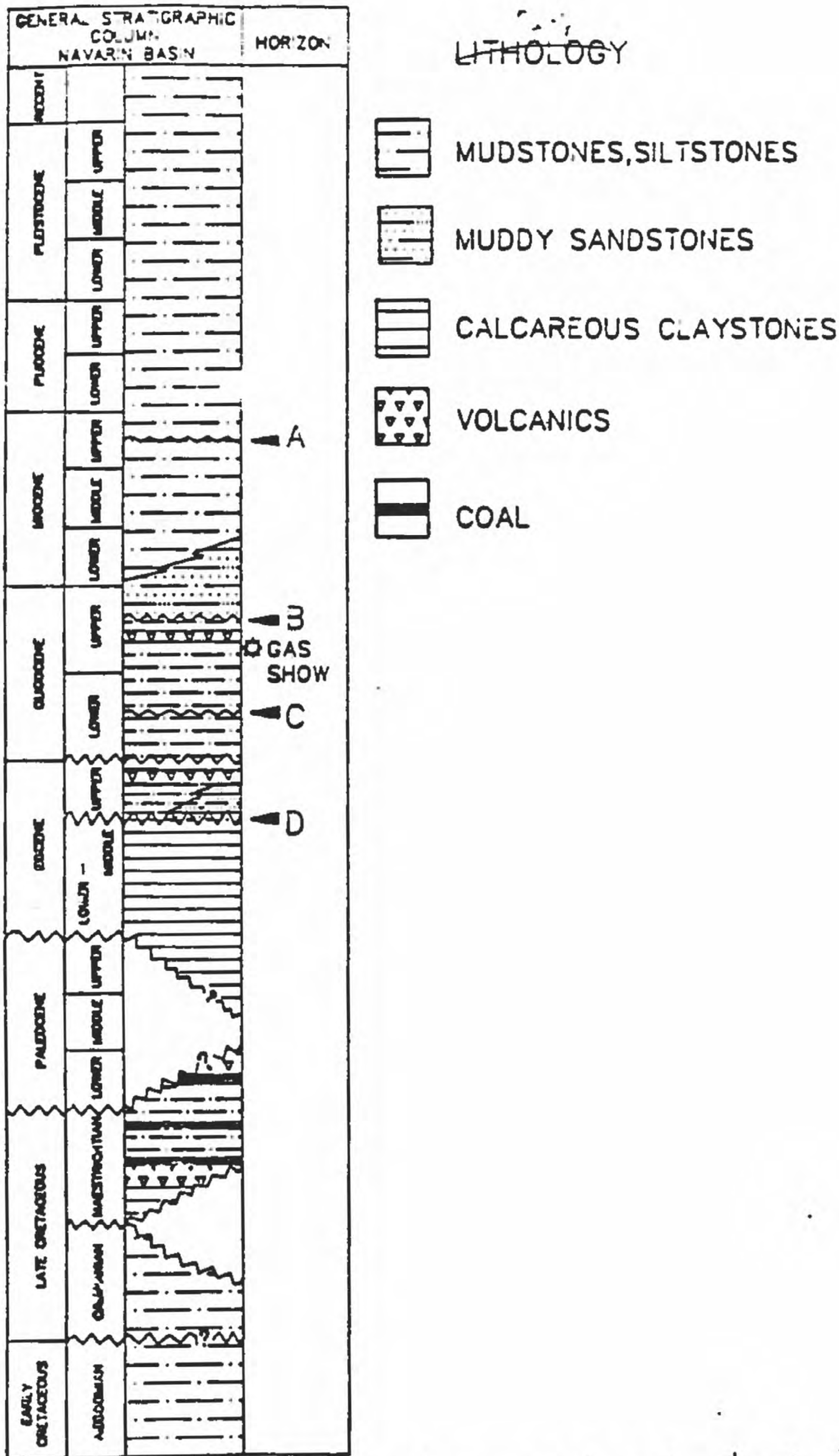

Figure V.D.9. Stratigraphic column of Navarin Basin, Pri-na

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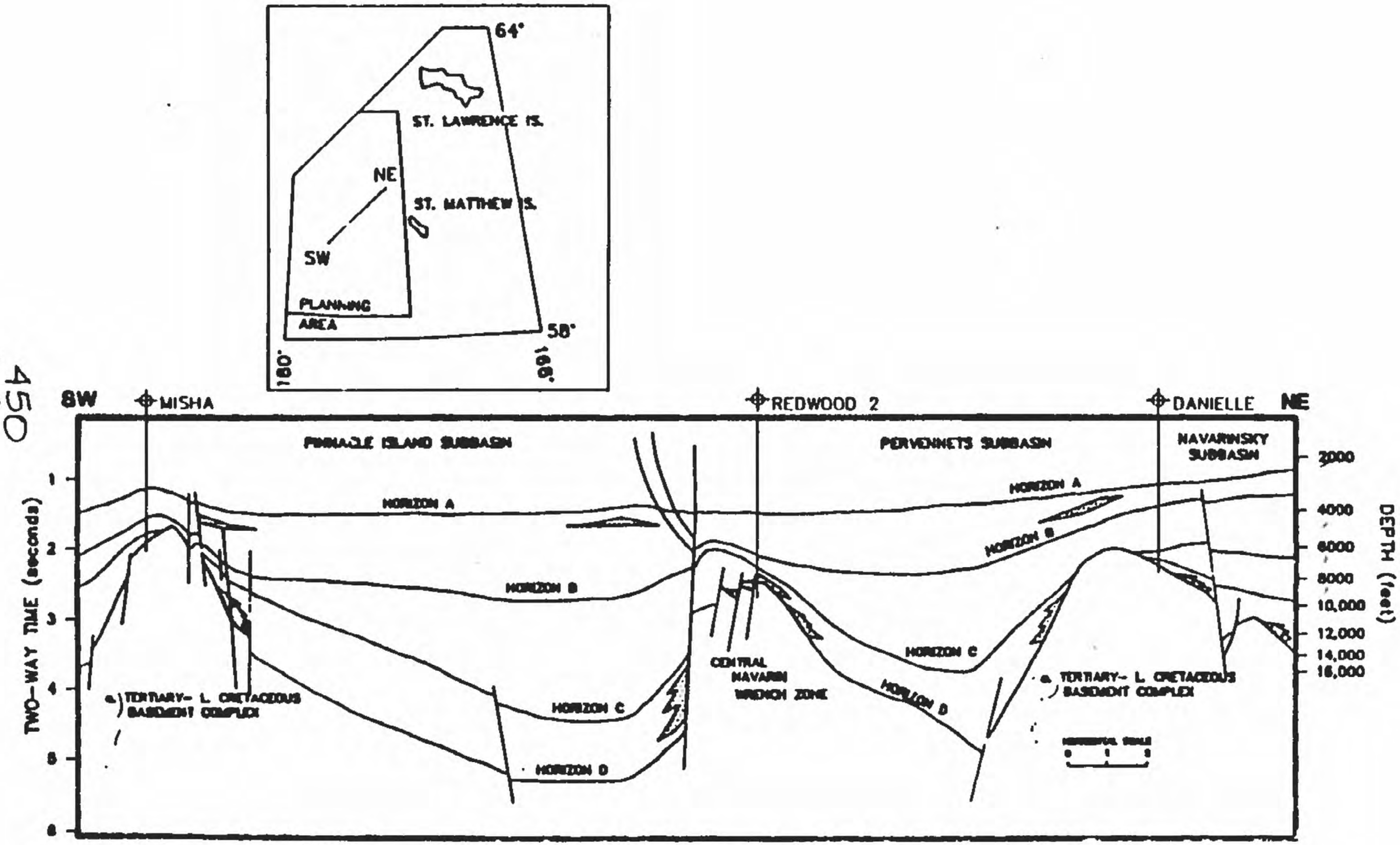

Figure IV.D.10. CROSS SECTION OF ~~THE~~ NAVARIN BASIN Province

Source Rocks

The best quality thermally mature source rocks occur in early Oligocene to to Eocene claystones. The rocks contain up to 2 percent of both amorphous (oil prone) and structured (gas prone) kerogens (Turner, 1985). Poorer quality source rock occurs in late Oligocene mudstones and claystones. Organic carbon is under 1 percent, and at least some of the interval is thermally immature. A gas seep emanating from surface faulting related to diapirism has been observed.

Reservoir Rocks

The best reservoir sequences occur in early Miocene to late Oligocene sandstones. Porosity is generally in the 25-35 percent range, but permeability has been adversely affected by cementation and contamination by fine-grained particulates.

Undiscovered Potential

Drilling in the Navarin Basin was a disappointment given the thick sedimentary section and large number of attractive prospects. Because of the apparent basin-wide permeability problem, the best remaining plays are probably locally derived sands along the flanks of topographic highs. As mentioned previously, timing also seems to be a concern.

Table - Resource Estimates, Navarin Basin Province

	Condl. Mean Oil Bbl	Condl. Mean Gas Tcf	MP_{hc}	Risked Mean Oil Bbl	Risked Mean Gas Tcf
Economically recoverable at $18/barrel	1.14	0	0.03	0.03	0
Undiscovered resource base	1.33	4.62	0.05	0.07	0.23

St. George Basin Province

The province lies on the Bering Sea continental shelf south of the Pribilof Islands and west of Bristol Bay.

Geologic Setting

The St. George Basin Province includes two Tertiary basins, the St. George and Pribilof grabens. The St. George graben is the largest, measuring 10-25 miles wide by about 200 miles long (fig. (VD.11)). The smaller Pribilof Basin to the east measures about 30 by 70 miles and contains about 20,000 feet of Tertiary strata.

Interest has centered on the St. George graben and an area to the south of it. The graben contains up to 40,000 feet of Tertiary volcaniclastics overlying Mesozoic calcareous shales, mudstones, and sandstones. Mesozoic rocks are well indurated, slightly metamorphosed in some areas, and constitute economic basement in much of the basin.

Drilling History

COST well No. 1 was drilled in 1976, with a second in 1982. Nine exploratory wells (one of which was sidetracked) were drilled in 1984 and 1985 on land leased in OCS Lease Sale 70. The wells were drilled in the St. George graben and in an area of thick sediments to the south of it. Two of the wells had minor shows of gas, but no commercial discoveries. All wells have been plugged and abandoned.

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Location diagram

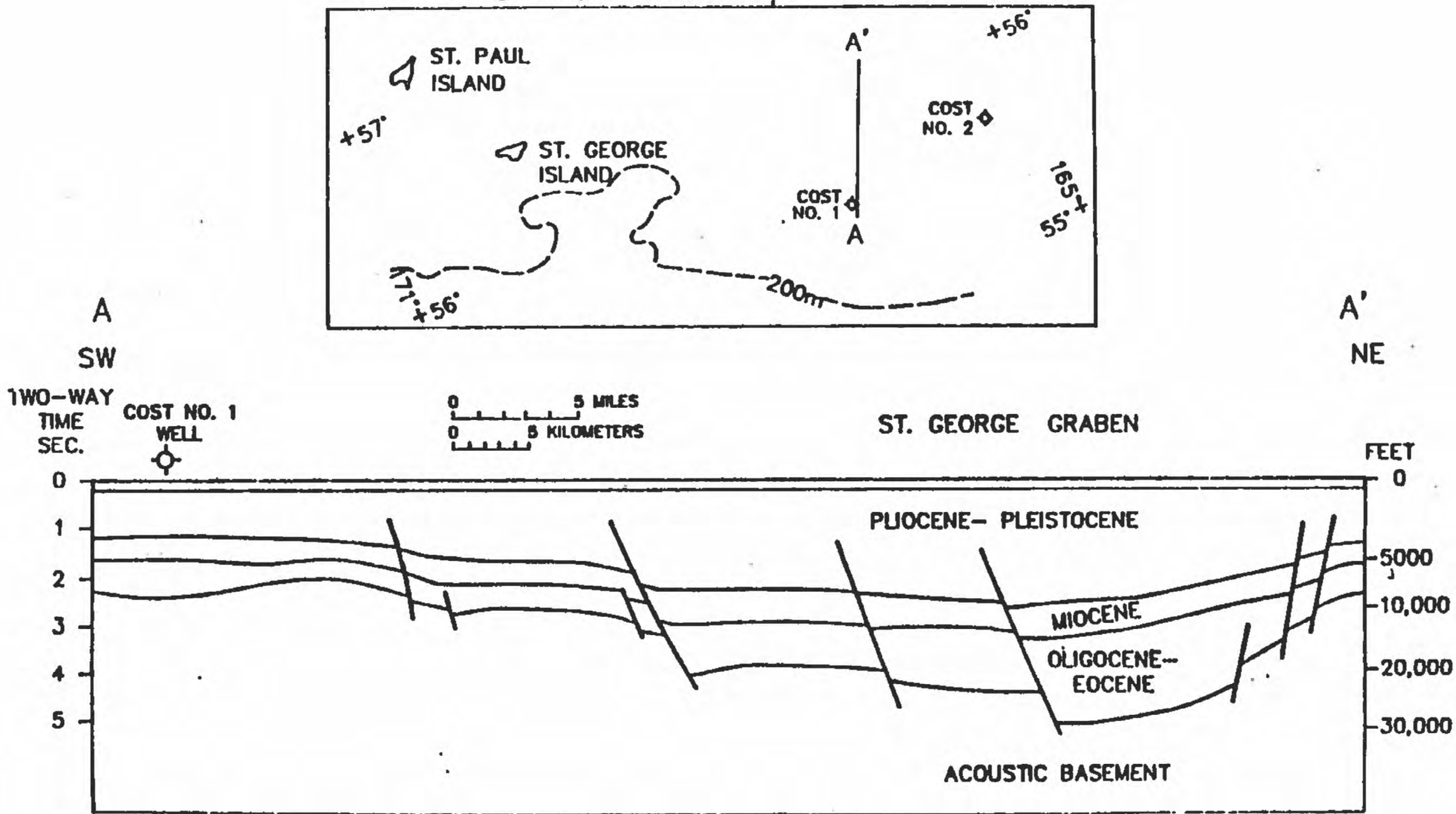

Figure 11. V.D. Schematic cross section of St. George Basin ...

Source Rocks

Well data indicate that the potential for adequate thicknesses of high quality source rocks is poor (Turner, 1984). Geochemical data show Tertiary sediments include less than 1 percent of convertible organic carbon. Organic carbon percentages in Mesozoic strata slightly exceed 1 percent, but the rocks are believed to be overmature. Structured kerogens predominate, indicating that the potential for significant accumulations of liquid hydrocarbons is poor.

Reservoir Rocks

Tertiary rocks in the study area are largely volcaniclastics, which tend to lose porosity rapidly with depth because of compaction and solution effects. The few good sands that exist are in the Oligocene (fig. V.D.11.) above the thermally mature interval in much the same setting as those previously described in the Navarin Province (Turner, 1984). The Tertiary volcaniclastic section tends to be poorly sorted so that any sand has a high fraction of clay-and silt-sized contaminants and is thus tight.

Undiscovered Potential

The thickest part of the sedimentary section in the province has not been tested. The structurally deepest part of the St. George graben may have been a closed basin at one time and could contain anoxically deposited sediments that include oil-prone kerogens. Potential reservoir rocks may include locally derived flank sands, which are perhaps coarser and cleaner and retain permeability better than the volcaniclastic section. The regional rock characteristics may not be especially favorable for oil and gas generation and retention, but considerable local variation is probably present in this tectonically complex province.

Table - Resource Estimates, St. George Basin Province

	Condl. Mean Oil Bbl	Condl. Mean Gas Tcf	MP_{hc}	Risked Mean Oil Bbl	Risked Mean Gas Tcf
Economically recoverable at $18/barrel	0.39	0	0.02	0.01	0
Undiscovered resource base	0.59	7.41	0.05	0.03	0.37

North Aleutian Basin Province

The province is bounded on the west by the 165° W. longitude line and on the south by the Aleutian Archipelago. Bristol Bay is the eastern limit.

