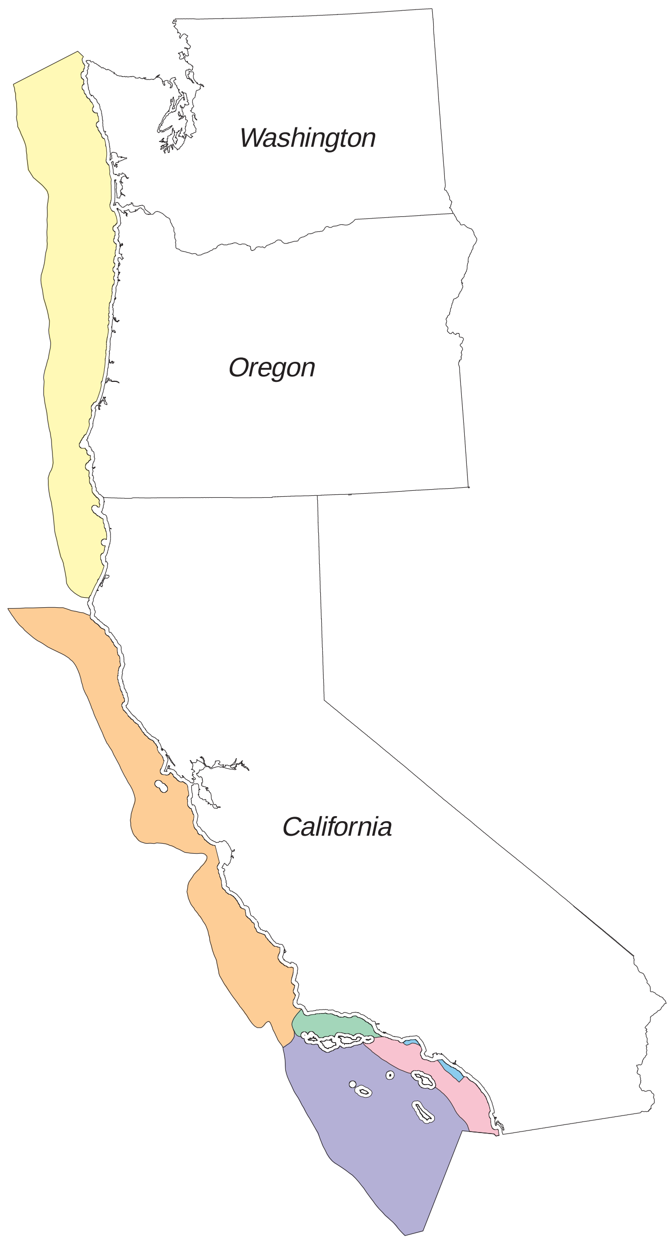
OCS Report
MMS 97-0019

1995 National Assessment of United States Oil and Gas Resources
Assessment of the Pacific Outer Continental Shelf Region



U.S. Department of the Interior
Minerals Management Service
Pacific Outer Continental Shelf Region

Front Cover. *Map of the Pacific OCS Region showing provinces defined for this assessment. Provinces are indicated by color as follows:*

Pacific Northwest Province .... yellow
Central California Province .... orange
Santa Barbara-Ventura Basin Province .... green
Los Angeles Basin Province .... blue
Inner Borderland Province .... pink
Outer Borderland Province .... purple

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1995 National Assessment of United States Oil and Gas Resources
Assessment of the Pacific Outer Continental Shelf Region

Edited by

Catherine A. Dunkel
Kenneth A. Piper

U.S. Department of the Interior
Minerals Management Service
Pacific OCS Region
Office of Resource Evaluation

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Copies of this publication may be obtained upon request from:

Minerals Management Service
Pacific OCS Region
Technical Information Specialist
770 Paseo Camarillo
Mail Stop 7000
Camarillo, CA 93010

(800) 672-2627

Comments and questions regarding this publication may be directed to:

Minerals Management Service
Pacific OCS Region
Office of Resource Evaluation
770 Paseo Camarillo
Mail Stop 7100
Camarillo, CA 93010

(805) 389-7700 (voice)
(805) 389-7737 (fax)

na95pocs@mms.gov

Additional information regarding the Minerals Management Service Pacific OCS Region may be obtained from:

Minerals Management Service
Pacific OCS Region
Office of Public Affairs
770 Paseo Camarillo
Mail Stop 7000
Camarillo, CA 93010

(805) 389-7520 (voice)
(805) 389-7526 (fax)

http://www.mms.gov/omm/pacific

The Department of the Interior Mission

As the Nation's principal conservation agency, the Department of the Interior has responsibility for most of our nationally owned public lands and natural resources. This includes fostering sound use of our land and water resources; protecting our fish, wildlife, and biological diversity; preserving the environmental and cultural values of our national parks and historical places; and providing for the enjoyment of life through outdoor recreation. The Department assesses our energy and mineral resources and works to ensure that their development is in the best interests of all our people by encouraging stewardship and citizen participation in their care. The Department also has a major responsibility for American Indian reservation communities and for people who live in island territories under U.S. administration.

The Minerals Management Service Mission

As a bureau of the Department of the Interior, the Minerals Management Service's (MMS) primary responsibilities are to manage the mineral resources located on the Nation's Outer Continental Shelf (OCS), collect revenue from the Federal OCS and onshore Federal and Indian lands, and distribute those revenues.

Moreover, in working to meet its responsibilities, the **Offshore Minerals Management Program** administers the OCS competitive leasing program and oversees the safe and environmentally sound exploration and production of our Nation's offshore natural gas, oil and other mineral resources. The MMS **Royalty Management Program** meets its responsibilities by ensuring the efficient, timely and accurate collection and disbursement of revenue from mineral leasing and production due to Indian tribes and allottees, States and the U.S. Treasury.

The MMS strives to fulfill its responsibilities through the general guiding principles of: (1) being responsive to the public's concerns and interests by maintaining a dialogue with all potentially affected parties and (2) carrying out its programs with an emphasis on working to enhance the quality of life for all Americans by lending MMS assistance and expertise to economic development and environmental protection.

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Abbreviations and Acronyms

assmblg.	assemblage
Bbbl	billion (10^9) barrels
bbl	barrels
BBOE	billion (10^9) barrels of combined oil-equivalent resources
Bcf	billion (10^9) cubic feet
BOE	barrels of combined oil-equivalent resources
cf	cubic feet
cf.	confer
commun.	communication
Disc.	Discovered (pools)
DSDP	Deep Sea Drilling Project
E & D	exploratory and delineation
EIA	Energy Information Administration
FASPAG	Fast Appraisal System for Petroleum Aggregation
Fm.	Formation
Fms.	Formations
GOR	gas-to-oil ratio
GRASP	Geologic Resource Assessment Program
GSC	Geological Survey of Canada
Is.	Island
Mbbl	thousand (10^3) barrels
MBOE	thousand (10^3) barrels of combined oil-equivalent resources
Mbr.	Member
Mcf	thousand (10^3) cubic feet
MMbbl	million (10^6) barrels
MMBOE	million (10^6) barrels of combined oil-equivalent resources
MMcf	million (10^6) cubic feet
MMS	Minerals Management Service
Mudst.	Mudstone
N/A	not applicable
N/R	not reported
NRC	National Research Council
OCS	Outer Continental Shelf
OCS-P	Pacific Outer Continental Shelf lease designation
PETRIMES	Petroleum Resource Information Management and Evaluation System
PRC	Public Resources Code (State of California lease designation)
PRESTO	Probabilistic Resource Estimates Offshore
PRIMES	Petroleum Resource Information Management and Evaluation System
Ss.	Sandstone
Tcf	trillion (10^{12}) cubic feet
TOC	total organic carbon
U.S.	United States
USGS	United States Geological Survey

Symbols

^{o}API	degrees API, a unit of measurement of the American Petroleum Institute of the gravity of oil
^{o}C	degrees Celcius, a unit of measurement of temperature
^{o}F	degrees Fahrenheit, a unit of measurement of temperature
$<$	less than the cited value
$>$	greater than the cited value
μ	mu, the natural logarithm of the median value of a lognormal pool-size distribution
σ^2	sigma squared, the variance of a lognormal pool-size distribution

1995 POCS National Assessment: Executive Summary

This report documents an assessment of the undiscovered oil and gas resources of the Pacific Outer Continental Shelf (OCS) Region of the United States (i.e., the Federal offshore areas of Washington, Oregon, and California). The assessment was performed as part of a national assessment of undiscovered oil and gas resources in which the onshore and State offshore areas of the Nation were assessed by the U.S. Geological Survey (USGS) and the Federal offshore areas of the Nation were assessed by the Bureau in order to develop an updated appraisal of the location and volume of undiscovered resources.

The commodities that have been assessed consist of *oil* (including crude oil and condensate) and *natural gas* (including associated and nonassociated gas). Two categories of undiscovered resources have been assessed: *undiscovered conventionally recoverable resources* are those that can be removed from the subsurface with conventional extraction techniques; *undiscovered economically recoverable resources* are those undiscovered conventionally recoverable resources that can be extracted profitably under specified economic and technological conditions. Additionally, the *total resource* endowment consisting of the sum of discovered and undiscovered resources has been estimated.

The assessment of the Pacific OCS Region was performed by a team of geoscientists in Camarillo, California, using a large volume and variety of proprietary and nonproprietary data (including geological, geochemical, geophysical, petroleum engineering, and economic data) available as of January 1, 1995. Data and interpretations from many of the nearly 1,100 wells and 200,000 miles of seismic-reflection profiles in the Region were used for the assessment.

For this assessment, the Region was subdivided into six assessment provinces: Pacific Northwest, Central California, Santa Barbara-Ventura Basin, Los Angeles Basin, Inner Borderland, and Outer Borderland (see front cover). The provinces encompass 21 geologic basins and areas in which sediments accumulated and hydrocarbons may have formed. Fifty *petroleum geological plays* (groups of geologically related hydrocarbon accumulations) have been defined and described in 13 assessment areas, and 46 of these plays have been formally assessed.

The principal procedural components of the assessment consisted of *petroleum geological analysis* to ascertain the areal and stratigraphic extent of potential petroleum source rocks, reservoir rocks, and traps; *play definition and analysis* to identify and describe the properties of plays; and *resource estimation* to develop estimates of the volume of undiscovered oil and gas resources, and the total resource endowment. Estimation of the volume of undiscovered conventionally recoverable resources was performed for each play by developing a pool-size distribution (describing the number and size of discrete hydrocarbon accumulations) of the play and statistically aggregating the estimated volume of resources in the undiscovered pools; estimates of undiscovered conventionally recoverable resources are expressed as probability distributions to reflect their uncertainty. Estimation of the volume of undiscovered economically recoverable resources was performed for each assessment area by developing a field-size distribution (describing the number and size of fields, which may consist of multiple pools), and mathematically simulating the exploration and development of the area to determine the volume of undiscovered conventionally recoverable resources that can be extracted profitably; estimates of undiscovered economically recoverable resources are expressed as mean values for a range of economic scenarios. Estimation of the total resource endowment was performed by adding the estimated volume of discovered resources (from other studies) and the mean estimated volume of undiscovered conventionally recoverable resources from this assessment.

The total volume of undiscovered conventionally recoverable oil resources (including crude oil and condensate) of the Region as of January 1, 1995, is estimated to range from 9.0 to 12.6 Bbbl with a mean estimate of 10.7 Bbbl. Relatively large volumes of these oil resources (greater than 1 Bbbl) are estimated to exist in the Point Arena basin, Santa Barbara-Ventura basin, Bodega basin, and Oceanside-Capistrano basin. The total volume of undiscovered conventionally recoverable gas resources (including associated and nonassociated gas) in the Region is estimated to range from 15.2 to 23.2 Tcf with a mean estimate of 18.9 Tcf. Relatively large volumes of these gas resources (greater than 1 Tcf) are estimated to exist in the Santa Barbara-Ventura basin, Washington-Oregon area, Point Arena basin, Eel River basin, Bodega basin, Oceanside-Capistrano basin, and Cortes-Velero-Long area. Major contributors of undiscovered conventionally recoverable oil and gas resources are frontier and conceptual plays (in which hydrocarbon accumulations have not yet been discovered), oil plays (containing predominantly crude oil and associated gas), and plays having fractured siliceous reservoir rocks (e.g., Monterey Formation).

The total volume of undiscovered conventionally recoverable resources of the Region that is estimated to be economically recoverable at economic and technological conditions as of January 1, 1995 (i.e., at prices of $18 per bbl of oil and $2.11 per Mcf of gas), is 5.3 Bbbl of oil and 8.3 Tcf of gas (mean estimates). These resources include relatively large volumes of oil (greater than 1 Bbbl) and gas (greater than 1 Tcf) in the Santa Barbara-Ventura basin and Bodega basin. Larger volumes of resources are estimated to be economically recoverable at more favorable economic conditions.

The total resource endowment of the Region is estimated to be 12.8 Bbbl of oil and 22.1 Tcf of gas (mean estimates). This estimated endowment is composed of 2.1 Bbbl and 3.1 Tcf of discovered resources (including 680 MMbbl and 740 Bcf of cumulative production and 1.4 Bbbl and 2.4 Tcf of remaining reserves) and 10.7 Bbbl and 18.9 Tcf of undiscovered conventionally recoverable resources. Undiscovered resources are estimated to compose a major portion (approximately 85 percent on the basis of mean estimates) of the total oil and gas resource endowment of the Region.

Estimates of the volume of undiscovered conventionally recoverable oil and gas resources in the Region from this assessment are larger than estimates from previous Bureau assessments, due primarily to the use of significantly different methodology and some additional data for this assessment. The increased estimates of the volume of undiscovered economically recoverable oil and gas resources in the Region from this assessment are attributed to the increased estimated volume of undiscovered conventionally recoverable resources.

INTRODUCTION

In 1992, the Minerals Management Service (MMS) embarked on a project to assess the location and volume of undiscovered oil and gas resources of the United States Outer Continental Shelf (OCS) (i.e., the Federal offshore portion of the United States). This 4-year project was initiated and conducted concurrently with a project to assess the undiscovered oil and gas resources of the onshore and State offshore portions of the United States by the U.S. Geological Survey (USGS) (Gautier and others, 1995; U.S. Geological Survey, 1995). These assessments were conducted cooperatively to develop a comprehensive and up-to-date appraisal of the location and volume of the Nation's undiscovered oil and gas resources as of January 1, 1995.

Some of the results of the MMS assessment are summarized in MMS OCS Report 96-0034 (Minerals Management Service, 1996). The report discusses the history of MMS assessments; summarizes the goals, commodities, areas, and general methodologies of this assessment; presents the estimates of undiscovered oil and gas resources in each OCS region and the entire OCS from this assessment; and compares these estimates to those from previous assessments.

This report documents the specific commodities, resources, areas, data, and methodologies of this assessment of the Pacific OCS Region and presents the principal results of the assessment of each subarea of the Region. These principal results include descriptions of the petroleum geologic characteristics of each play, assessment area, and province in the Region and the estimates of undiscovered oil and gas resources therein. Additionally, this report presents a summary of the resource estimates, a discussion of the geographic and geologic distribution of the estimated resources, and a comparison of the resource estimates to those from previous assessments.

COMMODITIES ASSESSED

Hydrocarbon resources are naturally occurring liquid, gaseous, or solid compounds of predominantly hydrogen and carbon that exist primarily in the subsurface as crude oil and natural gas. The commodities of hydrocarbon resources that have been assessed for this project are described in the following definitions.

Oil is a liquid hydrocarbon resource, which may consist of crude oil and/or condensate. *Crude oil* exists in a liquid state in the subsurface and at the surface; it may be described on the basis of its API gravity as "light" (i.e., approximately 20 to 50 °API) or "heavy" (i.e., generally less than 20 °API). *Condensate (natural gas liquids)* is a very high-gravity (i.e., generally greater than 50 °API) liquid; it may exist in a dissolved gaseous state in the subsurface but liquefy at the surface. Crude oil with a gravity greater than 10 °API and condensate can be removed from the subsurface with conventional extraction techniques and have been assessed for this project; other oil resources (e.g., crude oil with a gravity less than 10 °API and oil shale) have not been assessed. The volumetric estimates of oil resources from this assessment represent combined volumes of crude oil and condensate and are reported as standard stock tank barrels (hereafter "barrels" or "bbl").

Natural Gas is a gaseous hydrocarbon resource, which may consist of associated and/or nonassociated gas; the terms *natural gas* and *gas* are used interchangeably in this report. *Associated gas* exists in spatial association with crude oil; it may exist in the subsurface as free (undissolved) gas within a "gas cap" or as gas that is dissolved in crude oil ("solution gas"). *Nonassociated gas (dry gas)* does not exist in association with crude oil. Gas resources that can be removed from the subsurface with conventional extraction techniques have been assessed for this project; other gas resources (e.g., gas shale and gas hydrates) have not been assessed. The volumetric estimates of gas resources from this assessment represent aggregate volumes of associated and nonassociated gas and are reported as standard cubic feet (hereafter "cubic feet" or "cf").

Oil-equivalent gas is a volume of gas (associated and/or nonassociated) expressed in terms of its energy equivalence to oil (i.e., 5,620 cubic feet of gas per barrel of oil) and is reported as barrels. The combined volume of oil and oil-equivalent gas resources is referred to as *combined oil-equivalent resources* or *BOE* (barrels of oil equivalent) and is reported as barrels.

RESOURCE CATEGORIES

Hydrocarbon resources are generally categorized by their discovery status and economic viability (fig. 1). Two categories of undiscovered resources have been assessed for this project, and total resource endowments have been estimated. Discovered resources have not been assessed for this project; however, knowledge of their location and volume has been utilized in the assessment of undiscovered resources and estimation of total resource endowments. The following definitions are provided to ensure proper understanding of the assessed resource categories.

DISCOVERED RESOURCES

Discovered resources (reserves) are resources that have been discovered and whose location and volume have been estimated using specific geologic knowledge. They include original recoverable reserves and reserves appreciation.

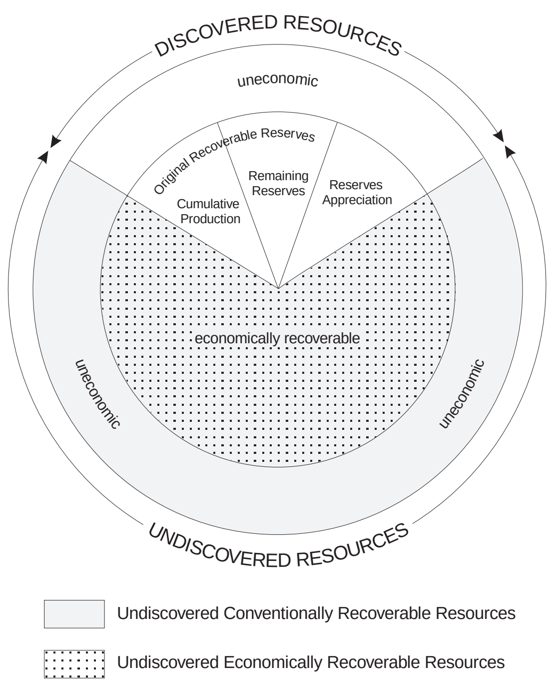


Figure 1. *Diagram showing hydrocarbon resource categories discussed in this report. The shaded and stippled areas represent resource categories that have been assessed; the entire circle represents the total resource endowment, which has been estimated. No proportional volumetric scale is implied.*

Original recoverable reserves are the total amount of discovered resources that are estimated to be economically recoverable; they include cumulative production and remaining reserves. *Cumulative production* is the total amount of discovered resources that have been extracted from an area. *Remaining reserves* are discovered resources that remain to be extracted from an area; they include proved reserves and unproved reserves. *Proved reserves* are discovered resources that can be estimated with reasonable certainty to be economically recoverable under current economic conditions. *Unproved reserves* are discovered resources that can not be estimated with reasonable certainty to be economically recoverable under current economic conditions.

Reserves appreciation (reserves growth) is the amount of resources in known accumulations that is expected to augment proved reserves as a consequence of the extension of known pools or fields, discovery of new pools within existing fields, or the application of improved extraction techniques. Prediction of reserves appreciation is generally based on statistical analysis of historical field data. Pacific OCS Region field data are insufficient for this type of statistical analysis; therefore, reserves appreciation in the Region has not been assessed. Appendix A presents a more detailed explanation of the rationale for nonassessment of reserves appreciation in the Region.

UNDISCOVERED RESOURCES

Undiscovered resources are resources that have not been discovered but are estimated to exist outside and within known accumulations based on broad geologic knowledge and theory. Two categories of undiscovered resources—conventionally recoverable resources and economically recoverable resources—have been assessed.

Conventionally recoverable resources are resources that can be removed from the subsurface with conventional extraction techniques (i.e., technology whose usage is considered common practice as of this assessment); they include crude oil with a gravity greater than 10 °API, condensate, and gas but do not include crude oil with a gravity less than 10 °API, oil shale, gas shale, or gas hydrates.

Economically recoverable resources are conventionally recoverable resources that can be extracted profitably under specified economic conditions.

Total Resource Endowment

The *total resource endowment*—consisting of the sum of the discovered resources (original recoverable reserves) and undiscovered resources—has been estimated for areas where resources have been discovered. Elsewhere, the amount of undiscovered conventionally recoverable resources composes the total resource endowment. The estimation of total resource endowment is based on previous assessments of discovered resources and this assessment of undiscovered resources.

Assessment Areas and Entities

The Pacific OCS Region is one of four OCS regions of the United States (Minerals Management Service, 1996), and comprises submerged Federal lands offshore Washington, Oregon, and California (see front cover). The geologic framework of the Pacific coastal margin formed the basis for the delineation of assessment areas and the assessment of oil and gas resources in the Region. The following definitions are provided to ensure proper understanding of the assessment areas and entities cited in this report.

Provinces, Basins, and Areas

The terms *province*, *basin*, and *area* have the following meanings in this report. A *province* is an area of petroleum geologic homogeneity, which may include one or more geologic basins or geologic areas; the terms *province* and *assessment province* are used interchangeably in this report. A *basin* is a depressed and geographically confined area of the earth's crust in which sediments accumulated and hydrocarbons may have formed; the terms *basin* and *geologic basin* are used interchangeably in this report. A *geologic area* is a depressed and geographically unconfined area of the earth's crust in which sediments accumulated and hydrocarbons may have formed; the terms *geologic area* and *area* are used interchangeably in this report. A *composite assessment area* comprises two or more geologic basins and/or geologic areas that have been combined for the explicit purpose of this assessment.

For this assessment, the Pacific OCS Region was subdivided into six provinces: Pacific Northwest, Central California, Santa Barbara-Ventura Basin, Los Angeles Basin, Inner Borderland, and Outer Borderland (see front cover). The provinces encompass many geologic basins and geologic areas. Detailed descriptions and illustrations of the location, petroleum geology, and resource assessment of the Region and each assessed subarea are provided in the *Petroleum Geology and Resource Estimates* section of this report.

Plays

The assessment of undiscovered conventionally recoverable resources within geologic basins and areas was performed at the *play* level. A *play* is a group of geologically related hydrocarbon accumulations that share a common history of hydrocarbon generation, accumulation, and entrapment; the terms *play* and *petroleum geologic play* are used interchangeably in this report.

Plays have been classified according to their exploration and discovery status to qualitatively express the probability that hydrocarbon accumulations exist. *Established plays* are those in which hydrocarbon accumulations have been discovered. *Frontier plays* are those in which hydrocarbon accumulations have not been discovered but in which hydrocarbons have been detected (e.g., shows, bright spots). *Conceptual plays* are those in which hydrocarbons have not been detected but for which data suggest that hydrocarbon accumulations may exist.

Plays have also been classified according to their expected predominant hydrocarbon type. An *oil play* contains predominantly crude oil and associated gas. A *gas play* contains predominantly nonassociated gas and may contain condensate. A *mixed play* contains crude oil, associated gas, and nonassociated gas, and may contain condensate.

Plays have also been classified according to the age and lithology (rock type) of their reservoir rocks. Plays having *Neogene clastic reservoir rocks* include reservoir rocks that consist of Miocene and/or Pliocene sandstone, siltstone, shale, and/or breccia. Plays having *Neogene fractured siliceous reservoir rocks* include reservoir rocks that consist of Miocene fractured chert, siliceous shale, porcelanite, dolomite, and/or limestone. Plays having *Paleogene-Cretaceous clastic reservoir rocks* include reservoir rocks that consist of Cretaceous through Oligocene sandstone, siltstone, and/or shale. Plays having *Melange reservoir rocks* include reservoir rocks that consist of sandstone within Cretaceous through Miocene melange.

For this assessment, fifty individual plays have been defined and described, and 46 of these have been assessed to estimate the volume of hydrocarbon resources they contain; four plays, which lack sufficient petroleum geologic data or for which data suggest that petroleum potential is negligible, have not been assessed. Detailed descriptions of the location, definition, classification, petroleum geologic characteristics, and resource assessment of each play are provided in the *Petroleum Geology and Resource Estimates* section of this report.

HYDROCARBON ACCUMULATIONS

The terms *prospect*, *pool*, and *field* describe potential and proven hydrocarbon accumulations within plays and have the following meanings in this report. A *prospect* is an untested geologic feature having the potential for trapping and accumulating hydrocarbons. A *pool* is a discrete accumulation (discovered or undiscovered) of hydrocarbon resources that is hydraulically separated from any other hydrocarbon accumulation; it is typically related to a single stratigraphic interval or structural feature. A *field* is a single- or multiple-pool accumulation of hydrocarbon resources that has been discovered. An *oil field* contains predominantly crude oil and associated gas; a *gas field* contains predominantly nonassociated gas and may contain condensate.

SOURCES OF DATA

The assessment of undiscovered oil and gas resources of the Pacific OCS Region was performed using data and information available to MMS assessors as of January 1, 1995. A large volume and variety of data (including geological, geochemical, geophysical, petroleum engineering, and economic data) were utilized. The specific types, quality, and quantity of data vary among assessment areas and are briefly described in the area-specific parts of the *Petroleum Geology and Resource Estimates* section of this report. A generalized description of the types of data used for the assessment is presented here.

Knowledge of the geologic framework and history of each assessment area was garnered primarily from Federal offshore wells[1] and seismic-reflection profiles[2]. Previous analyses and interpretations of these data by MMS geoscientists were utilized where possible; however, some new and revised analyses and interpretations were performed. Additionally, data from some State offshore and onshore wells, outcrops, and many published sources were considered. Publications that contributed significant information are cited in the area-specific parts of the *Petroleum Geology and Resource Estimates* section. An appreciable amount of geologic information was also obtained through verbal and written communications with individuals in other government agencies, the petroleum industry, academia, and the local geological community.

The petroleum geologic characteristics (i.e., source rocks, reservoir rocks, and traps) of plays have been predicted using play-specific information from wells and seismic-reflection profiles, and/or analogous information from geologically similar plays along the Pacific coastal margin. Where possible, the presence and generative potential of mature petroleum source rocks have been predicted using geochemical and/or compositional data (some of which were newly acquired); however, the limited amount of these data in most assessment areas commonly necessitated reliance upon analogy. The presence and quality of reservoir rocks, and the thickness of productive intervals, have been similarly predicted using petrologic data from offshore wells and/or by analogy. In many assessment areas, subsurface structure maps generated from the interpretation of seismic-reflection profiles provided the basis for the identification of many potential petroleum traps; the location, areal size, and number of unidentified traps (i.e., those which were not detected with the available data) were subjectively estimated. The petroleum production characteristics (i.e., oil recovery factor, gas recovery factor, and gas-to-oil ratio) of nonproducing plays have been predicted by analogy to geologically similar plays in which production has been established.

Volumetric estimates of discovered oil and gas resources (reserves) in offshore and onshore accumulations were used to develop the predicted probability distributions of pools and fields in some assessment areas. Many of these estimates were

[1] Nearly 1,100 wells (including 327 exploratory oil and gas wells, 765 development wells, and 2 deep stratigraphic test wells) and hundreds of coreholes had been drilled in the Region as of January 1, 1995. Data from many of these wells have been used for this assessment.

[2] Nearly 200,000 miles of seismic-reflection profiles traverse the Region; the density of the profiles ranges from sparse in frontier areas (e.g., approximately 5 miles between profiles in the central part of the Pacific Northwest province) to extremely dense in mature producing areas (e.g., less than one-half mile between profiles in the Santa Barbara-Ventura Basin province). Interpretations of many of these profiles have been used for this assessment.

obtained from published sources (Sorensen and others, 1993, 1994, 1995; California Division of Oil, Gas, and Geothermal Resources, 1993, 1995; Conservation Committee of California Oil Producers, 1961; Conservation Committee of California Oil and Gas Producers, 1991, 1993) and unpublished sources (Minerals Management Service, 1995). Some estimates were newly developed when these existing sources were considered to be insufficient.

The results of the assessment of undiscovered conventionally recoverable resources (i.e., the predicted number and volume of undiscovered pools) were utilized in the assessment of undiscovered economically recoverable resources. The economic assessment was predicated on the January 1995 level of petroleum technology, and a number of assumptions regarding future economic conditions (exploration and development costs, oil and gas prices, rates of return), infrastructure requirements (platforms and pipelines), and timing of exploration and development.

PROBABILISTIC NATURE OF RESOURCE ASSESSMENT

There are numerous uncertainties regarding the geologic framework and petroleum geologic characteristics of a given area and the location and volume of its undiscovered oil and gas resources. Some of these include uncertainty regarding the presence and quality of petroleum source rocks, reservoir rocks, and traps; the timing of hydrocarbon generation, migration, and entrapment; and the location, number, and size of accumulations. The value and uncertainty regarding these petroleum geologic factors can be qualitatively expressed (e.g., “there is a high probability that the quality of petroleum source rocks is good”). However, in order to develop volumetric resource estimates, the value and uncertainty regarding some factors must be quantitatively expressed (e.g., “there is a 95-percent probability that reservoir rocks will have porosities of 10 percent or more”). Each of these factors—and the volumetric resource estimate derived from them—is expressed as a range of values with each value having a corresponding probability. The following definitions are provided to ensure proper understanding of the probabilistic nature of this assessment and the resource estimates presented in this report.

Probability (chance) is the predicted likelihood that an event, condition, or entity exists; it is expressed in terms of *success* (the chance of existence) or *risk* (the chance of nonexistence). *Petroleum geologic probability* is the chance that an event (e.g., generation of hydrocarbons), property (permeability of reservoir rocks), or condition (presence of traps) necessary for the accumulation of hydrocarbons exists. A description of the criteria, analysis, and use of petroleum geologic probability in this assessment is provided in the *Methodology* section of this report and in appendix B.

A *probability distribution* is a range of predicted values with corresponding probabilities of occurrence; the terms *probability distribution* and *distribution* are used interchangeably in this report. The estimates of undiscovered conventionally recoverable resources from this assessment have been developed as *cumulative probability distributions*, in which a specified volume or more of resources corresponds to a probability of occurrence. These estimates are reported as a range of values from each cumulative probability distribution, which includes a *low estimate* corresponding to the 95th-percentile value of the distribution (i.e., the probability of existence of the estimated volume or more is 95 in 100), a *mean estimate* corresponding to the statistical average of all values in the distribution, and a *high estimate* corresponding to the 5th-percentile value of the distribution (i.e., the probability of existence of the estimated volume or more is 5 in 100). The low, mean, and high estimates of undiscovered resources that are presented in this report correspond to these specific probabilistic criteria and have not been rounded to reflect their relative precision.

Conditional estimates are estimates of the volume of hydrocarbon resources in an area, given the assumption (condition) that hydrocarbons actually exist; they do not incorporate the probability (risk) that hydrocarbons do not exist. No conditional estimates have been developed for this assessment. *Risked (unconditional) estimates* are estimates of the volume of hydrocarbon resources in an area, including the probability (risk) that hydrocarbons do not actually exist. All estimates presented in this report are risked estimates.

METHODOLOGY

The assessment of hydrocarbon resources is a statistical analysis of geologic data. The principal procedural components of the assessment process consisted of petroleum geological analysis, play definition and analysis, and resource estimation. Petroleum geological analysis provided the geological and geophysical information that was the basis for all other components of the assessment. Play definition and analysis involved identifying and quantifying the necessary elements for the estimation of resources in geologic plays in a form that could be used for statistical resource estimation. The resource-estimation process used a set of computer programs developed for the statistical analysis of play data. The results of that statistical analysis are estimates of the undiscovered conventionally recoverable resources of geologic plays. The resource estimates were further subjected to a separate statistical analysis that incorporated economic and engineering parameters to estimate the undiscovered economically recoverable resources for the assessment areas. For those areas with existing production, estimates of discovered resources were added to estimates of undiscovered conventionally recoverable resources to obtain a measure of total resource endowment.

In order to address recommendations regarding previous MMS assessments[3], the MMS adopted a play-based approach for identification and estimation of resource parameters. A statistical methodology was developed to estimate resources based on these parameters. This section describes the process used by the MMS Pacific Region National Assessment team (hereafter "the assessment team") to analyze the geologic data, identify and evaluate the resource parameters, and develop resource estimates. Because this document is intended primarily as a review of the assessment results, only a brief description of the resource estimation methodology is presented here. A detailed explanation of the general methodology will be provided in a separate document (Pulak K. Ray, oral commun., 1996). This report describes the methodology as applied for the assessment of the Pacific OCS Region. The major procedural steps are shown diagrammatically in figure 2.

In addition to adopting revised geological and statistical methodology and computer programs for this assessment, several public workshops were convened for industry, academia, and other interested parties to discuss MMS geologic interpretations and assumptions used in the assessment process. Additionally, the services of three experts in the fields of petroleum geology and resource assessment were secured to provide technical advice to the assessment team.

Petroleum Geological Analysis

The first component of the assessment process involved analysis of the geologic and geophysical data to identify areas of hydrocarbon potential and to ascertain the areal and stratigraphic extent of potential petroleum source rocks, reservoir rocks, and traps within these areas. The information obtained through this process was the basis for the definition of geologic plays and for the quantification of parameters in the play definition and analysis component. Based on previous assessment experience, assessment areas were defined and grouped within assessment provinces. Individual members of the assessment team were assigned primary responsibility for detailed geological and play analyses of specific assessment areas; however, a team approach was adopted in order to take advantage of the interdisciplinary makeup of the group (geologists, geophysicists, a paleontologist, and a petroleum engineer).

Published and proprietary reports and information were compiled to better understand the depositional and tectonic history of each province and assessment area, to identify the areas of hydrocarbon potential, and to better establish the petroleum geologic framework on which the plays would be defined. The scope of these reports ranged from studies of the regional geology and tectonics of an

[3] Following a 1984 MMS assessment of undiscovered OCS resources (Cooke, 1985), a National Research Council (NRC) committee reviewed the MMS resource assessment methodologies and results and recommended certain changes for future assessments (National Research Council, 1986). Similarly, MMS procedures employed in a 1987 assessment (Cooke and Dellagiarino, 1990) were reviewed by a NRC committee and additional recommendations were published (National Research Council, 1991). Additional reviews of the MMS assessment methodologies and reporting procedures were conducted by the Association of American State Geologists, the Energy Information Administration of the U.S. Department of Energy, and the American Petroleum Institute. Following these reviews and the resulting recommendations, MMS embarked on an effort to revise and improve its resource estimation and reporting procedures.

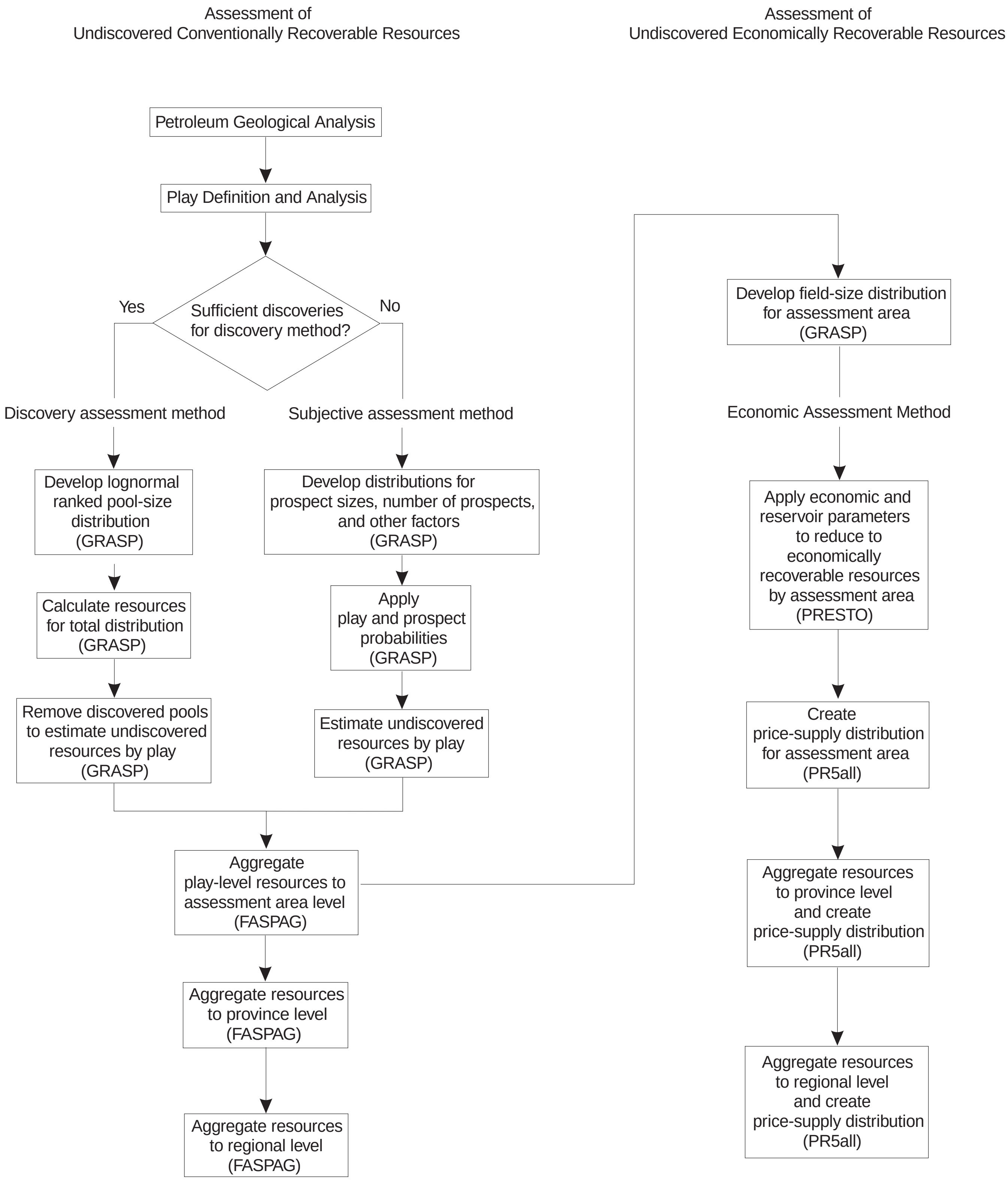


Figure 2. *Assessment process flowchart. Boxes represent process or program steps. The diamond represents a decision. Computer programs used to perform steps are shown in parentheses. The left side of the flowchart shows the process for estimating undiscovered conventionally recoverable resources. The right side shows the process for estimating the part of those resources that are economically recoverable.*

area to detailed geochemical and well-log analyses from exploratory wells and coreholes. Exploratory well information and interpretations of seismic-reflection profiles were the bases for identifying stratigraphic intervals within the assessment areas. Paleontological and lithological analyses were used to determine the age and environment of deposition of stratigraphic units.