Geologic Setting

The principal depocenter in the province is the North Aleutian Basin, which underlies parts of the Alaska Peninsula and the Bering Sea continental shelf. The basin is filled with up to 20,000 feet of Cenozoic volcaniclastics and terrigenous clastics (Dellagiarino, 1986). Exposures in the onshore portion of the basin show a series of Pleistocene volcanic flows and breccias overlying Neogene conglomerates, sandstones, and mudstones. Paleogene strata are predominently volcaniclastics with scattered coal beds. Seismic data indicate the stratigraphy continues into the OCS portion of the basin. Figure I.D12. shows the structure and chronostratigraphy of the area.

Drilling History

Ten exploratory wells have been drilled in the onshore part of the basin starting in 1959. A COST well was drilled on the OCS in 1983. The best shows of oil and gas originated from a series of wells drilled in the southwestern part of the basin near Port Moller. No commercial production developed from any of the wells and all were plugged and abandoned. (The COST well results are proprietary until a sale is held.) No further drilling will be conducted until litigation related to OCS Lease Sale 92 is resolved.

Source Rocks

Data from onshore wells show that Paleogene rocks are rich in organic matter, particularly in an Oligocene sequence of black marine shales and siltstones. The rocks are thermally immature, but because the axis of the depocenter lies

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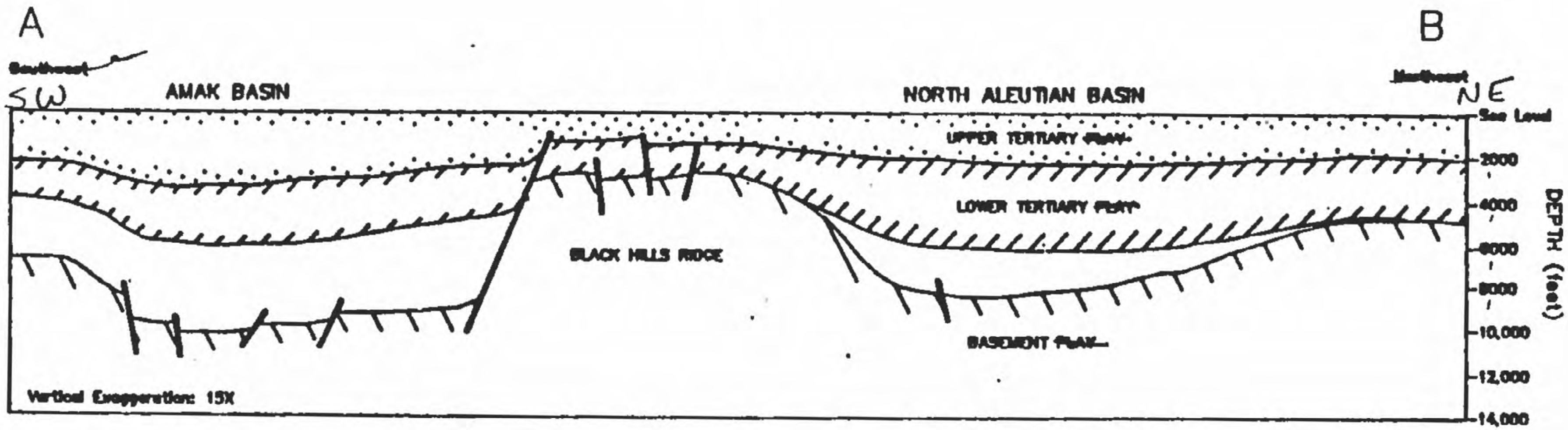
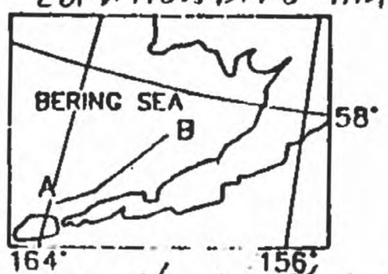


LOCATION DIAGRAM



IV.D.12 Schematic

offshore, the rocks may be buried deeply enough in the center of the basin to have achieved thermal maturity. The basal Neogene includes marine shales and siltstones that may also have some source potential. Mesozoic sedimentary basement rocks appear to have poor source rock characteristics.

Reservoir Rocks

The best reservoir rocks appear to be Miocene sandstones (Dellagiarino, 1986). Porosity exceeds 35 percent, and permeability measurements over 1,000 millidarcies have been recorded. Paleogene sands have poor reservoir characteristics because of compaction and solution effects related to the high proportion of volcaniclastics in the section. Mesozoic rocks, at least where tested, appear to have essentially no permeability.

Undiscovered Potential

Well data in the northeastern part of the basin show that the prospects for economic accumulations of oil and gas are poor. However, the southwestern part is believed to have significantly greater potential, particularly in the offshore portion of the basin where the sedimentary section is considerably thicker.

Table - Resource Estimates, North Aleutian Basin Province

	Condl. Mean Oil Bbbl	Condl. Mean Gas Tcf	MP_{hc}	Risked Mean Oil Bbbl	Risked Mean Gas Tcf
Economically recoverable at $18/barrel	0.61	0	0.02	0.01	0
Undiscovered resource base	0.52	3.12	0.05	0.03	0.16

Shumagin Shelf Province

The province lies between 156° and 165° W. longitude. It is bounded on the north by the Alaskan Peninsula and on the south by the edge of the continental shelf.

Geologic Setting

The geologic setting of the Shumagin shelf has been determined largely by the interaction of the Pacific plate and the continental land mass. The structural grain of the province parallels that of the Aleutian Trench. Basement rocks consist of a highly deformed sequence of Oligocene and older volcaniclastics (?), which are overlain by Oligocene and younger undisturbed sediments (fig. IVD13 A). Neogene sediments are gently deformed and are over 25,000 feet thick in a few areas (Dellagiarino, 1986). Heat flow in the area is high, and sediments below about 10,000 feet are probably thermally mature.

Drilling History

None

Source Rocks

No data.

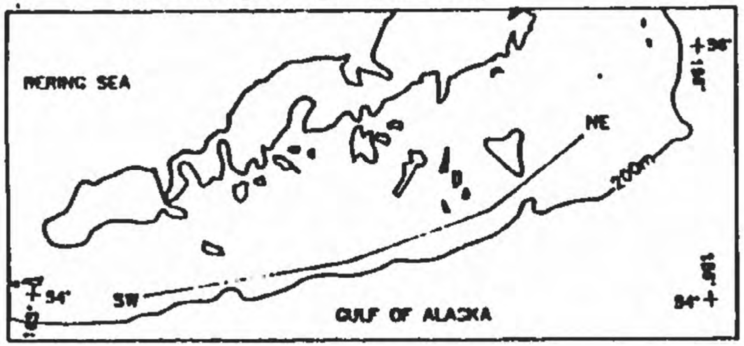
Reservoir Rocks

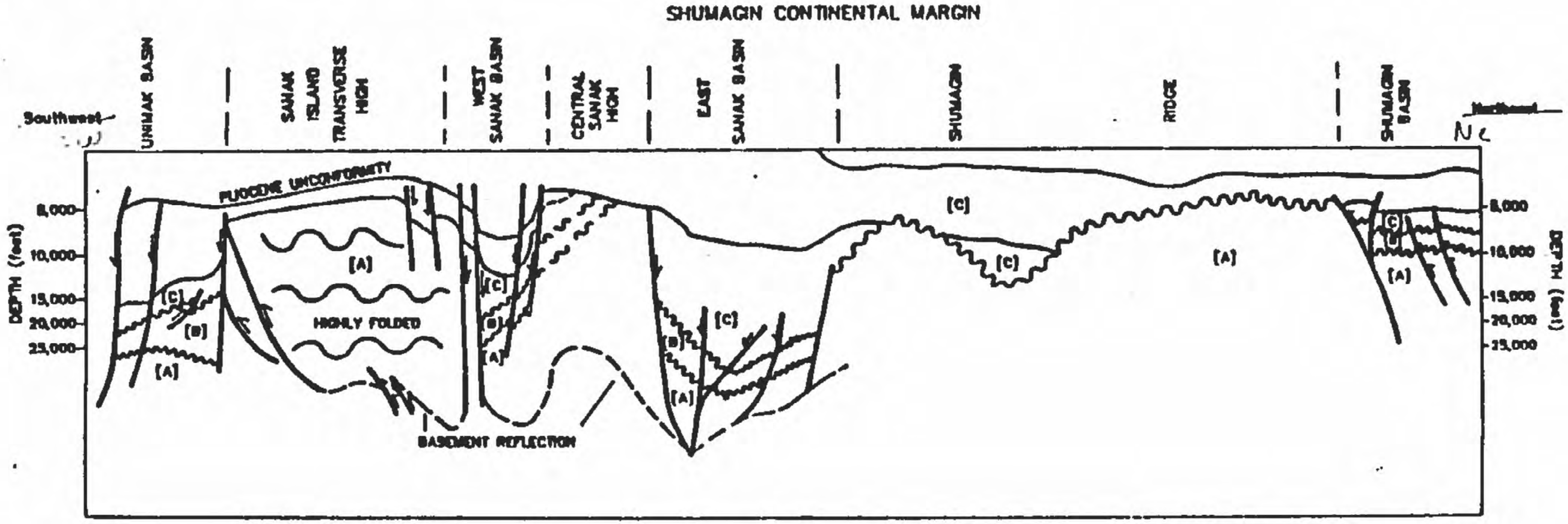
No data.

Undiscovered Potential

Since no geologic data from the OCS other than a few dredge samples exists, the undiscovered potential cannot be assessed. Numbers of traps are present at appropriate depths, but the potential for entrapment of commercial accumulations of hydrocarbons is completely unknown.

LOCATION DIAGRAM





DEPTH FROM SEISMIC RETRACTION DATA

SEISMIC SEQUENCES

NORMAL FAULT
REVERSE FAULT

[C] – Predominantly Neogene clastics
[B] – Paleogene clastics
[A] – Cretaceous, early Paleogene turbidites and granitic intrusives

Figure V.D.13 Schematic cross section of Shumagin Study Province

Table - Resource Estimates, Shumagin Shelf Province

	Condl. Mean Oil Bbbl	Condl. Mean Gas Tcf	MP_{hc}	Risked Mean Oil Bbbl	Risked Mean Gas Tcf
Economically recoverable at $18/barrel	0.28	0	0.01	Negl.	0
Undiscovered resource base	0.40	1.96	0.02	0.01	0.04

Kodiak Shelf Province

The Kodiak Province extends seaward from the State-Federal boundary to the edge of the continental shelf. The 156° W. longitude line forms the western boundary and Kayak Island the eastern.

Geologic Setting

The geologic setting of the Kodiak shelf has been determined largely by the interaction of the Pacific plate and the continental land mass (Fisher, 1980). The province is underlain by two basic stratigraphic units (fig. VD.14 A). Basement rocks are mostly Paleogene flysch and volcanics that have been highly deformed by tectonism related to subduction at the margin. Neogene sediments up to 25,000 feet thick unconformably overlie basement. Neogene strata are parallel to subparallel and are only slightly deformed.

Drilling History

Six stratigraphic test wells were drilled on the Kodiak shelf in 1976 and 1977. No indications of potentially commercial hydrocarbons resulted.

Source Rocks

Source rock quality is poor, usually less than 1 percent. Neogene kerogens are structured (gas prone) and thermally immature throughout much of the area.

Reservoir Rocks

There are essentially no high quality reservoir rocks.

Undiscovered Potential

The Paleogene section is not considered prospective because of extremely poor reservoir characteristics. Neogene strata are generally internally conformable resulting in few structural traps. Undiscovered potential is thus low to nonexistent.

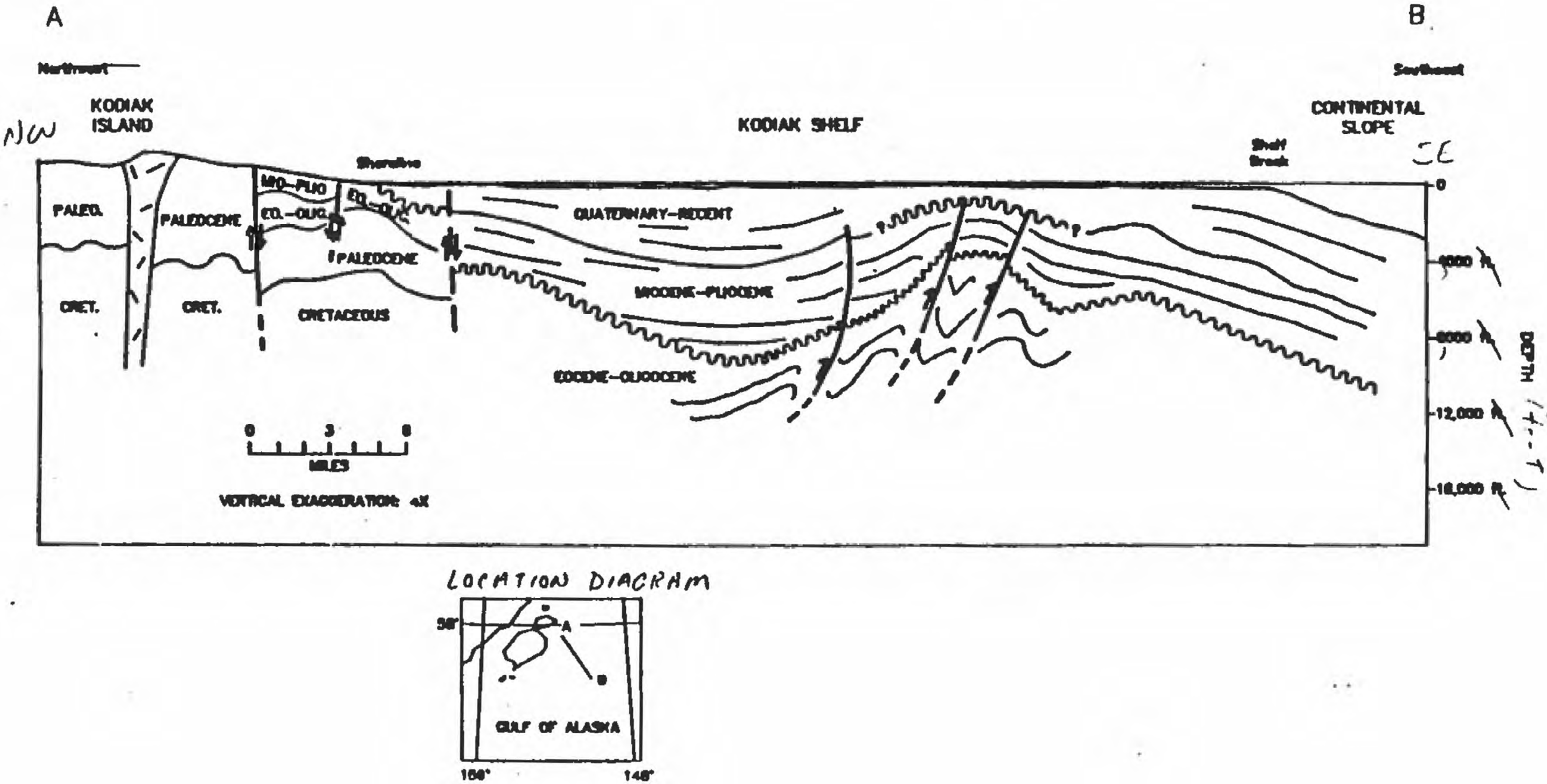


Figure IV.D.14 Schematic cross-section of Kodiak Shelf Province

Table - Resource Estimates, Kodiak Shelf Province

	Condl. Mean Oil Bbbl	Condl. Mean Gas Tcf	MP_{hc}	Risked Mean Oil Bbbl	Risked Mean Gas Tcf
Economically recoverable at $18/barrel	0.53	0	0.04	0.02	0
Undiscovered resource base	0.81	3.92	0.05	0.04	0.20

Gulf of Alaska Shelf Province

The province extends seaward from the State-Federal boundary to the continental margin. It is between Kayak Island on the west and United States-Canadian border on the southeast.

Geologic Setting

The province includes a number of small dispersed Tertiary basins, some of which are filled with up to 32,000 feet of terrigenous clastic and igenous rocks (fig. V.D.15 A). Neogene sediments are largely mudstones, fine-grained sandstones, turbidites, and siltstones (Plafker and others, 1975). Paleogene rocks consist of sandstones, siltstones, mudstones, some coal, and in the deeper part of the section, black, organic rich, Eocene shales.

A period of increased tectonism in the Miocene related to plate interaction, which resulted in structural overprinting in older sediments. Miocene and younger rocks are complexly faulted and folded due to this compressional phase.

Drilling History

Eleven exploratory wells (one of which was sidetracked) and one COST well have been drilled in the province since 1976. No commercial discoveries resulted, and all wells were plugged and abandoned.

Source Rocks

The best source rocks appear to be a series of organic-rich glauconitic Eocene shales. These rocks were slowly deposited in a closed anoxic basin and contain more than 1 percent of convertible organic carbon. Both structured (gas-prone) and amorphous (oil-prone) kerogens are present.

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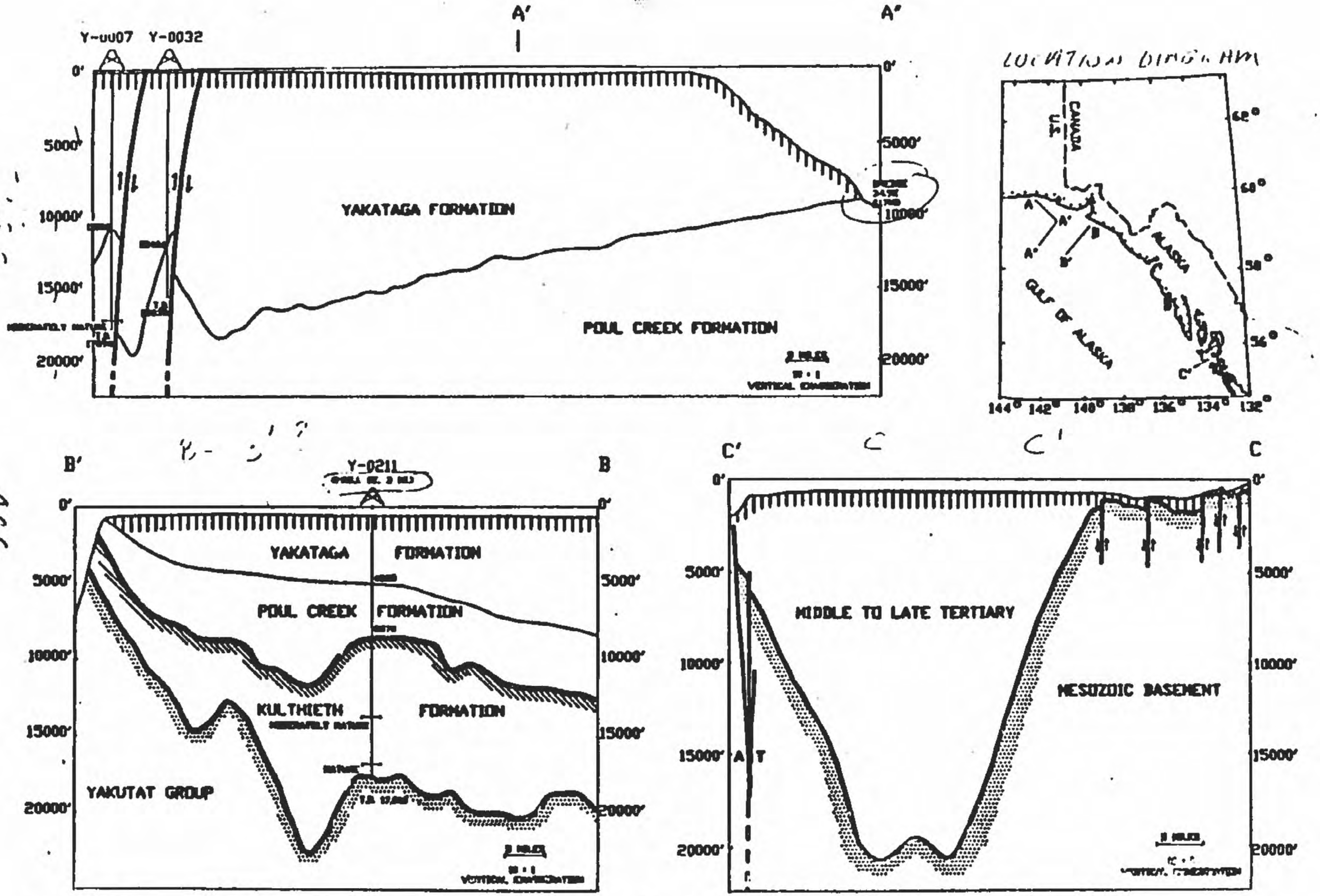

FIGURE ~~5~~ IV.D.15, Schematic CROSS SECTION OF ~~THE SHELF~~, GULF OF ALASKA shelf provinces: A-A", ICY BAY; B-B', YAKUTAT; C-C', SOUTHEAST ALASKA.

Reservoir Rocks

Potential reservoir rocks occur throughout the geologic section. The best are in the upper part of the section where most of the original primary porosity has been preserved. Porosity and permeability appear to decline rapidly with depth due to solution effects and the presence of intergranular particulates.

Undiscovered Potential

A small oil field was discovered near Kayak Island in 1902, and seeps are common throughout the onshore part of the province (Dellagiarino, 1986). Some offshore wells had shows, but few of them reached the most prospective intervals. Heat flow in the area is low, and thermal generation of hydrocarbons does not appear possible above about 10,000 feet.

The best source rocks (Eocene shales) appear to be confined to the offshore area between Icy Bay and Kayak Island. This area also has the thickest sediments and is, therefore, the most prospective.

Table - Resource Estimates, Gulf of Alaska Shelf Province

	Condl. Mean Oil Bbbl	Condl. Mean Gas Tcf	MP_{hc}	Risked Mean Oil Bbbl	Risked Mean Gas Tcf
Economically recoverable at $18/barrel	0.87	0	0.04	0.03	0
Undiscovered resource base	1.17	6.70	0.10	0.12	0.67

Lower Cook Inlet Province

The Cook Inlet Province includes Federal waters in Cook Inlet and the Shelikof Strait.

Geologic Setting

Rocks in this province are part of a NE/SW trending belt of Mesozoic to recent sediments that underlie parts of the Alaska Peninsula, Cook Inlet, and the Shelikof Strait. The maximum thickness of Mesozoic rocks is about 35,000 feet, and Cenozoic rocks are roughly 25,000 feet thick in the northeast part of the basin (fig. V.D.16 A). Jurassic and Cretaceous lithologies are largely marine shales, siltstones, and sandstones. Tertiary rocks unconformably overlie Mesozoic strata and consist of terrigenous conglomerates, sandstones, siltstones, and coal, with a substantial fraction of volcanics (Wills and others, 1978).

The structural grain of the province generally parallels the northeast-southwest trend of the basin. An exception is the east-west trending Augustine-Seldovia Arch, which essentially separates Lower Cook Inlet from the Shelikof Strait.

Drilling History

A COST well was drilled in 1977, followed by 10 exploratory wells drilled between 1978 and 1985. Although at least two wells encountered subeconomic accumulations of oil, no commercial production was found and all wells were plugged and abandoned.

LOCATION DIAGRAM

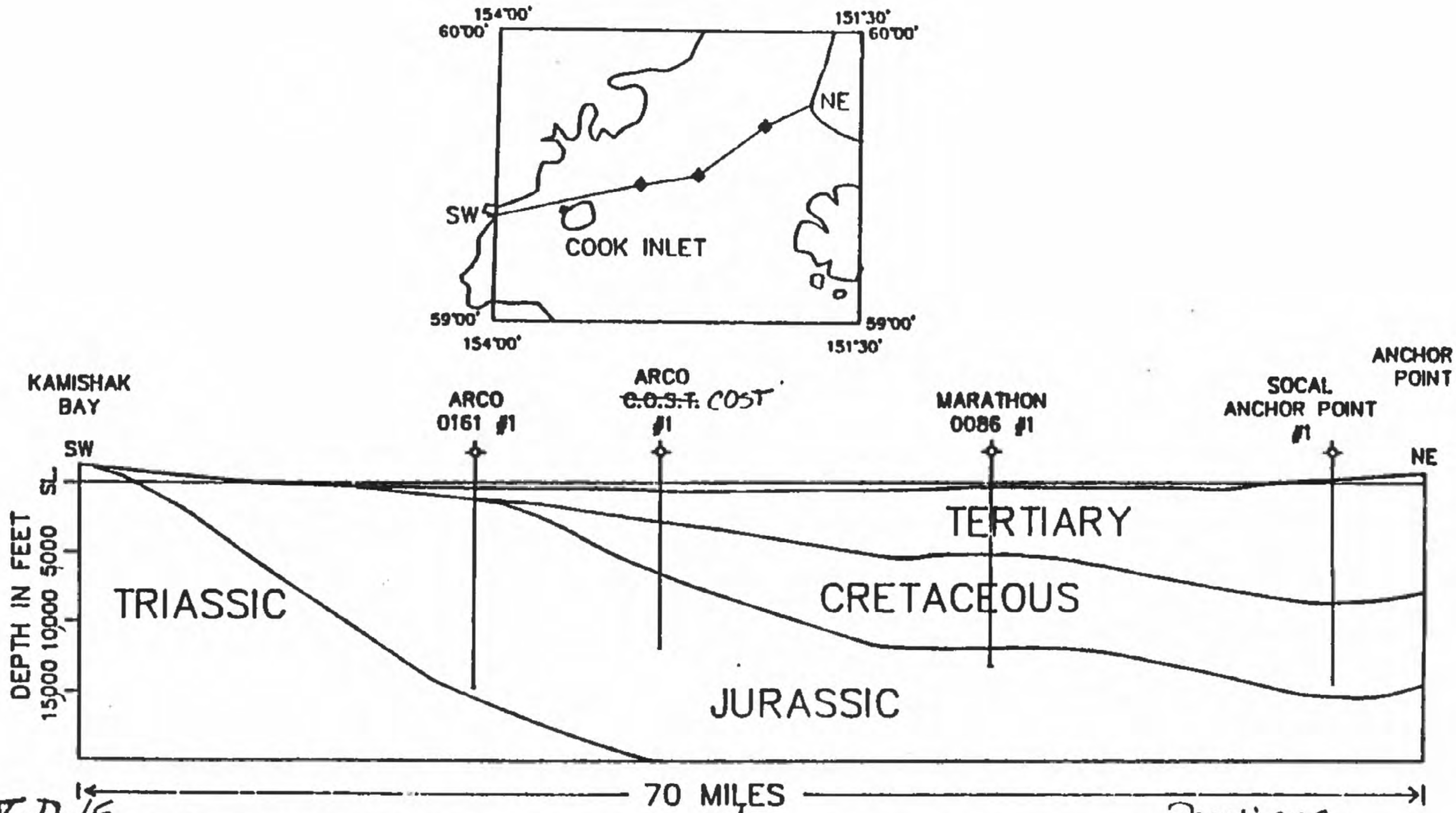

Figure ~~8~~ IV.D.16 ~~GENERALIZED~~ Generalized CROSS SECTION of LOWER COOK INLET Province ~~ALASKA~~

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Source Rocks

The source rocks for oil and gas produced in State waters in Cook Inlet are believed to be Middle Jurassic marine shales. Since these lithologies underlie most of the province, any place they occur should, to some extent, be considered prospective.

Reservoir Rocks

The Mesozoic section is tight, except for the Upper Cretaceous, but good quality reservoir rocks occur in Tertiary conglomerates and sandstones. These rocks are not widely distributed and tend to be restricted to the northeastern part of the province (i.e., in State waters).

Undiscovered Potential

The most attractive prospects in the province have already been drilled with little result. An anticlinal lineation along the southeast side of Lower Cook Inlet and traps along the Augustine-Seldovia Arch may have some potential. A series of anticlines paralleling the Shelikof Strait may be prospective, but the traps appear to be small and poorly developed.

Table - Resource Estimates, Lower Cook Inlet Province

	Condl. Mean Oil Bbbl	Condl. Mean Gas Tcf	MP_{hc}	Risked Mean Oil Bbbl	Risked Mean Gas Tcf
Economically recoverable at $18/barrel	0.17	0	0.01	Negl.	0
Undiscovered resource base	0.32	0.47	0.10	0.03	0.05

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VI. OIL, GAS, AND NATURAL GAS LIQUIDS PRODUCTION AND RESERVES

by D.H. Root

A. INTRODUCTION

The following tables give cumulative production, measured, indicated, and inferred reserves of oil and gas for Regions, for the State and Federal offshore areas and for the entire United States. Natural gas liquids production and reserves are given for the total onshore, total offshore, and the entire U.S.

Cumulative production is the sum of the figures reported in Circular 860 and subsequent production through December, 1986, as reported in the Energy Information Administration's Monthly Energy Reviews. Production figures for the Lower 48 States were allocated to onshore regions in proportion to reported production figures from several sources, including the NRG Associates Significant Oil and Gas Fields of the United States computer data file[6] and published state reports.

Cumulative production figures for state waters were furnished by the Dallas Field Office of the Energy Information Administration.

Measured and indicated reserves for the onshore and state offshore areas were taken from the 1986 Annual Report (Energy Information Administration, 1987). Where it was necessary to divide state reserves among two or more regions, the allocation was made proportional to the reserves for the parts of states calculated from NRG Associates Significant Oil and Gas Fields of the United States data file. Measured reserves for the federal offshore areas are independently determined by the Minerals Management Service (Hewitt and others, 1987; Raftery and others, 1987). Inferred reserves figures are taken from section II.H (this report).

In table VI.B.3, natural gas liquids production prior to 1946 was estimated to be 30 bbl per million cubic feet of gas, inferred reserves were taken to be 40 bbls per million cubic feet of inferred gas reserves.

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[6]The NRG Associates Significant Oil and Gas Fields of the United States field data file is a commercially available file of oil and gas field data, which includes estimates of cumulative production and proved reserves. The 1986 version of this file that contains data on discoveries through 1983 was used. Use of this file does not constitute an endorsement of the data by the United States Geological Survey.

Table VI.B.1.—Crude oil production and reserves by region.

Region	Cumulative Production	Measured Reserves	Indicated Reserves	Inferred Reserves
	Crude Oil Production and Reserves (MM bbls)			
1 - Alaska				
Onshore	5238	6875	902	5477
State Offshore	867	*	*	*
2 - Pacific Coast				
Onshore	18279	4192	600	541
State Offshore	1982	542	18	75
Federal Offshore	370	1300	**	150
3 - Colo. Plateau and Basin & Range	3070	632	121	323
4 - Rocky Mountain and No. Great Plains	7134	1229	207	1129
5 - West Texas and East. New Mexico	30153	5416	1026	2810
6 - Gulf Coast				
Onshore	41704	3552	546	4280
State Offshore	1442	121	2	920
Federal Offshore	6930	3950	**	450
7 - Mid-Continent	17327	1143	24	1359
8 - Eastern Interior	8376	482	38	698
9 - Atlantic Coast	76	24	0	32
Totals				
Onshore	131357	23545	3464	16649
State Offshore	4291	663	20	995
Federal Offshore	7300	5250		600
Grand Total	142949	29457	3483	18245

*Included with onshore.