Potential petroleum generative sources were identified through the use of published and proprietary geochemical studies and MMS proprietary data from exploratory and development drilling. Hydrocarbon indications from exploratory and production wells were used along with analyses of well data to identify potential petroleum source rocks and to estimate source-rock properties. Geophysical well information was used along with interpretations of seismic-reflection profiles to estimate generative areas within those source-rock units.

Potential hydrocarbon reservoirs and possible migration pathways from source to reservoir were identified primarily through the use of exploratory well data and interpretations of seismic-reflection profiles. Reservoir-rock properties and the presence of trapping mechanisms were estimated by using information from well-log analysis and from analogous stratigraphic units in producing areas. Geophysical interpretations of seismic-reflection profiles were used to infer migration pathways and to estimate the extent of stratigraphic intervals in which reservoir-quality rocks are expected.

Identification of potential structural traps (prospects) was based primarily on existing MMS interpretation and subsurface mapping of proprietary seismic-reflection data. Where feasible and appropriate, the interpretations were modified to incorporate new data and ideas. In some areas, interpretations were based on sparse seismic-reflection data, and although those interpretations could be used to identify depositional and structural trends, they could not be used to identify individual prospects. In such cases, and for assessment areas which were outside of areas with existing data or interpretations, estimates of the number and areal size of prospects were based on interpretations from geologically analogous areas. The specific analogs are identified by play in the *Petroleum Geology and Resource Estimates* section of this report.

Play Definition and Analysis

As previously stated, MMS adopted a play-based approach (White and Gehman, 1979; White, 1988; 1992) for the purpose of identifying and estimating resource parameters necessary for the estimation of resources. Play definition involves the identification, delineation, and qualitative description of a body of rocks that potentially contains geologically related hydrocarbon accumulations. As previously stated, a *play* is a group of hydrocarbon accumulations that share a common history of hydrocarbon generation, accumulation, and entrapment. A corollary to this definition is that a group of hydrocarbon accumulations within a properly defined play can be considered as a single entity for statistical evaluation. It is with this understanding that plays were defined for this assessment. Plays were defined based on the determination of source-rock, reservoir-rock, and trap characteristics of stratigraphic units. Individual play definitions were reviewed for consistency by the assessment team. Most plays were defined on the basis of reservoir-rock stratigraphy and were delineated by the extent of the reservoir rocks. A few plays were defined on the basis of structural characteristics of prospective traps. Plays may overlap areally and may in some cases also occupy the same stratigraphic interval (fig. 3).

Play analysis involves the quantitative description of parameters relating to the volumetric hydrocarbon potential of the play. The presence of necessary conditions for the generation, migration, and entrapment of hydrocarbons is unknown, but probabilities for their existence and quantification can be estimated, and these can then be used in the resource-estimation process to develop probability distributions for quantities of hydrocarbon resources. Play analysis provided the necessary quantitative information in the form of play-specific probability distributions; these distributions reflect the uncertainty about the values of the parameters and were used as the basis for the statistical resource-estimation process.

Each play may be characterized by parameters that, in combination, describe the volumetric resource potential of the play, assuming that the play does contain hydrocarbon accumulations. A range of values was assigned to each parameter, based on information obtained through the petroleum geological analysis component; summaries of the parameters by play are provided in appendix C. Again, a team approach was used to ensure that parameters relating to the likelihood of hydrocarbon occurrence and prospective volumes of hydrocarbon resources were comparable among assessment areas. Some of these values (e.g., areas of mapped prospects

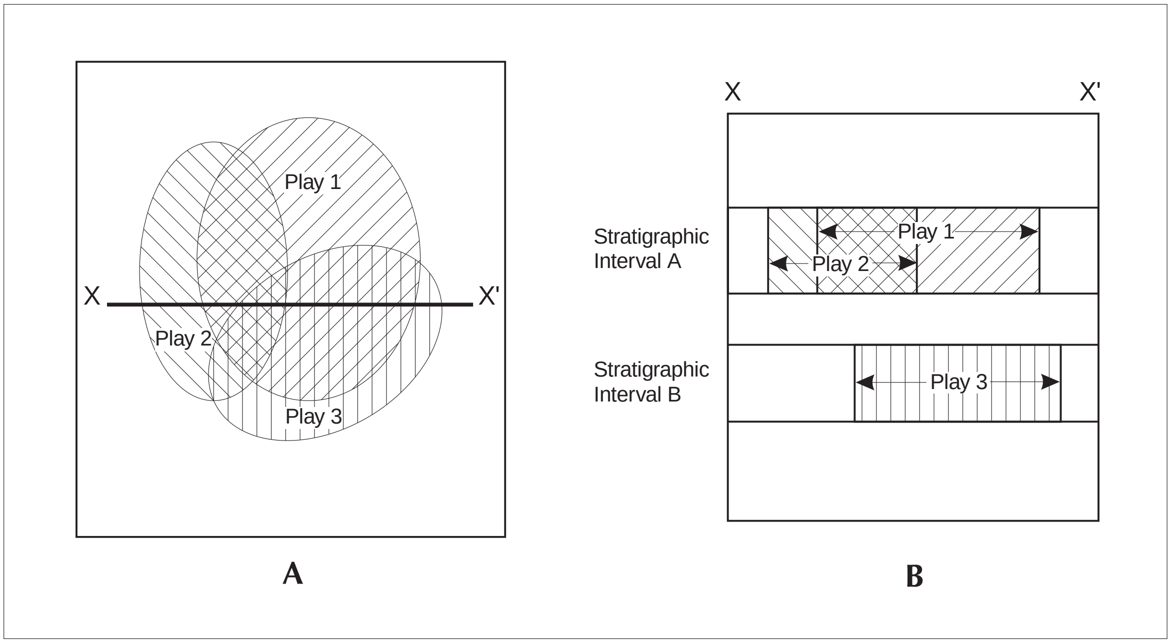


Figure 3. *Map-view (A) and cross-sectional (B) representations of three overlapping hypothetical plays. Plays 1 and 2 are within the same stratigraphic interval and overlap areally; play 3 is within a deeper stratigraphic interval.*

and thicknesses of expected reservoir-rock units) were based on geophysical mapping. Others (e.g., rock and hydrocarbon properties) were based on exploratory well information. Certain rock and hydrocarbon properties (e.g., net pay, reservoir-rock porosity and permeability, and oil viscosity) are unknown in the absence of exploratory drilling; in such cases, values were based on known properties in areas that are expected to be similar. Where data were insufficient or unavailable, scientifically based subjective judgments were made regarding appropriate geologic analog data that could be used for modeling purposes. The selection of analog data was typically a team decision.

In addition, plays were assigned success probabilities based on discovery status and on a subjective evaluation by the assessment team. Play and prospect probabilities for success were assigned based on a methodology modified from that presented by White (1993). Probability analysis (often called risk analysis) was performed on individual components that are necessary for success of a play or prospect. The probability analysis form used for this assessment is shown in appendix B, along with guidelines for its use. The probabilities (chances) of success of individual components are combined to yield the probability of success for the play as a whole (play chance) and the probability of success for individual prospects within the play (conditional prospect chance). Play chance is the probability that at least one accumulation of conventionally recoverable resources exists in a play. Conditional prospect chance is the probability that conventionally recoverable resources exist within an individual prospect in the play, given the conditional assumption that the play is successful. Combination of the play chance and conditional prospect chance yields the average prospect chance (including the chance that the play may not be successful).

The components of the probability analysis include the probability of adequate hydrocarbon fill, the probability that reservoir rocks are present and of sufficient quality, and the probability that trapping conditions exist. Each of these components was assigned a value by a qualitative assessment of several elements. Play chance factors were assigned as the probability of adequacy anywhere within the play; the combination of these factors yields the probability that all necessary conditions are present together in at least one location within the play. Prospect chance factors were assigned as the probability of adequacy at an individual prospect; the combination of these factors yields the probability that all necessary conditions are present together at an individual prospect, assuming that the play is successful.

The assessment team used an iterative peer-review process to ensure that probabilities were appropriately assigned among the assessment plays. The resulting probabilities for each of the elements and the combined play and prospect success probabilities are presented in appendix C.

RESOURCE ESTIMATION

Volumetric estimates of undiscovered conventionally recoverable resources and undiscovered economically recoverable resources were based on the geologic and petroleum engineering information developed through petroleum geological analysis and quantified through play analysis. These estimates were developed in two stages. First, undiscovered conventionally recoverable resources were assessed for each play. There was no explicit consideration of resource commodity prices or costs (although there was recognition that current technology is affected by costs and profitability). Then, economic and petroleum engineering factors were included for each assessment area, using a separate methodology, to estimate the portion of these resources that is economically recoverable over a broad range of commodity prices. The following parts of this section describe the main procedural elements of each methodology as used for assessing the resources of the Pacific OCS Region. Several computer programs were used in the resource-estimation process. The use of these programs is indicated diagrammatically in figure 2 and described in the following parts of this section.

ASSESSMENT OF UNDISCOVERED CONVENTIONALLY RECOVERABLE RESOURCES

A probabilistic methodology was developed to estimate undiscovered conventionally recoverable resources based on the resource parameters that were quantified through play analysis. This included adoption of computer programs developed by the Geological Survey of Canada (GSC) with appropriate modifications to better allow for the simultaneous estimation of oil and gas resources.

Prospect sizes within plays with sufficient data coverage, discovered field sizes within mature basins (those with extensive exploration and production histories), and many other geologic properties have distributions that approximate a statistical pattern called lognormality (figs. 4 and 5). MMS assessment of the volume of conventionally recoverable resources is based on the assumption that, within a properly defined play, the size distribution of the entire population of accumulations (which consists of discovered and undiscovered accumulations) will also be lognormal. This means that in a play with discoveries, the undiscovered accumulations will, in combination with those discoveries, describe a lognormal distribution. Also, in a play with no discoveries, the undiscovered accumulations alone will describe a lognormal distribution.

The concept of lognormal distributions of play parameters was used in the *Petroleum Resource Information Management and Evaluation System* (PETRIMES or PRIMES), a set of computer programs developed by the GSC (Lee and Wang, 1984; 1985; 1990). This play-based approach has an advantage over prospect-based methods in its ability to estimate the size and number of undiscovered accumulations in a play and thus allows for a

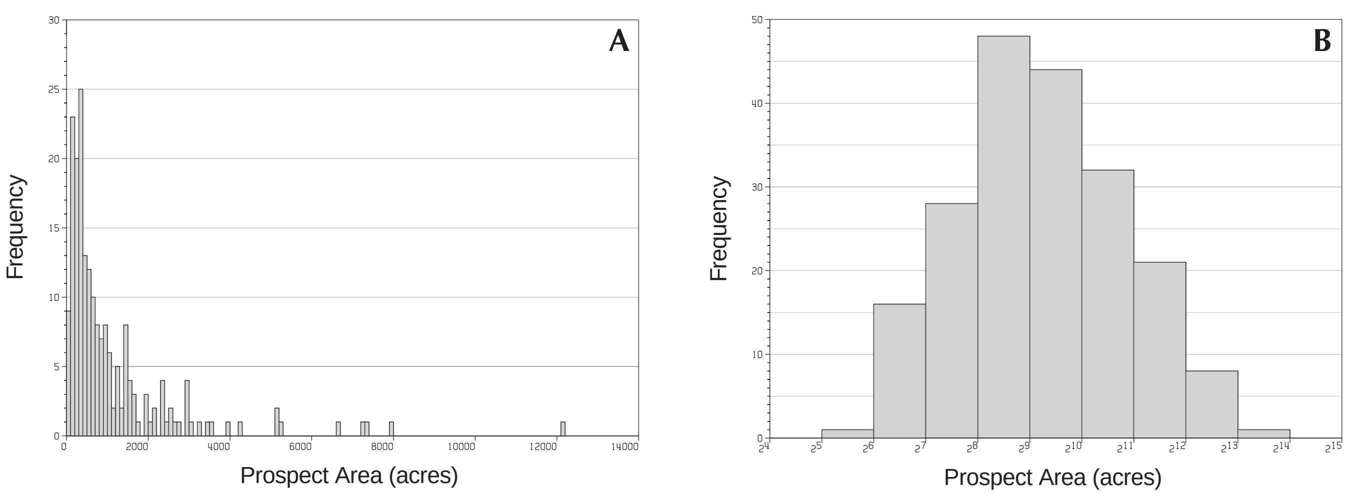


Figure 4. *Frequency-versus-size plots of a lognormal distribution. The example shows the areal sizes of mapped prospects in an area where data were sufficient for detailed mapping. The data plot as a skewed distribution when plotted on a linear scale (A). When the data are plotted on a logarithmic scale (B), the approximately normal (bell shape) appearance demonstrates the lognormal nature of the distribution. The example is for 199 mapped prospects in the Monterey Fractured play of the Point Arena Basin assessment area.*

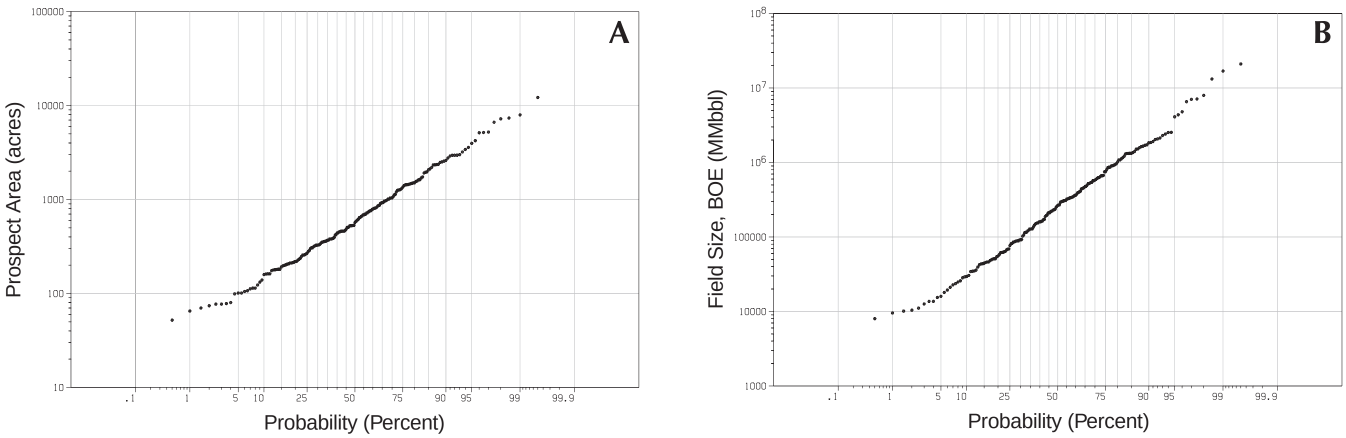


Figure 5. *Log-probability plots of lognormal distributions. A logarithmic plot of size versus probability is approximately linear for lognormal size distributions. Figure 5A is a plot of the data shown in figure 4. Figure 5B is a plot of the sizes of 155 fields in the Santa Barbara-Ventura basin proper (onshore and offshore).*

better estimation of undiscovered resources. However, PETRIMES was designed for single-commodity plays such as an oil play or a gas play; many OCS plays are mixed plays. MMS adopted the methodology but modified the original PETRIMES to provide for separate estimation of liquid (oil and condensate) and gas (associated and nonassociated gas) hydrocarbon phases in order to better estimate OCS resources. The MMS version of the system is called the *Geologic Resource Assessment Program* (GRASP). GRASP includes several modules that can be used either for direct modeling of predicted ranked pool-size distributions *(discovery assessment method)*, or for modeling of more subjectively derived parameter estimates, which together define the overall volumetric distribution of resources *(subjective assessment method)*.

Discovery Assessment Method

The discovery assessment method may be used for plays that have a sufficient number of discovered pools and for which the sizes of those pools are sufficiently well known. Where there are sufficient data, mapped prospect areas approximate lognormality (figs. 4 and 5A). Fields (discoveries) within mature basins generally have size distributions which are lognormal (fig. 5B). If the subset of prospects that contain hydrocarbons is representative (i.e., if there is no statistical bias), the volumes of those accumulations will also be expected to display lognormality. Therefore, the discovered accumulations in a play, when combined with the undiscovered accumulations, will approximate a lognormal distribution.

GRASP provides a computational means to fit the sizes of the discovered pools of a play into a lognormal distribution, which then represents the entire distribution of pools for the play. Figure 6 is a pool-size rank plot showing the size ranges of pools, which are ranked on the basis of their mean estimated volume of combined oil-equivalent resources. This distribution of discovered and undiscovered pools was developed from the estimated resource volumes of the discovered pools by fitting them within a lognormal distribution. The discovered pools, along with the requirement for approximate lognormality, determine a minimum for the total number of pools in the play; however, lognormal distributions can be defined for a larger number of pools. Therefore, additional information (e.g., prospect mapping) and subjective judgment were employed in order to estimate the total number of pools within the constraints of the data. After development of such a distribution for a play, the undiscovered pools were sampled using Monte Carlo methodology[4] to estimate the total volume of undiscovered resources in the play.

Subjective Assessment Method

For plays with few or no discoveries, the subjective assessment method was used. In this method, parameter estimates are combined to yield an approximately lognormal ranked size distribution of pools. Measured prospect sizes (e.g., from geophysical prospect mapping) and other parameters were used to estimate pool sizes. If data were sufficient

[4] The Monte Carlo method is a multiple-trial procedure in which, for each trial, values for constituent parameters are selected at random from their distributions and combined to provide a single result for that trial. The results of many trials compose the overall distribution.

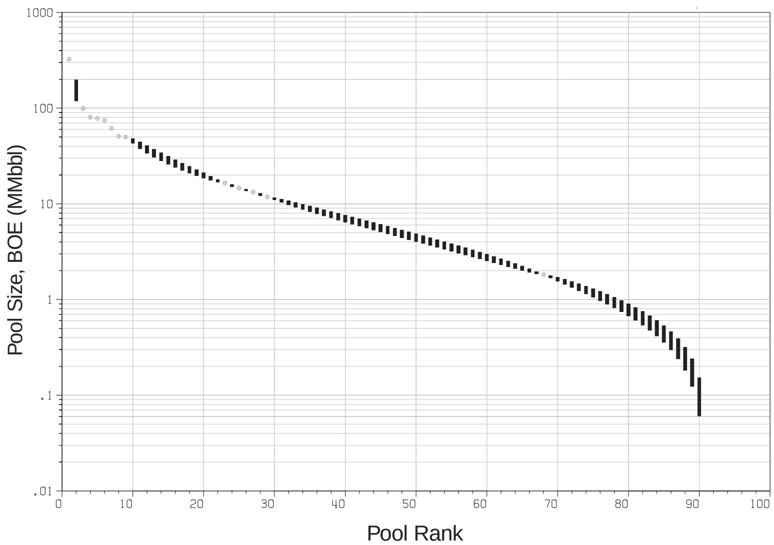


Figure 6. *A lognormal pool-size rank plot derived from the discovery assessment method. The total distribution was developed using GRASP by fitting the sizes of discovered pools to a lognormal distribution and using other information to constrain the range for the size and number of pools. The 13 discoveries are shown as gray dots. The black bars represent the 25th- to 75th-percentile size distribution for the undiscovered pools. Ranking is based on resource volume (expressed as barrels of combined oil-equivalent resources). Because the pool distribution is ranked by size, knowledge of the sizes of discovered pools reduces the uncertainty regarding the size of adjacently ranked undiscovered pools (and consequently the height of the corresponding bar) in the plot. The number of pools shown is the predicted total number of pools. The example is for the Monterey Fractured play of the Santa Maria-Partington Basin assessment area.*

for detailed mapping, the areal sizes of mapped prospects in the play approximated a lognormal distribution (fig. 4 and 5A). In many assessment areas, prospect mapping is incomplete, so the uncertainty is greater. For plays in such areas, the areal size distribution of the mapped prospects was extrapolated to develop distributions for the areal size and number of prospects in the entire play. Similarly, other parameters (e.g., net pay and recovery factors) were estimated. These estimates were statistically combined to derive a ranked pool-size distribution for the play (fig. 7). The resulting plot is different from that for the discovery method (fig. 6) because it shows the maximum number of pools in the play (fewer pools may actually exist, depending on the probability of occurrence); pool-size rank plots for the discovery method show only those pools whose resource volumes are aggregated to derive play resources. Also, size distributions for individual pools are less tightly constrained. Results of the probability analysis (described in the *Play Definition and Analysis* part of this section) were used to reduce the distribution of prospects (possible pools) to a distribution of pools (containing resources). Monte Carlo methodology was used to statistically combine the various parameters to derive probability distributions for the volume of undiscovered conventionally recoverable resources in the play.

Aggregation of Undiscovered Conventionally Recoverable Resource Estimates

The probability distributions for the volume of undiscovered conventionally recoverable resources in individual plays were aggregated to the assessment area level, then to the province and regional levels using a computer program called the *Fast Appraisal System for Petroleum Aggregation* (FASPAG) developed by the USGS (Crovelli and Balay, 1988; 1990). This program describes probability distributions in terms of their statistical mean and variance values and uses this information to calculate aggregate resources at the assessment area level (fig. 8).

A few plays in the Pacific OCS Region are partially dependent on some property (e.g., hydrocarbon fill) of another play for their own success; for those dependent plays, their success may be termed a conditional probability. If that property of the independent play has a chance value of less than one, then the success of the dependent play must be reduced for proper aggregation. In all such cases, the property had been determined to be assured (i.e., to have a chance of one), and the play success of the dependent play was fully accounted for during the play-analysis process; therefore, no adjustment was needed during aggregation of resources.

Assessment of Undiscovered Economically Recoverable Resources

Following the assessment of undiscovered conventionally recoverable resources and their aggregation to the assessment area level, an economic evaluation was performed using the mean aggregate resource estimate for each assessment area to estimate the portion of those resources that could be extracted profitably over a range of commodity prices, at the present level of technology, and including the effects of current and expected future economic factors. Those factors include costs for exploration, development, and production of resources; market prices

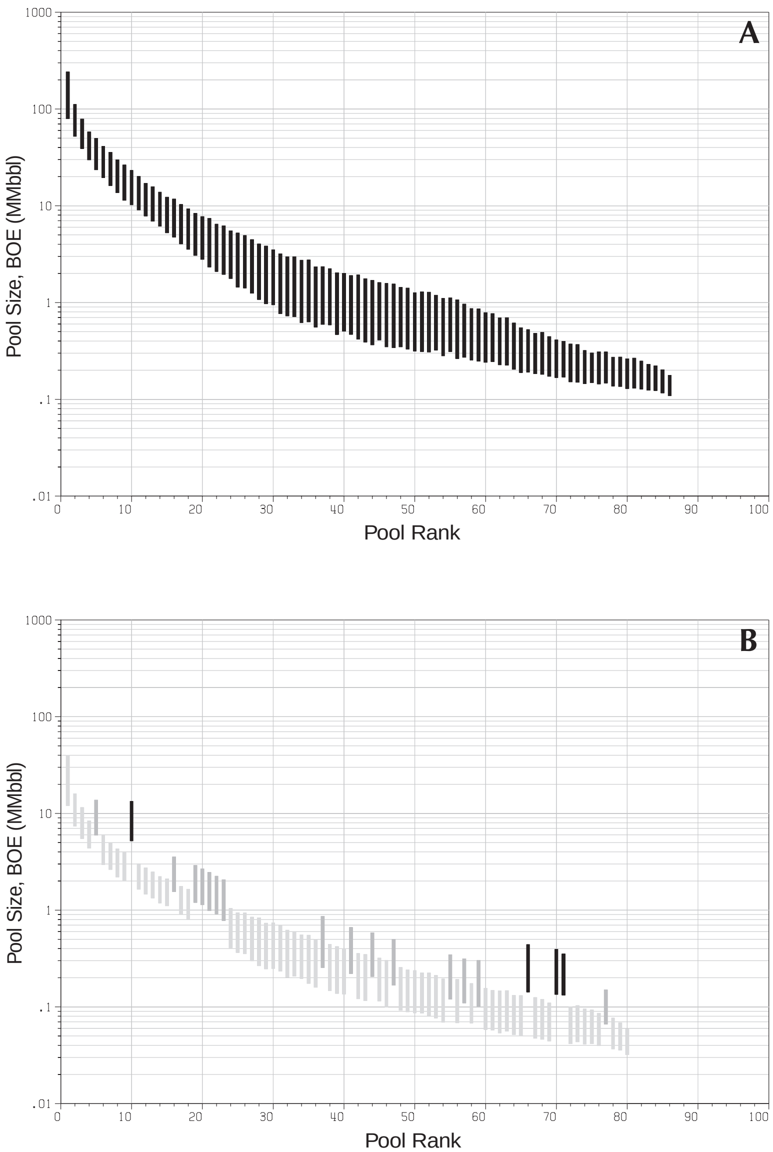


Figure 7. *Lognormal pool-size rank plots derived from the subjective assessment method. The bars represent the 25th- to 75th-percentile size distribution for the undiscovered pools. Ranking is based on pool volume (expressed as acre-feet). The range of the size distribution for each pool is much greater than for the pools predicted by the discovery assessment method (fig. 6), indicating a greater uncertainty in predicted pool sizes. The number of pools shown is the maximum number; fewer pools may actually exist, depending on the probability of occurrence. Plots are shown for an oil play (A) and a mixed play (B). Because the ranking is based on pool volume (rather than resource volume) and pools are randomly defined as oil pools, gas pools, or mixed pools (according to their proportional probability), pools in a mixed play do not plot in ranked order on the pool-size rank plot. The oil pools, gas pools, and mixed pools in the example are shown in black, dark gray, and light gray, respectively. Figure 7A is the Monterey Fractured play of the Año Nuevo Basin assessment area. Figure 7B is the Neogene Fan Sandstone play of the Eel River Basin assessment area.*

of the various hydrocarbon commodities; and other economic conditions (e.g., interest rates, which affect the cost of capital, and revenues that could alternatively be gained by investing capital elsewhere).

Stacked Plays and Field Sizes

The oil and gas resource totals within each assessment area were the basis for the assessment of economically recoverable resources. Because many of the plays in the Pacific OCS Region are areally superposed (fig. 3), pools in one play may be located near or above or below pools in another play. Such pools are commonly developed as a single field to minimize development costs.

To apply costs appropriately in an economic evaluation, the GRASP discovery assessment method was used as a tool to help create ranked field-size distributions at the assessment area level in a procedure similar to that used for creating ranked pool-size distributions at the play level. The mean estimates of the combined oil-equivalent resources for the fields together describe a lognormal distribution. These distributions, which consist of discovered fields and predicted undiscovered fields, were developed to be compatible with the combined play-level ranked pool-size distributions. The mean aggregate volume of resources (both oil and gas) for the fields matches the mean aggregate volume of resources of all plays within the assessment area. The number of fields was constrained to be no less than the mean number of pools in any play (corresponding to maximum pool stacking) and no greater than the sum of the means of the number of pools for all plays (minimum pool stacking). Because the fields are considered to be made up of one or more pools from the constituent plays, this

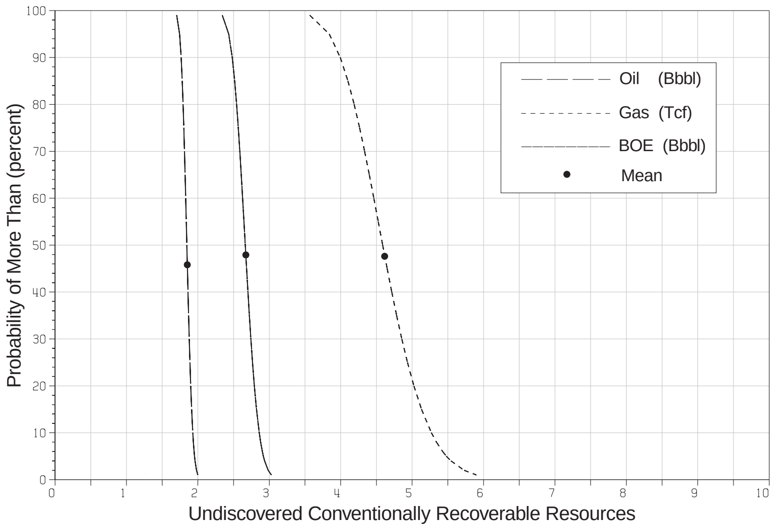


Figure 8. *Cumulative probability plot showing distributions for estimated undiscovered conventionally recoverable oil, gas, and combined oil-equivalent resources. The probability value corresponding to a given resource volume indicates the probability of occurrence of that volume or more. The example shows resource distributions for the Santa Barbara-Ventura Basin assessment area.*

also placed constraints on the mean field size and the statistical range (minimum to maximum) of the distribution. The resulting distributions are considered to be equivalent—for modeling purposes—to the resource distribution of the assessment area.

Economic Assessment Method

To estimate the portion of undiscovered conventionally recoverable resources that can be profitably extracted given particular economic constraints, MMS developed an enhanced version of its *Probabilistic Resource Estimates Offshore* (PRESTO) program (Cooke, 1985; Cooke and Dellagiarino, 1990). For estimation of undiscovered economically recoverable resources in the Pacific OCS Region, ranked field-size distributions (developed as described above) were input into PRESTO, along with engineering, cost, and economic factors, to reduce the mean undiscovered conventionally recoverable resources to economically recoverable values over a range of commodity prices. Because the ranked field-size distributions were considered equivalent, for modeling purposes, to the combined ranked pool-size distributions of the constituent plays (which include the effects of play and prospect chance), no additional risks were applied.

PRESTO uses Monte Carlo methodology to simulate the exploration, development, production, and delivery of the field resources in each assessment area (fig. 2). The ranked field-size distributions are sampled along with probability distributions for costs, production properties (e.g., gas-to-oil proportion, production rates, and decline rates), and other engineering and economic factors (select data used for the analyses are shown in appendix D). For each field, the program simulates exploration, delineation, installation of production and delivery facilities, and drilling of development wells. Costs, production, and revenues are scheduled over the lifetime of the field. Each field is modeled separately to determine its individual economic viability—the program develops a risk-weighted discounted cash flow and calculates a present economic value for the field. Then, the economic resources in all fields are combined with additional costs specific to the assessment area to determine its economic resources. Costs for equipment and infrastructure are included at the field level (e.g., platform and production well costs) or assessment area level (e.g., trunk pipeline), as appropriate. This procedure is performed iteratively for varying oil and gas prices to develop a probability distribution of the undiscovered economically recoverable oil and gas resources. The oil price represents the world oil price as defined by the Department of Energy (Energy Information Agency, 1994) and is equivalent to the average refiner's acquisition cost of domestic oil. Local market price variations (e.g., due to varying quality of crude oil or cost of transportation) are accounted for at the assessment area level. The gas price is fixed relative to the oil price at 66 percent of the oil price for equivalent energy content (e.g., an oil price of $18.00 per bbl corresponds to a gas price of $2.11 per Mcf).

This assessment allowed for uncertainty in oil and gas prices by developing a continuous series of resource estimates over a wide range of prices; the estimates are portrayed graphically in a *price-supply plot* (fig. 9) for each assessment area, province, and the Region. The price-supply plots (created by an MMS program called PR5all) show the mean volume of resources—both oil and gas—that can be profitably developed, as a function of price. The oil and gas curves on a price-supply plot are linked;

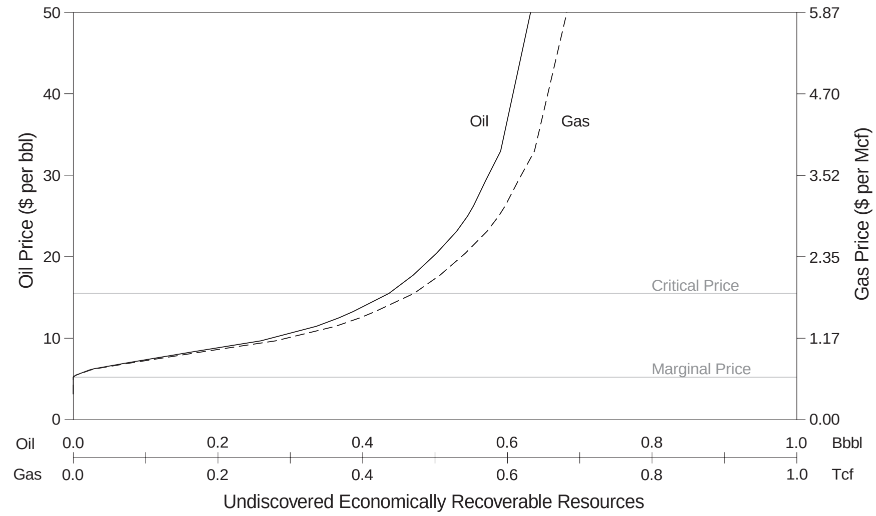


Figure 9. *Price-supply plot showing estimated undiscovered economically recoverable oil and gas resources over a range of prices. Because gas prices are tied to oil prices, the individual curves are not independent; the resource values for oil and gas are linked at a given price. The marginal price is the price below which no PRESTO trials were economic within the assessment area. The critical price is the price above which all trials were economic within the assessment area. At intermediate prices, some trials were economic. The example is for the Santa Maria-Partington Basin assessment area.*

that is, the supply value of both commodities must be determined together at a given oil price (and its corresponding gas price). This is because the economic viability of an individual field is calculated assuming the presence of both oil and gas together, at a fixed ratio for any given field. Because of this linkage, the oil and gas supply estimates do not reflect relative market-demand effects between the two commodities (i.e., a relative increase or decrease in the market value of gas relative to that of oil is not accounted for in the model).

Aggregation of Undiscovered Economically Recoverable Resource Estimates

The volumetric price-supply estimates of undiscovered economically recoverable resources were derived at the assessment area level for the mean case. These mean estimates were aggregated to the province and regional levels. For tabulated mean values, aggregation was performed by simple arithmetic addition. Aggregation of price-supply distributions and creation of aggregate price-supply plots was performed using PR5all. Because the price-supply plots give only mean values at each price, aggregation was by simple arithmetic addition at each increment of pricing.

Estimation of Total Resource Endowment

The total resource endowment, which is the sum of the discovered resources (originally recoverable reserves) and undiscovered conventionally recoverable resources, was estimated for three assessment areas where resources have been discovered. Field-level estimates of originally recoverable reserves (including cumulative production and remaining reserves) in Santa Maria-Partington basin, Santa Barbara-Ventura basin, and Los Angeles basin were tabulated and summed to determine the total volume of discovered resources in each assessment area. The estimate of discovered resources in each assessment area was then added to the mean estimate of undiscovered conventionally recoverable resources to obtain a mean estimate of the total resource endowment in that area. Estimates of discovered resources, undiscovered resources, and total resource endowment were then summed to the province and regional levels.

PETROLEUM GEOLOGY AND RESOURCE ESTIMATES OF THE PACIFIC OCS REGION

Location

The Pacific OCS Region extends from the United States-Canada maritime boundary to the United States-Mexico maritime boundary and comprises submerged Federal lands (i.e., beyond the 3-mile line) offshore Washington, Oregon, and California (see front cover). The Region encompasses an area of complex geology along a tectonically active crustal margin. Intermittent periods of Cenozoic sedimentary deposition, volcanism, folding, and faulting within this region have created a number of environments favorable for the generation, accumulation, and entrapment of hydrocarbons. Numerous geologic basins and areas exist along the continental shelf and slope within the Region (fig. 10). Some of these are geological extensions of onshore basins and have proven hydrocarbon accumulations; several other areas are sparsely explored but are expected to have considerable petroleum potential.

Geologic Setting

The geologic history of the Pacific coastal margin has been dominated by the interaction of oceanic and continental crustal plates. The modern tectonic framework includes juxtaposed oceanic and continental crust along three primary tectonic boundaries: (1) subduction of oceanic crust beneath continental crust along the Cascadia subduction zone, (2) right-lateral strike-slip movement of oceanic crust along the east-west-trending Mendocino fracture zone, and (3) right-lateral strike-slip movement of continental crust along the northwest-trending San Andreas fault zone. The Mendocino fracture zone separates the Region into two distinct tectonic realms: (1) a northern area where Cenozoic geologic history has been consistently dominated by convergent tectonics along the Cascadia subduction zone and (2) a southern area where early Cenozoic geologic history has been dominated by convergent tectonics along an ancient subduction zone and where middle to late Cenozoic geologic history has been dominated by wrench tectonics along the San Andreas and subsidiary faults.

Regional stratigraphic relationships also differ between these tectonic realms. Based on limited drilling information, the Cenozoic stratigraphic section north of the Mendocino fracture zone appears to consist of interbedded sedimentary, volcanic, and volcaniclastic strata that were deposited in shelf and slope environments within a forearc setting. South of the fracture zone, the Cenozoic stratigraphic section is divisible into three major stratigraphic sequences: (1) Cretaceous to lower Miocene clastic (pre-Monterey) strata deposited as transgressive-regressive marine sequences in shelf and slope environments within a forearc setting, (2) middle to upper Miocene siliceous and calcareous (Monterey Formation) strata deposited in primarily slope environments, and (3) upper Miocene and younger clastic (post-Monterey) strata deposited in shelf and slope environments. All or part of this tripartite stratigraphic framework is generally recognized in basins of varying geologic settings, although the thickness and compositional character of strata vary from one basin to another.

The Region is separated into two distinct petroleum geologic realms as a result of the tectonic and stratigraphic histories—gas and oil. Within the tectonically convergent area north of the Mendocino fracture zone, predominantly gas resources are expected to reside in clastic reservoir rocks. Basins south of this zone have been formed or structurally modified primarily by lateral and rotational crustal movements along the San Andreas and related faults; many of these basins contain thick sequences of “Monterey” strata, which are important petroleum source and reservoir rocks, and clastic reservoir rocks in which predominantly oil resources are expected to reside.

Exploration and Discovery Status

Petroleum exploration in the Pacific OCS Region has been underway for more than 40 years. Numerous exploratory wells and coreholes have been drilled; most of these are located offshore southern California where several oil and gas fields have been discovered (Sorensen and others, 1995; 1996). The Region is traversed by nearly 200,000 miles of seismic-reflection profiles; the density of these data ranges from sparse in frontier areas (e.g., Washington-Oregon area) to extremely dense in mature producing areas (e.g., Santa Barbara-Ventura basin). The most important petroleum reservoirs discovered as of this assessment are fractured siliceous rocks of the Monterey Formation; additional petroleum accumulations exist in clastic reservoirs underlying and overlying the Monterey.