*Included with measured reserves estimated by the Minerals Management Service.

Table VI.B.2.--Natural gas production and reserves by region.

Region	Natural Gas Production and Reserves (BCF)		
	Cumulative Production	Measured Reserves	Inferred Reserves
1 - Alaska			
Onshore	2497	31303	3000
State Offshore	1333	1361	*
2 - Pacific Coast			
Onshore	31610	3689	2559
State Offshore	1558	254	*
Federal Offshore	330	2140	270
3 - Colo. Plateau and Basin & Range	24658	17109	4947
4 - Rocky Mountain and No. Great Plains	13131	7640	3609
5 - W. Texas & Eastern New Mexico	82188	16714	12943
6 - Gulf Coast			
Onshore	272444	31539	41008
State Offshore	13186	2044	1300
Federal Offshore	75200	47040	5790
7 - Mid-Continent	145407	37538	18289
8 - Eastern Interior	33949	8169	5041
9 - Atlantic Coast	9	2	3
Totals			
Onshore	605892	153703	91399
State Offshore	16077	3659	1300
Federal Offshore	75530	49180	6060
Grand Total	697500	206543	98758

*Included with onshore.

Table VI.B.3.--Natural Gas Liquids Production and Reserves

	Natural Gas Liquids Production and Reserves (MM bbls)		
	Cumulative Production	Measured Reserves	Inferred Reserves
Onshore		7434	3783
Offshore		731	167
TOTAL	24365	8165	3950

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VII. UNCONVENTIONAL RESOURCES

A. INTRODUCTION

The preceding sections of this Working Paper deal with the primary assessment of conventional oil and gas resources, comparable in kind and quality to those which this nation has been dependent upon during the life of the modern petroleum industry. These conventional resources were assessed by the USGS in previous national assessments (Circular 725, Miller and others, 1975; Circular 860, Dolton and others, 1981) and by the MMS in offshore assessments (OCS Report 85-0012). Unconventional resources, so different in terms of character and availability, are appropriately treated separately by most workers in the field. We include the following discussions for perspective and as an overview of some parts of these resources.

Unconventional resources include oil from very heavy oil deposits, tar deposits, oil shales, gas from low-permeability fractured shale reservoirs, and tight sandstones with in-situ permeabilities to gas of <0.1 millidarcies, coalbed gas, geopressured shales and brines, and gas hydrates. Further, synthetic petroleum products may be extracted from oil shales and coals.

Many of these resource occurrences are not, in fact, undiscovered, but rather are well known as to location, although not well evaluated as to extraction. In-place quantities of the commodities in these deposits can be estimated to be deceptively large, although in several important cases, the geologic models are not yet adequately developed for assessment. Their assessment for potential development requires separate and detailed analysis utilizing different time frames and particular economic and technologic assumptions and projections.

Currently, some oil and gas is being produced from these sources, however, we believe that future improvements in technology and increased economic incentives will be required for extensive development. In a longer time frame, these resources will undoubtedly play an important role.

For the purpose of demonstrating the magnitude of unconventional resources, estimates are presented here for the important western U.S. tight gas reservoirs and the Devonian gas shales of the Appalachian basin.

B. WESTERN TIGHT GAS RESERVOIRS
by Charles W. Spencer and Ben E. Law

Introduction

Previous USGS National resource assessments have not included any assessments of gas in western, very low-permeability (tight gas) reservoirs. This policy was followed, partly because other institutions and agencies were making tight gas assessments, and partly because data were lacking on this major unconventional gas resource. Starting in 1977, the U.S. Geological Survey began cooperative tight gas reservoir research with the U.S. Department of Energy (DOE). This work was targeted to help advance the state-of-the-art of recovery technology and provide data and supporting research for high-quality resource assessments of tight gas in three primary study basins in the United States. The three primary tight-gas basins are the Piceance, Greater Green River, and Uinta (fig. VII.B.1).

Tight gas reservoirs are gas-bearing rocks that usually have an in-situ permeability to gas of less than 0.1 md. Artificial stimulation, such as hydraulic fracturing, is almost always needed in order to produce the gas. The principal western U.S. basins containing tight gas reservoirs are shown in figure VII.B.1. The gas occurs in a variety of rock types that include sandstone, siltstone, sandy carbonate rocks, limestone, dolomite, and chalk. There are three main types of tight gas reservoirs in the western United States as defined by geologic and engineering parameters. These three types are: 1) marginal-marine blanket, 2) lenticular, and 3) shallow blanket reservoirs. Many areas have more than one type. Marginal-marine blanket reservoirs may be carbonates or sandstones, chiefly deposited in shallow marine or marginal-marine environments (Finley, 1984; 1986). Marginal-marine blanket reservoirs usually respond to artificial fracturing in a predictable or near predictable manner (Spencer, 1985). Lenticular reservoirs include sandstones deposited by streams and river systems in continental environments. The distribution and nature of individual reservoirs is difficult to determine. The effectiveness of artificial stimulation of these rocks is rarely predictable using current technology (Spencer, 1985). Shallow-blanket reservoirs consist of very fine-grained sandstone, siltstone, silty shale, and chalk deposited in open-marine or marine-shelf environments (Rice and Shurr, 1980; Spencer, 1985). They occur at shallow depths, and many of these reservoirs have subnormal reservoir pressure. Subsurface correlation of these strata is relatively easy. Shallow-blanket reservoirs are being actively developed in southeastern Alberta and Saskatchewan, Canada. In the United States these tight reservoirs are present in the northern Great Plains and eastern Plains regions (fig. VII.B.1). Shallow-blanket reservoirs in the United States are estimated to contain recoverable resources of nearly 100 trillion cubic feet (TCF) of gas (National Petroleum Council, 1980). However, exploration for shallow-blanket reservoirs in the United States is at an early stage of development partly owing to low gas prices and lack of pipelines in the region.

The porosity of tight reservoirs can range from less than 5 percent in sandstones and carbonates to more than 25 percent in chalks. Tight rocks can be separated into two main porosity types (Spencer, 1985). One type has low porosity (generally <12 percent), low permeability, and high-capillary pressure as the result of post-depositional cementation (diagenesis) of

Figure VII.B.1. Tight gas basins and areas in the western United States from National Petroleum Council (1980) and Spencer (1985). Basins and areas studied by the National Petroleum Council (1980) are shown by patterned areas. Tight-gas basins not shown are Bighorn and Hanna in Wyoming and Raton in Colorado and New Mexico.

conventional reservoir rocks. The second type has high porosity (15 to 35 percent) and low permeability to gas because the rock is very fine grained. The fine-grain size causes the reservoir rock to have a high surface area and abundant very small (generally <10 μm) intergranular pore spaces. These rocks generally have high-capillary pressures.

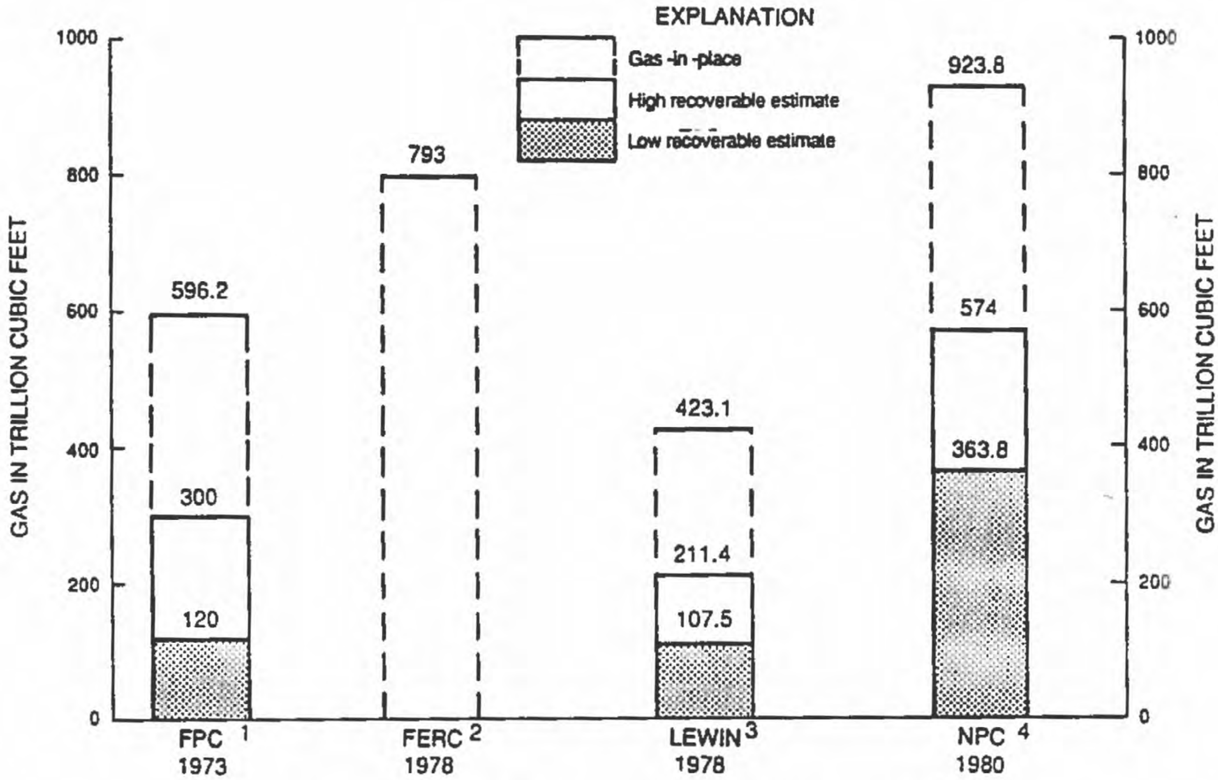
The lenticular and marginal-marine blanket rocks are the low-porosity type and the shallow-blanket reservoirs are the high-porosity type. The low-porosity type reservoirs are usually found at depths greater than 6,000 ft; whereas the shallow-blanket reservoirs of the northern Great Plains occur at depths generally less than 4,000 ft.

Previous Estimates of Gas Resources

The spot shortages of natural gas in the early 1970's focused attention on the importance of gas from unconventional sources. A number of estimates of gas recoverable from tight reservoirs have been made (fig. VII.B.2). In 1973, the Federal Power Commission (FPC) estimated in-place-gas resources of 596.2 TCF from only three Rocky Mountain area basins (Supply-Technical Advisory Task Force, 1973). The basins analyzed were the Green River, Piceance, and Uinta (fig. VII.B.1). No estimates were made of the amount of gas recoverable from each basin. However, various scenarios were presented relative to recovery from hypothetical wells, including wells stimulated with nuclear explosives. Figure VII.B.2 shows arbitrary 20 and 50 percent-recovery volumes for comparison with the other estimates.

Lewin and Associates, Inc. studied the tight-gas resources of 13 basins in the western United States (Kuuskraa and others, 1978, exhibit 3-18) and they estimated in-place-gas resources in the 13 basins of 423.1 TCF. They considered that 211.4 TCF was technically recoverable from the study basins using future technology, or about 50 percent of the gas in place. However, they considered that somewhat less than this volume should actually be considered recoverable. In this regard, Lewin assessed the recoverable resource using two models: (1) "base case technology", and (2) "advanced case technology." Their base case model assumed the level of technology anticipated to be developed by industry from 1979 to 1984 without additional Federal technological research. Their advanced case was based on -- "The level of the technology expected to be attained by virtue of active federal-industry collaboration." (Kuuskraa and others, 1978, p. 1-24). The maximum price for gas considered was $4.50 per MCF in 1978 dollars. Using the base case, tight gas reservoirs in the basins studied were estimated to ultimately yield 107.5 TCF and the advanced case estimate was 187.7 TCF (Kuuskraa and others, 1978, exhibit 1-11). The tight gas reservoirs were not well defined at the time of the Lewin study and a small but poorly defined amount of the reservoir volume they studied were actually conventional reservoirs (i.e. >0.1 md permeability to gas at in-situ conditions).

The National Petroleum Council Committee on Unconventional Gas resource study (referred to as the NPC) included resources in tight gas reservoirs in 113 gas producing provinces and basins in the U.S., both onshore and offshore in the Lower 48 States. However, only 12 basins, also in the western United States, were studied and appraised in detail. The data from these 12 basins were then extrapolated to provide a resource figure for the other 101 areas. The NPC study was clearly the most thorough study of its



[1]Supply-Technical Advisory Task Force, 1973, Task force report: national gas supply, in National Gas Survey volume II: Federal Power Commission, 662 p.

[2]Supply-Technical Advisory Task Force, 1978, National gas survey, in Report to the Federal Energy Regulatory Commission by the Supply-Technical Advisory Task Force on Nonconventional Natural Gas Resources: U.S. Department of Energy Federal Energy Regulatory Commission, 108 p.

[3]Kuuskraa, V.A., Brashear, J.P., Doscher, T.M., and Elkins, L.E., 1978, Enhanced recovery of unconventional gas, the program--Volume II: U.S. Department of Energy, HCP/T2705-02, 537 p. (variously paginated).

[4]National Petroleum Council, 1980, Tight gas reservoirs; part I, in National Petroleum Council Unconventional Gas Resource: Washington, D.C., 222 p. with appendices.

Figure VII.B.2. Selected estimates of gas-in-place and recoverable gas in western tight gas reservoirs in the United States.

kind as of 1980. The NPC estimated that there were 12 TCF of already "proven" (identified) reserves and 574 TCF of economically recoverable undiscovered tight gas (NPC, 1980, table 1) in the 113 areas and basins. The 574 TCF estimate was derived assuming advanced technology and using a gas price of $9.00/MCF in 1979 dollars and a 15 percent rate of return on investment.

The term "undiscovered", as applied to unconventional gas, is misleading since most of the areas included in the resource assessment have dryholes drilled through at least part of the potential tight reservoir section. These wells commonly had encountered gas shows and (or) tested noncommercial volumes of gas on drillstem tests or through perforations. Analysis of these "dryholes" forms the data base upon which much of the assessments were predicated, not only by the NPC but also by Levin, and the USGS.

The wide variation between the highest Levin (Kuuskraa and others, 1978) United States resource estimate (187.7 TCF) and the recent NPC study (574 TCF) is partly related to different methods of study, economic factors utilized, and interpreted lateral and vertical extent of the potential reservoir rocks. Another significant factor is the <u>number</u> of basins and areas considered to have potential for resources of <u>tight</u> gas. Levin based their resource estimate on 13 such areas; whereas, the NPC studied 12 western United States basins and extrapolated data to 101 more basins for a total of 113. Levin did not assess gas resources deeper than 12,700 ft and the NPC did not include gas resources deeper than 15,000 ft. Tight gas reservoirs are actually present in some basins at depths in excess of 20,000 ft. However, 13 western basins and areas studied by Levin are essentially the same as the 12 examined by the NPC but it is difficult to make a direct comparison of the work because of the different approaches to assessment and different methods of data presentation. The NPC included a very small amount of resources in reservoirs with up to 0.3 md permeability but most of the assessed gas was in rocks with permeabilities of <0.1 md.

In 1978, the Federal Energy Regulatory Commission (FERC) studied gas resources from various unconventional sources (Supply-Technical Advisory Task Force, 1978). They accepted the tight sandstone formation gas estimates of about 600 TCF in-place resources in 3 basins estimated by the previous Supply-Technical Advisory Task Force (1973) and added 63 TCF for in-place-gas in the San Juan basin, New Mexico and an additional 130 TCF of in-place-gas for the northern Great Plains shallow gas in Montana and North Dakota (fig. VII.B.1). These additions yield a total in-place-gas resource estimate of 793 TCF for the five basins and areas.

<u>New Estimates of Tight Gas Resources</u>

The U.S. Geological Survey has been conducting geologic research on western tight gas reservoirs for the U.S. Department of Energy (DOE) since 1977. This cooperative geologic research has resulted in the publication of more than 150 technical reports, many of which are listed in Spencer and Krupa (1985).

This research, plus available published and unpublished engineering and other data, forms the basis for new resource estimates in the Piceance, Greater Green River, Uinta, Wind River, and Denver basins. DOE initially identified the northern Great Plains area and Greater Green River, Piceance, and Uinta basins as the areas having the best resource potential. Consequently, the USGS research has been concentrated in these areas. As a result of this work, a recoverable gas estimate of more than 100 TCF was assessed (Rice and Shurr, 1980) for tight reservoirs in the northern Great Plains. The NPC (1980), in cooperation with the USGS, then estimated the recoverable gas in the northern Great Plains to range from 54.73 to 99.34 TCF. More recently, preliminary resource assessments were made for the Piceance (Johnson and others, 1987) and Greater Green River basins. The USGS used a different approach in these two detailed resource assessments.

The baseline for any assessment of unconventional resource is a realistic in-place-gas determination for a given basin or area. Previous assessments reported in-place-gas volumes but in actuality they were a very selective high-grading of the best basin areas. Furthermore, the two most quantitative studies (Kuuskraa and others, 1978, and NPC, 1980) excluded large geographic areas with potential resources because of existing shallow conventional development overlying thick sequences of tight gas rocks. These areas were classified as "developed". The two studies also excluded large areas of sparse well control. These areas were considered too speculative to be included. As noted earlier, they used a depth cutoff for resource consideration. The parameters both studies used were designed to provide a much-needed, realistic, near-term estimate of recoverable gas.

The USGS objective was somewhat different. We are concerned with the near-term and the very long-term development of the resource. No one has any concrete picture of future technology and prices. We only know that technology eventually will be greatly improved and gas prices will be competitive with other energy sources. In the future, gas may command a premium price over other fossil energy sources because it is less damaging to the environment.

Gas-in-place estimates.--With these objectives in mind the USGS approach in the two study basins was to make an estimate of the total gas-in-place in all sandstone reservoirs more than 10 ft thick. To reach this objective the total geology of the basins was studied. The objective tight reservoir strata were then separated into plays. Within these plays, probability distributions for reservoir parameters were determined. The input parameters included thickness of saturated sandstone (>10 ft), depth, porosity, gas saturation, pressure, temperature, and gas compressibility. These data were processed to yield ranges of estimated gas-in-place. These numbers have a fairly solid geological basis; however, attempting to estimate the percent of recoverable gas-in-place is much more difficult.

Recoverable gas estimates.--Two recovery scenarios were developed for the USGS estimates; a current technology recovery case and an advanced technology recovery case. The current technology estimates assume the application of present-day, state-of-the-art drilling and completion methods. State-of-the-art means operators will use the best available tight gas well completion methods considering all aspects of the formation because these reservoirs have a high potential for formation damage (Spencer, 1985).

Present-day technology also assumes no pipeline (market) constraints and a gas price of $5/MCF in 1987 dollars. It is perceived that $5/MCF is a price that would encourage exploratory drilling and development of at least the most attractive areas or reservoirs (i.e., marginal-marine blanket reservoirs.

Piceance Basin

The Piceance basin is located in northwest Colorado (fig. VII.B.1). The basin has a maximum sediment thickness of more than 20,000 ft. The widespread presence of Upper Cretaceous tight gas reservoirs in this basin has been known for more than 30 years. Reservoirs range in depth from less than 5,000 ft to deeper than 12,000 ft. The basin was the site of two nuclear explosive experiments to stimulate the gas-bearing reservoirs. The NPC estimated recoverable gas from all tight reservoirs in the basin to range from a low of 12.87 TCF at $2.50 (1979 dollars) and current technology to a high of 29.71 TCF at $9.00 and advanced technology (NPC, 1980, table 9, p. 42). Most of the gas they assessed is in the Upper Cretaceous Mesaverde Group and its equivalents. The NPC included some gas resources in the Tertiary Fort Union Formation and Lower Cretaceous and Jurassic reservoirs, but most of the Fort Union reservoirs are actually conventional reservoirs.

In 1987, Johnson and others (1987) estimated the gas-in-place in the Piceance basin using a modified volumetric approach. As noted previously, most of the tight gas resources are contained in the Mesaverde Group, which is further subdivided into a lower Iles Formation and an upper Williams Fork Formation. A marginal-marine sandstone interval called the Rollins or Trout Creek Sandstone Member occurs at the top of the Iles Formation. This sandstone member has slightly better reservoir characteristics than the adjacent rocks and commonly is water-bearing at greater depths in the basin than other stratigraphic units. The Williams Fork Formation consists of dominantly lenticular, low-porosity continental sandstones, siltstones, shales, and coals. In the Piceance basin, the Mesaverde Group ranges in thickness from less than 3,000 ft to slightly more than 6,000 ft. For the purpose of this assessment it was subdivided into three stratigraphic units based on sandstone thickness, reservoir geometry, and organic richness. These three units were each further subdivided into two zones (Johnson and others, 1987). These two zones are called "transition", and "basin center". Johnson and others (1987) observed that the occurrence of gas coincided with certain levels of thermal maturity (vitrinite reflectance). The transition zone in each of the stratigraphic units has a vitrinite reflectance from 0.73 to 1.1 percent R_o and consists of stratigraphically trapped, normally pressured, gas-bearing sandstones interbedded with water-bearing sandstones.

The basin center zones occur at greater present-day burial depths and have experienced more severe diagenesis (more loss of porosity and permeability). The basin center rocks have maturation levels of 1.1 percent Ro and higher. They are slightly overpressured, with little or no free water (no gas-water contacts), and the gas is stratigraphically entrapped (Johnson and others, 1987).

Johnson and others (1987), using detailed geologic mapping, made probabilistic in-place-gas estimates for each of six plays based on the two zones for each stratigraphic unit, and estimated recoveries. The input, methodology, and output for this assessment are given in detail in Johnson and others (1987). Table VII.B.1 shows estimates of gas-in-place and recoverable gas for the Mesaverde Group in the Piceance basin.

The NPC (1980, table 9, p. 42) estimated gas-in-place of 49.14 TCF and recoverable gas for advanced technology and high prices of 29.71 TCF or a recovery factor of about 60 percent of the in-place gas for advanced technology and high prices. In essence, they assumed that most of the recoverable gas would come from the best reservoirs. The new recovery technology research conducted by DOE at the multiwell experiment (MWX) site in the southern Piceance basin has shown that gas can be produced at low rates from virtually any tight sandstone throughout the Mesaverde interval. The gross gas saturated interval at the MWX site is at least 2,600 ft thick. The gas resources reside both in gas-filled porosity and natural fractures. The key is to communicate the wellbore to the natural fracture system using artificial stimulation techniques that minimize the damage (reduction of permeability) of the natural fractures and the pore-permeability system.

The NPC (1980) study was the most complete previous gas assessment of tight reservoirs for the Piceance basin. It is difficult to make an exact comparison with the present USGS work because the NPC combined some of the Tertiary and Cretaceous reservoirs, but a general comparison can be made. The NPC estimated 12.87 TCF was recoverable at base case (current technology) and 1979 $2.50/MCF gas prices from Tertiary, Cretaceous and Jurassic tight sandstone reservoirs. Johnson and others (1987) estimated recoverable gas of 13.42 TCF from only the Cretaceous Mesaverde using current technology and 1987 $5/MCF gas prices and 67.95 TCF for advanced technology (table VII.B.1). Table VII.B.2 shows the comparison between USGS and NPC estimates.

The most significant differences between the two studies are that the NPC (1980) used a reduced net pay thickness and did not estimate gas-in-place for all gas-saturated sandstones. They then applied a very high recovery factor. For instance, for the Mesaverde and <u>equivalents</u> and <u>combined</u> Cretaceous-Tertiary, the gas-in-place was estimated at 49.143 TCF (NPC, 1980, table 9). Of that amount they estimated 18.423 TCF were recoverable at base case and $5/MCF, or 37 percent of the gas-in-place. Considering the lenticularity and low permeability of the reservoirs, 37 percent is a very high recovery factor. It is obvious they assessed gas-in-place in only the best reservoirs in the basin. Whereas, the USGS approach was to estimate gas-in-place for <u>all</u> sandstones thicker than 10 ft and apply a current technology recovery factor. The low recovery factor takes into account such problems as distribution of natural fractures, inability of wells to contact or communicate the wellbore with a significant percentage of the lenticular sandstones in a given square mile, well spacing, and other factors. Somewhat higher recovery factors were used when assuming advanced technology and very high future gas prices.

Table VII.B.1.--Piceance basin tight gas resource estimates (TCF)[1].

Play	In-Place[3] Low F95	In-Place[3] High F5	In-Place[3] Mean	Recoverable[2] Current Technology[4] Low F95	Recoverable[2] Current Technology[4] High F5	Recoverable[2] Current Technology[4] Mean	Recoverable[2] Advanced Technology[5] Low F95	Recoverable[2] Advanced Technology[5] High F5	Recoverable[2] Advanced Technology[5] Mean
Williams Fork Transition	69.0	189.5	119.9	2.07	5.68	3.60	12.42	34.11	21.58
Williams Fork Basin Center	133.0	286.9	200.8	3.99	8.61	6.02	19.95	43.04	30.11
Iles Transition	14.0	39.4	24.7	0.84	2.37	1.48	2.81	7.89	4.94
Iles Basin Center	43.1	107.3	70.7	1.29	3.22	2.12	6.47	16.10	10.61
Rollins-Trout Creek Transition	0.2	0.9	0.5	0.02	0.09	0.05	0.05	0.20	0.10
Rollins-Trout Creek Basin Center	1.2	6.1	3.0	0.06	0.30	0.15	0.23	1.21	0.60
Aggregation of six plays[6]	274.5	605.3	419.6	8.75	19.41	13.42	44.23	98.39	67.95

[1] Data from Johnson and others (1987).
[2] Rounded to nearest one-hundredth.
[3] Rounded to nearest one-tenth.

[4] Current technology assumes present-day, state-of-the-art drilling and completion methods and existing well spacing and $5 per MCF (1987 dollars). The price was selected based on the assumption that this price would presently encourage economic development of the resource.

[5] Advanced technology assumes exotic drilling and completion methods that will maximize well and stimulation contact with the greatest feasible number of reservoirs. It assumes nondamaging communication can be made between the wellbore and the natural fractures. It also assumes very high gas prices on a par or higher than other future energy sources.

[6] Fractile values are not additive.

Table VII.B.2.--USGS and NPC[1] recoverable gas estimates[2].

	USGS							
	Current Technology			Advanced Technology			NPC[1]	
Area	Low F95	High F5	Mean	Low F95	High F5	Mean	Base Low[4]	Advanced high[5]
Piceance basin	8.75	19.41	13.42	41.93	102.55	67.94	12.87	29.71
Greater Green River basin	27.39	150.29	73.35	186.87	812.13	430.41	3.08	74.38
Uinta basin	5.28	28.27	13.92[3]				12.22	15.27
Wind River basin	2.47	12.46	6.26				7.04	18.78
Denver basin	0.20	1.28	0.59				0.00	7.60
Totals			107.54			498.35	35.21	145.74

[1]National Petroleum Council (1980).

[2]In trillion cubic feet (TCF).

[3]USGS modification of NPC (1980) estimates.

[4]Base case and $2.50/MCF, 1979 dollars.

[5]Advanced case and $9.00/MCF, 1979 dollars.

Advanced technology will include new techniques to stimulate reservoirs in a manner that will not cause formation damage and may include new drilling techniques such as inclined drilling. Inclined drilling has the potential of intersecting more open vertical fractures in lenticular and blanket reservoirs than a vertically drilled hole.

Greater Green River Basin

The evaluation of gas resources contained in tight reservoirs in the Greater Green River basin is greatly facilitated as a result of earlier work recognizing the relationship between gas-bearing reservoirs and overpressuring (Law and others, 1979, 1980; McPeek, 1981; Law, 1984; Law and Dickinson, 1985; Law and others, 1986; Spencer, 1987). Because of the low-permeability of the reservoirs and the close association of the reservoirs to good source rocks, thermogenic gas accumulates in the reservoirs at a rate greater than it is lost, causing fluid (gas) pressure to rise above regional hydrostatic pressure. Thus, overpressuring is a direct indication of gas-bearing reservoirs. Overpressuring is detected directly by pressure analysis of drill-stem tests and indirectly by noting variations of drilling mud weight, measurement of thermal maturity, and subsurface temperature mapping. The gas-bearing overpressured reservoirs occur in stratigraphic sequences that are as thick as 14,000 ft (4,267 m) and occupy the deeper part of the basin, downdip from water-bearing normally pressured reservoirs. Structural and stratigraphic trapping aspects in these unconventional reservoirs are not as important as in conventional reservoirs. The top of overpressuring cuts across structural and stratigraphic boundaries.

The overpressured gas-bearing sequence was subdivided into five stratigraphic intervals which in ascending order include: 1) the Lower Cretaceous Dakota Sandstone and Upper Cretaceous Frontier Formation, 2) the Upper Cretaceous Mesaverde Group, 3) the Upper Cretaceous Lewis Shale, 4) the Upper Cretaceous Lance Formation, and 5) the lower Tertiary Fort Union Formation. The assessment of gas contained in each of these units utilizes a reservoir equation in which the gas volumes are determined from probability distributions of the geological and engineering variables. The variables include the areal extent of overpressured gas reservoirs, reservoir thickness, porosity, gas saturation, reservoir depth, geothermal gradient, pressure gradient, and gas compressibility.

Table VII.B.3 shows the estimate of gas in the Greater Green River basin. The aggregate gas in-place resource of the plays range from 3,469 TCF to 6,828 TCF, with 4,971 TCF as the mean estimate. Recoverable gas was estimated for each play under the following scenarios: 1) current technology, with a price of $5/MCF in 1987 dollars and 2) advanced technology, with no price limit. For the current technology scenario, the aggregated recoverable gas ranges from 27 to 150 TCF, with 73 TCF as the mean estimate. For the advanced technology scenario, the aggregated recoverable gas ranges from 187 to 812 TCF, with 430 TCF as the mean estimate. For comparison, the National Petroleum Council (1980) estimated the total in-place gas resource in the Greater Green River basin at about 136 TCF and the recoverable gas for the advanced case at 86.52 TCF, or a recovery factor of about 55 percent of the gas-in-place. At current technology and $2.50/MCF (in 1979 dollars) the recovered gas volume was estimated to be 3.08 TCF, or a recovery factor of 2 percent.

Table VII.B.3.--Greater Green River basin tight gas resource estimates (TCF).

Play	In-Place			Recoverable: Current Technology[1]			Recoverable: Advanced Technology[2]		
	Low F95	High F5	Mean	Low F95	High F5	Mean	Low F95	High F5	Mean
Fort Union	58.79	110.76	82.20	0.37	1.96	0.97	3.16	13.35	7.15
Lance/Fox Hills	361.44	1004.30	632.27	2.54	16.05	7.47	21.28	110.62	55.01
Lewis	499.81	991.34	719.32	7.31	45.31	21.22	45.16	173.93	96.39
Mesaverde	2212.10	4427.60	3200.00	13.15	86.06	39.60	96.02	515.85	253.60
Frontier-Dakota	219.26	489.48	337.51	1.43	8.68	4.09	8.45	33.21	18.27
Aggregation of all five plays	3469.20	6828.30	4971.27	27.39	150.29	73.35	186.87	812.13	430.41
Aggregation of first four plays	3225.80	6376.70	4633.76	25.59	142.70	69.26	176.93	782.67	412.15

[1] Current technology assumes present-day, state-of-the-art drilling and completion methods and existing well spacing and $5 per MCF (1987 dollars). The price was selected based on the assumption that this price would presently encourage economic development of the resource.