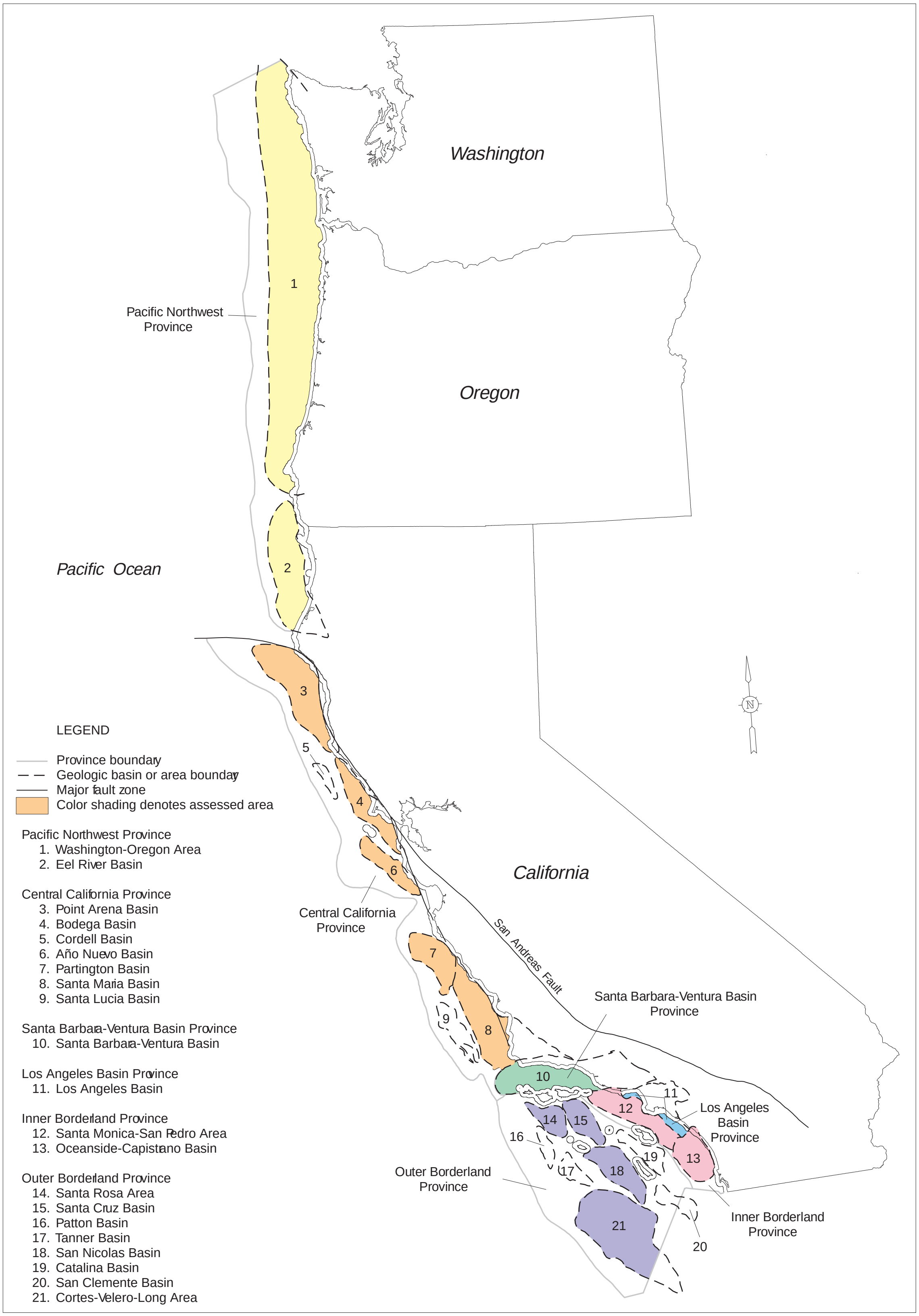


Figure 10. *Map of the Pacific OCS Region showing assessment provinces, geologic basins and areas, and assessed areas. Colors correspond to the provinces shown on the front cover and discussed in the text.*

Table 1. *Location, name, and classifications of petroleum geologic plays defined for this assessment of the Pacific OCS Region. Continued on next page.*

Assessment Area	Play	Exploration & Discovery Status[1]	Hydrocarbon Type[2]	Reservoir Rock Type[3]
		Pacific Northwest Province		
Washington-Oregon Area	Growth Fault	Conceptual	Mixed	Neogene Clastic
	Neogene Fan Sandstone	Frontier	Mixed	Neogene Clastic
	Neogene Shelf Sandstone	Conceptual	Mixed	Neogene Clastic
	Paleogene Sandstone	Frontier	Mixed	Paleogene-Cretaceous Clastic
	Melange[4]	Frontier	Oil	Melange
Eel River Basin	Neogene Fan Sandstone	Established	Mixed	Neogene Clastic
	Neogene Shelf Sandstone	Frontier	Mixed	Neogene Clastic
	Paleogene Sandstone	Frontier	Mixed	Paleogene-Cretaceous Clastic
	Melange[4]	Conceptual	Oil	Melange
		Central California Province		
Point Arena Basin	Neogene Sandstone	Frontier	Oil	Neogene Clastic
	Monterey Fractured	Frontier	Oil	Neogene Fractured Siliceous
	Pre-Monterey Sandstone	Frontier	Oil	Paleogene-Cretaceous Clastic
Bodega Basin	Neogene Sandstone	Frontier	Oil	Neogene Clastic
	Monterey Fractured	Frontier	Oil	Neogene Fractured Siliceous
	Pre-Monterey Sandstone	Frontier	Oil	Paleogene-Cretaceous Clastic
Año Nuevo Basin	Neogene Sandstone	Frontier	Oil	Neogene Clastic
	Monterey Fractured	Frontier	Oil	Neogene Fractured Siliceous
	Pre-Monterey Sandstone	Frontier	Oil	Paleogene-Cretaceous Clastic
Santa Maria-Partington Basin	Basal Sisquoc Sandstone	Frontier	Oil	Neogene Clastic
	Monterey Fractured	Established	Oil	Neogene Fractured Siliceous
	Paleogene Sandstone	Conceptual	Oil	Paleogene-Cretaceous Clastic
	Breccia	Conceptual	Oil	Neogene Clastic
		Santa Barbara-Ventura Basin Province		
Santa Barbara-Ventura Basin	Pico-Repetto Sandstone	Established	Mixed	Neogene Clastic
	Monterey Fractured	Established	Oil	Neogene Fractured Siliceous
	Rincon-Monterey-Topanga Sandstone	Established	Oil	Neogene Clastic
	Sespe-Alegria-Vaqueros Sandstone	Established	Mixed	Paleogene-Cretaceous Clastic
	Gaviota-Sacate-Matilija Sandstone	Established	Mixed	Paleogene-Cretaceous Clastic
	Cretaceous-Paleocene Sandstone[4]	Established	Mixed	Paleogene-Cretaceous Clastic
		Los Angeles Basin Province		
Los Angeles Basin	Puente Fan Sandstone	Established	Oil	Neogene Clastic
	San Onofre Breccia	Frontier	Oil	Neogene Clastic
		Inner Borderland Province		
Santa Monica-San Pedro Area	Pliocene Clastic[4]	Conceptual	Oil	Neogene Clastic
	Upper Miocene Sandstone	Frontier	Oil	Neogene Clastic
	Modelo	Conceptual	Oil	Neogene Clastic
	Dume Thrust Fault	Frontier	Oil	Neogene Clastic
	San Onofre Breccia	Conceptual	Oil	Neogene Clastic
Oceanside-Capistrano Basin	Upper Miocene Sandstone	Conceptual	Oil	Neogene Clastic
	Monterey Fractured	Conceptual	Oil	Neogene Fractured Siliceous
	Lower Miocene Sandstone	Conceptual	Oil	Neogene Clastic
	Paleogene-Cretaceous Sandstone	Established	Oil	Paleogene-Cretaceous Clastic

Table 1. *Location, name, and classifications of petroleum geologic plays defined for this assessment of the Pacific OCS Region. Continued from previous page.*

Assessment Area	Play	Exploration & Discovery Status[1]	Hydrocarbon Type[2]	Reservoir Rock Type[3]
		Outer Borderland Province		
Santa Cruz Basin	Monterey Fractured	Conceptual	Oil	Neogene Fractured Siliceous
	Lower Miocene Sandstone	Conceptual	Oil	Neogene Clastic
Santa Rosa Area	Monterey Fractured	Conceptual	Oil	Neogene Fractured Siliceous
	Lower Miocene Sandstone	Conceptual	Oil	Neogene Clastic
Santa Cruz-Santa Rosa Area	Paleogene-Cretaceous Sandstone	Conceptual	Oil	Paleogene-Cretaceous Clastic
San Nicolas Basin	Upper Miocene Sandstone	Conceptual	Oil	Neogene Clastic
	Monterey Fractured	Conceptual	Oil	Neogene Fractured Siliceous
	Lower Miocene Sandstone	Conceptual	Oil	Neogene Clastic
	Paleogene-Cretaceous Sandstone	Conceptual	Oil	Paleogene-Cretaceous Clastic
Cortes-Velero-Long Area	Lower Miocene Sandstone	Conceptual	Oil	Neogene Clastic
	Paleogene-Cretaceous Sandstone	Conceptual	Oil	Paleogene-Cretaceous Clastic

[1] Plays are classified according to their exploration and discovery status as follows:
Established plays are those in which hydrocarbon accumulations have been discovered.
Frontier plays are those in which hydrocarbon accumulations have not been discovered, but in which hydrocarbons have been detected (e.g., shows, bright spots).
Conceptual plays are those in which hydrocarbons have not been detected, but for which data suggest that hydrocarbon accumulations may exist.

[2] Plays are classified according to their expected predominant hydrocarbon type as follows:
An *oil play* contains predominantly crude oil and associated gas.
A *gas play* contains predominantly nonassociated gas and may contain condensate.
A *mixed play* contains crude oil, associated gas, and nonassociated gas, and may contain condensate.

[3] Plays are classified according to the age and lithology (rock type) of their reservoir rocks as follows:
Plays having *Neogene clastic reservoir rocks* include reservoir rocks that consist of Miocene and/or Pliocene sandstone, siltstone, shale, and/or breccia.
Plays having *Neogene fractured siliceous reservoir rocks* include reservoir rocks that consist of Miocene fractured chert, siliceous shale, porcelanite, dolomite, and/or limestone.
Plays having *Paleogene-Cretaceous clastic reservoir rocks* include reservoir rocks that consist of Cretaceous through Oligocene sandstone, siltstone, and/or shale.
Plays having *Melange reservoir rocks* include reservoir rocks that consist of sandstone within Cretaceous through Miocene melange.

[4] Not formally assessed.

ASSESSMENT PROVINCES, ASSESSMENT AREAS, AND PLAYS

The petroleum geologic framework of the region provided the basis for the delineation of assessment provinces, assessment areas, and petroleum geologic plays. For this assessment, the Pacific OCS Region is subdivided into six assessment provinces: Pacific Northwest, Central California, Santa Barbara-Ventura basin, Los Angeles basin, Inner Borderland, and Outer Borderland (see front cover). Each province comprises one or more assessment areas (i.e., geologic basins or areas), within which petroleum geologic plays have been defined (fig. 10). Fifty individual plays within the Region have been defined and described, and 46 of these have been formally assessed (table 1). Some areas and plays that lack sufficient petroleum geologic data or for which data suggest that petroleum potential is negligible have not been assessed. Additionally, several late Tertiary submarine fans exist within the Region; these areas of deep-sea sedimentation lack sufficient data and also have not been assessed.

The subareas defined for this assessment are similar, but not identical, to those defined for previous assessments. Notable differences are the consolidation of the Washington-Oregon area and Eel River basin as the Pacific Northwest province, and the inclusion of the Santa Maria and Partington basins in the Central California province. Other changes to the names and boundaries of some subareas have been made for ease of reference and assessment.

Table 2. *Estimates of undiscovered conventionally recoverable oil and gas resources in the Pacific OCS Region as of January 1, 1995, by province. All estimates are risked values. The low, mean, and high estimates correspond to the 95th-percentile, mean, and 5th-percentile values of a probability distribution, respectively. Percentile values are not additive; some total mean values may not equal the sum of the component values due to independent rounding.*

Province	Oil (Bbbl)			Gas (Tcf)			BOE (Bbbl)		
	Low	Mean	High	Low	Mean	High	Low	Mean	High
Pacific Northwest	0.19	0.41	0.75	2.34	3.91	6.03	0.61	1.11	1.79
Central California	4.17	4.95	5.82	4.21	5.23	6.39	4.94	5.88	6.93
Santa Barbara-Ventura Basin	1.74	1.85	1.95	3.84	4.61	5.48	2.43	2.67	2.92
Los Angeles Basin	0.19	0.31	0.49	0.17	0.32	0.53	0.22	0.37	0.58
Inner Borderland[1]	0.87	1.79	3.18	0.79	2.07	4.19	1.04	2.16	3.85
Outer Borderland	0.63	1.40	2.56	0.98	2.79	5.89	0.82	1.89	3.56
Total Pacific OCS Region[1]	*8.99*	*10.71*	*12.62*	*15.21*	*18.94*	*23.19*	*11.82*	*14.08*	*16.60*

[1] Includes a small area and volume of resources in the State offshore and onshore area adjacent to the Federal offshore area.

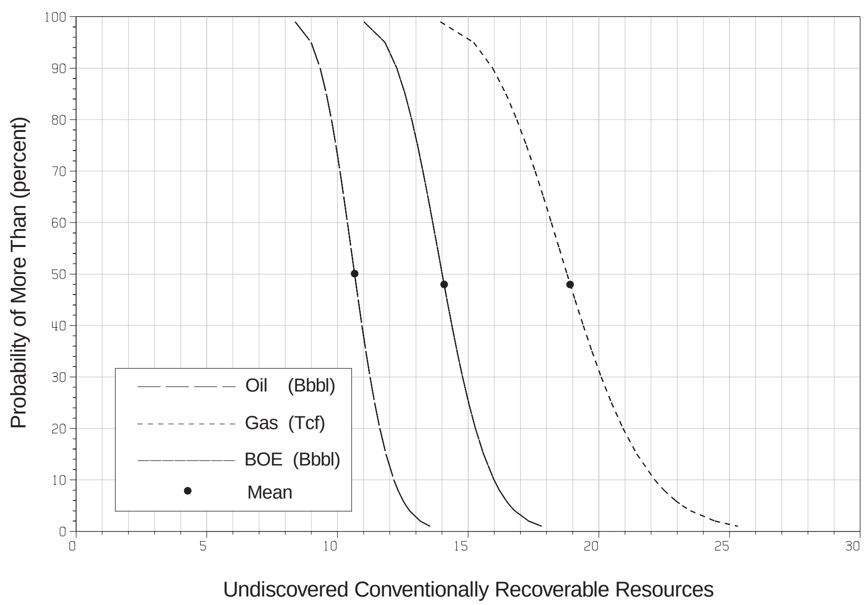


Figure 11. *Cumulative probability plot of estimated undiscovered conventionally recoverable resources of the Pacific OCS Region.*

Resource Estimates

Undiscovered Conventionally Recoverable Resources

Estimates of the total volume of undiscovered conventionally recoverable resources in the Region have been developed by statistically aggregating the constituent province estimates. As a result of this assessment, the total volume of undiscovered conventionally recoverable oil and gas resources in the Pacific OCS Region is estimated to be 10.71 Bbbl of oil and 18.94 Tcf of gas (mean estimates). The low, mean, and high estimates of resources in the Region are listed in table 2 and illustrated in figure 11. A discussion of the contribution of undiscovered conventionally recoverable resources in the Pacific OCS Region to the undiscovered resources in the United States OCS is presented in appendix E.

Undiscovered Economically Recoverable Resources

Estimates of the total volume of undiscovered conventionally recoverable resources in the Region that may be economically recoverable under various

Table 3. *Estimates of undiscovered economically recoverable oil and gas resources in the Pacific OCS Region as of January 1, 1995 for three economic scenarios, by province. All estimates are risked mean values. The $18-per-barrel scenario is based on prices of $18 per bbl of oil and $2.11 per Mcf of gas; the $25-per-barrel scenario is based on prices of $25 per bbl of oil and $2.94 per Mcf of gas; the $50-per-barrel scenario is based on prices of $50 per barrel of oil and $5.87 per Mcf of gas. Some total values may not equal the sum of the component values due to independent rounding.*

Province	$18-per-barrel Scenario			$25-per-barrel Scenario			$50-per-barrel Scenario		
	Oil (Bbbl)	Gas (Tcf)	BOE (Bbbl)	Oil (Bbbl)	Gas (Tcf)	BOE (Bbbl)	Oil (Bbbl)	Gas (Tcf)	BOE (Bbbl)
Pacific Northwest	0.10	0.93	0.27	0.14	1.32	0.38	0.22	2.13	0.60
Central California	2.59	2.77	3.08	3.17	3.38	3.77	3.98	4.22	4.73
Santa Barbara-Ventura Basin	1.17	2.91	1.68	1.37	3.43	1.98	1.64	4.11	2.38
Los Angeles Basin	0.21	0.21	0.25	0.24	0.25	0.29	0.28	0.29	0.33
Inner Borderland[1]	1.19	1.37	1.43	1.39	1.60	1.67	1.61	1.85	1.94
Outer Borderland	0.06	0.10	0.08	0.30	0.52	0.40	0.94	1.83	1.27
Total Pacific OCS Region[1]	*5.31*	*8.30*	*6.79*	*6.61*	*10.49*	*8.48*	*8.67*	*14.42*	*11.24*

[1] Includes a small area and volume of resources in the State offshore and onshore area adjacent to the Federal offshore area.

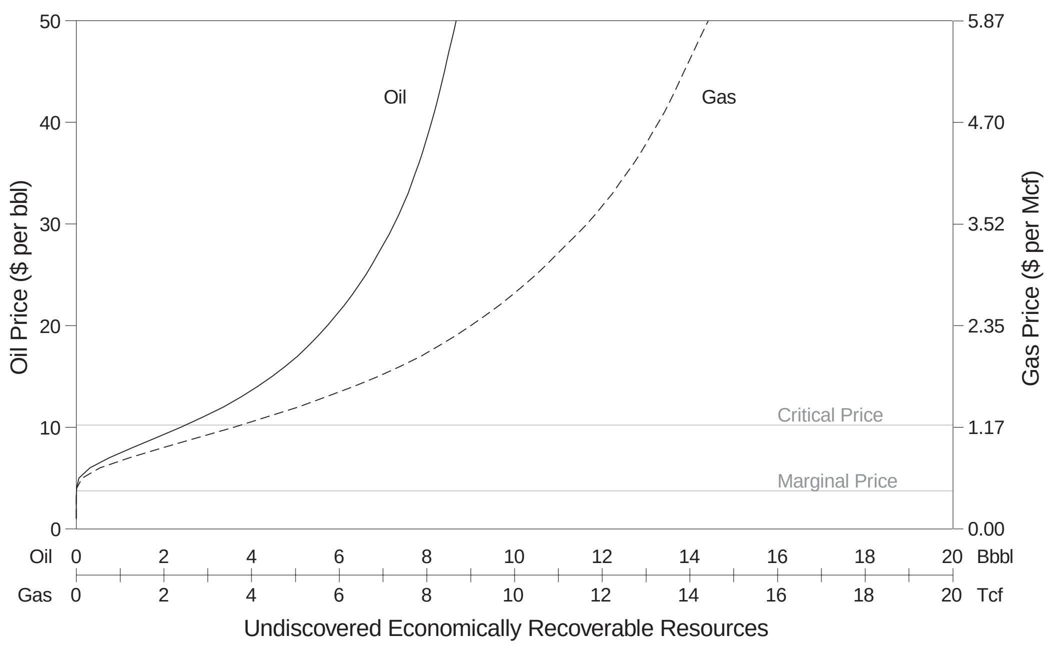


Figure 12. *Price-supply plot of estimated undiscovered economically recoverable resources of the Pacific OCS Region.*

economic scenarios have been developed by statistically aggregating the constituent province estimates. As a result of this assessment, 5.31 Bbbl of oil and 8.30 Tcf of gas are estimated to be economically recoverable from the Pacific OCS Region under economic conditions existing as of this assessment (i.e., the $18-per-barrel economic scenario) (table 3).

Larger volumes of resources are expected to be economically recoverable under increasingly favorable economic conditions (fig. 12). A discussion of the contribution of undiscovered economically recoverable resources in the Pacific OCS Region to the undiscovered resources in the United States OCS is presented in appendix E.

Table 4. *Estimates of the total endowment of oil and gas resources in the Pacific OCS Region, by province. Estimates of discovered resources (including cumulative production and remaining reserves) and undiscovered resources are as of January 1, 1995. Estimates of undiscovered conventionally recoverable resources are risked mean values. Some total values may not equal the sum of the component values due to independent rounding.*

Province	Discovered Resources (Reserves)						Undiscovered Conventionally Recoverable Resources			Total Resource Endowment		
	Cumulative Production			Remaining Reserves								
	Oil (Bbbl)	Gas (Tcf)	BOE (Bbbl)	Oil (Bbbl)	Gas (Tcf)	BOE (Bbbl)	Oil (Bbbl)	Gas (Tcf)	BOE (Bbbl)	Oil (Bbbl)	Gas (Tcf)	BOE (Bbbl)
Pacific Northwest	0	0	0	0	0	0	0.41	3.91	1.11	0.41	3.91	1.11
Central California	0.12	0.04	0.13	0.67	0.66	0.78	4.95	5.23	5.88	5.74	5.93	6.79
Santa Barbara-Ventura Basin	0.49	0.67	0.61	0.65	1.72	0.96	1.85	4.61	2.67	2.99	7.01	4.24
Los Angeles Basin	0.07	0.02	0.07	0.06	0.01	0.06	0.31	0.32	0.37	0.44	0.36	0.50
Inner Borderland[1]	<0.01	<0.01	<0.01		negligible		1.79	2.07	2.16	1.79	2.07	2.16
Outer Borderland	0	0	0	0	0	0	1.40	2.79	1.89	1.40	2.79	1.89
Total Pacific OCS Region[1]	*0.68*	*0.74*	*0.81*	*1.38*	*2.39*	*1.80*	*10.71*	*18.94*	*14.08*	*12.77*	*22.07*	*16.69*

[1] Includes a small area and volume of resources in the State offshore and onshore area adjacent to the Federal offshore area.

Total Resource Endowment

As of this assessment, cumulative production from the Region was 678 MMbbl of oil and 738 Bcf of gas; remaining reserves were estimated to be 1.38 Bbbl of oil and 2.39 Tcf of gas (Sorensen and others, 1995). These discovered resources and the aforementioned undiscovered conventionally recoverable resources collectively compose the Region's estimated total resource endowment of 12.77 Bbbl of oil and 22.07 Tcf of gas (table 4).

ORGANIZATION AND CONTENT OF THIS SECTION

The following parts of this section present detailed information regarding the petroleum geology and resource estimates of provinces, assessment areas, and plays in the Region. The information is organized in a hierarchical order of a province, its constituent assessment areas, and their constituent plays. Although there are apparent differences in the degree of detail of the information presented, there is general consistency among the organizational formats of the respective discussions.

Province discussions include descriptive information regarding the location, geologic setting, and resource estimates of each province. Illustrations include a map showing the location of the province and its constituent assessment areas, a cumulative probability plot of the estimated undiscovered conventionally recoverable resources, and a price-supply plot of the undiscovered economically recoverable resources. Tabular lists of estimates of undiscovered conventionally recoverable resources, undiscovered economically recoverable resources, and total resource endowment (where resources have been discovered) by assessment area are also presented.

Assessment area discussions include descriptive information regarding the location, geologic setting, exploration, and resource estimates of the area. Illustrations include a map showing the location of the area and its constituent plays, a stratigraphic column showing the stratigraphic units, hydrocarbon attributes, and plays, a field-size rank plot and cumulative probability plot of estimated undiscovered conventionally recoverable resources, and a price-supply plot of the undiscovered economically recoverable resources. Tabular lists of estimates of undiscovered conventionally recoverable resources, undiscovered economically recoverable resources, and total resource endowment (where resources have been discovered) by play are also presented.

Play discussions include descriptive information regarding the location, petroleum geologic characteristics (source rocks, reservoir rocks, and traps), exploration, and resource estimates of the play, as well as a pool-size rank plot of estimated undiscovered conventionally recoverable resources.

Every effort has been made to completely and accurately cite the work of others in these discussions. Additional references providing relevant information not cited in the text are listed at the end of some discussions.

PACIFIC NORTHWEST PROVINCE

by Kenneth A. Piper

Location

The Pacific Northwest province extends from Cape Flattery, Washington, to Cape Mendocino, California, a distance of about 550 miles. This Federal offshore assessment province is bounded on the east by the 3-mile line and on the west by the base of the continental slope (fig. 13).

Geologic Setting

The province is a convergent margin characterized by a relatively narrow continental shelf and slope and a trench complex to the west. The high rate of sedimentation in this area has resulted in a thick Neogene sedimentary sequence on the shelf and a poorly defined bathymetric trench. The oceanic plate

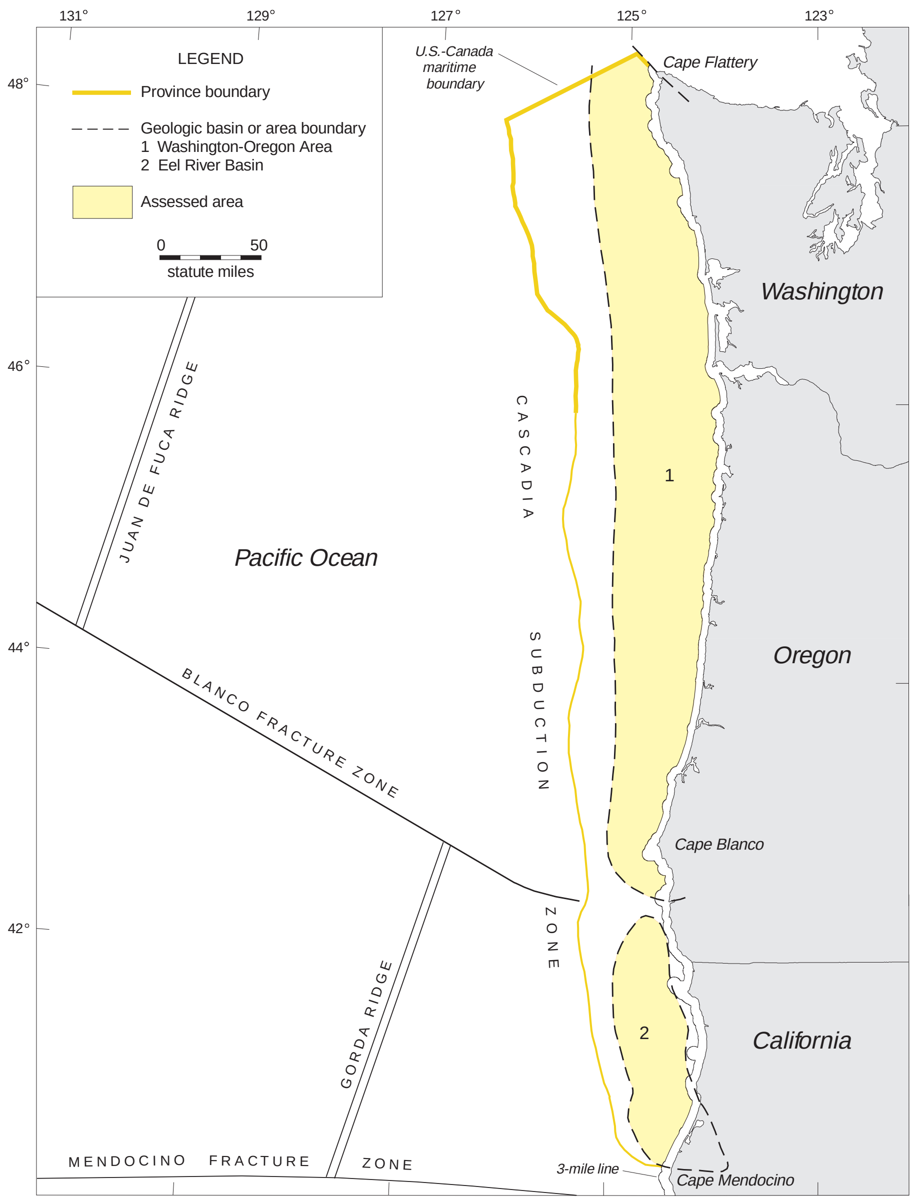


Figure 13. *Map of the Pacific Northwest province showing geologic basins and areas, assessed areas, and tectonic features.*

Table 5. *Estimates of undiscovered conventionally recoverable oil and gas resources in the Pacific Northwest province as of January 1, 1995, by assessment area. All estimates are risked values. The low, mean, and high estimates correspond to the 95th-percentile, mean, and 5th-percentile values of a probabilitydistribution, respectively. Percentile values are not additive; some total mean values may not equal the sum of the component values due to independent rounding.*

Assessment Area	Oil (Bbbl)			Gas (Tcf)			BOE (Bbbl)		
	Low	Mean	High	Low	Mean	High	Low	Mean	High
Washington-Oregon Area	0.14	0.36	0.69	0.95	2.30	4.28	0.32	0.76	1.42
Eel River Basin	0.03	0.05	0.08	1.06	1.61	2.32	0.23	0.34	0.49
Total Province	*0.19*	*0.41*	*0.75*	*2.34*	*3.91*	*6.03*	*0.61*	*1.11*	*1.79*

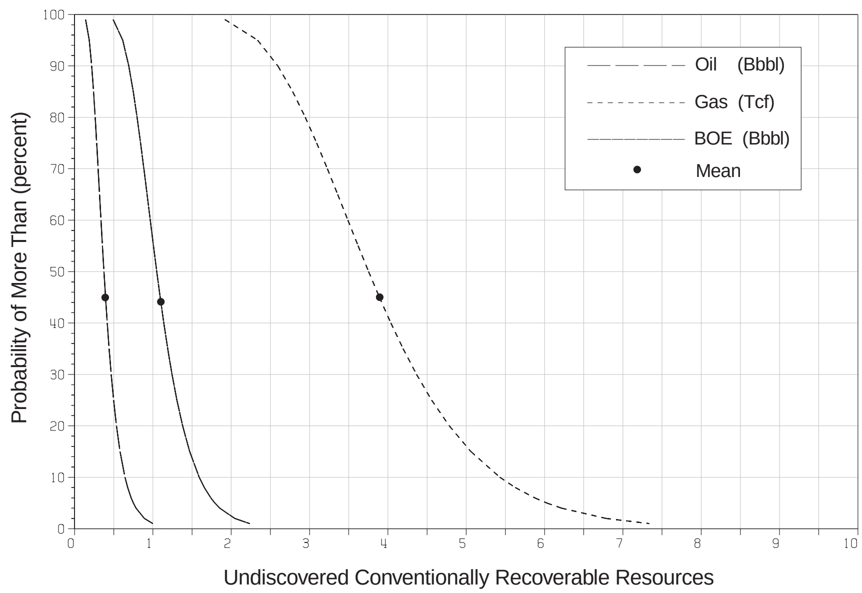


Figure 14. *Cumulative probability plot of estimated undiscovered conventionally recoverable resources of the Pacific Northwest province.*

on the west is divided into two subplates separated by the Blanco fracture zone offshore Cape Blanco, Oregon. This boundary divides the province into a northern group of poorly defined subbasins, which are collectively referred to as the Washington-Oregon area, and the Eel River basin, which extends south to the Mendocino fracture zone offshore Cape Mendocino. The two assessment areas (i.e., Washington-Oregon area and Eel River basin) of the province and the petroleum geologic plays defined within them are described following this province summary.

Resource Estimates

Undiscovered Conventionally Recoverable Resources

Estimates of the total volume of undiscovered conventionally recoverable resources in the province have been developed by statistically aggregating the constituent assessment area estimates. As a result of this assessment, the total volume of undiscovered conventionally recoverable resources in the Pacific Northwest province is estimated to be 410 MMbbl of oil (including oil and condensate) and 3.91 Tcf of gas (including associated and nonassociated gas) (mean estimates). The low, mean, and high estimates of resources in the province are listed in table 5 and illustrated in figure 14.

Table 6. *Estimates of undiscovered economically recoverable oil and gas resources in the Pacific Northwest province as of January 1, 1995 for three economic scenarios, by assessment area. All estimates are risked mean values. The $18-per-barrel scenario is based on prices of $18 per bbl of oil and $2.11 per Mcf of gas; the $25-per-barrel scenario is based on prices of $25 per bbl of oil and $2.94 per Mcf of gas; the $50-per-barrel scenario is based on prices of $50 per barrel of oil and $5.87 per Mcf of gas. Some total values may not equal the sum of the component values due to independent rounding.*

Assessment Area	$18-per-barrel Scenario			$25-per-barrel Scenario			$50-per-barrel Scenario		
	Oil (Bbbl)	Gas (Tcf)	BOE (Bbbl)	Oil (Bbbl)	Gas (Tcf)	BOE (Bbbl)	Oil (Bbbl)	Gas (Tcf)	BOE (Bbbl)
Washington-Oregon Area	0.09	0.65	0.21	0.13	0.90	0.29	0.20	1.37	0.44
Eel River Basin	<0.01	0.28	0.06	0.01	0.42	0.09	0.03	0.77	0.16
Total Province	*0.10*	*0.93*	*0.27*	*0.14*	*1.32*	*0.38*	*0.22*	*2.13*	*0.60*

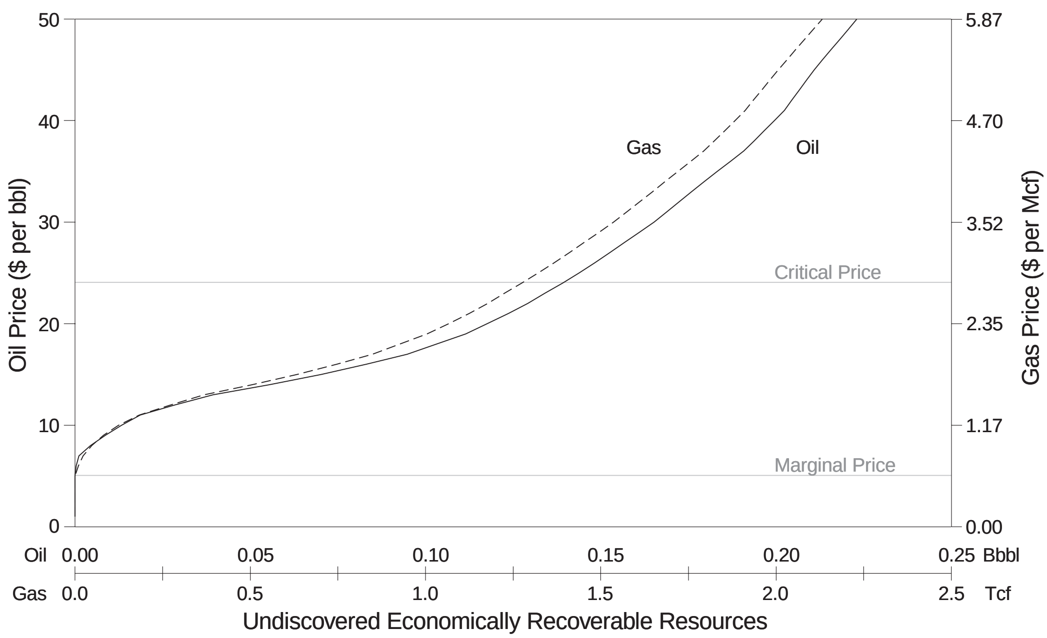


Figure 15. *Price-supply plot of estimated undiscovered economically recoverable resources of the Pacific Northwest province.*

Undiscovered Economically Recoverable Resources

Estimates of the total volume of undiscovered conventionally recoverable resources in the province that may be economically recoverable under various economic scenarios have been developed by statistically aggregating the constituent assessment area estimates. As a result of this assessment, 104 MMbbl of oil (including oil and condensate) and 932 Bcf of gas (including associated and nonassociated gas) are estimated to be economically recoverable from the Pacific Northwest province under economic conditions existing as of this assessment (i.e., the $18-per-barrel economic scenario) (table 6). Larger volumes of resources are expected to be economically recoverable under increasingly favorable economic conditions (fig. 15).

Total Resource Endowment

No accumulations of resources have been discovered in the province. Therefore, the aforementioned estimates of undiscovered conventionally recoverable resources compose the estimated total resource endowment of the province.

WASHINGTON-OREGON AREA

by Kenneth A. Piper

Location

The Washington-Oregon assessment area is the northern subarea of the Pacific Northwest province (fig. 13). This Federal offshore (i.e., seaward of the 3-mile line) area extends from Cape Flattery, Washington, to "Retirement ridge" (an informally named structural high) south of Cape Blanco, Oregon, a distance of about 400 miles (fig. 16). The area is about 30 to 50 miles wide and encompasses about 18,000 square miles. Water depth in the area ranges from about 100 feet on Nehalem Bank to about 1,200 feet locally along the shelf-slope boundary. Interpretation of a coarse grid of seismic-reflection profiles identified six Neogene depocenters or subbasins (Webster, 1985; Cranswick and Piper, 1992). The boundaries of the subbasins delineated by isochore mapping generally conform with basin outlines published by other investigators.

Geologic Setting

The deepest rocks penetrated by offshore wells include Paleocene to Miocene melange (fig. 17). The

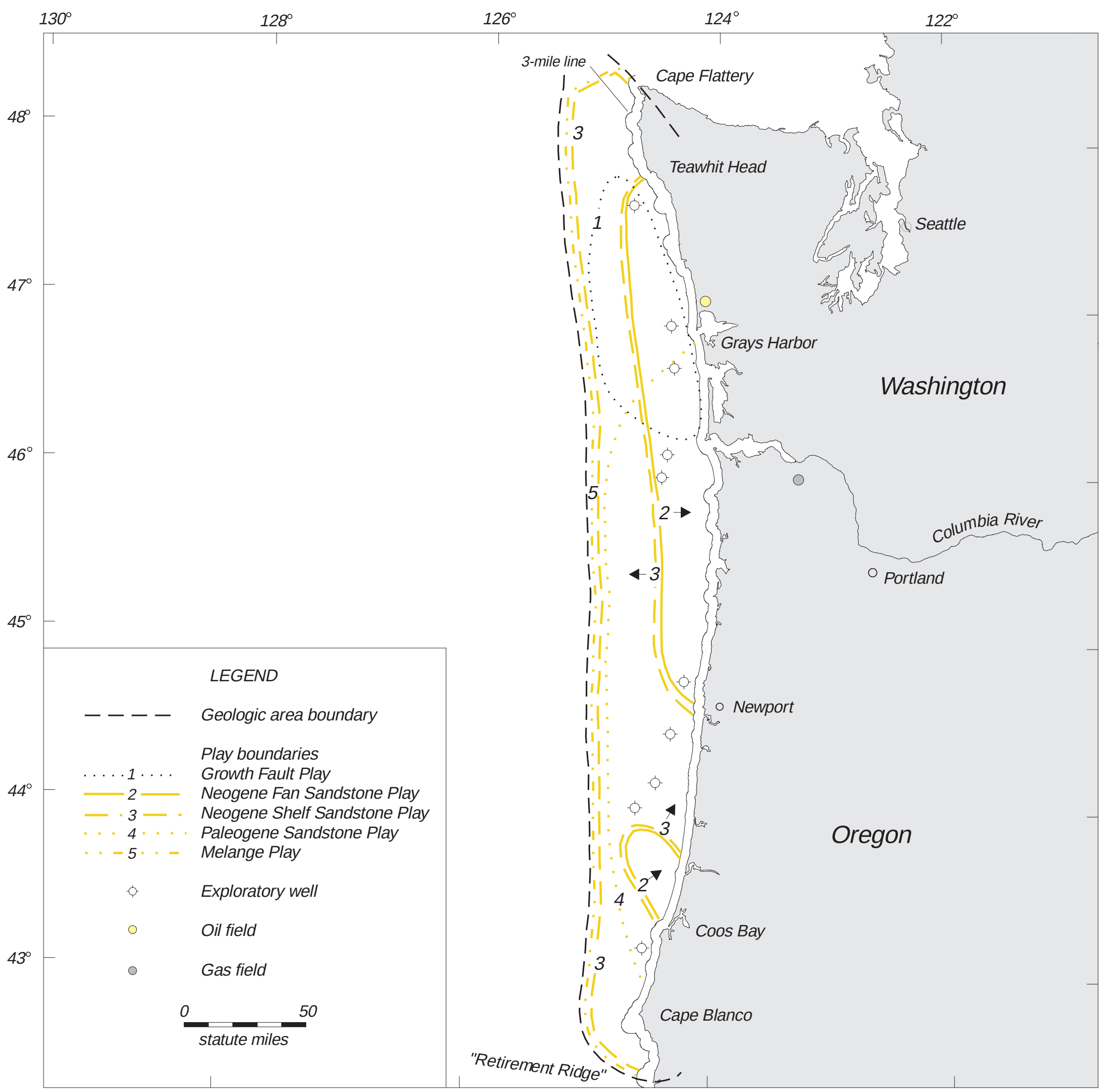


Figure 16. *Map of the Washington-Oregon assessment area showing petroleum geologic plays, wells, and fields.*

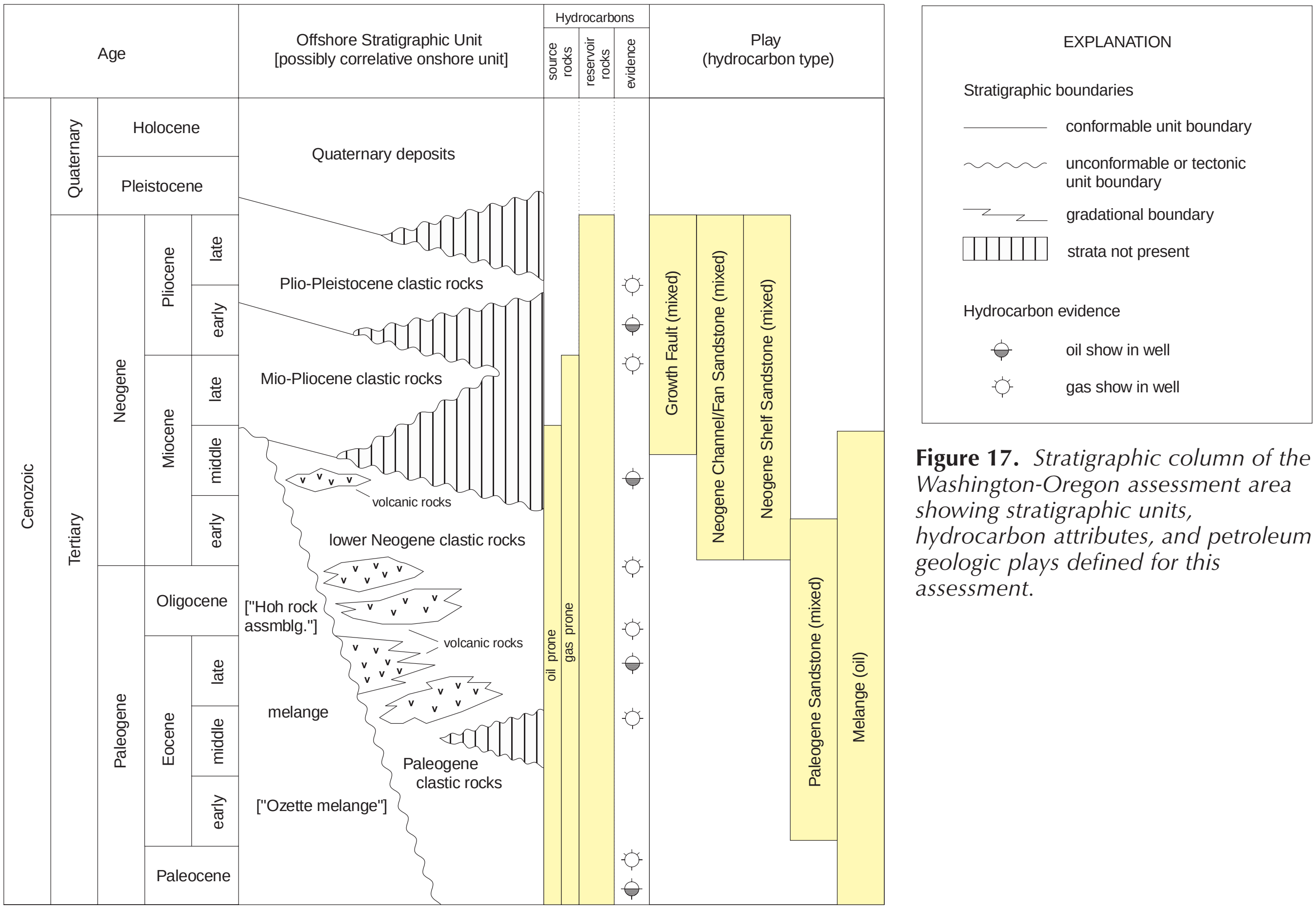


Figure 17. *Stratigraphic column of the Washington-Oregon assessment area showing stratigraphic units, hydrocarbon attributes, and petroleum geologic plays defined for this assessment.*

upper part of this section to at least the depth penetrated by the wells is considered to be largely olistostrome and turbidite deposition in trench and slope environments overlying the subduction complex. Onshore, lithologically correlative rocks exist in the Olympic Peninsula of Washington (Palmer and Lingley, 1989). In the eastern part of the area south of Grays Harbor, Washington, an assemblage of possibly allochthonous, Paleocene(?) to Eocene tholeiitic volcanic rocks overlies the melange (Snavely and Wells, 1984; Wells and others, 1984; Snavely, 1987). Above this lies a sequence of Paleocene to Holocene clastic strata, which attains a thickness in excess of 20,000 feet offshore central Oregon. North of Grays Harbor and along the western margin of the entire area, Neogene strata directly overlie the melange.

Most major structures are north- to northwest-trending and include compressional folds and faults, right-lateral strike-slip faults, and extensional faults. Large-scale extensional growth faults are a dominant feature offshore Washington, and shale diapirs are present offshore Washington and Oregon (Piper, 1994; Piper and others, 1995).

The rock record suggests a westward migration of subduction (Kulm and Fowler, 1974; Snavely, 1987; Snavely and others, 1988). Paleogene deposition occurred in the eastern part of the area; Neogene strata directly overlie the subduction complex to the west. The upper Tertiary accretionary complex developed adjacent to the older subduction zone and forearc basins developed along the modern continental shelf. The growth faulting, diapirism, and other extensional features suggest westward extension of the upper plate concurrent with rapid sedimentation since early Miocene time (Piper, 1994).

EXPLORATION

Twelve exploratory wells were drilled at 10 sites in the 1960's. Also, three Deep Sea Drilling Project (DSDP) coreholes were drilled offshore Oregon in 1971 (Kulm and others, 1973). Hydrocarbon shows were encountered at eight of the exploratory well sites. Drill-stem tests on two of the wells, OCS-P 0150 #1 (southwest of Grays Harbor, Washington) and OCS-P 0112 #1 (southwest of Coos Bay, Oregon) yielded gas at rates of 10 to 26, and 49 to 68 Mcf per day, respectively (Zieglar and Cassell, 1978). A small oil field in the Ocean City area, onshore north of Grays Harbor, Washington, produced about 12 Mbbl of high-gravity (38.9 °API) oil and about 6.5 MMcf of gas from 1957 to 1962; several other wells in the area encountered subcommercial quantities of oil and gas (Braislin and others, 1971; McFarland, 1983; Palmer and Lingley, 1989). Oil shows from wells near Grays Harbor and the Columbia River (OCS-P 0155 #1 and OCS-P 0072 #1, respectively) indicate the presence of high-gravity oil comparable with that produced in the Ocean City area (Zieglar and Cassell, 1978). Continuing production at Mist gas field onshore, west of Portland, Oregon, has yielded about 56 Bcf of gas as of January 1, 1995 (Dan Wermiel, Oregon Department of Geology and Mineral Industries, oral commun., 1995). Stratigraphic and paleontologic data from the offshore wells and a relatively sparse grid of seismic-reflection data are the bases for interpretation of the offshore geology.

PLAYS

For this assessment, five petroleum geologic plays were defined based on trapping and reservoir rock characteristics (figs. 16 and 17). Three Neogene plays, one Paleogene play, and a melange play were so defined. The plays are described following this assessment area summary. Rocks which are equivalent to rocks of these plays exist onshore and in the state offshore areas. Some of these rock units are included in plays which have been assessed within the Western Oregon-Washington province by the USGS (Johnson and Tennyson, 1995).

RESOURCE ESTIMATES

Undiscovered Conventionally Recoverable Resources

Play-specific estimates of undiscovered conventionally recoverable resources have been developed using the subjective assessment method, and these estimates have been statistically aggregated to estimate the total volume of resources in the area. Select data used to develop the resource estimates are shown in appendix C.

As a result of this assessment, the total volume of undiscovered conventionally recoverable resources in the Washington-Oregon assessment area is estimated to be 355 MMbbl of oil (including oil and condensate) and 2.30 Tcf of gas (including associated and nonassociated gas) (mean estimates). This volume may exist in 185 fields with sizes ranging from approximately 10 Mbbl to 125 MMbbl of combined oil-equivalent resources (fig. 18). The low, mean, and high estimates of resources in the area are listed in table 7 and illustrated in figure 19.

Undiscovered Economically Recoverable Resources

Estimates of undiscovered conventionally recoverable resources in the assessment area that may be economically recoverable under various economic scenarios have been developed using the economic assessment method. Select data used to develop the resource estimates are shown in appendix D.

As a result of this assessment, 95 MMbbl of oil (including oil and condensate) and 652 Bcf of gas (including associated and nonassociated gas) are estimated to be economically recoverable from the Washington-Oregon assessment area under economic conditions existing as of this assessment

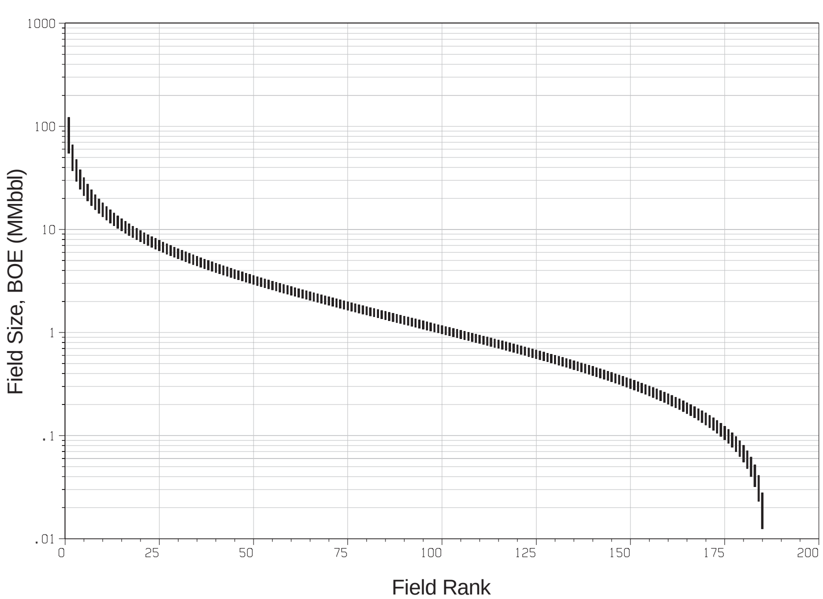
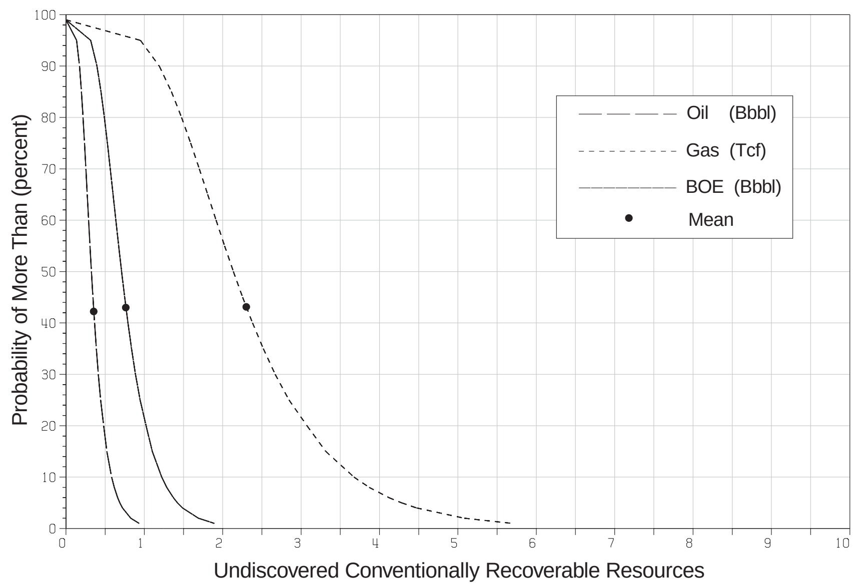


Figure 18. *Field-size rank plot of estimated undiscovered conventionally recoverable resources of the Washington-Oregon assessment area. Sizes of undiscovered fields are shown by bars; the top and bottom of a bar represent the 25th- and 75th-percentile values of a probability distribution, respectively.*

Table 7. *Estimates of undiscovered conventionally recoverable oil and gas resources in the Washington-Oregon assessment area as of January 1, 1995, by play. All estimates are risked values. The low, mean, and high estimates correspond to the 95th-percentile, mean, and 5th-percentile values of a probability distribution, respectively. Percentile values are not additive; some total mean values may not equal the sum of the component values due to independent rounding.*

Play	Oil (MMbbl)			Gas (Bcf)			BOE (MMbbl)		
	Low	Mean	High	Low	Mean	High	Low	Mean	High
Growth Fault	0	110	283	0	450	1,341	0	190	502
Neogene Fan Sandstone	0	98	207	0	882	1,854	0	255	522
Neogene Shelf Sandstone	0	138	287	0	596	1,303	0	244	510
Paleogene Sandstone	0	9	23	0	372	753	0	75	151
Melange					not assessed				
Total Assessment Area	*136*	*355*	*687*	*950*	*2,300*	*4,280*	*316*	*765*	*1,423*

Figure 19. *Cumulative probability plot of estimated undiscovered conventionally recoverable resources of the Washington-Oregon assessment area.*



(i.e., the $18-per-barrel economic scenario) (table 8). Larger volumes of resources are expected to be economically recoverable under increasingly favorable economic conditions (fig. 20).

Total Resource Endowment

No accumulations of resources have been discovered in the Washington-Oregon assessment area. Therefore, the aforementioned estimates of undiscovered conventionally recoverable resources compose the estimated total resource endowment of the area.

ACKNOWLEDGMENTS

The following individuals provided information, insight, and suggestions that greatly improved the quality of this assessment of the Washington-Oregon assessment area: Sam Johnson and Lynn Tennyson (U.S. Geological Survey), Bill Lingley (Washington State Department of Natural Resources), Dan Wermiel and Dennis Olmstead (Oregon Department of Geology and Mineral Industries), and Ed Edwards and Ron Heck (Heck & Associates). Micropaleontologic interpretation of offshore well samples by Scott Drewry (Minerals Management Service) was of key importance in establishing the offshore stratigraphic correlations. The Northwest Energy Association (formerly Northwest Petroleum Association) also provided assistance and hosted a public workshop in support of this assessment.

ADDITIONAL REFERENCE

McLean and Wiley, 1987

Table 8. *Estimates of undiscovered economically recoverable oil and gas resources in the Washington-Oregon assessment area as of January 1, 1995, by economic scenario. All estimates are risked mean values. The $18-per-barrel scenario is based on prices of $18 per bbl of oil and $2.11 per Mcf of gas; the $25-per-barrel scenario is based on prices of $25 per bbl of oil and $2.94 per Mcf of gas; the $50-per-barrel scenario is based on prices of $50 per barrel of oil and $5.87 per Mcf of gas.*

Economic Scenario	Oil (MMbbl)	Gas (Bcf)	BOE (MMbbl)
$18 per barrel	95	652	211
$25 per barrel	131	903	291
$50 per barrel	198	1,366	441

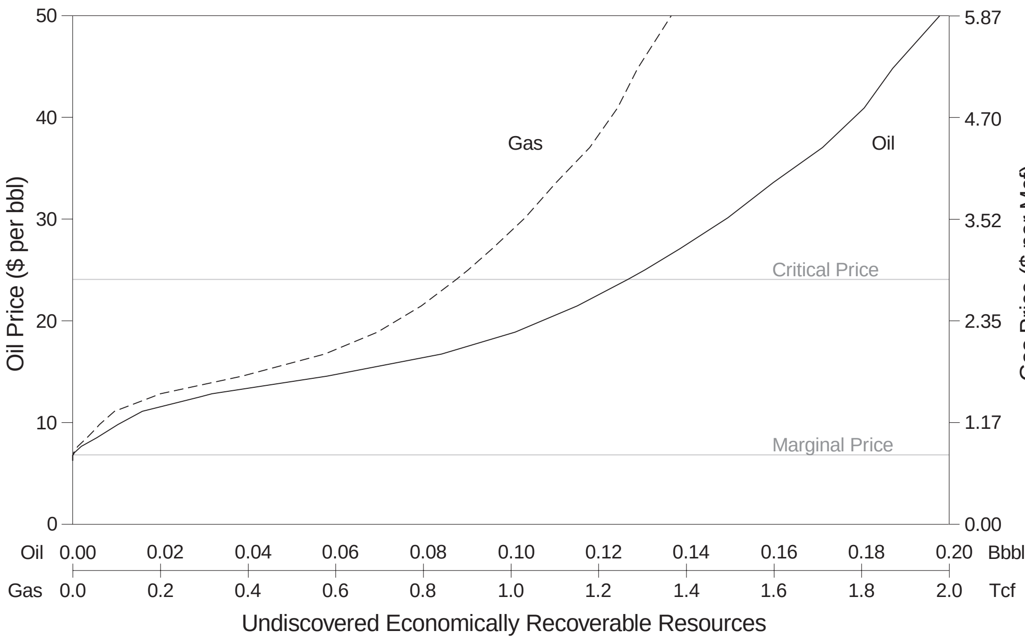


Figure 20. *Price-supply plot of estimated undiscovered economically recoverable resources of the Washington-Oregon assessment area.*

GROWTH FAULT PLAY

PLAY DEFINITION

The Growth Fault play of the Washington-Oregon assessment area is defined to include accumulations of oil and gas in Miocene and Pliocene sandstones deposited in deltaic and fan systems on the shelf and now incorporated in traps associated with growth faults. It is a conceptual play because no traps within this play have been tested. The play extends from Teawhit Head, Washington, to the Washington-Oregon border (Columbia River) and encompasses an area of about 3,400 square miles (fig. 16). It is defined on the basis of trap type.

The Growth Fault play includes rocks that are equivalent to those of the Neogene Fan Sandstone play and the Neogene Shelf Sandstone play; it is differentiated from those plays on the basis of expected trap characteristics and the increased likelihood of vertically stacked traps. Hydrocarbon accumulations may occur to about 8,000 feet below the seafloor.

PETROLEUM GEOLOGIC CHARACTERISTICS

The primary hydrocarbon source is Miocene and older melange, which, over most of the play area, directly underlies the Neogene sedimentary section (fig. 17). Based on seeps and past production from probable equivalent rocks in the western Olympic Peninsula, Washington (Palmer and Lingley, 1989), and near Eel River basin, California (Vander Leck, 1921; MacGinitie, 1943; California Division of Oil and Gas, 1960; 1982), these are expected to be primarily a source of high-gravity oil. In the southernmost one-fifth of the area, Eocene to Oligocene shales are present above the melange and are a possible gas source. Geothermal gradients (Snavely, 1987; Palmer and Lingley, 1989) suggest that source rocks are likely to be mature for oil generation at burial depths greater than about 10,000 to 12,000 feet. The Paleogene sedimentary rocks are not expected to exist below 10,000 feet within the play area, and kerogen type indicates that they are gas prone; they are, therefore, considered primarily a source of nonassociated gas.

Potential reservoirs are expected to be of good to fair quality. They consist of sandstones and siltstones deposited in shelf and slope environments where high rates of sedimentation upon an unstable trench/slope complex resulted in active growth faulting (Piper, 1994; Piper and others, 1995). Growth faulting produces much greater sediment thickness on the downthrown side relative to the upthrown side of the fault. The high sedimentation rate combined with the faulting is expected to have resulted in greater reservoir thicknesses compared to other plays and in increased potential for stacked reservoirs.

Potential traps include anticlinal rollovers on both sides of the faults and traps against the fault surface. The fault-related anticlines are generally larger and are the more important trap type; the faults may be conduits for escape of hydrocarbons rather than trapping them.

EXPLORATION

Although growth faults are abundant within the play area, no exploratory wells have been drilled into traps associated with them. However, there are indications of oil and gas in rocks considered to be likely source rocks for this play. In petroleum provinces elsewhere in the world, growth faults are considered important targets.

RESOURCE ESTIMATES

Undiscovered Conventionally Recoverable Resources

Estimates of undiscovered conventionally recoverable resources in the play have been developed using the subjective assessment method. Select data used to develop the resource estimates are shown in appendix C.

The play was modeled as a mixed-commodity (oil with associated gas, and nonassociated gas with condensate) play on the basis of expected source rocks. Potential pools in the northern part of the play are considered oil pools because the melange is the primary source. In the southern part, nonassociated gas sourced from the Paleogene section is considered to be a secondary commodity. Because of the low temperature gradient, oil generation is expected only where source rocks are present at burial depths greater than 10,000 feet. The Paleogene section is thin where present within the play area and is too shallow for oil generation. Overall, pools in the play were modeled as primarily oil; nonassociated gas was modeled as a component of 30 percent of the expected pools. Previous seismic mapping of the area—based on a relatively sparse seismic data grid—was revised for the assessment because growth faults had not been recognized. The estimated areas and number of prospects are based on that revision. Reservoir parameter distributions (e.g., recovery factors) were based largely on data from fields in California; however, the net-pay thickness distribution was increased to account for the thicker accumulations expected with growth faults.

As a result of this assessment, the play is estimated to contain 110 MMbbl of oil (including oil and condensate) and 450 Bcf of gas (including associated and nonassociated gas) (mean estimates). This volume of undiscovered conventionally recoverable resources may exist in as many as 46 pools with sizes ranging from approximately 210 Mbbl to 90 MMbbl of combined-oil equivalent resources (fig. 21). The

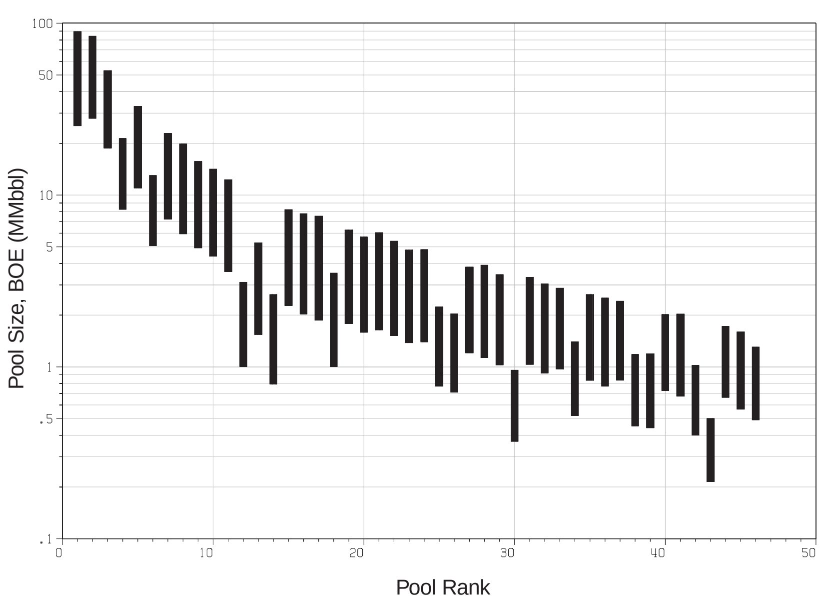


Figure 21. *Pool-size rank plot of estimated undiscovered conventionally recoverable resources of the Growth Fault play, Washington-Oregon assessment area. Sizes of undiscovered pools are shown by bars; the top and bottom of a bar represent the 25th- and 75th-percentile values of a probability distribution, respectively.*

majority of pools are expected to be oil pools (containing oil and associated gas); other pools may be gas pools (containing nonassociated gas and condensate) or mixed-commodity pools. The low, mean, and high estimates of resources in the play are listed in table 7.

NEOGENE FAN SANDSTONE PLAY

PLAY DEFINITION

The Neogene Fan Sandstone play of the Washington-Oregon assessment area is defined to include accumulations of oil and gas in Miocene and Pliocene sandstones deposited in deltaic and fan systems on the shelf and now incorporated in anticlinal, fault, and stratigraphic traps. It is a frontier play because there are indications of hydrocarbons within the play; however, no discoveries have been made. The play extends from Teawhit Head, Washington, to Newport, Oregon, with a separate subarea northwest of Coos Bay, Oregon (fig. 16). It encompasses areas offshore primary Neogene river systems, and covers about 5,000 square miles. It was defined primarily on the basis of reservoir rock stratigraphy.

The Neogene Fan Sandstone play is differentiated from the Neogene Shelf Sandstone play by the expectation of greater abundance of sand and larger grain size due to its more proximal location relative to sediment sourcing. Hydrocarbon accumulations may exist to about 12,000 feet below the seafloor.

Rocks that are probable equivalents to rocks of this play exist onshore and in State waters. These adjacent rocks are included in the Southwest Washington Miocene Sandstone and Astoria plays, which have been described and assessed by the USGS (Johnson and Tennyson, 1995).

PETROLEUM GEOLOGIC CHARACTERISTICS

Likely hydrocarbon source rocks include Eocene to Oligocene shales analogous to onshore strata in the Coos Bay area of south-coastal Oregon and Miocene and older melange, which underlies all other units throughout the area. Neogene shale interbeds are also considered possible source rocks by analogy with the Eel River basin. The melange is a less likely source for the eastern part of the areas off Oregon because a sequence of volcanic units separates it from the reservoir rocks of this play. Thicknesses of these rocks are unknown, but onshore rocks that may be equivalent are several thousand feet thick (Snavely and Wells, 1984; Snavely and others, 1980). North of Grays Harbor and along the western edge of the area offshore Coos Bay, Neogene rocks directly overlie melange. Geothermal gradients (Snavely, 1987; Palmer and Lingley, 1989) suggest that source rocks are likely to be mature for oil generation at burial depths greater than about 10,000 to 12,000 feet. Onshore data indicate that the Paleogene sedimentary rocks are gas prone (Brown and Ruth Laboratories, 1982; Niem and Niem, 1990); therefore, they are considered primarily a source of nonassociated gas regardless of burial depth. The melange is considered to be equivalent to rocks exposed onshore in the Olympic Mountains and south of the Eel River basin. Seeps at both locations and past production from melange near Grays Harbor and south of the Eel River basin suggest that the melange is primarily a source of high-gravity oil (Palmer and Lingley, 1989; Vander Leck, 1921; MacGinitie, 1943; California Division of Oil and Gas, 1960; 1982).

Potential reservoirs are expected to be of excellent to good quality. They consist of sandstones and siltstones deposited in shelf, slope, and submarine fan settings. The primary difference between this play and the Neogene Shelf Sandstone play is that within this play there is a greater likelihood of channel and thick fan deposits, so potential reservoir sandstones are likely to be thicker and coarser grained.

Potential traps include anticlinal folds, faults, and stratigraphic pinchouts. Offshore Washington and, to a lesser extent, offshore central Oregon, shale diapirs may provide both a source conduit and a trapping mechanism. The diapirs are sometimes associated with growth faults; but because they also occur alone, they are included among traps of the other Neogene plays. There is also a possibility of subthrust traps.

EXPLORATION

Exploratory wells at six sites have penetrated rocks of this play (fig. 16). Gas shows were reported in the Neogene section in two wells; gas in Paleogene rocks was reported in one of these. There is some indication of gas in Neogene rocks in a third well. Oil shows were reported in the Neogene section in one well and in the Paleogene section in two others.

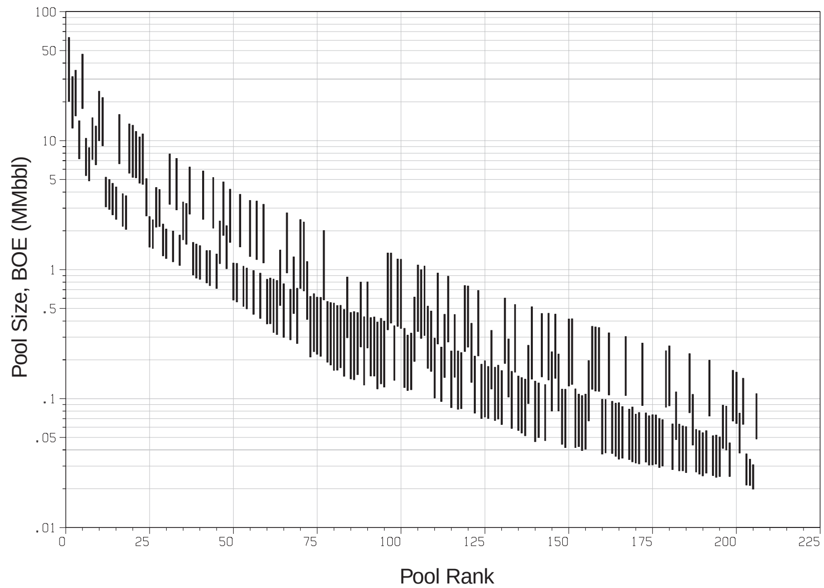


Figure 22. *Pool-size rank plot of estimated undiscovered conventionally recoverable resources of the Neogene Fan Sandstone play, Washington-Oregon assessment area. Sizes of undiscovered pools are shown by bars; the top and bottom of a bar represent the 25th- and 75th-percentile values of a probability distribution, respectively.*

RESOURCE ESTIMATES

Undiscovered Conventionally Recoverable Resources

Estimates of undiscovered conventionally recoverable resources in the play have been developed using the subjective assessment method. Select data used to develop the resource estimates are shown in appendix C.

The play was modeled as a mixed-commodity (oil with associated gas, and nonassociated gas with condensate) play on the basis of hydrocarbon shows and expected source rocks. Potential pools in the northern half of the northern subarea of the play are considered most likely to be oil pools because the melange is the primary source. In the southern half of the northern subarea and in the southern subarea, the pools are considered most likely to contain nonassociated gas sourced from the Paleogene section. Because of the low temperature gradient, oil generation is expected only where source rocks are present at burial depths greater than 10,000 feet. This is not a limiting factor for the melange source; however, it severely limits oil sourcing from the Paleogene section. Oil was modeled as a component of 45 percent of the expected pools; nonassociated gas was modeled as a component of 75 percent of the pools. Eel River basin prospect size and densities were used as analogs because structural style is similar; distributions of these variables were adjusted to account for the larger play area. Reservoir parameters were derived using data from analogous fields in California.

As a result of this assessment, the play is estimated to contain 98 MMbbl of oil (including oil and condensate) and 882 Bcf of gas (including associated and nonassociated gas) (mean estimates). This volume of undiscovered conventionally recoverable resources may exist in as many as 206 pools with sizes ranging from approximately 20 Mbbl to 65 MMbbl of combined-oil equivalent resources (fig. 22). The majority of pools are expected to be gas pools (containing nonassociated gas and condensate); other pools may be oil pools (containing oil and associated gas) or mixed-commodity pools. The low, mean, and high estimates of resources in the play are listed in table 7.

NEOGENE SHELF SANDSTONE PLAY

PLAY DEFINITION

The Neogene Shelf Sandstone play of the Washington-Oregon assessment area is defined to include accumulations of oil and gas in Miocene and Pliocene sandstones deposited in deltaic and fan systems on the shelf and upper slope and now incorporated in anticlinal, fault, and stratigraphic traps. It is a conceptual play because no hydrocarbons have been identified within rocks of this play. The play extends from Cape Flattery, Washington, to south of Cape Blanco, Oregon; it extends over the shelf (exclusive of the area of the Neogene Fan Sandstone play) and encompasses about 13,000 square miles (fig. 16). It was defined primarily on the basis of reservoir rock stratigraphy.

The Neogene Shelf Sandstone play is differentiated from the Neogene Fan Sandstone play by the expectation of lesser thicknesses of sand layers and smaller grain size due to its more distal location relative to sediment sourcing. Hydrocarbon accumulations may occur from about 2,000 feet to about 12,000 feet below the seafloor.

PETROLEUM GEOLOGIC CHARACTERISTICS

Likely hydrocarbon source rocks include Eocene to Oligocene shales analogous to onshore strata in the Coos Bay area of south-coastal Oregon and Miocene and older melange, which underlies all other units throughout the area (fig. 17). Neogene shale interbeds are considered possible source rocks by analogy with the Eel River basin. The melange is a less likely source for most of the area south of Grays Harbor, Washington, because a sequence of volcanic units separates it from the reservoir rocks of this play. Thicknesses of these rocks are unknown, but onshore rocks that may be equivalent are several thousand feet thick (Snavely and Wells, 1984; Snavely and others, 1980). Offshore most of Washington and along the western margin of the play, Neogene rocks directly overlie melange. Geothermal gradients (Snavely, 1987; Palmer and Lingley, 1989) suggest that source rocks are likely to be mature for oil generation at burial depths greater than about 10,000 to 12,000 feet. Onshore data indicate that the Paleogene sedimentary rocks are gas prone (Brown and Ruth Laboratories, 1982; Niem and Niem, 1990); therefore, they are considered primarily a source of nonassociated gas regardless of burial depth. The melange is considered to be equivalent to rocks exposed onshore in the Olympic Mountains and south of the Eel River basin. Seeps at both locations and past production from melange near Grays Harbor and south of the Eel River basin suggest that the melange is primarily an oil source (Palmer and Lingley, 1989; Vander Leck, 1921; MacGinitie, 1943; California Division of Oil and Gas, 1960; 1982).

Potential reservoirs are expected to be of good to fair quality. They consist of siltstones and sandstones deposited in shelf, slope, and submarine fan settings. The primary difference from the Neogene Fan Sandstone play is that potential reservoir rock section in this play is likely to be much thinner and finer grained because of its relatively distal location.

Potential traps include anticlinal folds, faults, and stratigraphic pinchouts. Offshore Washington and, to a lesser extent, offshore central Oregon, shale diapirs may provide both a source conduit and a trapping mechanism. The diapirs are sometimes associated with growth faults, but because they also exist alone, they are included among traps of the other Neogene plays. There is also a possibility of subthrust traps.

EXPLORATION

Exploratory wells at four sites have penetrated rocks of this play (fig. 16). No hydrocarbon shows were reported in the Neogene section in these wells; however, gas shows were reported in the Paleogene section in three wells and an oil show was reported in one of those at about 11,000 feet measured depth.

RESOURCE ESTIMATES

Undiscovered Conventionally Recoverable Resources

Estimates of undiscovered conventionally recoverable resources in the play have been developed using the subjective assessment method. Select data used to develop the resource estimates are shown in appendix C.

The play was modeled as a mixed-commodity (oil with associated gas, and nonassociated gas with condensate) play on the basis of hydrocarbon shows and expected source rocks. Potential pools in the western part of the play and in the part north of Grays Harbor are considered most likely to be high-gravity oil because the melange is the primary source. In the eastern part of the area south of Grays Harbor, nonassociated gas sourced from the Paleogene section is more likely to exist. Because of the low temperature gradient, oil generation is expected only where source rocks are present at burial depths

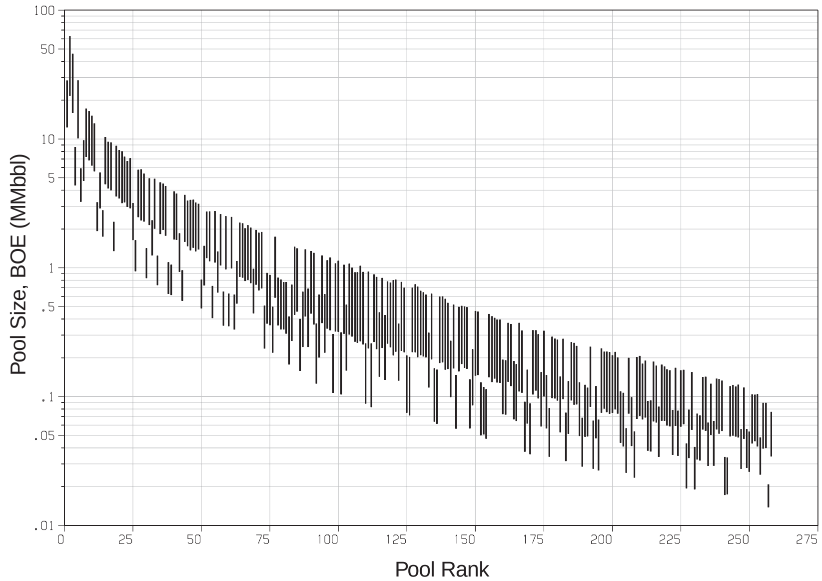


Figure 23. *Pool-size rank plot of estimated undiscovered conventionally recoverable resources of the Neogene Shelf Sandstone play, Washington-Oregon assessment area. Sizes of undiscovered pools are shown by bars; the top and bottom of a bar represent the 25th- and 75th-percentile values of a probability distribution, respectively.*

greater than 10,000 feet. This is not a limiting factor for the melange source; however, it severely limits oil sourcing from the Paleogene section. Oil was modeled as a component of 80 percent of the expected pools; nonassociated gas was modeled as a component of 40 percent of the pools. Eel River basin prospect sizes and densities were used as ana-logs, because structural style is similar; distributions of these variables were adjusted to account for the larger play area. Reservoir parameters were derived using data from analogous fields in California.