[2] Advanced technology assumes exotic drilling and completion methods that will maximize well and stimulation contact with the greatest feasible number of reservoirs. It assumes nondamaging communication can be made between the wellbore and the natural fractures. It also assumes very high gas prices on a par or higher than other future energy sources.

The USGS estimated large volumes of in-place gas but used relatively low recovery volumes for each play. At current technology, the overall gas recoveries varied from less than 1 percent to slightly more than 6 percent of the gas in-place. Table VII.B.2 shows the comparison between USGS and NPC estimates.

Estimates for Selected Rocky Mountain Basins

The NPC (1980) data were reviewed for a few basins where we have specific knowledge of tight reservoirs but do not presently have sufficient data to do the play-type of assessments done in the Piceance and Greater Green River basins. We used the NPC estimates and data, plus some of our own data to develop new subjective estimates of unconventional resources.

Uinta basin.--The USGS gas estimates for Tertiary and Cretaceous reservoirs in the Uinta basin range from 5.28 TCF to 28.27 TCF with a mean of 13.917 TCF (table VII.B.2). The starting point in this estimate was 12.22 TCF from the NPC base technology case and $2.50/MCF prices. At the 5.0% fractile level, we increased the NPC advanced case recoverable gas volume to account for additional section and area expected to be productive. No attempt was made to develop a separate scenario for advanced versus present technology. The 95% fractile assumes state-of-the-art current technology and $5/MCF; whereas, the 5.0% fractile assumes future advancements in technology and prices.

Wind River basin.--The USGS deep basin gas estimates for Cretaceous and Tertiary reservoirs in the Wind River basin range from 2.47 TCF to 12.45 TCF with a mean of 6.2 TCF (table VII.B.2). In this case, the NPC estimates and data were also used. The actual NPC (1980, table 9) estimates ranged from a low of 7.039 TCF at $2.50/MCF and base-case conditions to 18.778 TCF at $9/MCF and advanced case conditions.

The NPC estimates did not include any gas in reservoirs deeper than 15,000 ft. Potentially productive tight reservoirs are present in the Wind River basin at depths in excess of 20,000 ft.

Denver basin.--The Denver basin (fig. VII.B.1) currently produces gas from tight reservoirs in the Lower Cretaceous "J" Sandstone. Most of this production comes from the tighter facies in the Wattenberg field, located north of the city of Denver, Colorado.

The present study assumed another gas accumulation similar to Wattenberg will be developed. The estimated recoverable resources range from 0.20 TCF to 1.28 TCF and a mean of 0.59 TCF.

Summary and Conclusions

A much better understanding of western tight gas reservoirs has been developed in recent years. The U.S. Department of Energy has supported important geologic and engineering research. This research, plus special incentives developed under the Natural Gas Pricing Act of 1978 caused some large areas to be designated as tight gas producing areas and potentially productive areas. The assessment of gas contained in tight reservoirs in five Rocky Mountain basins indicate that 107.5 TCF is recoverable under the conditions of current technology. This assessment represents an increase of 72.3 TCF over previous estimates in the same basins. The increase of recoverable gas is largely due to the large in-place estimates in the Piceance and Greater Green River basins of 419.5 TCF and 4,971.3 TCF, respectively. The recognition of geologic criteria such as abnormally high or low pore pressure, level of thermal maturity, subsurface temperature distribution, and well-log analysis have enabled us to define the vertical and lateral extent of gas-bearing tight reservoirs more accurately than previously possible. Detailed assessments of tight gas reservoirs in other Rocky Mountain basins, like those conducted in the Piceance and Greater Green River basins would most likely result in significant increases in the estimates of gas in-place and recoverable gas.

We believe the estimated gas-in-place in the two detailed basins is fairly conservative. Gas in reservoirs less than 10 ft thick were excluded and we did not include gas occurring in organic-rich shales, coal beds, or fractures.

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C. GAS RESOURCES OF THE UNCONVENTIONAL DEVONIAN GAS SHALES OF THE APPALACHIAN BASIN

by Wallace de Witt, Jr.

The Devonian gas shales are a sequence of dark brown to black marine shales rich in organic matter that range in age from Middle Devonian to Early Mississippian. They crop out on the north and west flanks of the Appalachian basin, plunge eastward to a depth of more than 8,000 ft beneath the Appalachian Plateau, and are exposed to the east in thrust plates of the Valley and Ridge province (fig. VII.C.1). The total aggregate thickness of the black gas shales ranges from a feather-edge in south central Tennessee to more than 1,000 ft in parts of Pennsylvania and Virginia. Commonly the gas shales grade laterally into an eastward thickening sequence of gray shale, siltstone, and sandstone.

The amount of organic matter, the source of the gas in the shale, is greatest in the western part of the basin and decreases eastward. Gas is generated in the gas shales as the organic matter is heated and distilled by increasing earth temperature during burial beneath younger rocks. The organic matter in the shale adsorbs much of the newly generated gas. Consequently the Devonian gas shales are both source bed and reservoir rock. More than 250 trillion cubic feet of gas are trapped in the Devonian gas shales in the Appalachian basin. Gas is released very slowly from the low permeability black shale and migrates into joints, faults, and fractures that cut the shaly strata. Gas moves rapidly from the network of fractures to wells that intersect one or more of the fractures. Thus, gas moves slowly from minute pores in the shale and ultimately to the well bore. The volume of gas moving into a well may not be large. However, because of the great volume of gas adsorbed in the gas shales, wells producing from the gas-shale sequence commonly yield gas for many decades.

The major area for Devonian shale gas, the Big Sandy field of eastern Kentucky and adjacent West Virginia, has produced more than 2.5 trillion cubic feet of gas from more than 10,000 wells during the past 65 years. Most shale gas wells require stimulation by explosives or more recently by hydraulic fracturing methods to initiate or enhance permeability pathways from the fractured shale to the well bore before the wells will produce gas in commercially exploitable volumes.

In the past, determination of the size of the gas resource in the Devonian gas shales was very difficult because much of the geologic data necessary for the evaluation were not available. However, with the recent widespread use of wire-line geophysical logs much of these data have become available. In the late 1970's, the U.S. Geological Survey applied a modified play-analysis technique to determine the volume of gas-in-place in the black Devonian gas shale and also to the total of gray, brown, and black Devonian shale sequence in the Appalachian basin (Charpentier and others, 1982). The basin was subdivided into 19 major play areas, each with its specific suite of geologic factors that differ from those in other plays. The volume of gas-in-place was calculated for each play based upon its specific geology, and the sum of the volume of gas-in-place for all plays indicated about 280 trillion cubic feet of gas-in-place in the black Devonian gas shales. The total gray, brown, and black Devonian shale sequence contained from 577 to 1,131 trillion cubic feet of gas-in-place with a mean of 844 trillion cubic

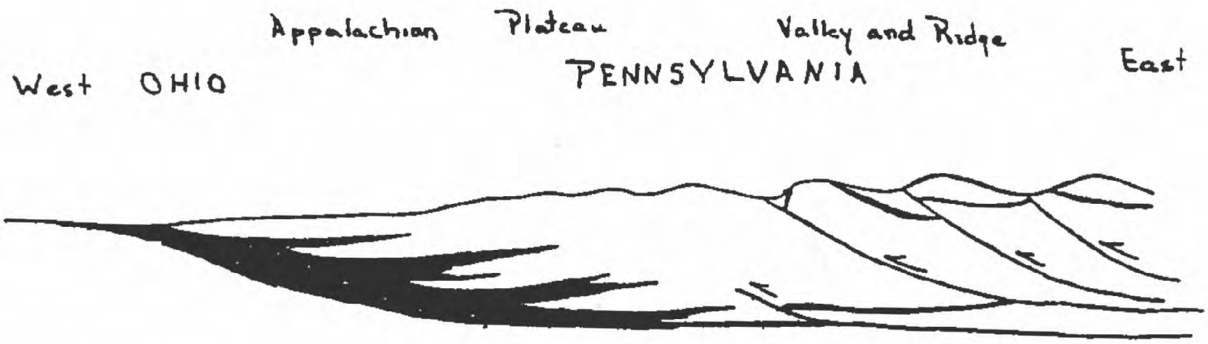

Figure VII.C.1. Generalized cross section of the Devonian black gas shales in the Appalachian basin. Gas shales shown in black.

feet of gas-in-place. Because present extraction techniques recover only a few percent of the gas-in-place from the unconventional fractured-shale reservoir strata of the Devonian gas-shale sequence, the recoverable resource from the Devonian gas shales is much less than the large in-place gas quantity.

In this study we estimated that the recoverable resources from the Devonian shale sequence in the Appalachian basin range from 7.9 to 25.8 trillion cubic feet with a mean estimate of 15.2 trillion cubic feet. These estimates were based on a 1987 gas price of $5.00/MCF.

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D. MAJOR TAR SAND DEPOSITS OF THE UNITED STATES
by
C. J. Schenk

The major tar-sand deposits in the United States shown in figure VII.D.1, defined as those deposits containing more than 100 million barrels of tar in-place, are in Alabama, Alaska, California, Kentucky, Texas, Utah, and Wyoming (Lewin and Associates, 1983). Between 1890 and 1940, nearly all of the major deposits were delineated, and most were quarried for paving material. With the discovery and production of large domestic and foreign reserves of conventional petroleum, the mining of domestic tar sands became uneconomic, and all operations ceased. The major deposits of tar are considered to be mostly uneconomic at present, but may be recoverable in the future by either in-situ or surface-mining recovery techniques. Minor tar-sand deposits with less than 100 million barrels are considered subeconomic resources, defined as those resources that have a more remote chance of extraction due principally to economic factors (Dolton and others, 1981). Tar is defined for this paper as any hydrocarbon with an API gravity of 10 degrees or less.

The total tar-sand resource of the United States ranges from 54 to 70 billion barrels, with the uncertainty arising from various estimates for the Tar-sand Triangle deposit in Utah, and the deposits on the Alaskan North Slope (Campbell and Ritzma, 1979; Lewin and Associates, 1983; Werner, 1987). With one exception, all of the major tar accumulations are sandstone hosted; the Anacacho deposit in Texas in the only major carbonate-hosted tar accumulation (Schenk, 1985). Deposits in Utah (fig. VII.D.1) include Sunnyside (3.5-6.1 billion barrels, original oil-in-place [OOIP], Raven Ridge (100 million barrels OOIP), P. R. Spring-Hill Creek (5.1-5.6 billion barrels OOIP), Asphalt Ridge (1.1-1.75 billion barrels OOIP), Whiterocks 120 million barrels OOIP), Tar-Sand Triangle (2.9-12 billion barrels OOIP), Circle Cliffs (1.3-1.7 billion barrels OOIP), and San Rafael (550 million barrels OOIP) (Campbell and Ritzma, 1979; Ritzma, 1979; Lewin and Associates, 1983). The Hartselle deposit of northern Alabama is estimated to contain 6.2 billion barrels OOIP (Lewin and Associates, 1983). However, most of the sandstone is characterized by relatively low tar saturation values over a wide area, accounting for the high value of oil-in-place (Lewin and Associates, 1983; Wilson, 1983). In addition, the play is mainly in the subsurface, decreasing the chances that the tar will be economically recoverable.

The tar-sand deposits in California include Edna (310 million barrels OOIP), Basal Foxen (1.9 billion barrels OOIP), Cat Canyon (1.1 billion barrels OOIP), Casmalia (260 million barrels OOIP), Zaca-Sisquoc (230 million barrels OOIP), and Oxnard (660 million barrels OOIP) (Lewin and Associates, 1983). The two deposits in Kentucky are the Big Clifty (2.1 billion barrels OOIP), and Caseyville (550 million barrels OOIP) (Noger, 1987). The two Texas deposits are the San Miguel (2-3 billion barrels OOIP) and Anacacho (950 million barrels OOIP) (Lewin and Associates, 1983; Britton, 1987). The Burnt Hollow deposit in northeast Wyoming contains 150 million barrels OOIP. Most of the major tar sand accumulations are, at least in part, exposed at the surface; others were delineated during drilling for conventional petroleum. As such, the possibility is remote that other major tar accumulations remain to be discovered in the United States.

Figure VII.D.1. Map of the United States showing the locations of the 24 major tar sand deposits. Note the grouping of deposits in California.

1. Hartselle deposit, Alabama
2. West Sak deposit, Alaska
3. Lower Ugnu deposit, Alaska
4. Upper Ugnu deposit, Alaska
5. Sagavanirktok deposit, Alaska
6. Edna deposit, California
7-10. Basal Foxen, Cat Canyon, Casmalia, and Zaca-Sisquoc deposits, Calif
11. Oxnard deposit, California
12. Big Clifty deposit, Kentucky
13. Caseyville deposit, Kentucky
14. San Mogul deposit, Texas
15. Anacacho deposit, Texas
16. P. R. Spring-Hill Creek deposit, Utah
17-19. Asphalt Ridge, Whiterocks, and Raven Ridge deposits, Utah
20. Sunnyside deposit, Utah
21. Tar Sand Triangle deposit, Utah
22. Circle Cliffs deposit, Utah
23. San Rafael deposit, Utah
24. Burnt Hollow deposit, Wyoming

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VIII. UNDISCOVERED CONVENTIONAL PETROLEUM RESOURCES OF GEOLOGIC PROVINCES

This section gives the estimates for undiscovered recoverable and economically recoverable conventional oil, gas and natural gas liquid resources for the onshore and offshore geologic provinces of the United States. Figures VIII.A.1 and VIII.A.2 show the province boundaries for the Lower 48 States and Alaska areas respectively. The province numbers on the map correspond to those given on tables VIII.B.1, VIII.B.2, VIII.B.3., and VIII.B.4.