As a result of this assessment, the play is estimated to contain 138 MMbbl of oil (including oil and condensate) and 596 Bcf of gas (including associated and nonassociated gas) (mean estimates). This volume of undiscovered conventionally recoverable resources may exist in as many as 258 pools with sizes ranging from approximately 15 Mbbl to 65 MMbbl of combined oil-equivalent resources (fig. 23). The majority of pools are expected to be oil pools (containing oil and associated gas); other pools may be gas pools (containing nonassociated gas and condensate) or mixed-commodity pools. The low, mean, and high estimates of resources in the play are listed in table 7.

PALEOGENE SANDSTONE PLAY

PLAY DEFINITION

The Paleogene Sandstone play of the Washington-Oregon assessment area is defined to include accumulations of oil and gas in Eocene and Oligocene sandstones. It is a frontier play because indications of hydrocarbons have been reported; however, no discoveries have been made. The play extends from Grays Harbor, Washington, to Coos Bay, Oregon; it encompasses the eastern part of the area, about 4,000 square miles (fig. 16). It was defined primarily on the basis of reservoir rock stratigraphy and includes Eocene and Oligocene sandstones deposited on the shelf and now incorporated in anticlinal, fault, and stratigraphic traps. These traps are expected to occur at about 2,000 to 20,000 feet burial depth.

Rocks that are possible equivalents to rocks of this play exist onshore and in State waters. These adjacent rocks are included in the Southwest Oregon Eocene Gas play, which has been described and assessed by the USGS (Johnson and Tennyson, 1995).

PETROLEUM GEOLOGIC CHARACTERISTICS

Source rocks include Eocene to Oligocene shales analogous to onshore strata in the Coos Bay area of south-coastal Oregon. Geothermal gradients (Snavely, 1987; Palmer and Lingley, 1989) suggest that source rocks are likely to be mature for oil generation at burial depths greater than 10,000 to 12,000 feet, although onshore data indicate that the rocks are primarily a source of nonassociated gas (Brown and Ruth Laboratories, 1982; Niem and Niem, 1990). The Paleogene sedimentary section attains depths of over 20,000 feet offshore central Oregon; however, diagenetic alteration and cementation are likely for arc-derived sediments at burial depths greater than about 15,000 feet (Galloway, 1979). On the western margin of the play area, there is the possibility for oil sourcing from the underlying melange.

Potential reservoirs are expected to be of poor to good quality. They consist of Eocene to Oligocene siltstones and sandstones deposited in shelf, slope, and submarine fan settings, and interbedded with the shales and mudstones.

Potential traps include anticlinal folds, faults, and stratigraphic pinchouts. There is also a possibility of subthrust traps. Trap seals may be provided by mudstones and shales; volcanic flows and sills, which are abundant within this section, may also provide seals.

EXPLORATION

Exploratory wells at eight sites have penetrated rocks presumed to be within this play (fig. 16); of these, five wells penetrated significant (greater than 3,000 feet) Paleogene section. Gas shows were reported in the Paleogene section in three wells; an oil show was reported in one well at about 11,000 feet measured depth.

RESOURCE ESTIMATES

Undiscovered Conventionally Recoverable Resources

Estimates of undiscovered conventionally recoverable resources in the play have been developed using the subjective assessment method. Select data used to develop the resource estimates are shown in appendix C.

The play was modeled as a mixed-commodity (oil with associated gas, and nonassociated gas with condensate) play; however, it is a primarily nonassociated gas play on the basis of hydrocarbon shows and expected source rocks. Because of the low temperature gradient, oil generation is expected only where depth to the base of Paleogene strata is greater than 10,000 feet. Oil may also be present on the western margin of the play where sourcing from the underlying melange is more likely. In light of this possibility, oil (with associated gas) was modeled as a component of about 10 percent of the

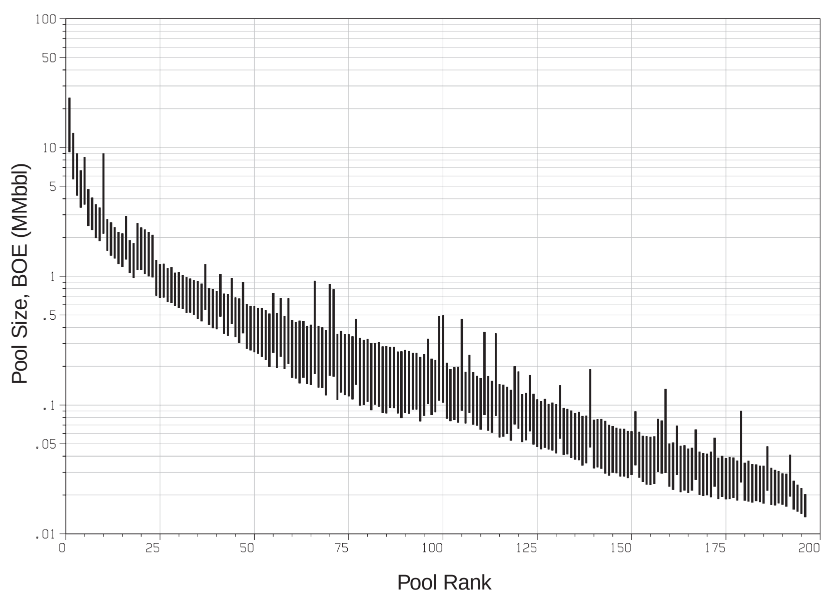


Figure 24. *Pool-size rank plot of estimated undiscovered conventionally recoverable resources of the Paleogene Sandstone play, Washington-Oregon assessment area. Sizes of undiscovered pools are shown by bars; the top and bottom of a bar represent the 25th- and 75th-percentile values of a probability distribution, respectively.*

expected pools. Eel River basin prospect sizes and densities were used as analogs, because structural style is similar; the distributions of these variables were adjusted to account for the larger play area. Reservoir parameters were derived using data from analogous fields in California.

As a result of this assessment, the play is estimated to contain 9 MMbbl of oil (including oil and condensate) and 372 Bcf of gas (including associated and nonassociated gas) (mean estimates). This volume of undiscovered conventionally recoverable resources may exist in as many as 196 pools with sizes ranging from approximately 15 Mbbl to 25 MMbbl of combined oil-equivalent resources (fig. 24). The majority of pools are expected to be gas pools (containing nonassociated gas and condensate); other pools may be oil pools (containing oil and associated gas) or mixed-commodity pools. The low, mean, and high estimates of resources in the play are listed in table 7.

Melange Play

Play Definition

The Melange play of the Washington-Oregon assessment area is defined to include accumulations of primarily oil and associated gas in discrete sandstone bodies within Eocene to Miocene rocks, which are subjacent to the mappable sedimentary section. Its extent is areawide, from Cape Flattery, Washington, to south of Cape Blanco, Oregon; it encompasses about 18,000 square miles (fig. 16). The upper part of this section, to the depth penetrated by exploratory wells, is considered to be primarily olistostrome and turbidite deposition on or near the continental slope. Below this is expected a tectonic melange resulting from shearing within the subduction complex. The boundary between these can not be determined from the seismic-reflection data. Hydrocarbons may exist in fractures within the tectonically sheared shale matrix as well as in sandstone lenses, which were the basis for trap modeling. In either case, individual hydrocarbon accumulations are expected to be small because of the sheared and discontinuous nature of rock units observed in melanges of this type.

Rocks that are lithologically and genetically equivalent to rocks of this play are exposed onshore in the western Olympic Mountains and exist elsewhere onshore and in State waters in the subsurface. These adjacent rocks are included in the Western Washington Melange play, which has been described and assessed by the USGS (Johnson and Tennyson, 1995).

Petroleum Geologic Characteristics

The melange is expected to be both source and reservoir for this play. Seeps in the onshore area on the Olympic Peninsula and south of Eel River basin suggest it is a source at least locally. Reservoirs are expected to be relatively small, discontinuous sandstone lenses incorporated into a matrix of shale and mudstone from which they are sourced. The small pool sizes indicated by the discovery history are probably typical and are consistent with that model. There is no way to identify or predict the locations of larger sand bodies given the lack of seismic signature, and there is no expectation for future advances in technology to increase this likelihood.

Exploration

Three offshore exploratory wells penetrated rocks of this play. Oil shows were encountered within the melange section in two of the three wells, and gas shows were encountered in one of those two. Petroliferous mudstones of Eocene to Miocene turbidite and melange sequences on the Olympic Peninsula, Washington (Palmer and Lingley, 1989), and Tertiary rocks of the Coastal Belt of the Franciscan Complex south of the Eel River basin are considered to be equivalent to rocks within this play. Past production of oil occurred in the Ocean City field near Grays Harbor, Washington (Palmer and Lingley, 1989), and in the Petrolia area south of the Eel River basin (Stalder, 1914; Harmon, 1914; Vander Leck, 1921; MacGinitie, 1943; California Division of Oil and Gas, 1960; 1982). The only field designated in the Petrolia area (Petrolia field) was only a few hundred barrels, and the Ocean City field produced about 12 Mbbl.

Resource Assessment

This play was not quantitatively assessed, although it is considered to be an important source of oil for the other plays in the area. It is a frontier play because there is evidence of hydrocarbon generation; however, the likelihood that accumulations of producible size exist is considered too low for this to be considered a viable play.

EEL RIVER BASIN

by Kenneth A. Piper

LOCATION

The Eel River basin is the southern subarea of the Pacific Northwest province (fig. 13). It extends from "Retirement ridge" (an informally named structural high) offshore of Gold Beach, Oregon, to Cape Mendocino, California. The basin is about 125 miles long and 30 miles wide and extends onshore about 25 miles in the vicinity of Eureka, California (fig. 25).

The Eel River Basin assessment area comprises only the Federal offshore portion of the basin (i.e., seaward of the 3-mile line) and encompasses about 3,200 square miles. Water depth in the assessment area ranges from about 200 feet at the 3-mile line to about 4,000 feet locally along the western limit of the basin.

GEOLOGIC SETTING

Tertiary sedimentary units throughout the Eel River basin are most likely underlain by a subduction melange (fig. 26). In the eastern offshore part of the basin, these rocks are apparently continuous

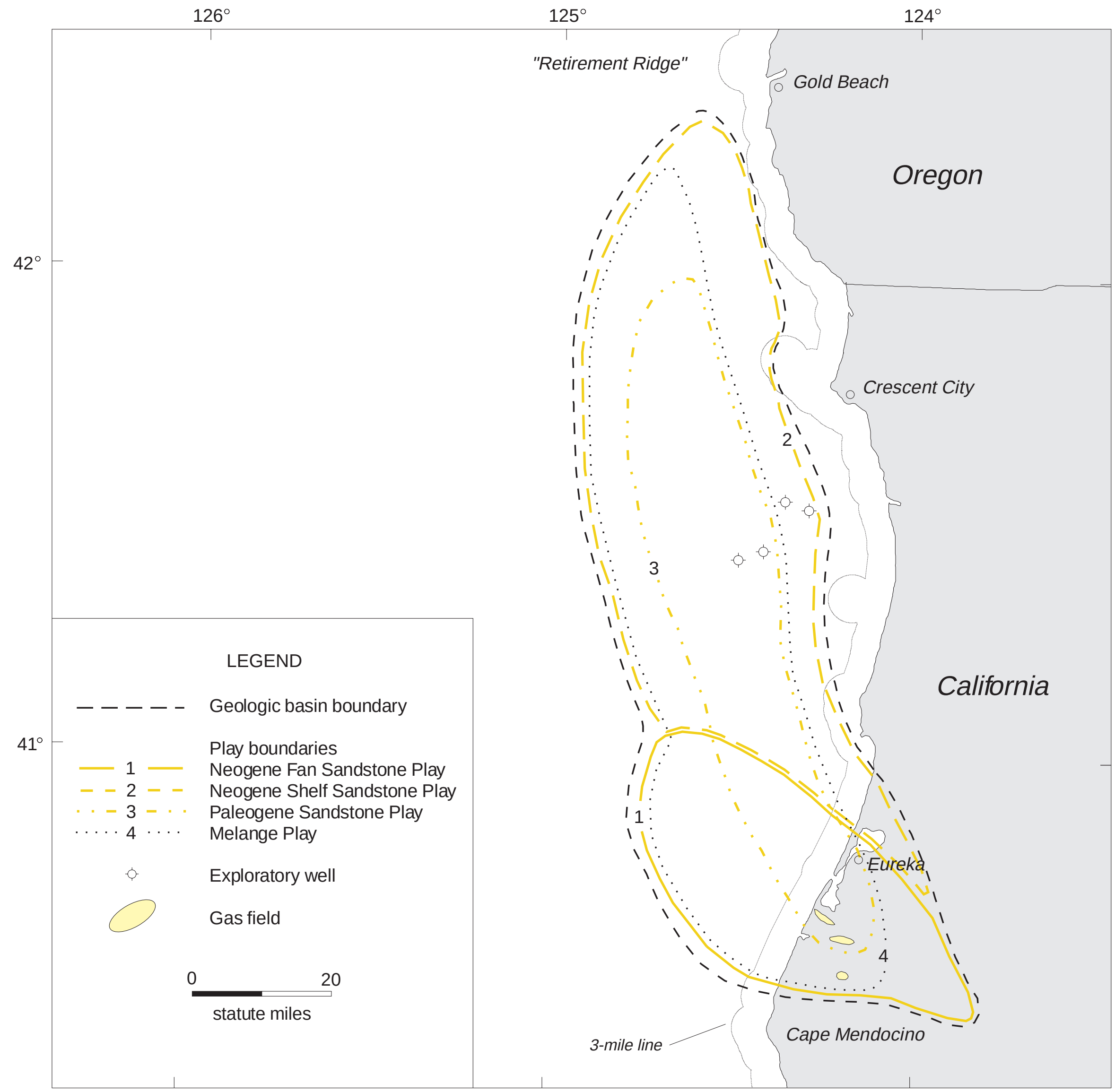
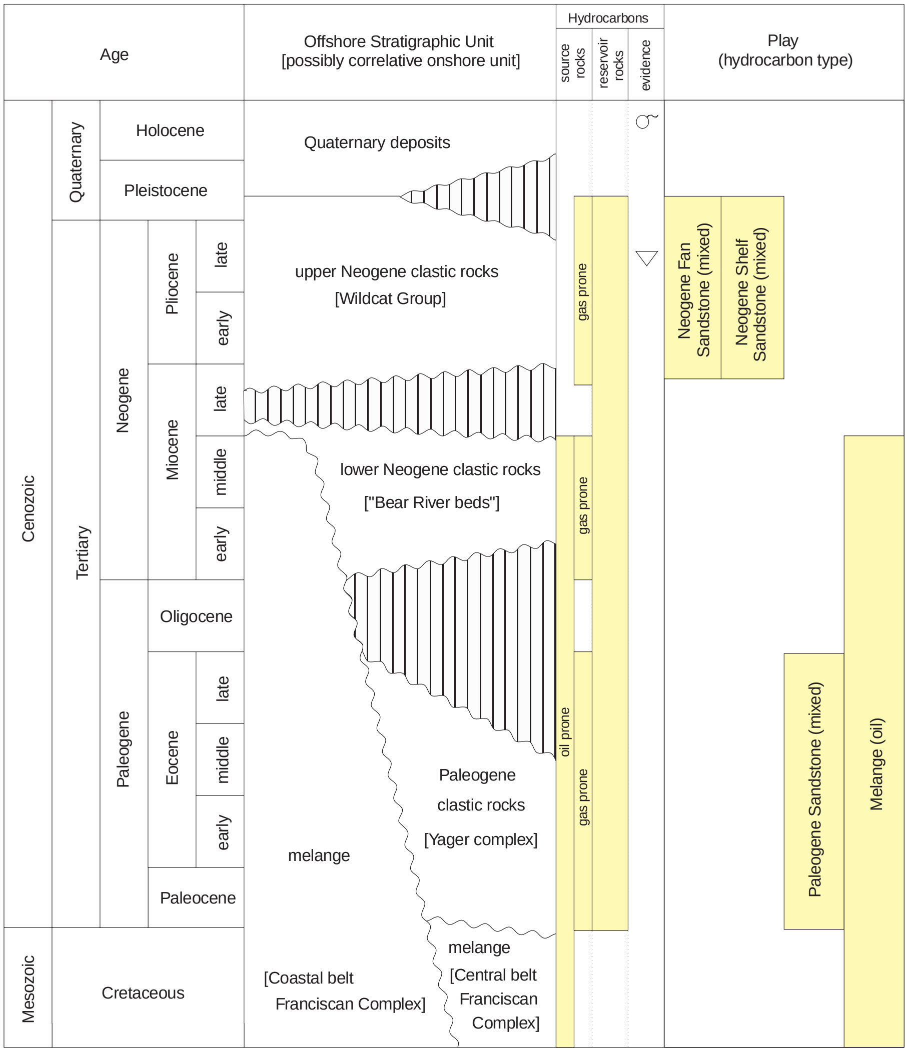


Figure 25. *Map of the Eel River Basin assessment area showing petroleum geologic plays, wells, and fields.*



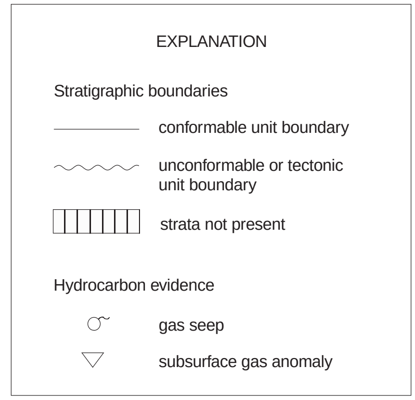


Figure 26. *Stratigraphic column of the Eel River Basin assessment area showing stratigraphic units, hydrocarbon attributes, and petroleum geologic plays defined for this assessment.*

with onshore rocks of the Jurassic to Cretaceous Eastern and Central belts of the Franciscan Complex (equivalent to Dothan Formation and related rocks in Oregon (Jayko and Blake, 1987)) as described by Clarke (1992). The melange under the western part of the basin is probably continuous with the mostly Tertiary Coastal belt of the Franciscan Complex. The latter unit, along with the overlying Yager complex, is thrust under the older Central belt rocks along an east-dipping blind reverse fault, which is the probable offshore extension of the Freshwater fault of Ogle (1953). Onshore exposures of this fault have also been called the “Coastal Belt thrust” by Jones and others (1978) and Aalto and others (1995), and the “Eel River fault” by Bachman and others (1984). As described by Underwood (1985), the Yager “structural complex” (a member of the Coastal belt Franciscan as defined by the USGS) includes turbidite sequences of shelf to slope depositional environments and lacks the pervasive stratal disruption and “exotic” blocks that are found in subduction complexes. It probably represents trench-slope and slope-basin sediments deposited atop the accreted units of the Coastal belt Franciscan (Bachman and others, 1984). If so, it may be genetically equivalent to the upper, depositional part of the melange in the Washington-Oregon assessment area. The Yager complex is overlain by Neogene and Quaternary clastic strata, which attain a thickness of over 12,000 feet in the offshore part of the basin. Along the western margin of the basin, Neogene strata may directly overlie the Coastal belt.

Fault and fold trends range from predominantly west-northwest onshore and in the southern offshore part of the basin to north-northwest in the northern part of the basin. Shale diapirs are common, especially in the southern part of the basin, and are often associated with faulting.

The spatial relationship between the older Eastern and Central belts of the Franciscan Complex and the younger Coastal belt suggests that Mesozoic subduction occurred east of the present trench and that in the early Tertiary the locus of subduction migrated westward. This pattern is similar to the middle to late Tertiary migration of subduction described for the Washington-Oregon assessment area. The basin may at present be undergoing a change from a forearc to a strike-slip basin (Bachman and Crouch, 1987; Crouch and Bachman, 1987).

EXPLORATION AND DISCOVERY STATUS

Four exploratory wells were drilled in the central part of offshore Eel River basin in the 1960's. All were drilled on a structural high of Franciscan Complex rocks; only two wells penetrated significant Tertiary section before bottoming in the Franciscan rocks. The only indication of hydrocarbons encountered in the offshore wells was veins of gilsonite (an asphalt) in a core from the bottom of well OCS-P 0019 #1 (Zieglar and Cassell, 1978). However, gas has been recovered from a sample of unconsolidated sediment (Field and others, 1980), and abundant gas seeps have been mapped in the southern part of the offshore basin (Fairfield Industries, Inc., 1980; Kvenvolden and others, 1980; Kvenvolden and Field, 1981; Field and Kvenvolden, 1987).

Nonassociated gas has been produced from Neogene strata in three onshore gas fields. Tompkins Hill gas field was discovered in 1937 and production is ongoing. Most production is from fan-channel sands within the Rio Dell Formation (Crouch, Bachman, and Associates, Inc., 1988a). Ultimate production is expected to be about 120 Bcf of gas (Parker, 1987; California Division of Oil, Gas, and Geothermal Resources, 1995). Table Bluff field was discovered in 1960 and may contain as much as 8.5 Bcf of gas (Stanley, 1995a); however, the field was abandoned in 1968 after producing only 109 MMcf of gas (California Division of Oil, Gas, and Geothermal Resources, 1995). Grizzly Bluff field was discovered in 1964 (California Division of Oil and Gas, 1969) and may contain 2 to 3 Bcf of gas (Stanley, 1995a); however, no commercial production was ever established.

Onshore, south of the Eel River basin, the Petrolia field produced about 350 barrels of high-gravity (46 °API) oil from 1953 to 1954 (California Division of Oil and Gas, 1960; 1982). Abundant oil seeps exist, and minor amounts of high-gravity oil have been produced since the 1860's from wells drilled elsewhere in Coastal belt Franciscan and associated Tertiary rocks south of Eel River basin. In the same area, a well produced small amounts of gas for more than 40 years in the early part of the century from Yager or associated Neogene strata (Stalder, 1914; Harmon, 1914; Vander Leck, 1921; MacGinitie, 1943; Ogle, 1953).

The offshore geology has been extrapolated from the offshore well data and onshore geologic information and interpreted using a moderate to dense grid of seismic-reflection data. Prospect mapping in preparation for Lease Sale 53 (later limited to Santa Maria basin) and Lease Sale 91 (canceled) is the basis for parameters relating to prospects in plays of this basin and for analogous plays in the Washington-Oregon assessment area.

PLAYS

For this assessment, four petroleum geologic plays were defined, based on reservoir rock stratigraphy and source characteristics (figs. 25 and 26). Two Neogene Sandstone plays, a Paleogene Sandstone play, and a Melange play were so defined. The plays are described following this assessment area summary. Rocks in the onshore portions of the Neogene Sandstone plays are equivalent to rocks that are included in the Eel River Gas play of the Northern Coastal province, which was assessed by the USGS (Stanley, 1995a). Rocks in the onshore and State offshore portions of the Paleogene Sandstone and Melange plays are equivalent to rocks that are a part of the Franciscan Oil and Gas play of the Northern Coastal province, which was described but not quantitatively assessed by the USGS (Stanley, 1995a).

RESOURCE ESTIMATES

Undiscovered Conventionally Recoverable Resources

Play-specific estimates of undiscovered conventionally recoverable resources have been developed using the subjective assessment method, and these estimates have been statistically aggregated to estimate the total volume of resources in the assessment area. Select data used to develop the resource estimates are shown in appendix C.

As a result of this assessment, the total volume of undiscovered conventionally recoverable resources in the Eel River Basin assessment area is estimated to be 55 MMbbl of oil (including oil and condensate) and 1.61 Tcf of gas (including associated and nonassociated gas) (mean estimates). This volume may exist in 156 fields with sizes ranging from approximately 10 Mbbl to 50 MMbbl of combined oil-equivalent resources (fig. 27). The low, mean, and high estimates of resources in the area are listed in table 9 and illustrated in figure 28.

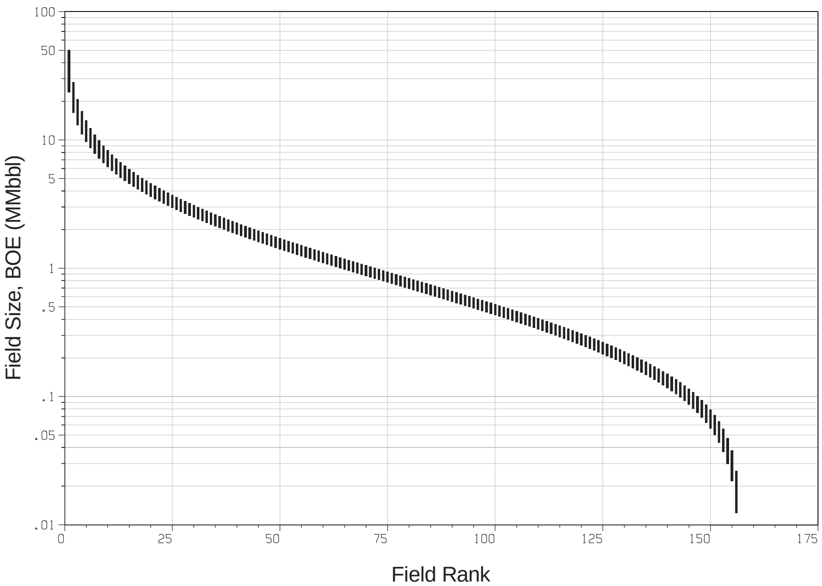


Figure 27. *Field-size rank plot of estimated undiscovered conventionally recoverable resources of the Eel River Basin assessment area. Sizes of undiscovered fields are shown by bars; the top and bottom of a bar represent the 25th- and 75th-percentile values of a probability distribution, respectively.*

Table 9. *Estimates of undiscovered conventionally recoverable oil and gas resources in the Eel River Basin assessment area as of January 1, 1995, by play. All estimates are risked values. The low, mean, and high estimates correspond to the 95th-percentile, mean, and 5th-percentile values of a probability distribution, respectively. Percentile values are not additive; some total mean values may not equal the sum of the component values due to independent rounding.*

Play	Oil (MMbbl)			Gas (Bcf)			BOE (MMbbl)		
	Low	Mean	High	Low	Mean	High	Low	Mean	High
Neogene Fan Sandstone	9	17	29	429	639	1,000	90	131	198
Neogene Shelf Sandstone	0	34	52	0	943	1,266	0	202	269
Paleogene Sandstone	0	4	12	0	31	110	0	9	31
Melange					not assessed				
Total Assessment Area	*33*	*55*	*84*	*1,061*	*1,612*	*2,316*	*227*	*342*	*488*

Figure 28. *Cumulative probability plot of estimated undiscovered conventionally recoverable resources of the Eel River Basin assessment area.*

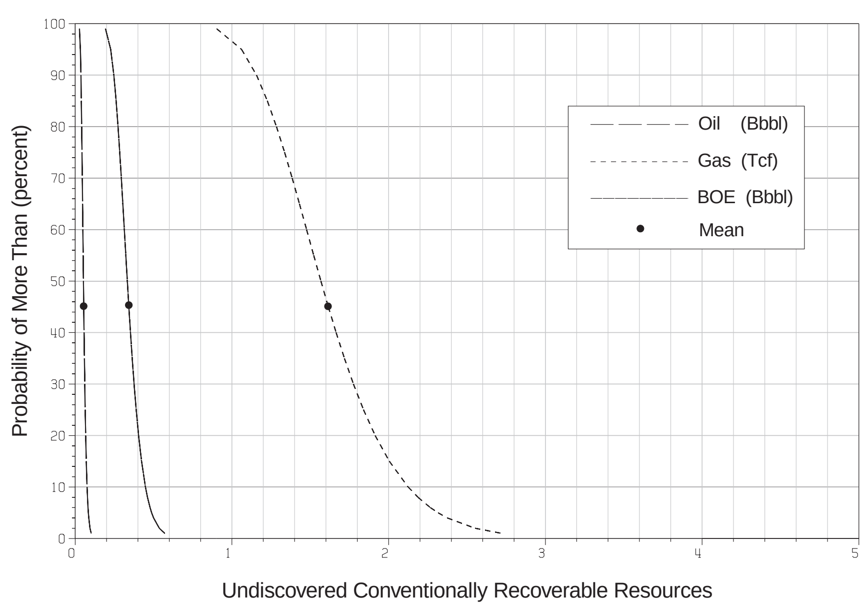


Table 10. *Estimates of undiscovered economically recoverable oil and gas resources in the Eel River Basin assessment area as of January 1, 1995, by economic scenario. All estimates are risked mean values. The $18-per-barrel scenario is based on prices of $18 per bbl of oil and $2.11 per Mcf of gas; the $25-per-barrel scenario is based on prices of $25 per bbl of oil and $2.94 per Mcf of gas; the $50-per-barrel scenario is based on prices of $50 per barrel of oil and $5.87 per Mcf of gas.*

Economic Scenario	Oil (MMbbl)	Gas (Bcf)	BOE (MMbbl)
$18 per barrel	9	280	59
$25 per barrel	13	419	88
$50 per barrel	25	766	162

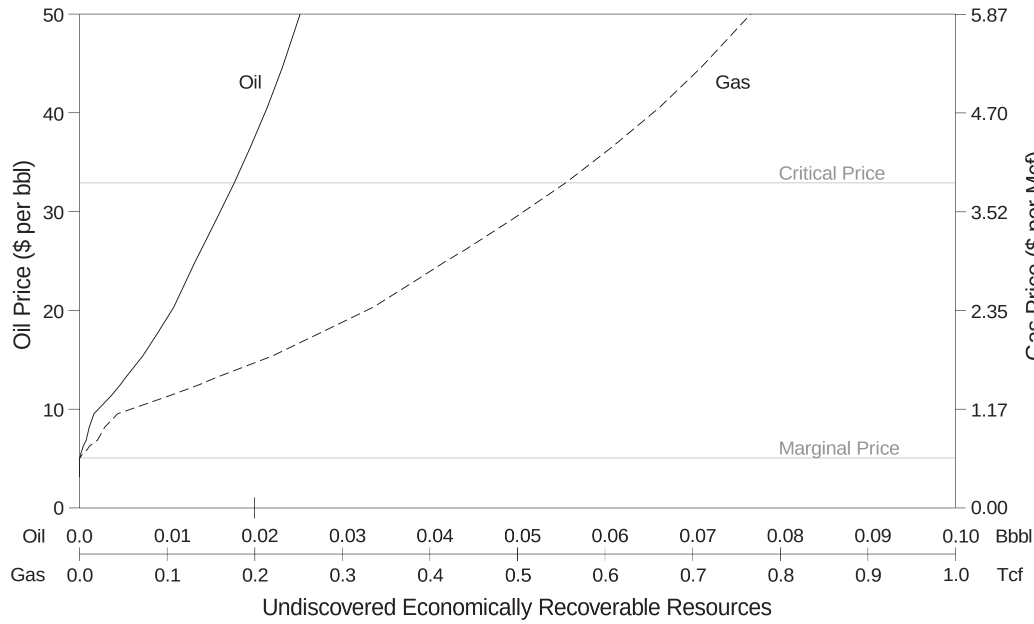


Figure 29. *Price-supply plot of estimated undiscovered economically recoverable resources of the Eel River Basin assessment area.*

Undiscovered Economically Recoverable Resources

Estimates of undiscovered conventionally recoverable resources in the assessment area that may be economically recoverable under various economic scenarios have been developed using the economic assessment method. Select data used to develop the resource estimates are shown in appendix D.

As a result of this assessment, 9 MMbbl of oil (including oil and condensate) and 280 Bcf of gas (including associated and nonassociated gas) are estimated to be economically recoverable from the Eel River Basin assessment area under economic conditions existing as of this assessment (i.e., the $18-per-barrel economic scenario) (table 10). Larger volumes of resources are expected to be economically recoverable under increasingly favorable economic conditions (fig. 29).

Total Resource Endowment

No accumulations of resources have been discovered in the assessment area. Therefore, the aforementioned estimates of undiscovered conventionally recoverable resources compose the estimated total aforeresource endowment of the area.

Acknowledgments

Rick Stanley (U.S. Geological Survey) and Jim Crouch (J.K. Crouch and Associates, Inc.) provided information, insight, and suggestions that improved the quality of this assessment of the Eel River basin. Previous geophysical interpretations by Jim Cummings and Peter Simon of MMS provided the basis for the present study.

Additional References

McLean and Wiley, 1987
Webster and others, 1986
Webster and Yenne, 1987

Neogene Fan Sandstone Play

Play Definition

The Neogene Fan Sandstone play of the Eel River Basin assessment area is defined to include accumulations of oil and gas in Miocene to Pleistocene sandstones deposited in deltaic and fan systems of the ancestral and present Eel River and now incorporated in anticlinal, fault, and stratigraphic traps. It is an established play because it extends onshore where there is ongoing gas production. The play extends northwesterly offshore the Eel River and encompasses the southern one-fifth of the offshore Eel River basin (fig. 25). The Federal offshore part of the play (an area of about 600 square miles) has been assessed. The play is defined primarily on the basis of reservoir rock stratigraphy.

The Neogene Fan Sandstone play is differentiated from the Neogene Shelf Sandstone play by the expectation of a greater abundance of channel sandstones and larger grain size due to its more proximal location relative to sediment sourcing. Hydrocarbon accumulations are expected to occur to about 10,000 feet below the seafloor.

Some of the rocks of this play extend onshore and into State waters. These are included as a part of the Eel River Gas play of the Northern Coastal province, which was assessed by the USGS (Stanley, 1995a).

Petroleum Geologic Characteristics

Potential source rocks include the Cretaceous(?) to Miocene Coastal belt of the Franciscan Complex and Tertiary deltaic and forearc basin strata (fig. 26). Kerogen type of onshore samples suggests the Coastal belt is primarily gas prone (Crouch, Bachman, and Associates, Inc., 1987); however, production from this unit south of the Eel River basin is primarily high-gravity oil (California Division of Oil and Gas, 1960; 1982). Kerogen type and onshore production indicate that the Tertiary strata may be a source of primarily non-associated gas. Thermal gradients (Underwood, 1985; Crouch, Bachman, and Associates, Inc., 1988a) suggest that source rocks are likely to be mature for oil generation at burial depths greater than 7,000 to 12,000 feet; however, the play is considered to be primarily a gas play on the basis of onshore production experience and abundant offshore gas seeps.

Potential reservoirs are expected to be of excellent to good quality. They consist of channel and fan sandstones and siltstones in the Rio Dell, Eel River, and Pullen Formations of the Miocene to Pleistocene Wildcat Group (MacGinitie, 1943; Ogle, 1953; Crouch, Bachman, and Associates, Inc., 1988a). Offshore, this section is up to about 10,000 feet thick, based on geophysical interpretation.

Potential traps include anticlinal folds, faults, and stratigraphic pinchouts. There is also a possibility of subthrust traps. The largest identified prospect offshore is about the size of the onshore Tompkins Hill gas field (1,400 acres).

Exploration

No exploratory wells have been drilled in the Federal offshore part of this play.

Gas measurements in the water column indicate hydrocarbons are present, although some may be of biogenic origin. Onshore, gas has been discovered and produced from three fields: Tompkins Hill (active with estimated ultimate production of 120 Bcf of gas), Table Bluff (abandoned), and Grizzly Bluff (abandoned). Most of the gas has been produced from the Rio Dell Formation; however, gas was tested in the Eel River and Pullen Formations in the Table Bluff field.

Resource Estimates

Undiscovered Conventionally Recoverable Resources

Estimates of undiscovered conventionally recoverable resources in the Federal offshore portion of the play have been developed using the subjective assessment method. Select data used to develop the resource estimates are shown in appendix C.

The play was modeled as primarily gas on the basis of the onshore gas production and offshore gas seeps. Due to the minor oil production from the Coastal belt Franciscan and its position as a possible source rock, oil was modeled as a component of about 20 percent of the expected pools. Play-specific prospect areas and the number of prospects were estimated based on detailed seismic mapping that used a dense (less than 1-mile spacing) grid of data. Reservoir parameters were derived using data from the onshore Tompkins Hill and Table Bluff gas fields and from analogous fields elsewhere in California.

As a result of this assessment, the Federal offshore portion of the play is estimated to contain 17 MMbbl of oil (including oil and condensate) and 639 Bcf of gas (including associated and nonassociated gas) (mean estimates). This volume of undiscovered conventionally recoverable resources may exist in as many as 80 pools with sizes ranging from approximately 30 Mbbl to 40 MMbbl of combined oil-equivalent resources (fig. 30). The majority of pools are expected to be gas pools (containing nonassociated gas and condensate); other pools may be oil pools (containing oil and associated gas) or mixed-commodity pools. The low, mean, and high estimates of resources in the play are listed in table 9.

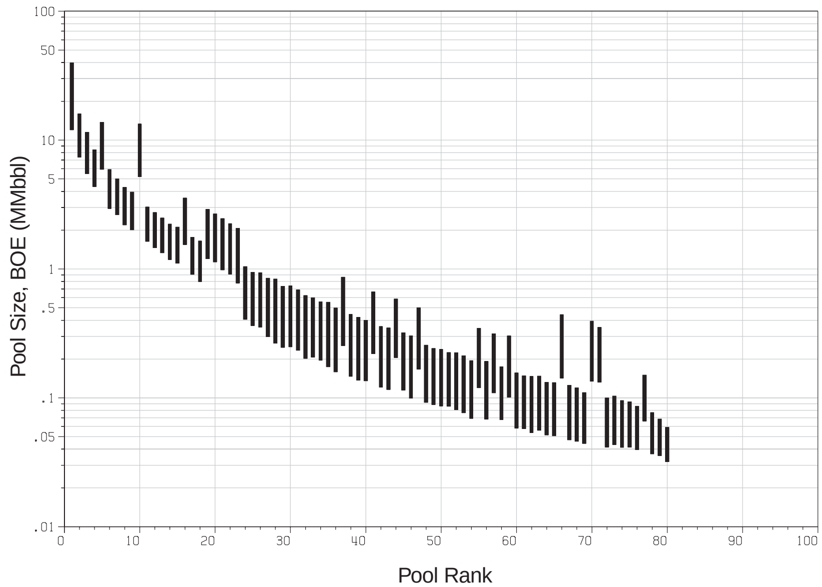


Figure 30. *Pool-size rank plot of estimated undiscovered conventionally recoverable resources of the Neogene Fan Sandstone play, Eel River Basin assessment area. Sizes of undiscovered pools are shown by bars; the top and bottom of a bar represent the 25th- and 75th-percentile values of a probability distribution, respectively.*

NEOGENE SHELF SANDSTONE PLAY

PLAY DEFINITION

The Neogene Shelf Sandstone play of the Eel River Basin assessment area is defined to include accumulations of oil and gas in Neogene sandstones outside the primary area of influence of the ancestral and present Eel River deltaic system. It is a frontier play because no discoveries have been made; however, seismic-reflection profiles and gas seeps strongly suggest the presence of gas accumulations. The play extends northward from the Neogene Fan Sandstone play to encompass the remaining four-fifths of the Eel River Basin assessment area, an area of about 2,600 square miles (fig. 25). It was defined primarily on the basis of reservoir rock stratigraphy. It includes Miocene to Pleistocene sandstones deposited on the shelf and now incorporated in anticlinal, fault, and stratigraphic traps.

The Neogene Shelf Sandstone play is differentiated from the Neogene Fan Sandstone play by the expectation of lesser thicknesses of sand layers and smaller grain size due to its more distal location relative to sediment sourcing. These traps are expected to exist to about 8,000 feet below the seafloor.

Some of the rocks of this play extend onshore and into State waters. These are included as a part of the Eel River Gas play of the Northern Coastal province, which was assessed by the USGS (Stanley, 1995a).

PETROLEUM GEOLOGIC CHARACTERISTICS

Potential source rocks include the Cretaceous(?) to Miocene Coastal belt Franciscan and Tertiary deltaic and forearc basin strata (fig. 26). Kerogen type of onshore samples suggests the Coastal belt is primarily gas prone (Crouch, Bachman, and Associates, Inc., 1987); however, production from this unit south of the Eel River basin is primarily high-gravity oil (California Division of Oil and Gas, 1960; 1982). Kerogen type and onshore production indicate that the Tertiary strata may be a source of primarily nonassociated gas. Thermal gradients (Underwood, 1985; Crouch, Bachman, and Associates, Inc., 1988a) suggest that source rocks are likely to be mature for oil generation at burial depths greater than 7,000 to 12,000 feet; however, the play is considered to be primarily a gas play on the basis of onshore gas production and abundant offshore seeps.

Potential reservoirs are expected to be of good to fair quality. They consist of sandstones and siltstones in rocks correlative with the Rio Dell, Eel River, and Pullen Formations of the Miocene to Pleistocene Wildcat Group. Geophysical interpretation indicates the Neogene section is up to about 8,000 feet thick, based on geophysical interpretation.

Potential traps include anticlinal folds, faults, and stratigraphic pinchouts. There is also a possibility of subthrust traps. Prospect sizes were estimated to be about the same as for the Neogene Fan Sandstone play.

Exploration

In the 1960's, four offshore exploratory wells were drilled in the eastern central part of the play. Only two wells penetrated significant Tertiary section. No hydrocarbon shows were reported within Tertiary section in any of the wells. Gas measurements in the water column in the southern and central parts of the basin indicate hydrocarbons are present, although some may be of biogenic origin.

Resource Estimates

Undiscovered Conventionally Recoverable Resources

Estimates of undiscovered conventionally recoverable resources in the Federal offshore portion of the play have been developed using the subjective assessment method. Select data used to develop the resource estimates are shown in appendix C.

The play was modeled as primarily gas on the basis of the onshore gas production and offshore gas seeps. Due to minor oil production from the Coastal belt Franciscan and its position as a possible source rock, oil was modeled as a component of about 20 percent of expected pools. Based on a moderate grid of seismic data, prospect sizes and densities were estimated to be about the same as for the Neogene Fan Sandstone play. This analogous play was mapped using a denser grid of seismic data; its prospect size and density distributions were adjusted to account for the larger area of the Neogene Shelf Sandstone play. Reservoir parameters were derived using data from the onshore Tompkins Hill and Table Bluff gas fields and from analogous fields elsewhere in California.

As a result of this assessment, the Federal offshore portion of the play is estimated to contain 34 MMbbl of oil (including oil and condensate) and 943 Bcf of gas (including associated and nonassociated gas) (mean estimates). This volume of undiscovered conventionally recoverable resources may exist in as many as 230 pools with sizes ranging from approximately 20 Mbbl to 35 MMbbl of combined oil-equivalent resources (fig. 31). The majority of pools are expected to be gas pools (containing nonassociated gas and condensate); other pools may be oil pools (containing oil and associated gas) or mixed-commodity pools. The low, mean, and high estimates of resources in the play are listed in table 9.

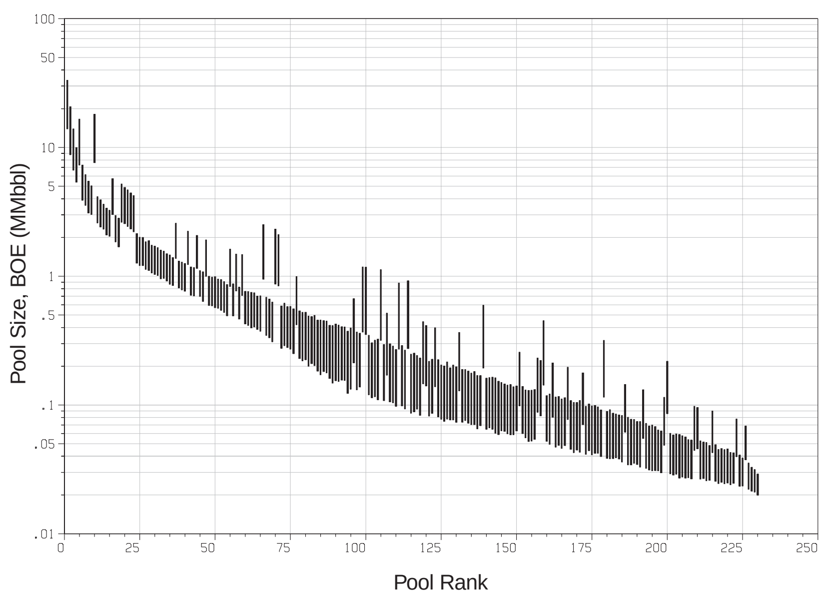


Figure 31. *Pool-size rank plot of estimated undiscovered conventionally recoverable resources of the Neogene Shelf Sandstone play, Eel River Basin assessment area. Sizes of undiscovered pools are shown by bars; the top and bottom of a bar represent the 25th- and 75th-percentile values of a probability distribution, respectively.*

PALEOGENE SANDSTONE PLAY

PLAY DEFINITION

The Paleogene Sandstone play of the Eel River Basin assessment area is defined to include accumulations of oil and gas in Paleogene sandstones. It is a conceptual play because hydrocarbons have not been detected within the play. The play extends northward from Humboldt Bay encompassing the central part of the Eel River basin and an area of about 900 square miles (fig. 25). It was defined primarily on the basis of reservoir rock stratigraphy and includes Paleocene to Eocene sandstones resulting from olistostrome and turbidite deposition on the continental slope and now incorporated in anticlinal, fault, and stratigraphic traps. Rocks of this play may be correlative with the upper part of the Melange play of the Washington-Oregon assessment area. Traps are expected to occur at burial depths of about 3,000 to 8,000 feet.

Some of the rocks of this play extend onshore and into State waters. These are included as a part of the Franciscan Oil and Gas play, which was defined but not quantitatively assessed by the USGS (Stanley, 1995a).

PETROLEUM GEOLOGIC CHARACTERISTICS

Source rocks include the Cretaceous(?) to Miocene Coastal belt Franciscan Complex, including shales of the Paleogene Yager member of the Coastal belt (fig. 26). Kerogen type of onshore samples suggests the Coastal belt is primarily gas prone (Underwood, 1987; Crouch, Bachman, and Associates, Inc., 1987; 1988a); however, production from Coastal belt rocks south of the Eel River basin is primarily high-gravity oil (Vander Leck, 1921; MacGinitie, 1943, California Division of Oil and Gas, 1960; 1982). Thermal gradients (Underwood, 1985; Crouch, Bachman, and Associates, Inc., 1988a) indicate that source rocks are likely to be mature for oil generation at burial depths greater than 7,000 to 12,000 feet; the play is considered to be a mixed-commodity (oil with associated gas, and nonassociated gas with condensate) play on the basis of likely source rocks.

Potential reservoirs are expected to be of fair to poor quality. They consist of sandstones and siltstones of the Yager complex resulting from turbidite and olistostrome deposition in slope and submarine fan settings. At many onshore localities, sandstones

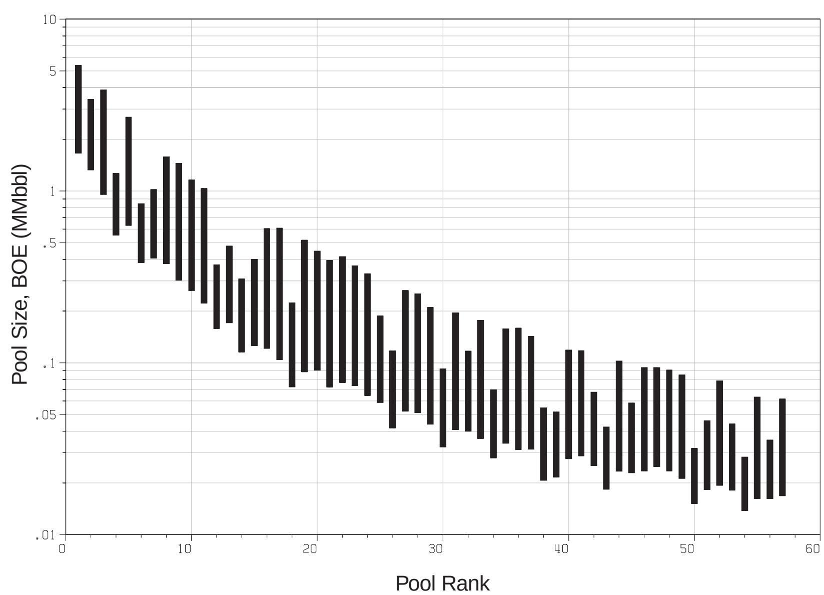


Figure 32. *Pool-size rank plot of estimated undiscovered conventionally recoverable resources of the Paleogene Sandstone play, Eel River Basin assessment area. Sizes of undiscovered pools are shown by bars; the top and bottom of a bar represent the 25th- and 75th-percentile values of a probability distribution, respectively.*

of the Yager are well cemented with laumontite filling pore spaces (Crouch, Bachman, and Associates, Inc., 1988a).

Potential traps include anticlinal folds, faults, and stratigraphic pinchouts. There is also a possibility of subthrust traps.

Exploration

In the 1960's, two exploratory wells (OCS-P 0014 #1 and OCS-P 0019 #1) were drilled in the eastern central part of the play and penetrated Eocene strata. The only indication of hydrocarbons was the presence of gilsonite (asphalt) veins in a core from the bottom of OCS-P 0019 #1 (Zieglar and Cassell, 1978). Onshore, one gas well south of the Eel River basin produced small quantities for more than 40 years in the early part of the century from Yager or associated Neogene strata (Vander Leck, 1921; MacGinitie, 1943). Numerous oil seeps and minor oil production (from the Petrolia field) occurred in Coastal belt rocks south of the Eel River basin.

Resource Estimates

Undiscovered Conventionally Recoverable Resources

Estimates of undiscovered conventionally recoverable resources in the Federal offshore portion of the play have been developed using the subjective assessment method. Select data used to develop the resource estimates are shown in appendix C.

The play was modeled as a mixed-commodity (oil with associated gas, and nonassociated gas with condensate) play on the basis of the expected source rocks. Due to minor oil production from the Coastal belt Franciscan and its position as a possible source rock, the resource potential of this play was weighted toward oil. Gas was modeled as a component of about half of the expected pools. Prospect sizes and densities were estimated to be about the same as for the Neogene Fan Sandstone play. This analogous play was mapped with a denser grid of seismic data; its prospect size and density distributions were adjusted to account for the larger play area of the Paleogene Sandstone play. Reservoir parameters were derived using data from analogous fields elsewhere in California.

As a result of this assessment, the Federal offshore portion of the play is estimated to contain 4 MMbbl of oil (including oil and condensate) and 31 Bcf of gas (including associated and nonassociated gas) (mean estimates). This volume of undiscovered conventionally recoverable resources may exist in as many as 57 pools with sizes ranging from approximately 15 Mbbl to 5 MMbbl of combined oil-equivalent resources (fig. 32). The majority of pools are expected to be oil pools (containing oil and associated gas); other pools may be gas pools (containing nonassociated gas and condensate) or mixed-commodity pools. The low, mean, and high estimates of resources in the play are listed in table 9.

Melange Play

Play Definition

The Melange play of the Eel River Basin assessment area is defined to include accumulations of oil and associated gas in discrete sandstone bodies within Tertiary rocks of the Coastal belt of the Franciscan Complex. These rocks are subjacent to the mappable sedimentary section over most of the play area; along the eastern margin they are thrust under rocks of the Central belt of the Franciscan Complex. The play's extent is basin-wide (west of the contact with the Central belt), from Gold Beach, Oregon, to Cape Mendocino, California; it encompasses about 3,200 square miles (fig. 25). The Yager complex (Paleogene Sandstone play) may be the result of turbidite and olistostrome deposition on or near the continental slope and, as such, would be correlative with the upper part of the Melange play in the Washington-Oregon assessment area. Below the Yager, rocks of the Melange play are a tectonic melange resulting from shearing within the subduction complex. The boundary between the Yager and underlying tectonic melange cannot be clearly established from the seismic-reflection data. Hydrocarbons may exist in fractures within the tectonically sheared shale matrix as well as in sandstone lenses, which were the basis for trap modeling. In either case, individual hydrocarbon accumulations are expected to be small because of the sheared and discontinuous nature of rock units observed in melanges of this type.

Some of the rocks of this play extend onshore and into State waters. These are included as a part of the Franciscan Oil and Gas play, which was defined but not quantitatively assessed by the USGS (Stanley, 1995a).

PETROLEUM GEOLOGIC CHARACTERISTICS

The Coastal belt of the Franciscan Complex is expected to be both source and reservoir for this play. Geochemical analysis shows the Coastal belt to have generally poor generative potential although a few local beds have fair to good potential (Crouch, Bachman, and Associates, Inc., 1987). However, seeps in the onshore area south of Eel River basin suggest it is a source locally. Reservoirs are expected to be relatively small, discontinuous sandstone lenses incorporated into a matrix of shale and mudstone from which they are sourced. The small pool sizes indicated by the discovery history are probably typical and are consistent with that model. There is no way to identify or predict the locations of larger sand bodies, given the lack of seismic signature, and there is no expectation for future advances in technology to increase this likelihood.

EXPLORATION

Two of the four offshore exploratory wells (OCS-P 0014 #1 and OCS-P 0019 #1) in the basin may have penetrated rocks of this play. The only indication of hydrocarbon reported was the presence of gilsonite (asphalt) veins in a core from the bottom of OCS-P 0019 #1 (Zieglar and Cassell, 1978). Rocks of the Coastal belt Franciscan south of the Eel River basin and petroliferous mudstones of Eocene to Miocene turbidite and melange sequences on the Olympic Peninsula, Washington, are considered to be equivalent to rocks of this play and the overlying Paleogene Sandstone play. Seeps exist in equivalent strata south of Eel River basin, and minor production has occurred since about 1860 (Stalder, 1914; Harmon, 1914; Vander Leck, 1921; MacGinitie, 1943). In the 1950's, about 350 bbl of high-gravity (46 °API) oil were produced in the Petrolia field south of the Eel River basin (California Division of Oil and Gas, 1960; 1982). From 1957 to 1962, about 12 Mbbl of high-gravity (38.9 °API) oil and about 6.5 MMcf of gas were produced in the Ocean City field near Grays Harbor, Washington (Braislin and others, 1971; McFarland, 1983; Palmer and Lingley, 1989).

RESOURCE ASSESSMENT

This play was not quantitatively assessed, although it is considered to be an important source of oil for the other plays in the basin. It is a conceptual play because no hydrocarbons have been detected within the play. There is evidence (outside of the Eel River basin) for hydrocarbon generation; however, the likelihood that accumulations of producible size exist is considered too low for this to be considered a viable play.

CENTRAL CALIFORNIA PROVINCE

by Catherine A. Dunkel, Drew Mayerson, and Kenneth A. Piper

Location

The Central California province is located offshore California from the Mendocino fracture zone near Cape Mendocino (on the north) to the "Amberjack high" (a northeast-trending subsurface structural trend) near Point Conception (on the south). This Federal offshore assessment province is bounded on the east by the 3-mile line and on the west by the base of the continental slope (fig. 33).

The province includes five Tertiary basins that lie primarily on the continental shelf: Point Arena, Bodega, Año Nuevo, Partington, and Santa Maria. The Partington and Santa Maria basins have been combined as a single assessment area, due to the interbasinal (continuous) extent of Neogene strata. Two late Tertiary, continental slope basins (Cordell and Santa Lucia) are also encompassed by the province; however, sufficient petroleum geologic data are lacking in these basins and they have not been evaluated in this assessment.

Geologic Setting

The central California continental margin is characterized by a predominant northwest-southeast structural grain that defines the orientation of basin axes, faults, folds, and paleohighs. Offshore and onshore data along the margin suggest that a number of the basins along the modern continental shelf and slope formed in early to middle Tertiary time by extension (Blake and others, 1978), and that by middle Tertiary time, the tectonic style along the margin was predominantly right-lateral translation (transpression to transtension) (McCulloch, 1987b). Most of the basins are bounded on the east by faults associated with the right-lateral San Andreas fault system, although the extent and timing of strike-slip displacement on individual faults are uncertain. The nature of basement rocks and the distribution of Cretaceous and Paleogene strata vary considerably across the province; however, thick sequences of Neogene strata are widely distributed over each of the basins, and these strata compose the bulk of the stratigraphic fill. Although the basins have somewhat similar stratigraphic and structural characteristics, each basin has a distinct history of development, subsidence, deposition, and deformation. A detailed discussion of the geologic framework and evolution of the central California margin is presented by McCulloch (1987b, 1989).

Significance of Siliceous Rocks

Strata in the assessed basins of the Central California province include thick sections of Neogene siliceous rocks, some of which have been identified as or are lithologically and temporally similar to rocks of the Miocene Monterey Formation. The Monterey Formation is an unusual and important rock unit in several well-explored California coastal basins (e.g., Santa Maria and Santa Barbara-Ventura basins) because it contains both source rocks and reservoir rocks for petroleum. Although there is limited direct information regarding Neogene siliceous rocks in the less-explored basins of the Central California province (e.g., Point Arena, Bodega, Año Nuevo, and Partington basins), they are expected to have lithologic characteristics similar to those in the well-explored basins and to be equally significant as a petroleum source and reservoir.

Neogene siliceous rocks in the California coastal basins typically consist of a series of siliceous facies that record the progressive diagenesis[5] of silica. The facies include (1) opal-A (biogenic opaline silica with amorphous crystalline structure), (2) opal-CT (diagenetic opaline silica with cristobalite-tridymite crystalline structure), and (3) diagenetic quartz. The diagenesis of opal-A to opal-CT and of opal-CT to quartz is accompanied by a successive reduction of matrix porosity and an increase in the density of the rock. Sufficient density contrasts across these silica diagenetic boundaries may be marked by prominent reflecting horizons on seismic-reflection profiles and/or increased density measurements on well logs. The dense and brittle rocks containing diagenetic silica (opal-CT and quartz) are susceptible to fracturing and may have secondary porosity in the form of fractures along which petroleum may migrate and accumulate. Recognition of the stratigraphic position of the diagenetic boundaries may, therefore, provide a means to predict the characteristics and relative prospectiveness of reservoir rocks.

Studies of the organic geochemistry and thermal maturity of Monterey Formation rocks in the Santa Maria and Santa Barbara-Ventura basins indicate

[5] Diagenesis is the alteration of sediment after its initial deposition by processes (e.g., compaction, cementation, and mineralogic replacement) that occur under conditions of pressure and temperature.

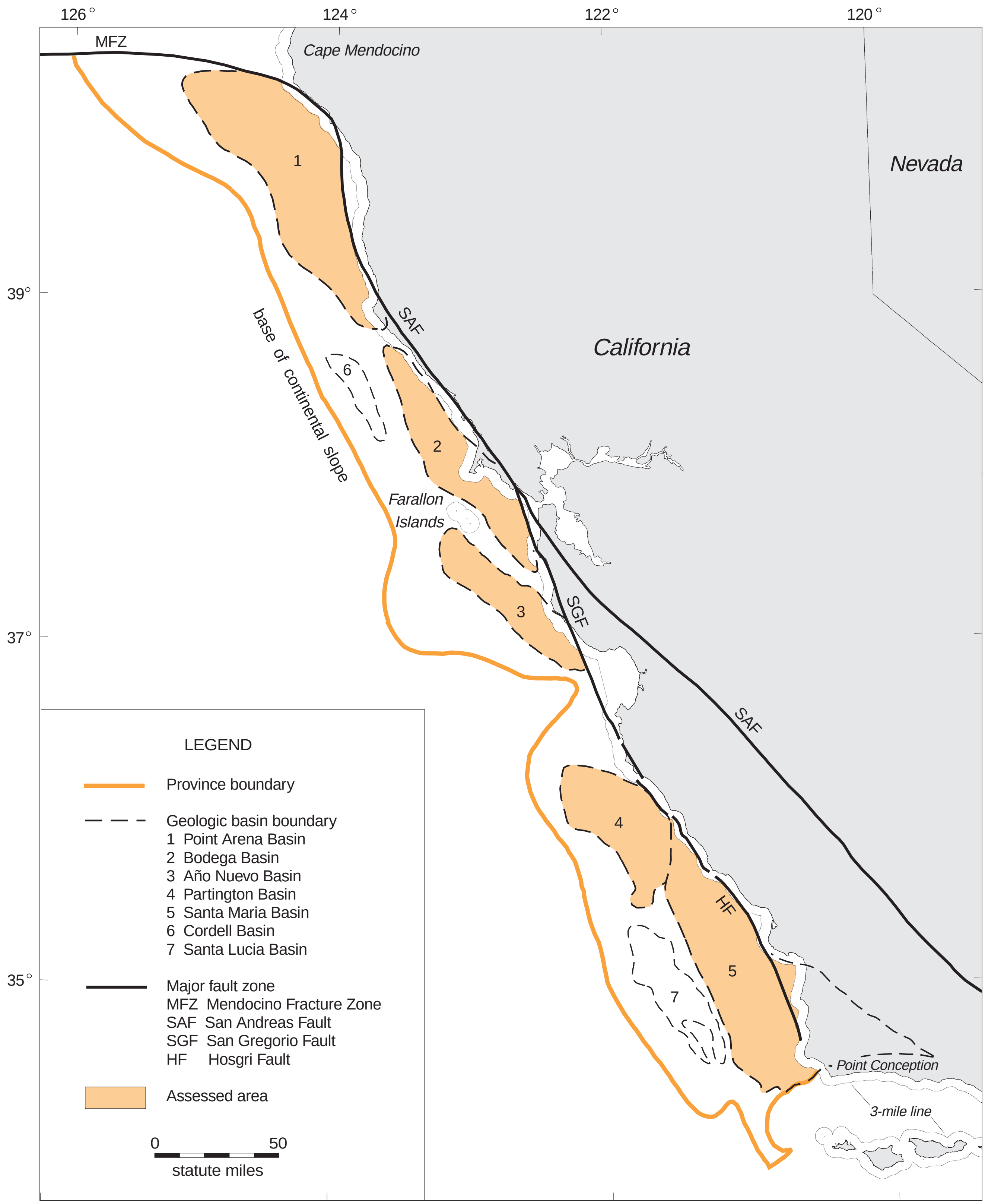


Figure 33. *Map of the Central California province showing geologic basins and assessed areas.*

that petroleum generation has occurred at low levels of organic metamorphism (Isaacs and Petersen, 1987; Petersen and Hickey, 1987) and suggest that generation has occurred at lower temperatures (i.e., less than 100 °C) and shallower depths than predicted by conventional organic metamorphic models (Isaacs and others, 1983). Although the specific temperature for oil generation in Monterey rocks is unknown, the thermal threshold appears to coincide with the temperature at which opal-CT is diagenetically transformed to quartz (i.e., approximately 80 °C) (Surdam and Stanley, 1981; Keller and Isaacs, 1985). The apparent thermal coincidence of the generation of petroleum and diagenesis of opal-CT to quartz is significant because it provides a basis for the estimation of paleotemperature and the depth and location of petroleum generation in the absence of geothermal, geochemical, and thermal maturity data.

Mineralogic analyses of Neogene siliceous rock samples from nine offshore wells in the Point Arena, Bodega, Año Nuevo, and Santa Maria basins indicate that diagenesis of opal-CT to quartz has occurred in all of the wells; the stratigraphic position of this diagenetic boundary has been correlated with a "diagenetic reflector" on seismic-reflection profiles that can be traced through part or much of the offshore areas of the basins (Mayerson and others, 1995). The analyses further indicate that petroleum generation may have occurred at relatively shallow depths (i.e., as shallow as 3,000 to 5,000 feet below the seafloor) and that generative source rocks and fractured reservoir rocks may exist over large areas of the basins. Recognition of the location and petroleum geologic significance of the silica diagenetic boundaries and facies in basins of the Central California province is considered to be a notable improvement from past assessments.

Basis for Play Definition

Petroleum geologic plays within each of the assessed basins have been defined on the basis of reservoir rock stratigraphy and occur in one of three reservoir groups: (1) Paleogene to lower Neogene clastic reservoirs, (2) Neogene fractured siliceous reservoirs, and (3) upper Neogene clastic reservoirs. Fractured siliceous strata were originally subdivided into three subplays; two of these were defined on the basis of silica diagenetic grade to distinguish between moderately fractured, opal-phase reservoirs and highly fractured, quartz-phase reservoirs in conventional structural traps. These subplays were eventually combined into a single play for practicality of statistical analysis. Additionally, a highly speculative subplay of quartz-phase stratigraphic traps sealed by low permeability above the opal-CT-quartz diagenetic boundary was defined but not assessed.

Exploration and Discovery Status

Several offshore oil fields have been discovered in the Santa Maria basin, where production is derived primarily from Monterey reservoirs. Although the Point Arena, Bodega, and Año Nuevo basins have been only sparsely explored, the limited exploration data suggest that significant hydrocarbon potential exists within these basins as well.

Resource Estimates

Undiscovered Conventionally Recoverable Resources

Estimates of the total volume of undiscovered conventionally recoverable resources in the province have been developed by statistically aggregating the constituent assessment area estimates. As a result of this assessment, the total volume of undiscovered conventionally recoverable resources in the Central California province is estimated to be 4.95 Bbbl of oil and 5.23 Tcf of associated gas (mean estimates). The low, mean, and high estimates of resources in the province are listed in table 11 and illustrated in figure 34.

Economically Recoverable Resources

Estimates of the total volume of undiscovered conventionally recoverable resources in the province that may be economically recoverable under various economic scenarios have been developed by statistically aggregating the constituent assessment area estimates. As a result of this assessment, 2.59 Bbbl of oil and 2.77 Tcf of associated gas are estimated to be economically recoverable from the Central California province under economic conditions existing as of this assessment (i.e., the $18-per-barrel economic scenario) (table 12). Larger volumes of resources are expected to be economically recoverable under increasingly favorable economic conditions (fig. 35).

Total Resource Endowment

As of this assessment, cumulative production from the province was 118 MMbbl of oil and 43 Bcf of gas; remaining reserves were estimated to be 667 MMbbl of oil and 659 Bcf of gas. These discovered resources and the aforementioned undiscovered conventionally recoverable resources collectively compose the province's estimated total resource endowment of 5.74 Bbbl of oil and 5.93 Tcf of gas (table 13).

Table 11. *Estimates of undiscovered conventionally recoverable oil and gas resources in the Central California province as of January 1, 1995, by assessment area. All estimates are risked values. The low, mean, and high estimates correspond to the 95th-percentile, mean, and 5th-percentile values of a probability distribution, respectively. Percentile values are not additive; some total mean values may not equal the sum of the component values due to independent rounding.*

Assessment Area	Oil (Bbbl)			Gas (Tcf)			BOE (Bbbl)		
	Low	Mean	High	Low	Mean	High	Low	Mean	High
Point Arena Basin	1.50	2.03	2.66	1.45	2.14	3.01	1.77	2.41	3.18
Bodega Basin	0.97	1.42	1.98	1.00	1.57	2.30	1.16	1.70	2.37
Año Nuevo Basin	0.49	0.72	1.01	0.49	0.78	1.16	0.58	0.86	1.21
Santa Maria-Partington Basin	0.68	0.78	0.89	0.60	0.74	0.90	0.79	0.91	1.05
Total Province	*4.17*	*4.95*	*5.82*	*4.21*	*5.23*	*6.39*	*4.94*	*5.88*	*6.93*

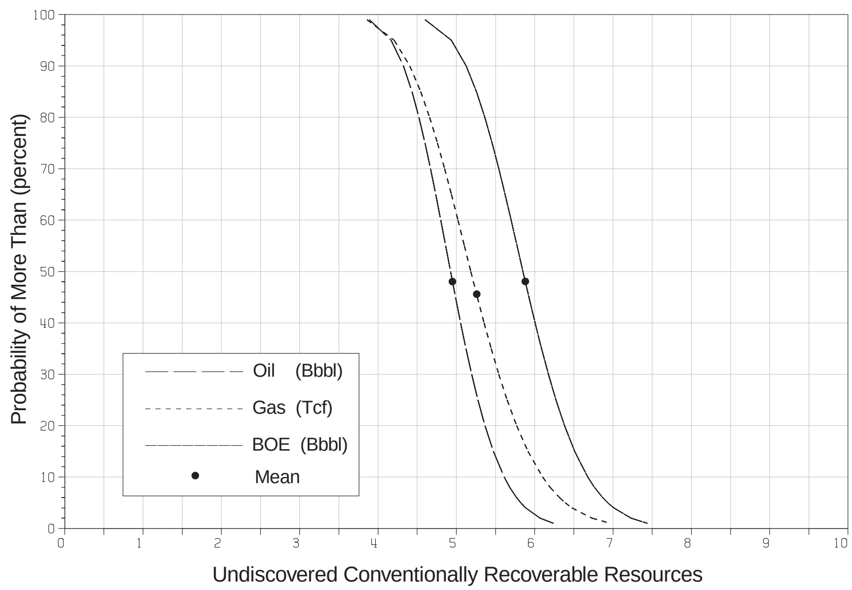


Figure 34. *Cumulative probability plot of estimated undiscovered conventionally recoverable resources of the Central California province.*

Table 12. *Estimates of undiscovered economically recoverable oil and gas resources in the Central California province as of January 1, 1995 for three economic scenarios, by assessment area. All estimates are risked mean values. The $18-per-barrel scenario is based on prices of $18 per bbl of oil and $2.11 per Mcf of gas; the $25-per-barrel scenario is based on prices of $25 per bbl of oil and $2.94 per Mcf of gas; the $50-per-barrel scenario is based on prices of $50 per barrel of oil and $5.87 per Mcf of gas. Some total values may not equal the sum of the component values due to independent rounding.*

Assessment Area	$18-per-barrel Scenario			$25-per-barrel Scenario			$50-per-barrel Scenario		
	Oil (Bbbl)	Gas (Tcf)	BOE (Bbbl)	Oil (Bbbl)	Gas (Tcf)	BOE (Bbbl)	Oil (Bbbl)	Gas (Tcf)	BOE (Bbbl)
Point Arena Basin	0.90	0.95	1.06	1.21	1.27	1.43	1.58	1.66	1.87
Bodega Basin	1.03	1.13	1.23	1.14	1.26	1.37	1.27	1.41	1.52
Año Nuevo Basin	0.48	0.51	0.57	0.55	0.59	0.65	0.63	0.68	0.75
Santa Maria-Partington Basin	0.19	0.18	0.22	0.28	0.26	0.32	0.50	0.47	0.58
Total Province	*2.59*	*2.77*	*3.08*	*3.17*	*3.38*	*3.77*	*3.98*	*4.22*	*4.73*

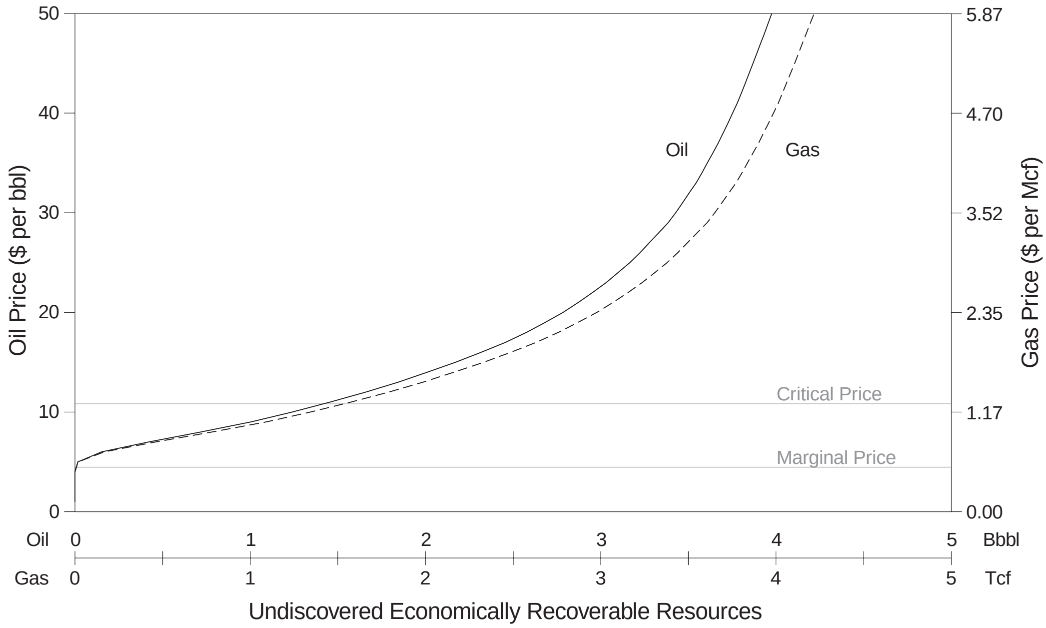


Figure 35. *Price-supply plot of estimated undiscovered economically recoverable resources of the Central California province.*

Table 13. *Estimates of the total endowment of oil and gas resources in the Central California province, by assessment area. Estimates of discovered resources (including cumulative production and remaining reserves) and undiscovered resources are as of January 1, 1995. Estimates of undiscovered conventionally recoverable resources are risked mean values. Some total values may not equal the sum of the component values due to independent rounding.*

Assessment Area	Discovered Resources (Reserves)						Undiscovered Conventionally Recoverable Resources			Total Resource Endowment		
	Cumulative Production			Remaining Reserves								
	Oil (Bbbl)	Gas (Tcf)	BOE (Bbbl)	Oil (Bbbl)	Gas (Tcf)	BOE (Bbbl)	Oil (Bbbl)	Gas (Tcf)	BOE (Bbbl)	Oil (Bbbl)	Gas (Tcf)	BOE (Bbbl)
Point Arena Basin	0	0	0	0	0	0	2.03	2.14	2.41	2.03	2.14	2.41
Bodega Basin	0	0	0	0	0	0	1.42	1.57	1.70	1.42	1.57	1.70
Año Nuevo Basin	0	0	0	0	0	0	0.72	0.78	0.86	0.72	0.78	0.86
Santa Maria-Partington Basin	0.12	0.04	0.13	0.67	0.66	0.78	0.78	0.74	0.91	1.57	1.44	1.82
Total Province	*0.12*	*0.04*	*0.13*	*0.67*	*0.66*	*0.78*	*4.95*	*5.23*	*5.88*	*5.74*	*5.93*	*6.79*

POINT ARENA BASIN

by Kenneth A. Piper

Location

The Point Arena basin is the northernmost basin in the Central California province (fig. 33). It extends from Punta Gorda to south of Point Arena, California, a distance of about 100 miles; it is about 30 miles wide and encompasses an area of about 3,000 square miles (fig. 36). A small part of the basin extends into State waters and onshore at Point Delgada and Point Arena.

The Point Arena Basin assessment area comprises only the Federal offshore portion of the basin (i.e., seaward of the 3-mile line). Water depth in the assessment area ranges from about 200 feet at the 3-mile line to about 5,000 feet along the western margin.