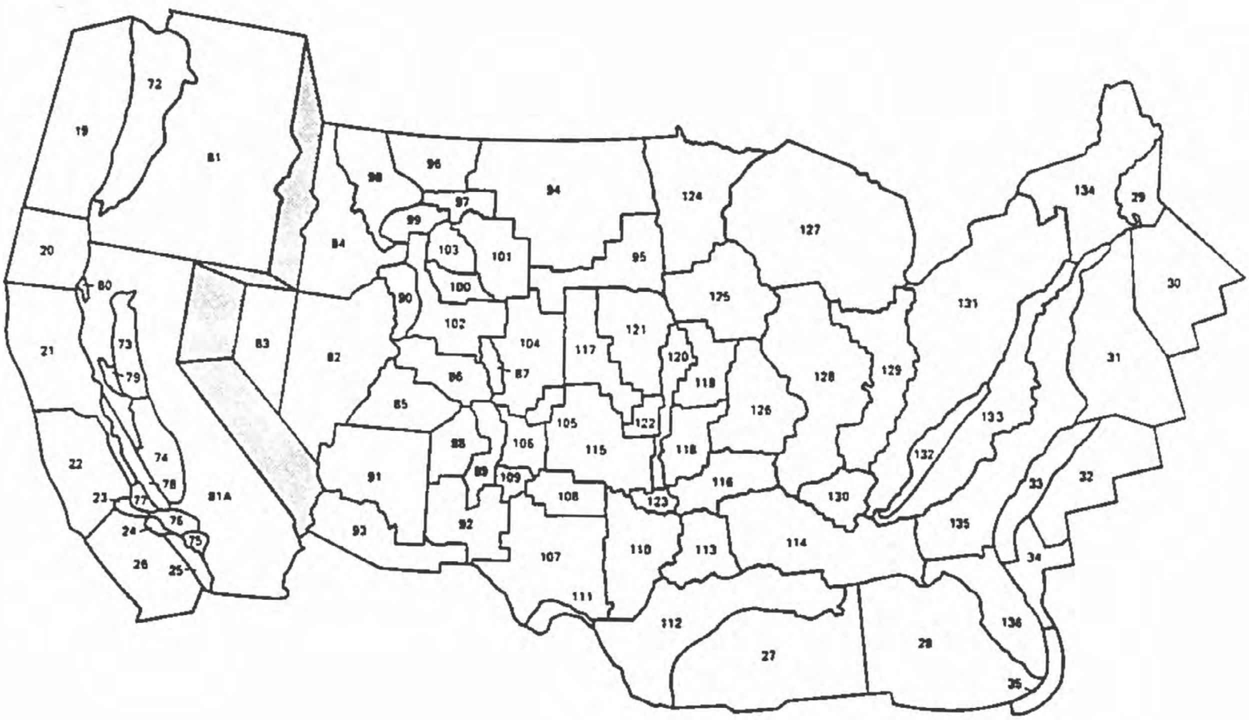

Figure VIII.A.1. Index map of Lower 48 States showing provinces assessed. Names of onshore and offshore provinces are listed by number on table VIII.B.1., and VIII.B.2.

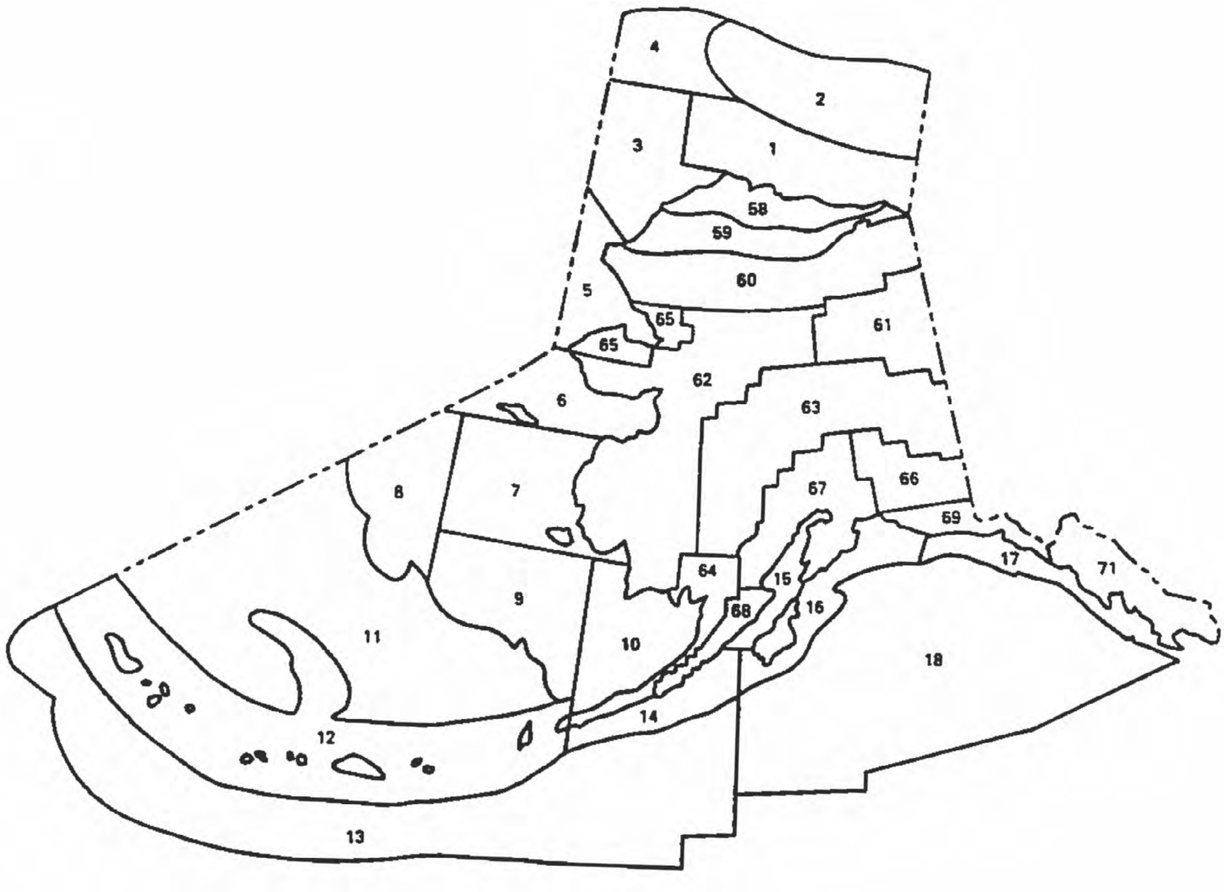

Figure VIII.A.2. Index map of Alaska showing provinces assessed. Names of onshore and offshore provinces are listed by map number on table VIII.B.1. and VIII.B.2.

Table VIII.B.1.--Estimates of undiscovered recoverable conventional oil, gas and natural gas liquids in onshore provinces and adjacent state waters of the United States.

		Crude Oil (Billion Barrels)			Total Gas (Trillion Cubic Feet)			NGL (Billion Barrels)		
		F95	F5	Mean	F95	F5	Mean	F95	F5	Mean
Region 1 - Alaska										
058	Arctic Coastal Plain	1.50	14.80	6.00	4.66	58.24	22.11	0.13	1.41	0.56
059	Northern Foothills	0.67	5.12	2.24	4.03	24.31	11.49	0.07	0.44	0.21
060	Southern Foothills	0.58	13.18	4.35	2.85	61.56	20.49	0.04	0.87	0.29
061	Kandik	0.00	0.49	0.11	0.00	0.49	0.11	0.00	0.00	0.00
062	Alaska Interior	0.00	0.00	0.00	0.45	2.85	1.33	0.00	Negl.	Negl.
063	Interior Lowlands (Incl. in 62)									
064	Bristol basin	0.00	0.00	0.00	0.11	0.67	0.32	0.00	0.00	0.00
065	Hope Basin	-	-	-	-	-	-	-	-	-
066	Copper River (Incl. in 62)									
067	Cook Inlet	0.09	0.64	0.29	0.35	3.91	1.53	0.00	Negl.	Negl.
068	Alaska Peninsula (Incl. in 62)									
069	Gulf of Alaska	0.03	0.58	0.19	0.03	2.00	0.56	Negl.	0.01	Negl.
070	Kodiak	-	-	-	-	-	-	-	-	-
071	SE Alaska	-	-	-	-	-	-	-	-	-
Region 2 - Pacific Coast										
072	W. Oregon-Washington	0.00	0.00	0.00	0.87	4.29	2.18	0.00	0.00	0.00
073	Sacramento basin	0.00	0.00	0.00	0.76	3.37	1.78	Negl.	Negl.	Negl.
074	San Joaquin basin	0.55	3.22	1.53	1.23	6.69	3.27	0.08	0.53	0.24
075	Los Angeles basin	0.24	1.42	0.68	0.29	1.69	0.81	0.02	0.09	0.04
076	Ventura basin	0.20	1.63	0.70	0.40	2.93	1.30	0.02	0.12	0.05
077	Santa Maria basin	0.13	0.49	0.27	0.11	0.44	0.24	0.01	0.02	0.01
078	Central Coastal	0.05	0.72	0.27	0.04	0.58	0.21	Negl.	0.02	0.01
079	Sonoma-Livermore basin	0.00	0.01	0.01	0.00	0.01	0.01	0.00	0.00	0.00
080	Humboldt basin	0.00	0.00	0.00	0.01	0.10	0.04	0.00	0.00	0.00
081	E. Oregon-Washington	0.00	0.00	0.00	0.43	2.39	1.16	Negl.	Negl.	Negl.
81A	Eastern California	-	-	-	-	-	-	-	-	-

Table VIII.B.1.--continued.

		Crude Oil (Billion Barrels)			Total Gas (Trillion Cubic Feet)			NGL (Billion Barrels)		
		F95	F5	Mean	F95	F5	Mean	F95	F5	Mean
Region 3 - Colorado Plateau and Basin & Range										
082	E. Basin & Range	0.09	0.65	0.29	0.03	0.47	0.17	Negl.	0.01	Negl.
083	W. Basin & Range	Negl.	0.06	0.02	Negl.	0.14	0.04	Negl.	Negl.	Negl.
084	Idaho-Snake River	0.00	0.00	0.00	0.01	0.10	0.04	0.00	0.00	0.00
085	Paradox basin	0.01	0.72	0.20	0.04	1.26	0.38	Negl.	0.01	Negl.
086	Uinta-Piceance	0.04	0.55	0.20	1.11	3.76	2.19	0.01	0.03	0.02
087	Park basin	Negl.	0.03	0.01	0.01	0.05	0.02	0.00	0.00	0.00
088	San Juan basin	0.04	0.16	0.09	1.40	2.73	2.00	Negl.	Negl.	Negl.
089	Albuquerque-Santa Fe rift	Negl.	0.07	0.02	0.06	0.63	0.25	0.00	0.00	0.00
090	Wyoming Thrust Belt	0.21	1.19	0.58	6.29	31.31	15.81	0.20	1.34	0.61
091	Northern Arizona	0.02	0.27	0.10	0.01	0.07	0.03	0.00	0.00	0.00
092	So. Central New Mexico	Negl.	0.05	0.02	0.05	0.70	0.26	0.00	0.00	0.00
093	So. Ariz.-SW New Mexico	Negl.	0.02	0.01	0.02	0.23	0.09	0.00	0.00	0.00
Region 4 - Rocky Mountains and Northern Great Plains										
094	Williston basin	0.49	1.15	0.78	0.49	1.07	0.74	0.03	0.06	0.04
095	Sioux Arch (Incl. in 094)									
096	Sweetgrass Arch	0.05	0.18	0.10	0.31	0.95	0.57	Negl.	Negl.	Negl.
097	Central Montana	0.01	0.06	0.03	0.01	0.02	0.01	0.00	0.00	0.00
098	Montana Overthrust	Negl.	0.04	0.01	0.42	8.72	2.92	0.01	0.19	0.07
099	SW Montana	Negl.	0.06	0.02	0.07	1.07	0.38	Negl.	0.02	0.01
100	Wind River basin	0.09	0.37	0.20	0.82	3.55	1.89	0.01	0.02	0.01
101	Powder River basin	1.16	3.82	2.25	1.38	4.78	2.76	0.03	0.12	0.06
102	SW Wyoming	0.06	0.47	0.21	1.32	6.76	3.38	0.02	0.09	0.05
103	Bighorn basin	0.10	0.48	0.25	0.18	1.59	0.66	Negl.	0.02	0.01
104	Denver basin	0.37	0.87	0.59	0.96	2.76	1.71	0.04	0.08	0.06
105	Las Animas arch	0.02	0.07	0.04	0.04	0.15	0.09	0.00	0.00	0.00
106	Raton-Sierra Grande	Negl.	0.02	0.01	0.02	0.36	0.13	Negl.	Negl.	Negl.

Table VIII.B.1.--continued.

	Crude Oil (Billion Barrels)			Total Gas (Trillion Cubic Feet)			NGL (Billion Barrels)		
	F95	F5	Mean	F95	F5	Mean	F95	F5	Mean
Region 5 - West Texas and Eastern New Mexico									
107 Permian basin	0.99	3.18	1.89	10.17	28.11	17.74	0.25	0.75	0.46
108 Palo Duro basin	0.05	0.24	0.13	0.02	0.11	0.05	0.00	Negl.	Negl.
109 Pedernal uplift	-	-	-	-	-	-	-	-	-
110 Bend arch	0.37	0.76	0.54	1.00	2.31	1.57	0.05	0.10	0.07
111 Marathon fold belt	0.00	0.00	0.00	0.28	1.63	0.78	Negl.	0.01	Negl.
Region 6 - Gulf Coast									
112 Western Gulf basin	1.59	5.16	3.05	38.71	99.79	64.78	1.02	2.78	1.76
113 East Texas basin	0.18	0.80	0.42	1.51	4.59	2.78	0.06	0.18	0.11
114 La.-Miss. Salt basins	0.48	1.16	0.77	8.06	24.59	14.91	0.57	1.80	1.07
Region 7 - Mid-Continent									
115 Anadarko basin	0.49	1.53	0.92	13.77	41.04	25.12	0.33	0.90	0.57
116 Arkoma basin	Negl.	0.07	0.03	1.01	3.24	1.93	0.00	0.00	0.00
117 Central Kansas Uplift	0.23	0.46	0.34	0.08	0.17	0.12	Negl.	Negl.	Negl.
118 Cherokee Platform	0.18	0.37	0.27	0.36	0.74	0.53	0.01	0.02	0.01
119 Forest City basin	Negl.	Negl.	Negl.	0.01	0.02	0.01	0.00	0.00	0.00
120 Nemaha Uplift	0.07	0.18	0.12	0.12	0.28	0.19	Negl.	0.01	Negl.
121 Salina basin	0.01	0.02	0.02	Negl.	0.01	Negl.	0.00	Negl.	Negl.
122 Sedgwick basin	0.06	0.11	0.08	0.32	0.66	0.47	0.01	0.01	0.01
123 So. Oklahoma	0.05	0.21	0.11	0.15	0.52	0.30	0.01	0.02	0.01
124 Sioux Uplift (Incl. in 125)									
125 Iowa Shelf	0.00	0.00	0.00	0.00	0.31	0.06	0.00	Negl.	Negl.
126 Ozark Uplift	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00

Table VIII.B.1.--continued.