Geologic Setting

Basement rocks are unknown. In the northwestern part of the basin, near the Mendocino fracture zone, deep-sea drill site 173 bottomed in andesite at 1,050 feet below the seafloor and stratigraphically beneath upper Oligocene to lower Miocene sediments (Kulm, von Huene, and others, 1973). The rock most likely originated as a subaqueous breccia flow and is compositionally similar to Cascade Range volcanics (MacLeod and Pratt, 1973). Reworked Cretaceous microfossils from site 173 cores and a dredge sample from south of the drill site (Silver and others, 1971) suggest Franciscan Complex underlies at least the western part of the basin

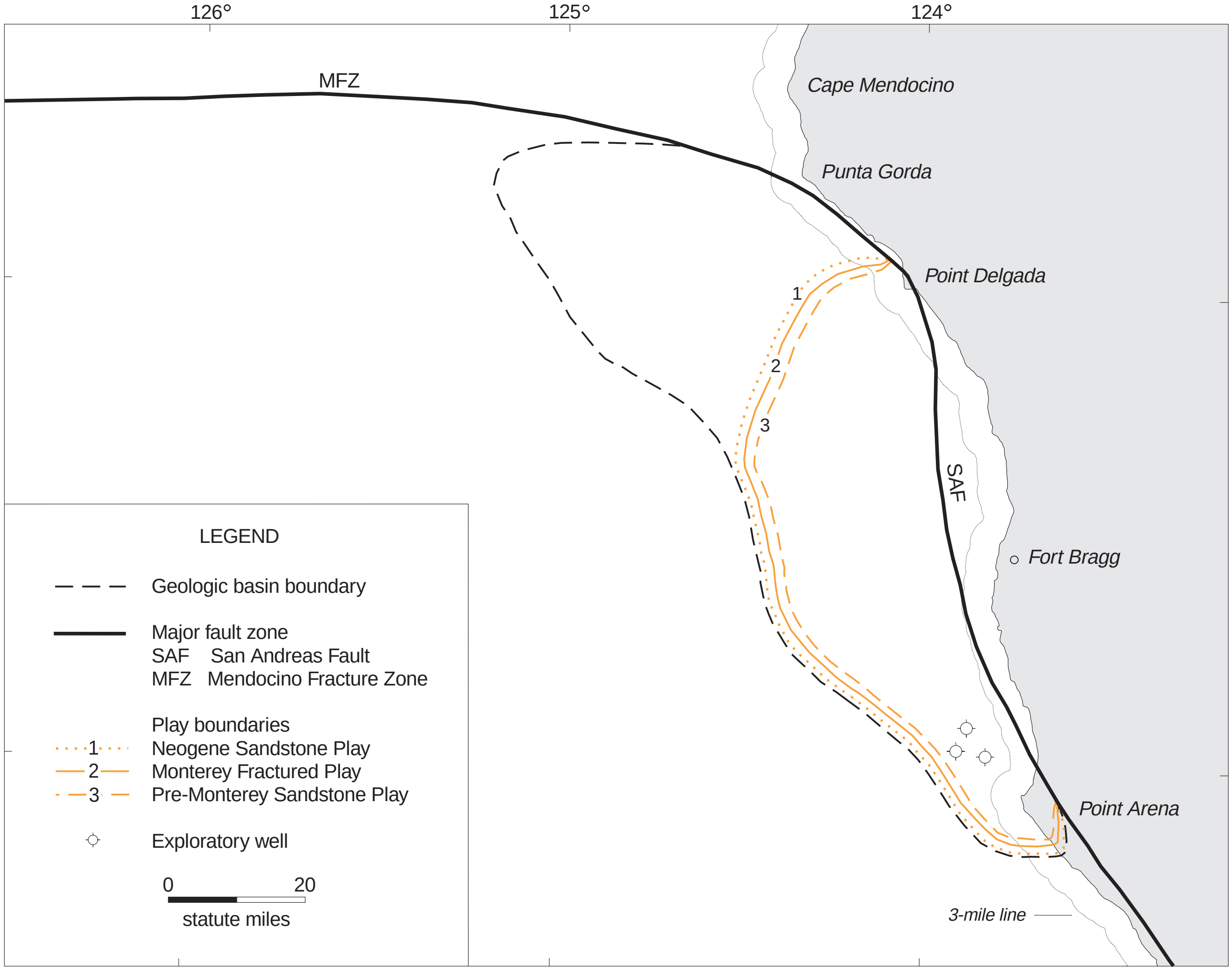


Figure 36. *Map of the Point Arena Basin assessment area showing petroleum geologic plays and wells.*

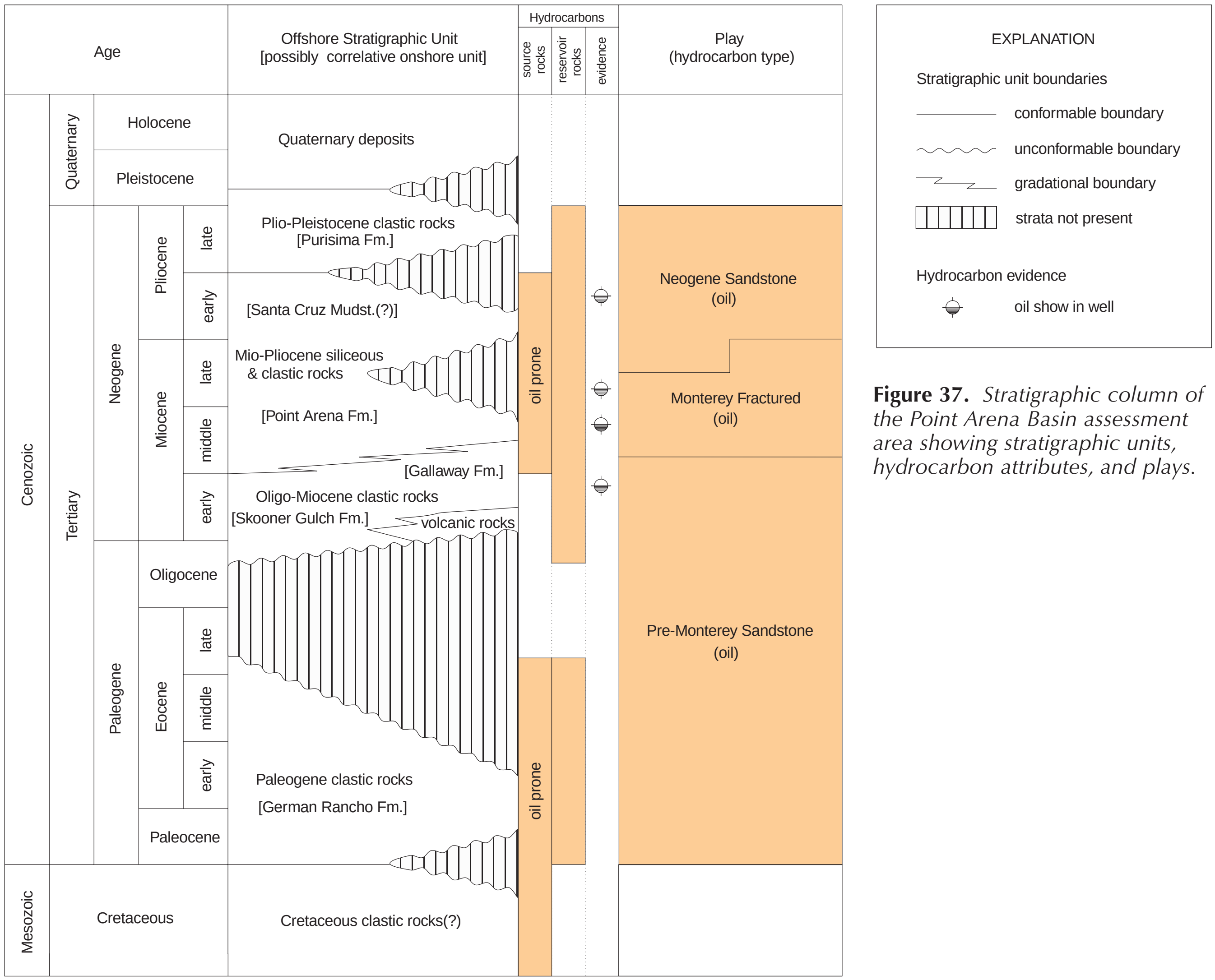


Figure 37. *Stratigraphic column of the Point Arena Basin assessment area showing stratigraphic units, hydrocarbon attributes, and plays.*

(Kulm, von Huene, and others, 1973; McCulloch, 1989). Well cuttings from an offshore exploratory well at the south end of the basin (OCS-P 0033 #1) are quartz-mica schist (Hoskins and Griffiths, 1971). This has been suggested as indicating Salinian basement may extend as far north as Point Arena (Bachman and Crouch, 1987). Others have suggested that the eastern part of the basin may be underlain by exotic terranes with origins thousands of miles to the south (McCulloch, 1987a, b).

The lowest known sedimentary unit in the assessment area is a probable equivalent to the Paleocene to Eocene German Rancho Formation (fig. 37). This unit is composed of 10,000 to 20,000 feet of deep-water turbidite sandstone, siltstone, and mudstone, which may have been deposited in the distal part of a forearc basin (Loomis and Ingle, 1994). Oligocene to Miocene volcanics overlie the Paleogene sediments. The volcanics are stratigraphically discontinuous offshore but are up to 900 feet thick onshore. These are in turn overlain by Neogene basinal sediments, which attain a thickness of over 10,000 feet. The lower Miocene section contains up to 3,000 feet of sandstones, siltstones, and shales deposited in increasing water depths suggestive of early basin formation. These are probable equivalents of the Skooner Gulch and Gallaway Formations described in the onshore (Weaver, 1943; Loomis and Ingle, 1994). These rocks are overlain by middle Miocene siliceous clastic rocks, which are locally named the Point Arena Formation but are lithologically and genetically equivalent to the Monterey Formation as described in the basins to the south. The Monterey Formation is in turn overlain by late Miocene to Pliocene clastic rocks, which are not present onshore. The lower part of this section consists of deep-water siliceous shales with interbedded siltstone and sandstone, and it may be lithologically equivalent to the Sisquoc Formation of the Santa Maria basin. These deposits are unconformably overlain by up to 4,000 feet of Pliocene and Pleistocene siltstones and mudstones with occasional sandstone layers.

Prior to the late Oligocene change in relative plate motions, this area was the site of a convergent plate boundary between the Farallon and North American plates. The paleotectonic setting and the presence of the Paleocene to Eocene turbidites suggest that this area may have been the seaward margin of a forearc basin in an environment similar to that postulated for the Yager complex of the Eel River basin (cf. Underwood, 1985). In the late Oligocene to early Miocene, the Farallon plate was nearly fully subducted and what remained apparently became sutured to the Pacific plate. A result of this was the change of the western margin of central California to a translational margin between the Pacific and North American plates. As elsewhere in central and southern California, volcanism was active in the late Oligocene to early Miocene, associated with the change in relative plate motions. The Neogene basin formed at this time and persists to the present.

The Neogene Point Arena basin is on a steeply sloping part of the continental shelf; it does not have a well-defined and structurally high uplift along the western margin and is, therefore, different from the other basins in the Central California province (Hoskins and Griffiths, 1971; McCulloch, 1987a). The San Andreas fault zone defines the northeast and east margins of the present Point Arena basin and intersects the Mendocino fracture zone directly north of the basin. Neogene and Quaternary tectonics have been dominated by strike-slip, wrench, and thrust faulting associated with these two major right-lateral translational plate boundaries. Major faults and elongate folds generally parallel the northwest-trending San Andreas fault zone, and deformation decreases away from it. Overall folding and faulting patterns suggest that the basin is undergoing transpression, although the orientation of the main trace of the San Andreas fault zone suggests variability between transpression and transtension.

EXPLORATION

During the 1960's, three offshore exploratory wells were drilled in the Point Arena basin (fig. 36). Oil shows were encountered in all three of these wells and in two onshore wells. The offshore area has been studied using a moderately dense to dense grid of seismic-reflection profiles. Silica diagenetic reflectors are seen on the seismic data in the southern part of the basin; their presence suggests that oil generation may have occurred as shallow as 3,000 feet below the seafloor, and that fractured reservoirs are likely in that part of the basin.

PLAYS

For the assessment, three petroleum geologic plays were defined based primarily on reservoir characteristics (figs. 36 and 37). The major play (Monterey Fractured) includes fractured siliceous shales of the Point Arena (Monterey) Formation and the lower siliceous part of the post-Monterey section. The Neogene sandstone play includes the upper, nonsiliceous part of the upper Miocene to Pliocene section. The Pre-Monterey Sandstone play includes sandstones of the German Rancho Formation and lower Miocene sandstones deposited during the Neogene basin formation. The plays are described following this assessment area summary.

RESOURCE ESTIMATES

Undiscovered Conventionally Recoverable Resources

Play-specific estimates of undiscovered conventionally recoverable resources have been developed using the subjective assessment method, and these estimates have been statistically aggregated to estimate the total volume of resources in the assessment area. Select data used to develop the estimates are shown in appendix C.

As a result of this assessment, the total volume of undiscovered conventionally recoverable resources in the Point Arena Basin assessment area is expected to be 2.03 Bbbl of oil and 2.14 Tcf of associated gas (mean estimates). This volume may exist in 112 fields with sizes ranging from approximately 80 Mbbl to 510 MMbbl of combined oil-equivalent resources (fig. 38). The majority of these resources (approximately 87 percent on a combined oil-equivalence basis) are estimated to exist in the Monterey Fractured play. The low, mean, and high estimates of resources in the area are listed in table 14 and illustrated in figure 39.

Undiscovered Economically Recoverable Resources

Estimates of undiscovered conventionally recoverable resources in the assessment area that may be economically recoverable under various economic scenarios have been developed using the economic assessment method. Select data used to develop the resource estimates are shown in appendix D.

As a result of this assessment, 896 MMbbl of oil and 946 Bcf of associated gas are estimated to be economically recoverable from the Point Arena

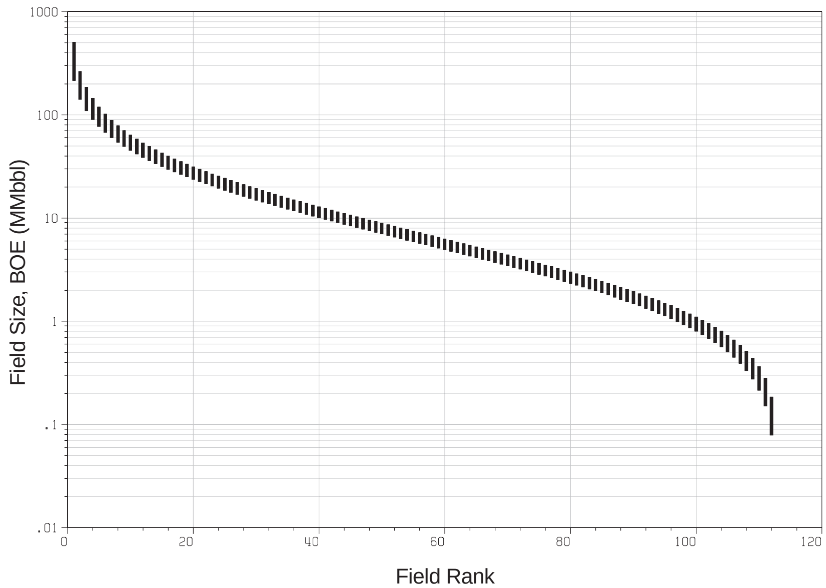


Figure 38. *Field-size rank plot of estimated undiscovered conventionally recoverable resources of the Point Arena Basin assessment area. Sizes of undiscovered fields are shown by bars; the top and bottom of a bar represent the 25th- and 75th-percentile values of a probability distribution, respectively.*

Table 14. *Estimates of undiscovered conventionally recoverable oil and gas resources in the Point Arena Basin assessment area as of January 1, 1995, by play. All estimates are risked values. The low, mean, and high estimates correspond to the 95th-percentile, mean, and 5th-percentile values of a probability distribution, respectively. Percentile values are not additive; some total mean values may not equal the sum of the component values due to independent rounding.*

Play	Oil (MMbbl)			Gas (Bcf)			BOE (MMbbl)		
	Low	Mean	High	Low	Mean	High	Low	Mean	High
Neogene Sandstone	0	80	230	0	94	267	0	97	277
Monterey Fractured	1,319	1,773	2,355	1,263	1,808	2,629	1,557	2,094	2,794
Pre-Monterey Sandstone	0	177	374	0	240	512	0	220	464
Total Assessment Area	*1,500*	*2,030*	*2,664*	*1,452*	*2,142*	*3,010*	*1,773*	*2,411*	*3,178*

Figure 39. *Cumulative probability plot of estimated undiscovered conventionally recoverable resources of the Point Arena Basin assessment area.*

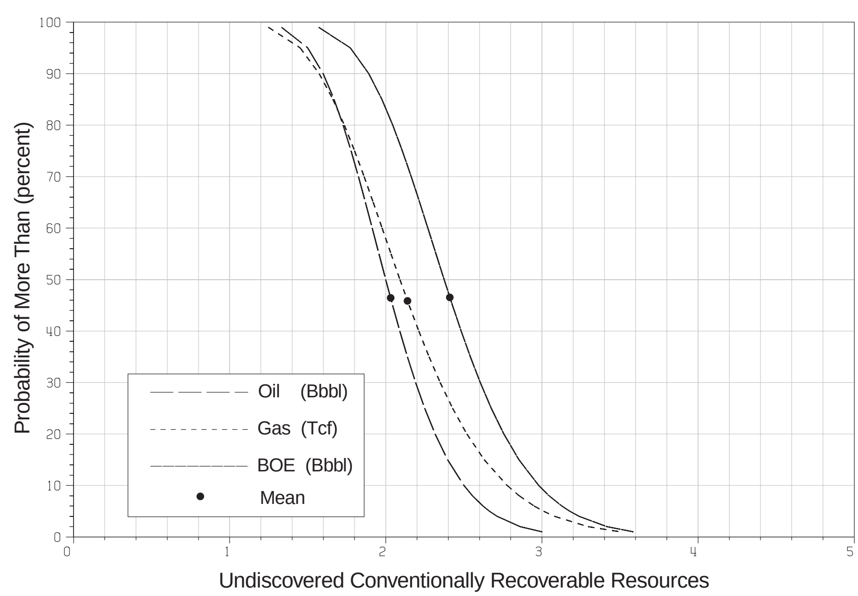


Table 15. *Estimates of undiscovered economically recoverable oil and gas resources in the Point Arena Basin assessment area as of January 1, 1995, by economic scenario. All estimates are risked mean values. The $18-per-barrel scenario is based on prices of $18 per bbl of oil and $2.11 per Mcf of gas; the $25-per-barrel scenario is based on prices of $25 per bbl of oil and $2.94 per Mcf of gas; the $50-per-barrel scenario is based on prices of $50 per barrel of oil and $5.87 per Mcf of gas.*

Economic Scenario	Oil (MMbbl)	Gas (Bcf)	BOE (MMbbl)
$18 per barrel	896	946	1,064
$25 per barrel	1,205	1,271	1,431
$50 per barrel	1,575	1,661	1,870

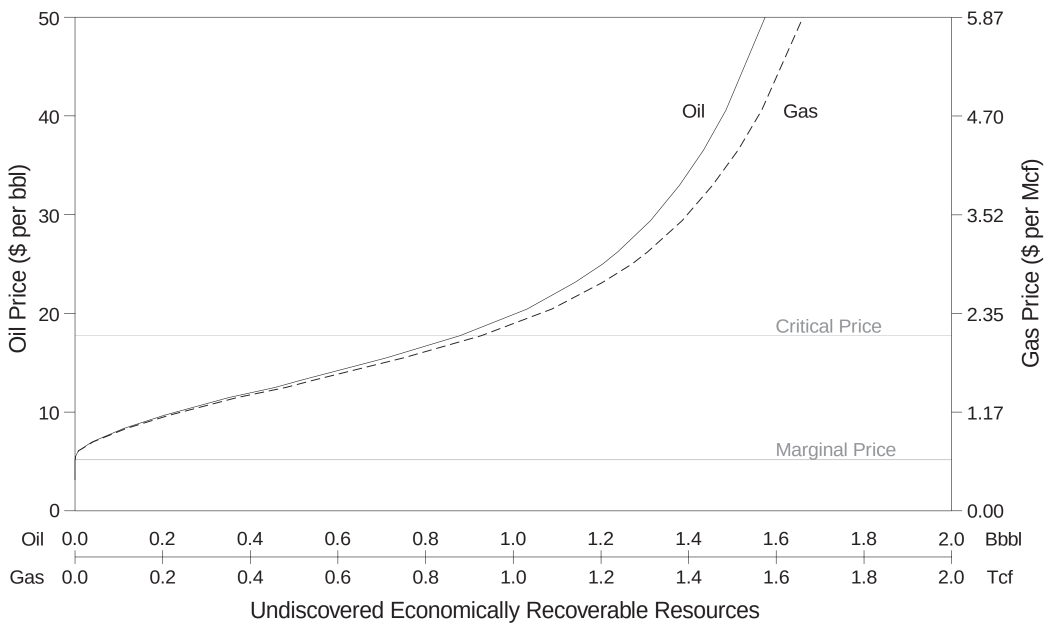


Figure 40. *Price-supply plot of estimated undiscovered economically recoverable resources of the Point Arena Basin assessment area.*

Basin assessment area under economic conditions existing as of this assessment (i.e., the $18-per-barrel economic scenario) (table 15). Larger volumes of resources are expected to be economically recoverable under increasingly favorable economic conditions (fig. 40).

Total Resource Endowment

No accumulations of resources have been discovered in the assessment area. Therefore, the aforementioned estimates of undiscovered conventionally recoverable resources compose the estimated total resource endowment of the area.

ACKNOWLEDGMENTS

Initial study of the Point Arena Basin assessment area was performed by Harry Cousminer (Minerals Management Service, retired); his work provided the basis for the play definitions. The following individuals also provided information, insight, and suggestions that improved the quality of the assessment of the Point Arena basin: Jim Crouch (J.K. Crouch and Associates, Inc.) and Mike Brickey and Jim Galloway (Minerals Management Service).

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Neogene Sandstone Play

Play Definition

The Neogene Sandstone play of the Point Arena Basin assessment area is defined to include upper Miocene through Pliocene shelf sandstones in anticlinal, fault, and stratigraphic traps. It is a conceptual play because no hydrocarbons have been detected within the play; however, there is evidence of the presence of oil in expected source rocks in all three offshore wells. The play exists in the central and southern part of the basin from Point Delgada to south of Point Arena; the Federal offshore portion of the play (seaward of the 3-mile line) was evaluated for the assessment (fig. 36). The play is defined on the basis of reservoir rock stratigraphy. Traps are expected to exist in discrete sandstone units within the dominantly siltstone and mudstone section at burial depths to about 5,000 feet.

Petroleum Geologic Characteristics

Source rocks are considered to be Miocene Monterey-equivalent, organic-rich, siliceous shales of the Point Arena Formation and the lower part of the overlying unnamed sedimentary section (fig. 37). The Point Arena Formation is highly petroliferous. A formation test in an offshore well recovered a small amount of 29 °API oil. Total organic carbon content is as high as 5.5 percent, with a median value of about 2 percent. These "Monterey" source rocks are expected to be thermally mature for oil generation as shallow as 3,000 feet below the seafloor based on diagenetic seismic reflectors, which may be indicators of paleotemperature (see Central California province summary). The oil is expected to have migrated upward and laterally along faults, fractures, and the unconformity into the overlying section.

Reservoir rocks for the play are discrete sandstone units (especially fan and fan-channel deposition) within the predominantly siltstones and mudstones of the Miocene to Pliocene section, which overlies the Miocene siliceous rocks. Reservoir sandstones are expected to be of excellent to good quality; porosities in excess of 30 percent were measured in the two offshore wells that penetrate this play.

Potential traps include anticlinal folds, faults, and stratigraphic pinchouts. Structural trends are similar to those in the underlying Miocene units, but folds are more open, of lower amplitude, and less abundant. Mudstones of the Purisima Formation may provide adequate seals.

Exploration

Two of the offshore exploratory wells (OCS-P 0032 #1 and OCS-P 0033 #1) drilled in the 1960's penetrated rocks of this play. There were no hydrocarbon shows in either of these wells within rocks of this play; however, both wells encountered oil shows in the Monterey-equivalent rocks expected to source this play.

Resource Estimates

Undiscovered Conventionally Recoverable Resources

Estimates of undiscovered conventionally recoverable resources in the Federal offshore portion of the play have been developed using the subjective assessment method. Select data used to develop the resource estimates are shown in appendix C.

The resource potential of the play was modeled to include oil and associated gas based on hydrocarbon occurrences in the expected source rocks. Prospect size was modeled using structural closures mapped in the underlying Miocene section; however, prospect density was reduced because the seismic data show less folding and faulting in the Pliocene section. Reservoir parameters were derived in conjunction with data from the other central California coastal basins using the available well data and incorporating some analog data from similar producing Pliocene rocks in southern California.

As a result of this assessment, the Federal offshore portion of the play is estimated to contain 80 MMbbl of oil and 94 Bcf of associated gas (mean estimates). This volume of undiscovered conventionally recoverable resources may exist in as many as 37 pools with sizes ranging from approximately 130 Mbbl to 70 MMbbl of combined oil-equivalent resources (fig. 41). The low, mean, and high estimates of resources in the play are listed in table 14.

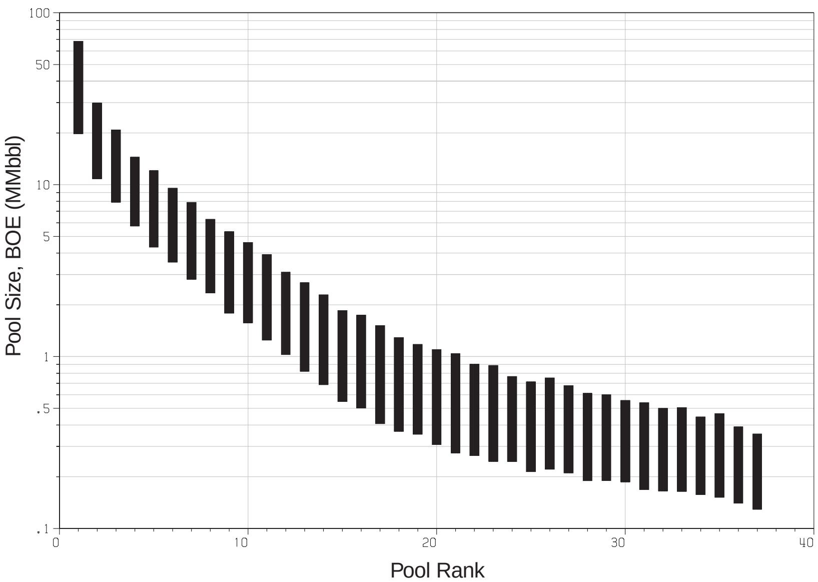

Figure 41. *Pool-size rank plot of estimated undiscovered conventionally recoverable resources of the Neogene Sandstone play, Point Arena Basin assessment area. Sizes of undiscovered pools are shown by bars; the top and bottom of a bar represent the 25th- and 75th-percentile values of a probability distribution, respectively.*

MONTEREY FRACTURED PLAY

PLAY DEFINITION

The Monterey Fractured play of the Point Arena Basin assessment area is defined to include fractured siliceous reservoirs in Miocene, Monterey-type siliceous shales of the Point Arena Formation and the lower part of the overlying unnamed sedimentary section. It is a frontier play because no discoveries have been made; however, there is evidence of the presence of oil in rocks of this play in all three offshore exploratory wells. The play exists in the central and southern part of the basin, from Point Delgada to south of Point Arena; the Federal offshore portion of the play (seaward of the 3-mile line) was evaluated for the assessment (fig. 36). The play is defined on the basis of reservoir rock stratigraphy. Traps are expected to exist in fractured shale in anticlinal, fault, and stratigraphic traps at burial depths from about 1,000 to 10,000 feet.

PETROLEUM GEOLOGIC CHARACTERISTICS

Rocks of the Point Arena Formation (described by Weaver, 1943) are considered to be equivalent to the Monterey Formation as it is described for the other central California basins on the basis of age and lithology (fig. 37). Strata immediately overlying the Point Arena Formation (possibly correlative with the Santa Cruz Mudstone; see Bodega and Año Nuevo basin summaries) are also considered to be lithologically equivalent to the Monterey Formation as evidenced by the presence of diagenetic seismic reflectors (which are considered to be indicators of highly siliceous strata). Monterey-type rocks are generally excellent hydrocarbon source rocks and also have potential as fractured reservoirs. The Point Arena Formation is highly petroliferous. One offshore formation test recovered a small amount of 29 °API oil. Total organic carbon content is as high as 5.5 percent with a median value of about 2 percent. These "Monterey" source rocks are expected to be thermally mature for oil generation as shallow as 3,000 feet below the seafloor based on the diagenetic seismic reflectors, which may also be indicators of paleotemperature (see Central California province summary).

Reservoirs are expected to be fractured zones within siliceous shales of the Point Arena Formation (and the lithologically similar overlying strata) and occasional discrete sandstone units interbedded within them. Fractured reservoir quality varies according to the amount of fracturing in the shale section, but Monterey reservoirs in producing basins are found to be excellent reservoirs. Reservoir quality is expected to be good in sandstone interbeds.

Potential traps include fractured zones in anticlinal folds and faults. Fault traps are expected to include subthrust traps. Structural trends are generally northwest-trending with increasing fold amplitudes and structural complexity to the northeast. Trap seals may be provided by less-fractured rocks within the section. Where silica has not been diagenetically altered to quartz (above the lower of two diagenetic reflectors) and in clastic-rich areas, decreased fracture density is expected; heavy oil in these areas may be trapped, thus creating a tar seal.

EXPLORATION

All three offshore exploratory wells (OCS-P 0030 #1, OCS-P 0032 #1, and OCS-P 0033 #1) penetrated rocks of this play. There were oil shows in the Point Arena Formation in all these wells; one well (OCS-P 0030 #1) had oil shows in the overlying strata (Santa Cruz Mudstone(?)).

RESOURCE ESTIMATES

Undiscovered Conventionally Recoverable Resources

Estimates of undiscovered conventionally recoverable resources in the Federal offshore portion of the play have been developed using the subjective assessment method. Select data used to develop the resource estimates are shown in appendix C.

The resource potential of the play was modeled to include oil and associated gas based on the hydrocarbon shows. Prospect sizes and the number of prospects were estimated based on structural closures mapped using a dense grid of seismic data. Reservoir parameters were derived in conjunction with data from the other central California coastal basins using the available well data and incorporating some analog data from producing Monterey fields in southern California.

As a result of this assessment, the Federal offshore portion of the play is estimated to contain 1.77 Bbbl of oil and 1.81 Tcf of associated gas (mean estimates). This volume of undiscovered conventionally recoverable resources may exist in as many as 139 pools with sizes ranging from approximately 50 Mbbl to 665 MMbbl of combined oil-equivalent resources (fig. 42). The low, mean, and high estimates of resources in the play are listed in table 14.

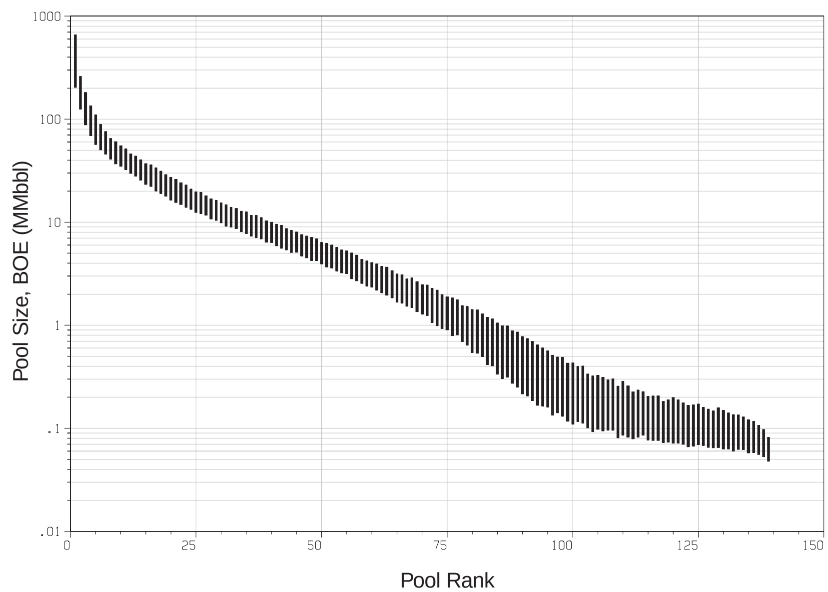

Figure 42. *Pool-size rank plot of estimated undiscovered conventionally recoverable resources of the Monterey Fractured play, Point Arena Basin assessment area. Sizes of undiscovered pools are shown by bars; the top and bottom of a bar represent the 25th- and 75th-percentile values of a probability distribution, respectively.*

PRE-MONTEREY SANDSTONE PLAY

PLAY DEFINITION

The Pre-Monterey Sandstone play of the Point Arena Basin assessment area is defined to include Paleocene to lower Miocene sandstones in anticlinal, fault, and stratigraphic traps. It is a frontier play because no discoveries have been made; however, there is evidence of the presence of oil in two offshore wells and two onshore wells. The play exists in the central and southern part of the basin, from Point Delgada to south of Point Arena; the Federal offshore portion of the play (seaward of the 3-mile line) was evaluated for the assessment (fig. 36). The play is defined on the basis of reservoir rock stratigraphy. Traps are expected to exist in discrete sandstone units within the mostly siltstone and mudstone section at burial depths from about 1,000 to 15,000 feet.

PETROLEUM GEOLOGIC CHARACTERISTICS

Sedimentary units present in offshore wells have been tentatively correlated (by MMS) with the onshore German Rancho, Skooner Gulch, and Gallaway Formations. Shales within the Paleocene to Eocene German Rancho Formation and Oligocene to Miocene Skooner Gulch and Gallaway Formation equivalents are considered to be the primary hydrocarbon sources for this play. Onshore samples of these shales indicate fair to good generative potential for oil with total organic carbon content of about 0.5 to 4.3 percent (Crouch, Bachman, and Associates, Inc., 1987). The German Rancho Formation has potential for nonassociated gas as well as oil generation (Crouch, Bachman, and Associates, Inc., 1987). There is also some potential for sourcing of this play from the overlying Monterey-type rocks; these source rocks are expected to be thermally mature for oil generation as shallow as 3,000 feet below the seafloor based on diagenetic seismic reflectors, which may be indicators of paleo-temperature (see Central California province summary).

Potential reservoirs are discrete sandstone units deposited in shelf and fan sequences within the section. The Skooner Gulch and Gallaway Formation equivalents are expected to have very good to excellent reservoir quality (porosities of about 15 to 25 percent have been measured in offshore wells. German Rancho Formation sandstones are considered to be of fair reservoir quality with moderate porosity (about 13 percent).

Potential traps include anticlinal folds and faults.Fault traps are expected to include subthrust traps. Structural trends are generally northwest-trending with increasing fold amplitudes and structural complexity to the northeast. Trap seals may be provided by interbedded shales and mudstones.

Exploration

All three offshore exploratory wells (OCS-P 0030 #1, OCS-P 0032 #1, and OCS-P 0033 #1) penetrated rocks of this play. There were oil shows within the Gallaway Formation equivalent in two of these wells (OCS-P 0030 #1 and OCS-P 0032 #1). There were oil shows in the Skooner Gulch Formation equivalent and both oil and gas shows in the German Rancho Formation in an onshore well (Sun Lepori #1).

Resource Estimates

Undiscovered Conventionally Recoverable Resources

Estimates of undiscovered conventionally recoverable resources in the Federal offshore portion of the play have been developed using the subjective assessment method. Select data used to develop the resource estimates are shown in appendix C.

The resource potential of the play was modeled to include oil and associated gas based on the hydrocarbon shows. Although there is some potential for nonassociated-gas sourcing within the German Rancho Formation, it was not modeled; however, its expected contribution has been considered and included within the modeled limits for associated gas. Prospect sizes and the number of prospects were estimated based on structural closures mapped using a dense grid of seismic data. Reservoir parameters were derived in conjunction with data from the other coastal basins in the Central California province using the available well data and incorporating some analog data from producing fields in southern California.

As a result of this assessment, the Federal offshore portion of the play is estimated to contain 177 MMbbl of oil and 240 Bcf of associated gas (mean estimates). This volume of undiscovered conventionally recoverable resources may exist in as many as 128 pools with sizes ranging from approximately 25 Mbbl to 85 MMbbl of combined oil-equivalent resources (fig. 43). The low, mean, and high estimates of resources in the play are listed in table 14.

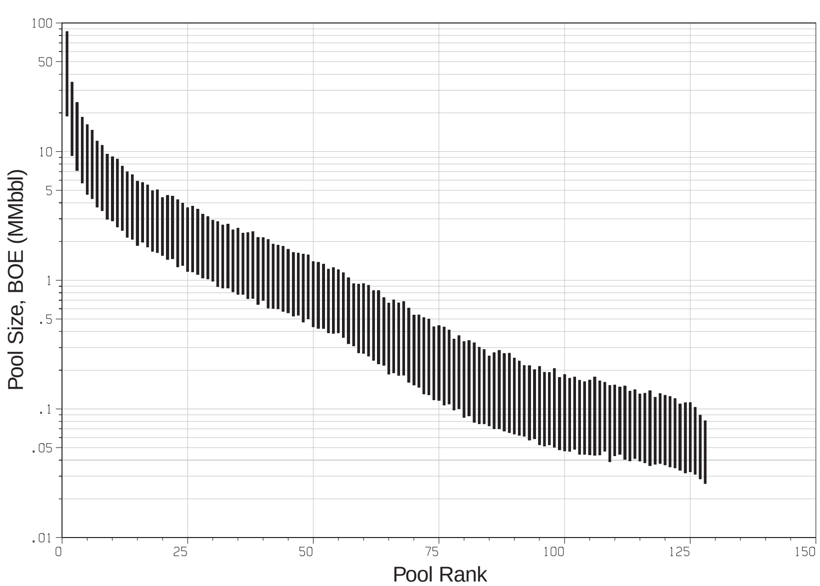

Figure 43. *Pool-size rank plot of estimated undiscovered conventionally recoverable resources of the Pre-Monterey Sandstone play, Point Arena Basin assessment area. Sizes of undiscovered pools are shown by bars; the top and bottom of a bar represent the 25th- and 75th-percentile values of a probability distribution, respectively.*

BODEGA BASIN

by Catherine A. Dunkel

Location

The Bodega basin is located between the Point Arena and Año Nuevo basins in the Central California province (fig. 33). This northwest-trending basin extends from Half Moon Bay to offshore Gualala, California (fig. 44). The basin is approximately 110 miles long and 20 miles wide, and occupies an area of approximately 1,700 square miles. The western margin of the basin is defined by the Farallon-Pigeon Point high; the basin is bounded on the east by the San Gregorio and San Andreas fault zones. A small portion of the basin lies in State waters and is exposed onshore at the Point Reyes Peninsula.

The Bodega Basin assessment area comprises only the Federal offshore portion of the basin (i.e., seaward of the 3-mile line). Water depths in the assessment area range from approximately 30 feet at the 3-mile line offshore San Francisco to approximately 1,000 feet near the transition between the continental shelf and slope north of the Farallon Islands.