		Crude Oil (Billion Barrels)			Total Gas (Trillion Cubic Feet)			NGL (Billion Barrels)		
		F95	F5	Mean	F95	F5	Mean	F95	F5	Mean
Region 8 - Eastern Interior										
127	Michigan basin	0.63	1.62	1.05	3.92	13.40	7.78	0.10	0.30	0.19
128	Illinois Basin	0.30	0.67	0.46	0.16	1.63	0.66	0.01	0.02	0.01
129	Cincinnati arch	0.05	0.18	0.10	0.07	0.22	0.13	Negl.	Negl.	Negl.
130	Black Warrior basin	Negl.	0.01	0.01	0.73	1.98	1.26	Negl.	0.01	0.01
131	Appalachian basin	0.08	0.25	0.15	2.77	12.29	6.46	0.07	0.31	0.16
132	Blue Ridge Overthrust	0.00	0.00	0.00	0.22	1.93	0.81	0.00	0.00	0.00
133	Piedmont	0.01	0.09	0.04	0.05	0.27	0.13	0.00	0.00	0.00
134	New England-Adirondack (Incl. in 132)									
Region 9 - Atlantic Coast										
135	Atlantic Coastal Plain (Incl. in 133)									
136	So. Florida	0.06	0.50	0.21	0.01	0.04	0.02	0.00	0.00	0.00

Table VIII.B.2.--Estimates of undiscovered recoverable oil and gas in Federal offshore areas of the United States.**

	Crude Oil (BBO)**			Gas (TCF)		
	F95	F5	Mean	F95	F5	Mean
<u>Region 1A - Alaska</u>						
Beaufort Shelf	0.49	3.74	1.27	2.14	12.81	8.26
Beaufort Basin	Negl.	Negl.	Negl.	Negl.	Negl.	Negl.
Chukchi Sea	0.00	7.19	2.22	0.00	16.87	6.33
Chukchi Borderland	Negl.	Negl.	Negl.	Negl.	Negl.	Negl.
Hope Basin	0.00	0.04	0.02	0.00	0.94	0.26
Norton Basin	0.00	0.05	0.01	0.00	1.79	0.19
St. Matthew-Hall	Negl.	Negl.	Negl.	Negl.	Negl.	Negl.
Navarin Basin	0.00	0.12	0.07	0.00	0.10*	0.23
St. George Basin	0.00	0.05	0.03	0.00	1.46	0.37
N. Aleutian Basin	0.00	0.02*	0.03	0.00	0.70	0.16
Bering Basin	Negl.	Negl.	Negl.	Negl.	Negl.	Negl.
Aleutian Arc	Negl.	Negl.	Negl.	Negl.	Negl.	Negl.
Aleutian Trench	Negl.	Negl.	Negl.	Negl.	Negl.	Negl.
Shumagin Shelf	0.00	0.00	0.01	0.00	0.00	0.04
Cook Inlet	0.00	0.30	0.03	0.00	0.67	0.05
Kodiak Shelf	0.00	0.18	0.04	0.00	0.39	0.20
GOA Shelf	0.00	1.39	0.12	0.00	4.59	0.67
GOA Basin	Negl.	Negl.	Negl.	Negl.	Negl.	Negl.
<u>Region 2A - Pacific</u>						
Oregon/Washington	0.00	0.24	0.06	0.00	2.57	0.57
Northern Cal.	0.00	0.40	0.13	0.00	5.04	1.61
Central California	0.68	2.45	1.55	0.83	3.63	1.93
Santa Maria	0.10	1.03	0.59	0.08	0.71	0.54
Santa Barbara	0.18	0.49	0.32	0.48	1.35	0.90
Los Angeles Basin	0.00	0.42	0.09	0.00	0.73	0.13
Inner Banks	0.07	0.83	0.45	0.06	1.84	0.78
Outer Banks	0.00	0.89	0.33	0.00	4.40	1.55
<u>Region 6A - Gulf of Mexico</u>						
Cenozoic	5.07	14.60	9.27	58.36	154.91	100.34
Mesozoic	0.12	0.52	0.30	0.55	7.84	3.00
<u>Region 9A - Atlantic</u>						
Gulf of Maine	0.00	0.00	Negl.	0.00	0.00	0.02
Georges Bank	0.00	0.38	0.10	0.00	6.75	1.94
Baltimore Canyon	0.05	1.16	0.48	1.34	22.46	9.72
Carolina Trough	0.00	0.71	0.20	0.00	13.37	3.57
SE Ga. Embayment	0.00	0.00	Negl.	0.00	0.00	0.02
Blake Plateau	0.00	0.56	0.08	0.00	7.66	1.38
Florida Straits	0.00	0.45	0.08	0.00	1.86	0.38

* In these cases, the low marginal probability causes the risked mean to be located at a percentile below the 5th percentile, resulting in the risked mean being greater than the risked 5% estimate.

** Includes natural gas liquids.

Table VIII.B.3.--Estimates of undiscovered economically recoverable conventional oil, gas and natural gas liquids in onshore provinces and adjacent state waters of the United States.

		Crude Oil (Billion Barrels)			Total Gas (Trillion Cubic Feet)			NGL (Billion Barrels)		
		F95	F5	Mean	F95	F5	Mean	F95	F5	Mean
Region 1 - Alaska										
058	Arctic Coastal Plain	0.00	10.93	3.36	0.00	0.00	0.00	0.00	0.00	0.00
059	Northern Foothills	0.00	2.64	0.72	0.00	0.00	0.00	0.00	0.00	0.00
060	Southern Foothills	0.00	12.64	3.59	0.00	0.00	0.00	0.00	0.00	0.00
061	Kandik	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
062	Alaska Interior	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
063	Interior Lowlands (Incl. in 062)									
064	Bristol basin	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
065	Hope basin	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
066	Copper River (Incl. in 062)									
067	Cook Inlet	0.05	0.60	0.24	0.15	3.69	1.20	0.00	Negl.	Negl.
068	Alaska Peninsula (Incl. in 062)									
069	Gulf of Alaska	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
070	Kodiak	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
071	SE Alaska	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
Region 2 - Pacific Coast										
072	W. Oregon-Washington	0.00	0.00	0.00	0.80	4.28	2.06	0.00	0.00	0.00
073	Sacramento basin	0.00	0.00	0.00	0.72	3.25	1.70	Negl.	Negl.	Negl.
074	San Joaquin basin	0.55	3.21	1.53	1.22	6.68	3.26	0.08	0.53	0.24
075	Los Angeles basin	0.20	1.50	0.66	0.25	1.60	0.78	0.01	0.08	0.04
076	Ventura basin	0.16	1.65	0.66	0.34	2.80	1.21	0.01	0.12	0.05
077	Santa Maria basin	0.11	0.50	0.26	0.10	0.43	0.23	0.01	0.02	0.01
078	Central Coastal	0.05	0.71	0.26	0.04	0.57	0.21	Negl.	0.02	0.01
079	Sonoma-Livermore basin	0.00	0.01	Negl.	0.00	0.01	Negl.	0.00	0.00	0.00
080	Humboldt basin	0.00	0.00	0.00	Negl.	0.08	0.02	0.00	0.00	0.00
081	E. Oregon-Washington	0.00	0.00	0.00	0.41	2.32	1.12	0.00	Negl.	Negl.
081A	E. California	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00

Table VIII.B.3.--Continued.

		Crude Oil (Billion Barrels)			Total Gas (Trillion Cubic Feet)			NGL (Billion Barrels)		
		F95	F5	Mean	F95	F5	Mean	F95	F5	Mean
Region 3 - Colorado Plateau and Basin & Range										
082	E. Basin & Range	0.08	0.62	0.26	0.03	0.44	0.16	0.00	0.01	Negl.
083	W. Basin & Range	Negl.	0.04	0.01	Negl.	0.13	0.04	0.00	Negl.	Negl.
084	Idaho-Snake River	0.00	0.00	0.00	0.00	0.10	0.03	0.00	0.00	0.00
085	Paradox basin	0.01	0.68	0.18	0.03	1.20	0.35	Negl.	0.01	Negl.
086	Uinta Piceance basin	0.03	0.54	0.19	1.08	3.70	2.15	0.01	0.03	0.02
087	Park basin	Negl.	0.03	0.01	0.01	0.05	0.02	0.00	0.00	0.00
088	San Juan Basin	0.04	0.15	0.08	1.39	2.70	1.97	0.00	Negl.	Negl.
089	Albuquerque-Santa Fe rift	Negl.	0.07	0.02	0.05	0.59	0.22	0.00	0.00	0.00
090	Wyoming Thrust Belt	0.21	1.17	0.56	6.22	31.15	15.70	0.20	1.33	0.61
091	Northern Arizona	0.02	0.27	0.10	0.01	0.07	0.03	0.00	0.00	0.00
092	So. Central New Mexico	Negl.	0.05	0.02	0.05	0.67	0.24	0.00	0.00	0.00
093	So. Ariz.-SW New Mexico	Negl.	0.01	0.01	0.02	0.21	0.08	0.00	0.00	0.00
Region 4 - Rocky Mountains and Northern Great Plains										
094	Williston basin	0.29	0.80	0.51	0.33	0.78	0.52	0.02	0.04	0.03
095	Sioux Arch (Incl. in 094)									
096	Sweetgrass Arch	0.04	0.17	0.09	0.30	0.93	0.56	Negl.	Negl.	Negl.
097	Central Montana	0.01	0.06	0.03	0.01	0.02	0.01	0.00	0.00	0.00
098	Montana Overthrust	Negl.	0.04	0.01	0.41	8.65	2.89	0.01	0.19	0.07
099	SW Montana	Negl.	0.05	0.01	0.06	1.04	0.36	Negl.	0.02	0.01
100	Wind River basin	0.09	0.36	0.19	0.79	3.49	1.84	0.01	0.02	0.01
101	Powder River basin	1.02	3.55	2.04	1.21	4.45	2.51	0.03	0.12	0.06
102	SW Wyoming	0.06	0.46	0.20	1.19	6.51	3.19	0.02	0.08	0.04
103	Bighorn basin	0.09	0.47	0.24	0.17	1.55	0.64	Negl.	0.02	0.01
104	Denver basin	0.26	0.67	0.43	0.77	2.44	1.46	0.03	0.06	0.04
105	Las Animas arch	0.02	0.06	0.03	0.04	0.15	0.08	0.00	0.00	0.00
106	Raton-Sierra Grande	Negl.	0.02	0.01	0.02	0.34	0.12	Negl.	Negl.	Negl.

Table VIII.B.3.--Continued.

	Crude Oil (Billion Barrels)			Total Gas (Trillion Cubic Feet)			NGL (Billion Barrels)		
	F95	F5	Mean	F95	F5	Mean	F95	F5	Mean
Region 5 - West Texas and Eastern New Mexico									
107 Permian basin	0.94	3.11	1.82	9.68	27.32	17.09	0.24	0.73	0.44
108 Palo Duro basin	0.05	0.23	0.12	0.02	0.10	0.05	Negl.	Negl.	Negl.
109 Pedernal	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
110 Bend arch	0.30	0.63	0.44	0.91	2.14	1.44	0.04	0.10	0.06
111 Marathon fold belt	0.00	0.00	0.00	0.26	1.58	0.74	Negl.	0.01	Negl.
Region 6 - Gulf Coast									
112 Western Gulf basin	1.51	5.14	2.99	36.30	97.84	62.36	0.96	2.74	1.71
113 East Texas basin	0.17	0.77	0.40	1.34	4.29	2.55	0.05	0.16	0.10
114 La.-Miss. Salt basins	0.36	0.96	0.62	7.09	23.90	14.41	0.49	1.90	1.05
Region 7 - Mid-Continent									
115 Anadarko basin	0.44	1.38	0.83	12.71	38.49	23.41	0.30	0.84	0.53
116 Arkoma basin	Negl.	0.07	0.02	0.90	3.05	1.77	0.00	0.00	0.00
117 Central Kansas Uplift	0.23	0.46	0.34	0.08	0.17	0.12	Negl.	Negl.	Negl.
118 Cherokee Platform	0.18	0.37	0.26	0.36	0.73	0.53	0.01	0.02	0.01
119 Forest City basin	Negl.	Negl.	Negl.	0.01	0.02	0.01	0.00	0.00	0.00
120 Nemaha Uplift	0.07	0.18	0.11	0.12	0.27	0.19	Negl.	0.01	Negl.
121 Salina basin	0.01	0.02	0.01	Negl.	0.01	Negl.	0.00	0.00	0.00
122 Sedgwick basin	0.05	0.10	0.08	0.31	0.64	0.46	0.01	0.01	0.01
123 So. Oklahoma	0.04	0.17	0.09	0.11	0.45	0.24	Negl.	0.02	0.01
124 Sioux Uplift (Incl. in 125)									
125 Iowa Shelf	0.00	0.00	0.00	0.00	0.22	0.05	0.00	Negl.	Negl.
126 Ozark Uplift	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00

Table VIII.B.3.--Continued.

	Crude Oil (Billion Barrels)			Total Gas (Trillion Cubic Feet)			NGL (Billion Barrels)		
	F95	F5	Mean	F95	F5	Mean	F95	F5	Mean
<u>Region 8 - Eastern Interior</u>									
127 Michigan basin	0.61	1.59	1.03	3.70	13.03	7.47	0.10	0.29	0.18
128 Illinois basin	0.30	0.67	0.46	0.16	1.63	0.66	0.01	0.02	0.01
129 Cincinnati arch	0.05	0.18	0.10	0.07	0.22	0.13	Negl.	Negl.	Negl.
130 Black Warrior basin	Negl.	0.01	0.01	0.68	1.90	1.19	Negl.	0.01	0.01
131 Appalachian basin	0.07	0.22	0.13	2.55	11.44	5.99	0.07	0.28	0.15
132 Blue Ridge Overthrust	0.00	0.00	0.00	0.18	1.93	0.76	0.00	0.00	0.00
133 Piedmont	0.01	0.08	0.04	0.04	0.23	0.11	0.00	0.00	0.00
134 New England-Adironack (Incl. in 132)									
<u>Region 9 - Atlantic Coast</u>									
135 Atlantic Coastal Plain (Incl. in 133)									
136 So. Florida	0.05	0.50	0.21	Negl.	0.04	0.02	0.00	0.00	0.00

Table VIII.B.4.--Estimates of undiscovered economically recoverable oil* and gas in Federal offshore areas of the United States.

	Crude Oil (BBO)*			Gas (TCF)		
	F95	F5	Mean	F95	F5	Mean
Region 1A - Alaska						
Beaufort Shelf	0.00	1.74	0.21	0.00	0.00	0.00
Beaufort Basin	Negl.	Negl.	Negl.	Negl.	Negl.	Negl.
Chukchi Sea	0.00	3.59	0.59	0.00	0.00	0.00
Chukchi Borderland	Negl.	Negl.	Negl.	Negl.	Negl.	Negl.
Hope Basin	0.00	0.00	Negl.	0.00	0.00	0.00
Norton Basin	0.00	0.00	Negl.	0.00	0.00	0.00
St. Matthew-Hall	Negl.	Negl.	Negl.	Negl.	Negl.	Negl.
Navarin Basin	0.00	0.00	0.03	0.00	0.00	0.00
St. George Basin	0.00	0.00	0.01	0.00	0.00	0.00
N. Aleutian Basin	0.00	0.00	0.01	0.00	0.00	0.00
Bering Basin	Negl.	Negl.	Negl.	Negl.	Negl.	Negl.
Aleutian Arc	Negl.	Negl.	Negl.	Negl.	Negl.	Negl.
Aleutian Trench	Negl.	Negl.	Negl.	Negl.	Negl.	Negl.
Shumagin Shelf	0.00	0.00	Negl.	0.00	0.00	0.00
Cook Inlet	0.00	0.00	Negl.	0.00	0.00	0.00
Kodiak Shelf	0.00	0.00	0.02	0.00	0.00	0.00
GOA Shelf	0.00	0.00	0.03	0.00	0.00	0.00
GOA Basin	Negl.	Negl.	Negl.	Negl.	Negl.	Negl.
Region 2A - Pacific						
Oregon/Washington	0.00	0.23	0.04	0.00	2.44	0.46
Northern Cal.	0.00	0.14	0.04	0.00	2.42	0.69
Central California	0.13	1.33	0.74	0.21	1.80	1.05
Santa Maria	0.02	0.61	0.26	0.02	0.53	0.25
Santa Barbara	0.13	0.48	0.29	0.41	1.25	0.79
Los Angeles Basin	0.00	0.43	0.09	0.00	0.76	0.13
Inner Banks	0.04	0.82	0.40	0.05	1.52	0.69
Outer Banks	0.00	0.90	0.23	0.00	4.22	1.11
Region 6A - Gulf of Mexico						
Cenozoic	2.24	9.04	5.36	28.24	102.33	62.10
Mesozoic	0.05	0.58	0.27	0.01	6.77	2.22
Region 9A - Atlantic						
Gulf of Maine	0.00	0.00	Negl.	0.00	0.00	0.02
Georges Bank	0.00	0.19	0.04	0.00	4.16	0.98
Baltimore Canyon	0.00	0.40	0.10	0.00	9.44	2.36
Carolina Trough	0.00	0.21	0.03	0.00	5.02	0.77
SE Ga. Embayment	Negl.	Negl.	Negl.	Negl.	Negl.	Negl.
Blake Plateau	0.00	0.16	0.02	0.00	2.51	0.30
Florida Straits	0.00	0.42	0.06	0.00	0.54	0.08

* Includes natural gas liquids.