Geologic Setting

The Bodega basin, as described here, comprises the "Bodega basin" and the offshore portion of the "Santa Cruz basin" (as these basins were described by Hoskins and Griffiths (1971)); the latter area has

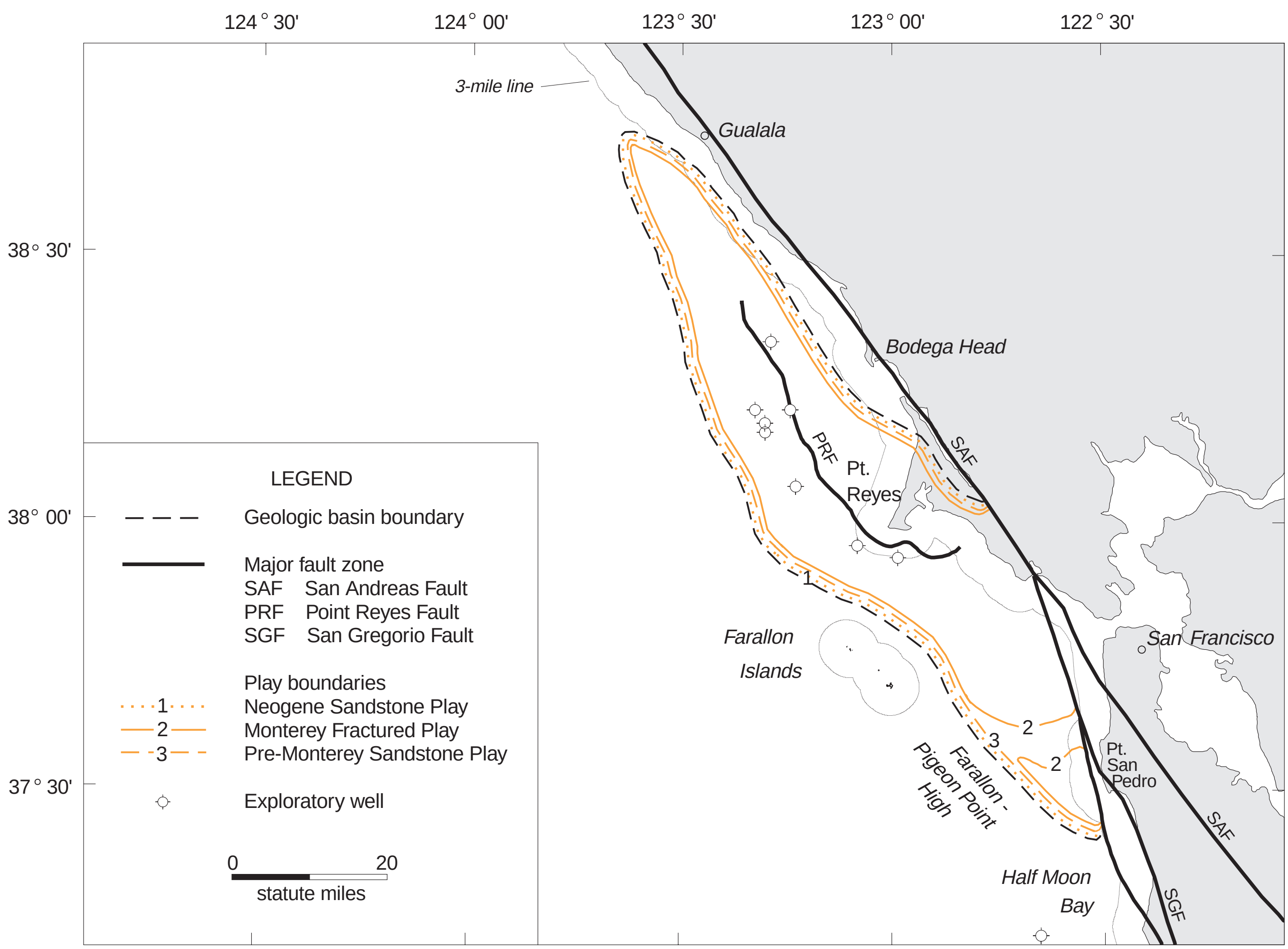

Figure 44. *Map of the Bodega Basin assessment area showing petroleum geologic plays and wells.*

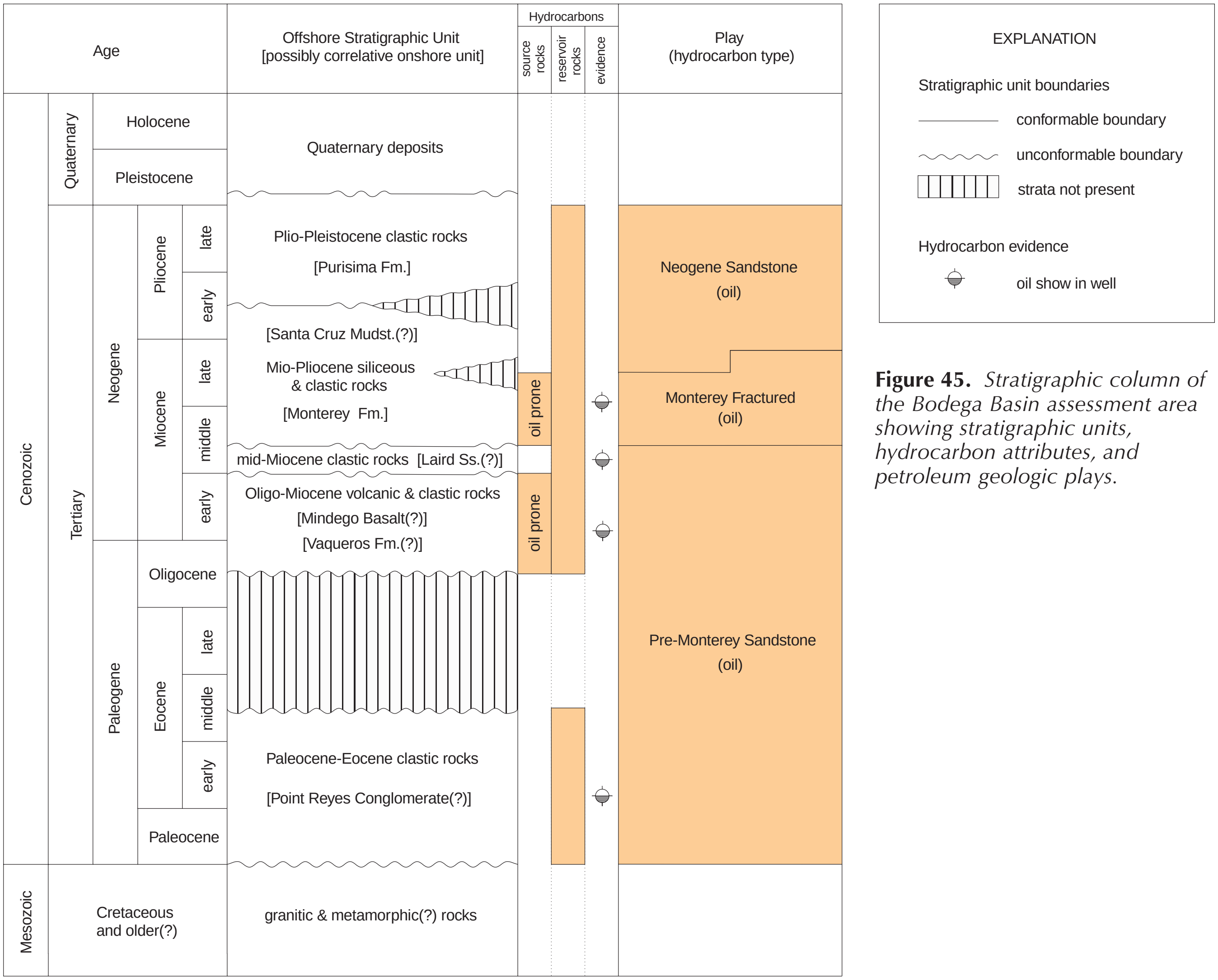

Figure 45. *Stratigraphic column of the Bodega Basin assessment area showing stratigraphic units, hydrocarbon attributes, and petroleum geologic plays.*

also been described as the offshore "La Honda basin" (Webster and Yenne, 1987). These areas appear to have been a continuous depocenter that is bisected in the vicinity of Point San Pedro by a northeast-trending, intrabasinal high.

The Cenozoic stratigraphic succession of the Bodega basin area indicates that the area has undergone a complex history of subsidence, sedimentary deposition, volcanism, uplift, and erosion (McCulloch, 1987b). The oldest rocks penetrated by offshore exploratory wells are Cretaceous granites similar to those exposed on the Farallon Islands and Point Reyes Peninsula (fig. 45). These rocks of the Salinia terrane are overlain offshore by Paleocene and Eocene conglomeratic rocks similar (and possibly correlative[6]) to submarine fan-channel deposits exposed at Point Reyes. The initial subsidence and formation of the Bodega basin proper may be recorded by the Paleocene and Eocene strata; alternatively, these strata may be a local remnant of a larger body of Cretaceous and Paleogene strata (i.e., including strata in the adjacent Point Arena and Año Nuevo basins) that were deposited, uplifted, and eroded prior to the formation of the basin. Following an episode of Paleogene uplift and

[6] Strata penetrated in the offshore wells of the Bodega basin were initially described by Hoskins and Griffiths (1971) and have been subsequently described by Zieglar and Cassell (1978) and McCulloch (1987b). Webster and Yenne (1987) assigned onshore formation names to the offshore strata based on lithologic and biostratigraphic (i.e., benthic foraminiferal) data from offshore well samples (fig. 45); however, given the limited number of wells and samples in the offshore Bodega basin, and the lack of demonstrated physical continuity between the offshore and onshore strata, these assignments and onshore-offshore correlations are uncertain. Therefore, the onshore-offshore correlations cited here and in figure 45 are considered to be possible correlations (and in some cases, possible partial correlations).

erosion (or nondeposition of middle Eocene to Oligocene strata), an episode of late Oligocene to early Miocene subsidence occurred, during which interbedded volcanic and marine clastic strata of early Miocene and possibly Oligocene age were deposited; the volcanic rocks are lithologically and temporally similar to those in other California coastal basins and may record a middle Tertiary extensional event that produced volcanism along the continental margin (McCulloch, 1987b). The bulk of the Bodega basin fill consists of a thick sequence of middle to upper Miocene marine clastic, siliceous, and siliciclastic rocks that record a middle Miocene transgression, subsequent subsidence, and hemipelagic siliceous deposition. Some of the siliceous deposits appear to have been uplifted and eroded during the late Miocene and early Pliocene. The uneroded siliceous rocks are overlain by Pliocene and Pleistocene marine clastic rocks and semiconsolidated Quaternary marine deposits. These major Tertiary stratigraphic sequences, which were deposited in marine shelf and slope settings, are separated by boundaries that are evident on seismic-reflection profiles. The boundaries are generally unconformable along the uplifted margins of the basin and are locally unconformable at intrabasinal highs.

The structural axis and many faults and folds in the basin are predominantly northwest-trending and subparallel (or at low angles) to the San Andreas fault zone; this suggests that the origin and early deformational history of the basin may have been largely controlled by this right-lateral strike-slip fault (Wilcox and others, 1973; Blake and others, 1978). However, the variable orientation of many fold and fault trends suggests that some structural features may be genetically related to the San Gregorio fault and/or late Cenozoic compression; recent (and possibly ongoing) compression along the Point Reyes fault has produced large vertical displacement of basement and overlying strata in the central portion of the basin (Hoskins and Griffiths, 1971; McCulloch, 1987b). The presence of rigid granitic basement rocks throughout most (if not all[7]) of the Bodega basin may have affected the structural style of overlying basinal strata (Hoskins and Griffiths, 1971); seismic-reflection profiles suggest that folds in the stratigraphic fill of the Bodega basin are broader and of less amplitude than in adjacent basins floored wholly or partially by less-rigid rocks of the Franciscan Complex.

[7] It has been suggested that basement rocks of the Bodega basin may include both granitic and metamorphic rocks of the Salinia terrane (McCulloch, 1987b); however, the presence of metamorphic basement rocks in the basin has not been confirmed.

Petroleum Geology

Knowledge of the petroleum geology of the basin has been garnered from 10 offshore exploratory wells drilled from nine sites in the northern and central portions of the basin (fig. 44) and from a moderately dense grid of seismic-reflection profiles. Data from onshore wells and outcrops, and published sources were also considered. The primary petroleum source rocks for all plays in the basin are presumed to be rocks of the Miocene Monterey Formation, by analogy with several California coastal basins. Although organic geochemical data are lacking for Monterey rocks in the Bodega basin, the presence of organic-rich, thermally mature source rocks is suggested by oil and gas shows in Monterey and other strata in the basin. Structurally anomalous reflectors on seismic-reflection profiles, density contrasts on well logs, and mineralogic compositions of well samples suggest that diagenetic alteration of opal-CT-phase silica to quartz-phase silica has occurred at burial depths of approximately 4,300 feet. If the temperature required for this mineralogic conversion is coincident with the onset of oil generation in Monterey rocks (as described in the Central California province discussion), thermally mature Monterey rocks may exist over much of the basin. Although Monterey rocks in the Bodega basin are thinner and less extensive than in adjacent basins (due to uplift and erosion), the original stratigraphic thickness and ultimate petroleum generative potential of these strata are presumed to have been comparable.

Shows in some of the offshore wells indicate that oil has generated and migrated in the Bodega basin, although the existence of a viable petroleum system (i.e., in which petroleum has generated, migrated, and accumulated within traps) is somewhat speculative due to the limited number and magnitude of the shows. Oil seeps and bituminous sandstones are abundant in the onshore Point Reyes area, and minor shows of oil and gas have been encountered in some onshore wells (Galloway, 1977; Stanley, 1995b); however, no commercial production has been established.

The petroleum potential of the offshore portion of the basin may be most prospective in the vicinity of the Point Reyes fault, where large vertical displacement has created an anomalously thick section of Monterey strata and a number of potential structural traps. However, the absence of significant shows in the offshore wells (many of which were drilled near the fault) suggests that this vertically continuous fault may have been a barrier (rather than pathway) to migrating hydrocarbons.

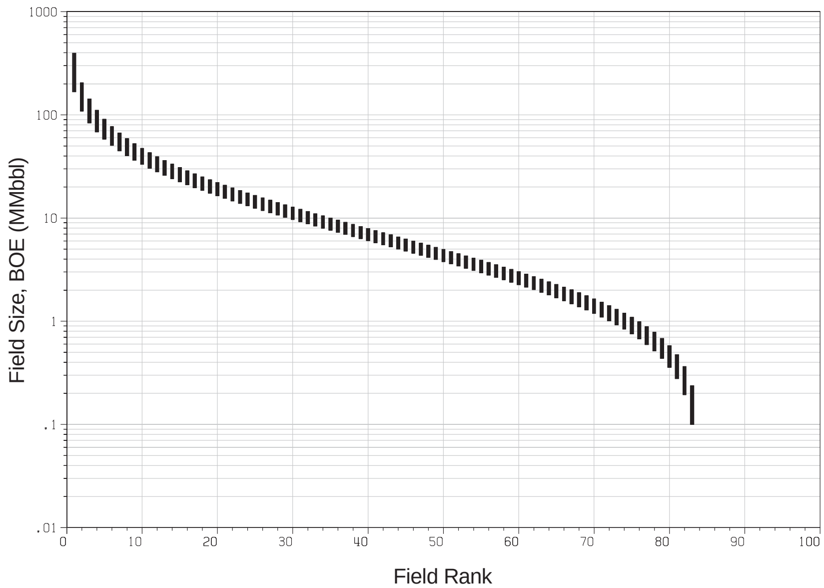

Figure 46. *Field-size rank plot of estimated undiscovered conventionally recoverable resources of the Bodega Basin assessment area. Sizes of undiscovered fields are shown by bars; the top and bottom of a bar represent the 25th- and 75th-percentile values of a probability distribution, respectively.*

PLAYS

Three petroleum geologic plays, defined on the basis of reservoir rock stratigraphy, have been assessed in the Federal offshore portion of the basin (figs. 44 and 45). These are (1) the Neogene Sandstone play (upper Miocene and Pliocene clastic reservoirs), (2) the Monterey Fractured play (middle and upper Miocene fractured siliceous reservoirs), and (3) the Pre-Monterey Sandstone play (Paleocene through middle Miocene clastic reservoirs).

Tertiary sedimentary and volcanic rocks that are stratigraphically similar (and possibly correlative) to some of the strata included in these plays exist in the State offshore and onshore areas of the basin. These adjacent rocks compose the Point Reyes Oil play of the Central Coastal province, which has been described and assessed by the U.S. Geological Survey (Stanley, 1995b).

RESOURCE ESTIMATES

Undiscovered Conventionally Recoverable Resources

Play-specific estimates of undiscovered conventionally recoverable resources have been developed using the subjective assessment method, and these estimates have been statistically aggregated to estimate the total volume of resources in the assessment area. Select data used to develop the resource estimates are shown in appendix C.

As a result of this assessment, the total volume of undiscovered conventionally recoverable resources in the Bodega Basin assessment area is estimated to be 1.42 Bbbl of oil and 1.57 Tcf of associated gas (mean estimates). This volume may exist in 83 fields with sizes ranging from approximately 100 Mbbl to 400 MMbbl of combined oil-equivalent resources (fig. 46). The majority of these resources (approximately 76 percent on a combined oil-equivalence basis) are estimated to exist in the Monterey Fractured play. The low, mean, and high estimates of resources in the assessment area are listed in table 16 and illustrated in figure 47.

Undiscovered Economically Recoverable Resources

Estimates of undiscovered conventionally recoverable resources in the assessment area that may be economically recoverable under various economic scenarios have been developed using the economic assessment method. Select data used to develop the resource estimates are shown in appendix D.

As a result of this assessment, 1.03 Bbbl of oil and 1.13 Tcf of associated gas are estimated to be economically recoverable from the Bodega Basin assessment area under economic conditions existing as of this assessment (i.e., the $18-per-barrel economic scenario) (table 17). Larger volumes of resources are expected to be economically recoverable under increasingly favorable economic conditions (fig. 48).

Table 16. *Estimates of undiscovered conventionally recoverable oil and gas resources in the Bodega Basin assessment area as of January 1, 1995, by play. All estimates are risked values. The low, mean, and high estimates correspond to the 95th-percentile, mean, and 5th-percentile values of a probability distribution, respectively. Percentile values are not additive; some total mean values may not equal the sum of the component values due to independent rounding.*

Play	Oil (MMbbl)			Gas (Bcf)			BOE (MMbbl)		
	Low	Mean	High	Low	Mean	High	Low	Mean	High
Neogene Sandstone	0	54	166	0	59	180	0	65	195
Monterey Fractured	802	1,094	1,524	774	1,139	1,639	945	1,297	1,797
Pre-Monterey Sandstone	0	272	553	0	370	824	0	338	694
Total Assessment Area	*972*	*1,420*	*1,979*	*1,004*	*1,568*	*2,300*	*1,160*	*1,699*	*2,374*

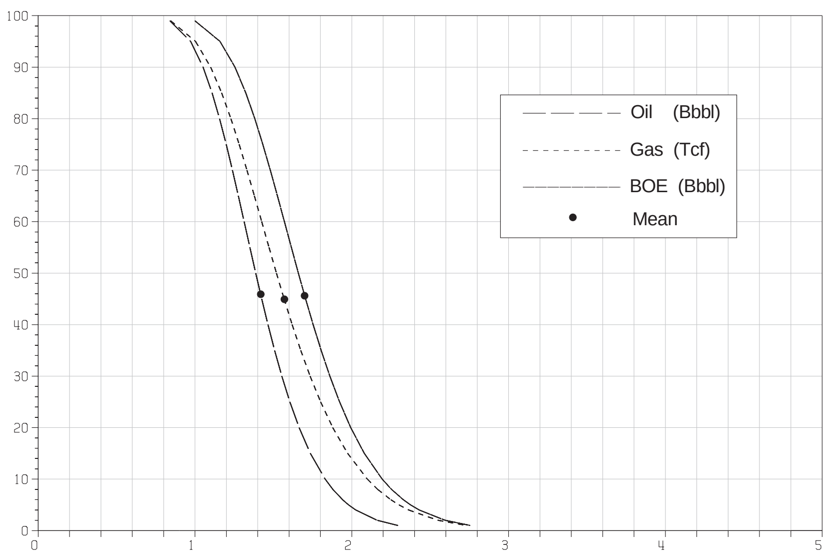

Figure 47. *Cumulative probability plot of estimated undiscovered conventionally recoverable resources of the Bodega Basin assessment area.*

Total Resource Endowment

No accumulations of resources have been discovered in the assessment area. Therefore, the aforementioned estimates of undiscovered conventionally recoverable resources compose the estimated total resource endowment of the area.

Acknowledgments

The author thanks Richard Stanley and James Crouch for sharing information and insight regarding the geology and petroleum potential of the central California coastal area and the Bodega basin, Harold Cousminer for initial study that led to the play definitions, and Scott Drewry for preparing figures.

Additional References

Crouch, Bachman, and Associates, Inc., 1985
Crouch, Bachman, and Associates, Inc., 1988b
Heck and others, 1990
J.K. Crouch and Associates, Inc., 1988
McCulloch, 1989
McLean and Wiley, 1987
Ogle, 1981
Webster and others, 1988

Table 17. *Estimates of undiscovered economically recoverable oil and gas resources in the Bodega Basin assessment area as of January 1, 1995, by economic scenario. All estimates are risked mean values. The $18-per-barrel scenario is based on prices of $18 per bbl of oil and $2.11 per Mcf of gas; the $25-per-barrel scenario is based on prices of $25 per bbl of oil and $2.94 per Mcf of gas; the $50-per-barrel scenario is based on prices of $50 per barrel of oil and $5.87 per Mcf of gas.*

Economic Scenario	Oil (MMbbl)	Gas (Bcf)	BOE (MMbbl)
$18 per barrel	1,026	1,133	1,228
$25 per barrel	1,142	1,261	1,367
$50 per barrel	1,272	1,405	1,522

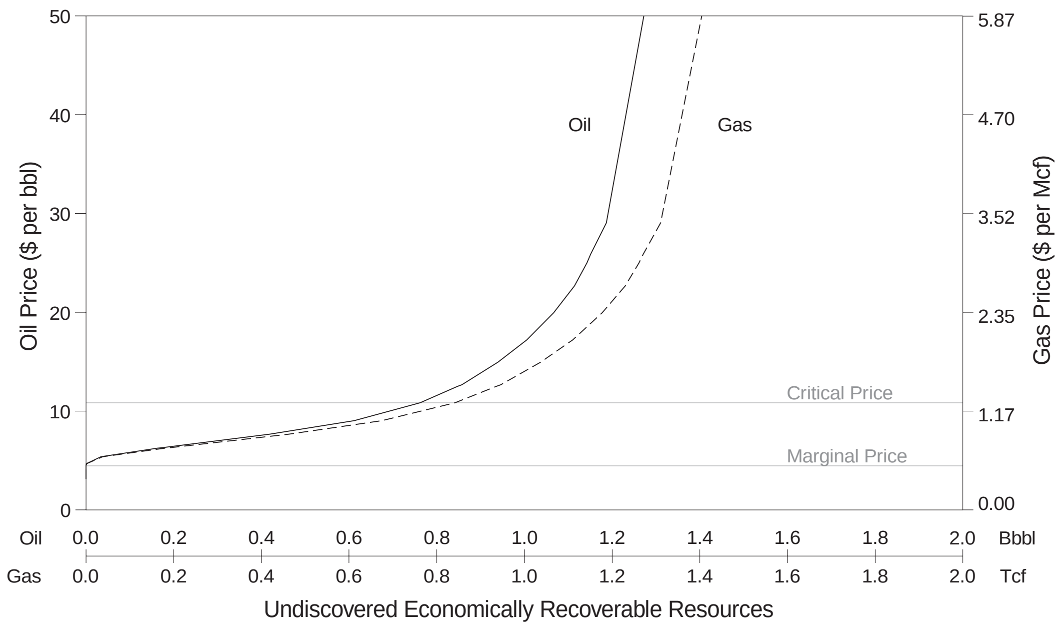

Figure 48. *Price-supply plot of estimated undiscovered economically recoverable resources of the Bodega Basin assessment area.*

NEOGENE SANDSTONE PLAY

PLAY DEFINITION

The Neogene Sandstone play of the Bodega Basin assessment area is defined to include accumulations of oil and associated gas in upper Miocene and Pliocene marine clastic rocks overlying the Monterey Formation. This basin-wide play encompasses an area of approximately 1,700 square miles (fig. 44) and exists at burial depths as great as 4,300 feet.

PETROLEUM GEOLOGIC CHARACTERISTICS

Potential petroleum source rocks for the play are oil-prone Monterey rocks (fig. 45), which may be thermally mature throughout the basin. The oil is expected to be heavy (15 to 20 °API) and high in sulfur, by analogy with Monterey-sourced oils produced from several California coastal basins. Speculatively, reservoirs in this play may contain a greater proportion of gas due to selective upward migration of free associated gas from underlying generative Monterey rocks. No other potential source rocks are presumed to exist for this play.

Potential reservoir rocks consist of upper Miocene to lower Pliocene sandstones and siltstones (possibly correlative in part to the Santa Cruz Mudstone) and lower to upper Pliocene sandstones and siltstones (possibly correlative in part to the Purisima Formation) (fig. 45). Core and log analyses indicate that the rocks have fair to good reservoir quality. Migration of oil and associated gas from underlying generative Monterey rocks is presumed to have occurred along fractures, faults, and unconformities.

Traps are presumed to be both structural and stratigraphic. Structural traps include anticlines, fault truncations, and faulted anticlines. Some potential structural traps have been mapped with seismic profiles; however, much of the post-Monterey section is relatively undeformed and lacks abundant and complex structural traps. Stratigraphic traps may exist at pinchouts of sandstone interbeds and where sandstones wedge out along the Farallon-Pigeon Point high. Seals may be provided by faults and unconformities and by Pliocene and Pleistocene mudstones and shales.

Exploration

Eight exploratory wells have penetrated the Federal offshore portion of this frontier play. No visible shows of oil were observed; however, some indirect indications of oil (i.e., through solvent, fluorescence, and odor) were encountered in a few wells.

Resource Estimates

Undiscovered Conventionally Recoverable Resources

Estimates of undiscovered conventionally recoverable resources in the Federal offshore portion of the play have been developed using the subjective assessment method. Select data used to develop the resource estimates are shown in appendix C.

Structural information from seismic profiles, stratigraphic information from the exploratory wells, and additional data from geologically analogous plays in the adjacent Point Arena and Año Nuevo basins were used to estimate the volume and number of pools in this play. The oil recovery factor (oil yield) was estimated by analogy with several producing fields in the Pico-Repetto Sandstone play of the Santa Barbara-Ventura basin; the solution gas-to-oil ratio was estimated by analogy with select Monterey-producing fields in the onshore and offshore portions of the Santa Maria basin. The viability of this play (play chance) is estimated to be good; the probability that at least one undiscovered accumulation exists is predicted to be 60 percent. However, many prospects are expected to lack adequate fill (i.e., the volume of generated hydrocarbons may be insufficient to fill all traps), reservoir rocks, and/or seal. Therefore, the prospect success ratio (conditional prospect chance) is estimated to be poor; only 30 percent of the prospects are predicted to be pools.

As a result of this assessment, the Federal offshore portion of the play is estimated to contain 54 MMbbl of oil and 59 Bcf of associated gas (mean estimates). This volume of undiscovered conventionally recoverable resources may exist in as many as 27 pools with sizes ranging from approximately 150 Mbbl to 50 MMbbl of combined oil-equivalent resources (fig. 49). The low, mean, and high estimates of resources in the play are listed in table 16.

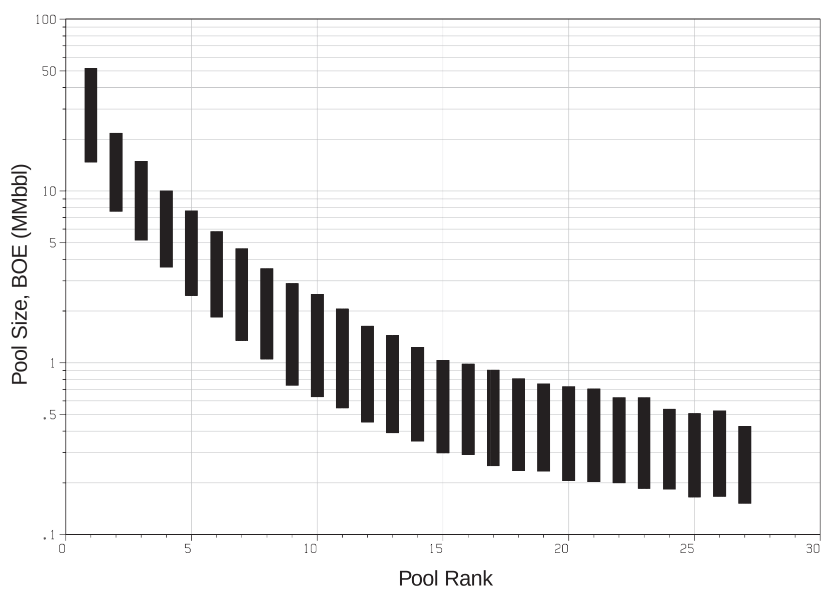

Figure 49. *Pool-size rank plot of estimated undiscovered conventionally recoverable resources of the Neogene Sandstone play, Bodega Basin assessment area. Sizes of undiscovered pools are shown by bars; the top and bottom of a bar represent the 25^{th}- and 75^{th}-percentile values of a probability distribution, respectively.*

MONTEREY FRACTURED PLAY

PLAY DEFINITION

The Monterey Fractured play of the Bodega Basin assessment area is defined to include accumulations of oil and associated gas in middle and upper Miocene fractured siliceous rocks within and overlying the Monterey Formation. This play exists over most of the basin, but is not present along an intrabasinal high near Point San Pedro, where Monterey strata have been uplifted and eroded. The play covers an area of approximately 1,650 square miles (fig. 44) and exists at burial depths as great as 6,000 feet.

PETROLEUM GEOLOGIC CHARACTERISTICS

Potential petroleum source rocks for the play are oil-prone Monterey rocks (fig. 45), which may be thermally mature throughout the basin. The oil is expected to be heavy (15 to 20 ^{o}API) and high in sulfur, by analogy with Monterey-sourced oils produced from several California coastal basins. Speculatively, reservoirs in the upper portion of this play may contain lighter, gas-enriched oil, due to selective upward migration of higher-viscosity oil and free associated gas.

Potential reservoir rocks consist of middle to upper Miocene fractured siliceous shales and cherts of the Monterey Formation and overlying strata (possibly correlative in part to the Santa Cruz Mudstone) (fig. 45). Mineralogic compositions of well samples indicate that the original biogenic (opal-A) silica in these rocks has been diagenetically altered to opal-CT and quartz. Core and log analyses indicate that the rocks have good to excellent reservoir quality, and that the best potential reservoir rocks may exist below the opal-CT-quartz diagenetic boundary, where fracture density and porosity may be enhanced. Multidirectional migration of oil and associated gas from in situ generative Monterey rocks is presumed to have occurred along fractures and faults, some of which breach the diagenetic boundary.

Predominantly structural traps are expected to exist in the play and to include anticlines, fault truncations, and simple to complexly faulted anticlines. Several potential structural traps have been mapped with seismic profiles. Speculatively, some stratigraphic traps formed by pinchouts of siliciclastic interbeds may exist in the play. Seals may be provided by fractures, faults, and unconformities; by an inferred "tar accumulation zone" at the diagenetic boundary; and by mudstones and shales of the overlying Pliocene section.

EXPLORATION

Nine exploratory wells have penetrated the Federal offshore portion of this frontier play. Shows of free tarry oil and tar stains on fractures were encountered within the Monterey section in some wells.

RESOURCE ESTIMATES

Undiscovered Conventionally Recoverable Resources

Estimates of undiscovered conventionally recoverable resources in the Federal offshore portion of the play have been developed using the subjective assessment method. Select data used to develop the resource estimates are shown in appendix C.

Structural information from seismic profiles, stratigraphic information from the exploratory wells, and additional data from geologically analogous plays in the adjacent Point Arena and Año Nuevo basins were used to estimate the volume and number of pools in this play. The oil recovery factor (oil yield) and solution gas-to-oil ratio were estimated by analogy with select Monterey-producing fields in the Federal offshore portion of the Santa Maria and Santa Barbara-Ventura basins. The viability of this play (play chance) is estimated to be assured; the probability that at least one undiscovered accumulation exists is predicted to be 100 percent. However, some prospects are expected to lack adequate fill (i.e., the volume of generated hydrocarbons may be insufficient to fill all traps), reservoir rocks, and/or seal. Therefore, the prospect success ratio (conditional prospect chance) is estimated to be fair; 50 percent of the prospects are predicted to be pools.

As a result of this assessment, the Federal offshore portion of the play is estimated to contain 1.09 Bbbl of oil and 1.14 Tcf of associated gas (mean estimates). This volume of undiscovered conventionally recoverable resources may exist in as many as 126 pools with sizes ranging from approximately 75 Mbbl to 420 MMbbl of combined oil-equivalent resources (fig. 50). The low, mean, and high estimates of resources in the play are listed in table 16.

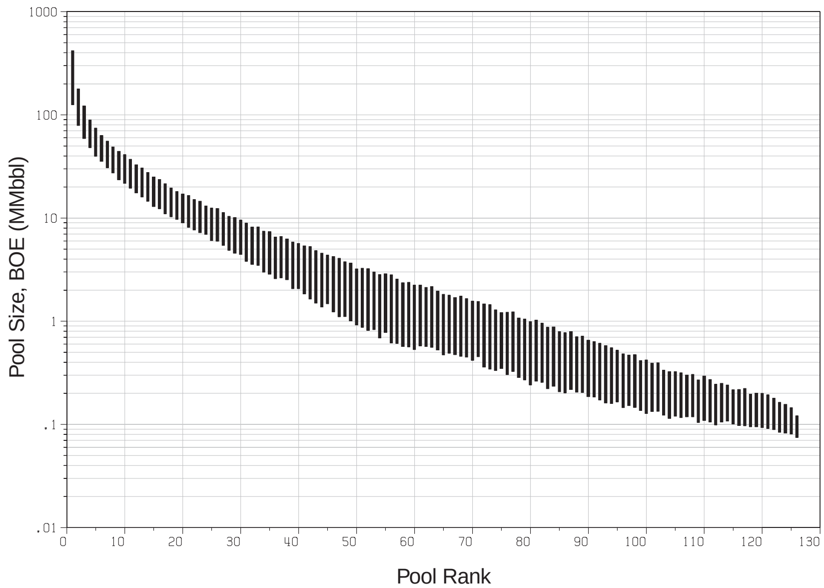

Figure 50. *Pool-size rank plot of estimated undiscovered conventionally recoverable resources of the Monterey Fractured play, Bodega Basin assessment area. Sizes of undiscovered pools are shown by bars; the top and bottom of a bar represent the 25th- and 75th-percentile values of a probability distribution, respectively.*

Pre-Monterey Sandstone Play

Play Definition

The Pre-Monterey Sandstone play of the Bodega Basin assessment area is defined to include accumulations of oil and associated gas in Paleogene and Neogene marine clastic rocks underlying the Monterey Formation. This basin-wide play encompasses an area of approximately 1,700 square miles (fig. 44) and exists at burial depths of approximately 600 to more than 10,000 feet.

Petroleum Geologic Characteristics

The primary potential petroleum source rocks for the play are oil-prone Monterey rocks (fig. 45), which may be thermally mature throughout the basin. The oil is expected to be heavy (15 to 20 °API) and high in sulfur, by analogy with Monterey-sourced oils produced from several California coastal basins. Other potential source rocks may exist in pre-Monterey rocks of this play; however, the generative potential of these in situ source rocks is considered less prospective than the overlying Monterey rocks. Oil from pre-Monterey rocks, if generated, is expected to have higher gravity (25 to 45 °API), lower sulfur content, and a greater proportion of dissolved gas, based on analogy with Paleogene-sourced oils produced from the Santa Barbara-Ventura and onshore La Honda basins.

Potential reservoir rocks consist of Paleocene to middle Eocene conglomeratic sandstones (possibly correlative to the Point Reyes Conglomerate), lower Miocene and possibly Oligocene sandstones and siltstones (possibly correlative in part to the Mindego Basalt and Vaqueros Formation), and middle Miocene sandstones (possibly correlative in part to the Laird Sandstone) (fig. 45). Core and log analyses suggest that these rocks may have fair reservoir quality, but that porosity and permeability may be diminished by the presence of volcaniclastic clays, compaction, and cementation. Migration of oil and associated gas from overlying generative Monterey rocks (and generative pre-Monterey rocks, if they exist) is presumed to have occurred along fractures, faults, and unconformities.

Traps are presumed to be both structural and stratigraphic. Structural traps include anticlines, fault truncations, and simple to complexly faulted anticlines. Several potential structural traps have been mapped with seismic profiles. Stratigraphic traps may exist at pinchouts of sandstone interbeds and where sandstones wedge out along the Farallon-Pigeon Point high. Seals may be provided by faults and unconformities, volcanic rocks and shales of this play, and siliceous shales and cherts of the overlying Miocene and Pliocene sections.

EXPLORATION

Nine exploratory wells have penetrated the Federal offshore portion of this frontier play. Weak oil shows and log analysis indicate the presence of hydrocarbons in a few wells.

RESOURCE ESTIMATES

Undiscovered Conventionally Recoverable Resources

Estimates of undiscovered conventionally recoverable resources in the Federal offshore portion of the play have been developed using the subjective assessment method. Select data used to develop the resource estimates are shown in appendix C.

Structural information from seismic profiles, stratigraphic information from the exploratory wells, and additional data from geologically analogous plays in the adjacent Point Arena and Año Nuevo basins were used to estimate the volume and number of pools in this play. The oil recovery factor (oil yield) was estimated by analogy with select producing fields in the Sespe-Alegria-Vaqueros Sandstone play in the Santa Barbara-Ventura basin. This analog data set and field data from fractured Monterey reservoirs in the onshore and offshore Santa Maria basin were jointly considered in estimating the solution gas-to-oil ratio of this play, to account for the possibility of multiple (pre-Monterey and Monterey) sourcing. The viability of this play (play chance) is estimated to be good; the probability that at least one undiscovered accumulation exists is predicted to be 70 percent. However, many prospects are expected to lack adequate fill (i.e., the volume of generated hydrocarbons may be insufficient to fill all traps), reservoir rocks, and/or seal. Therefore, the prospect success ratio (conditional prospect chance) is estimated to be poor; 30 percent of the prospects are predicted to be pools.

As a result of this assessment, the Federal offshore portion of the play is estimated to contain 272 MMbbl of oil and 370 Bcf of associated gas (mean estimates). This volume of undiscovered conventionally recoverable resources may exist in as many as 92 pools with sizes ranging from approximately 105 Mbbl to 120 MMbbl of combined oil-equivalent resources (fig. 51). The low, mean, and high estimates of resources in the play are listed in table 16.

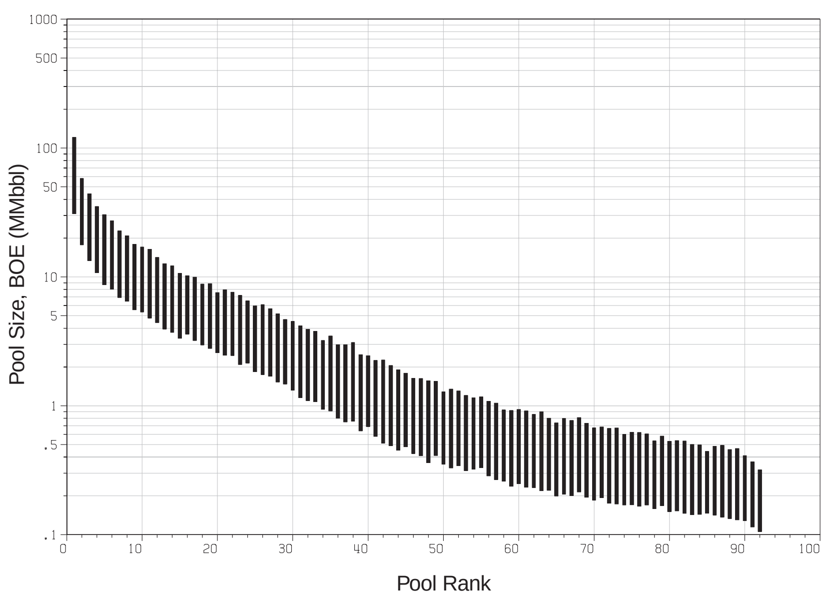

Figure 51. *Pool-size rank plot of estimated undiscovered conventionally recoverable resources of the Pre-Monterey Sandstone play, Bodega Basin assessment area. Sizes of undiscovered pools are shown by bars; the top and bottom of a bar represent the 25th- and 75th-percentile values of a probability distribution, respectively.*

AÑO NUEVO BASIN

by Catherine A. Dunkel

LOCATION

The Año Nuevo basin (or "Outer Santa Cruz basin," as originally defined by Hoskins and Griffiths (1971)) is located between the Bodega and Partington basins in the Central California province (fig. 33). This elongate, northwest-trending basin extends approximately 80 miles from Monterey Bay to the Farallon Islands, is approximately 15 miles wide, and occupies an area of approximately 1,000 square miles (fig. 52). The basin is bounded on the west by the Outer Santa Cruz high and on the east by the Farallon-Pigeon Point high and the San Gregorio fault zone. A small portion of the basin lies in State waters and is exposed onshore at Point Año Nuevo.

The Año Nuevo Basin assessment area comprises only the Federal offshore portion of the basin (i.e., seaward of the 3-mile line). Water depths in the assessment area range from approximately 200 feet at the 3-mile line near Point Año Nuevo to more than 4,000 feet on the continental slope southwest of the Farallon Islands.

GEOLOGIC SETTING

The Cenozoic stratigraphic succession of the Año Nuevo basin area indicates that the area has undergone a complex history of subsidence, sedimentary deposition, volcanism, uplift, and erosion (McCulloch, 1987b). The oldest rocks penetrated by offshore exploratory wells are Upper Cretaceous

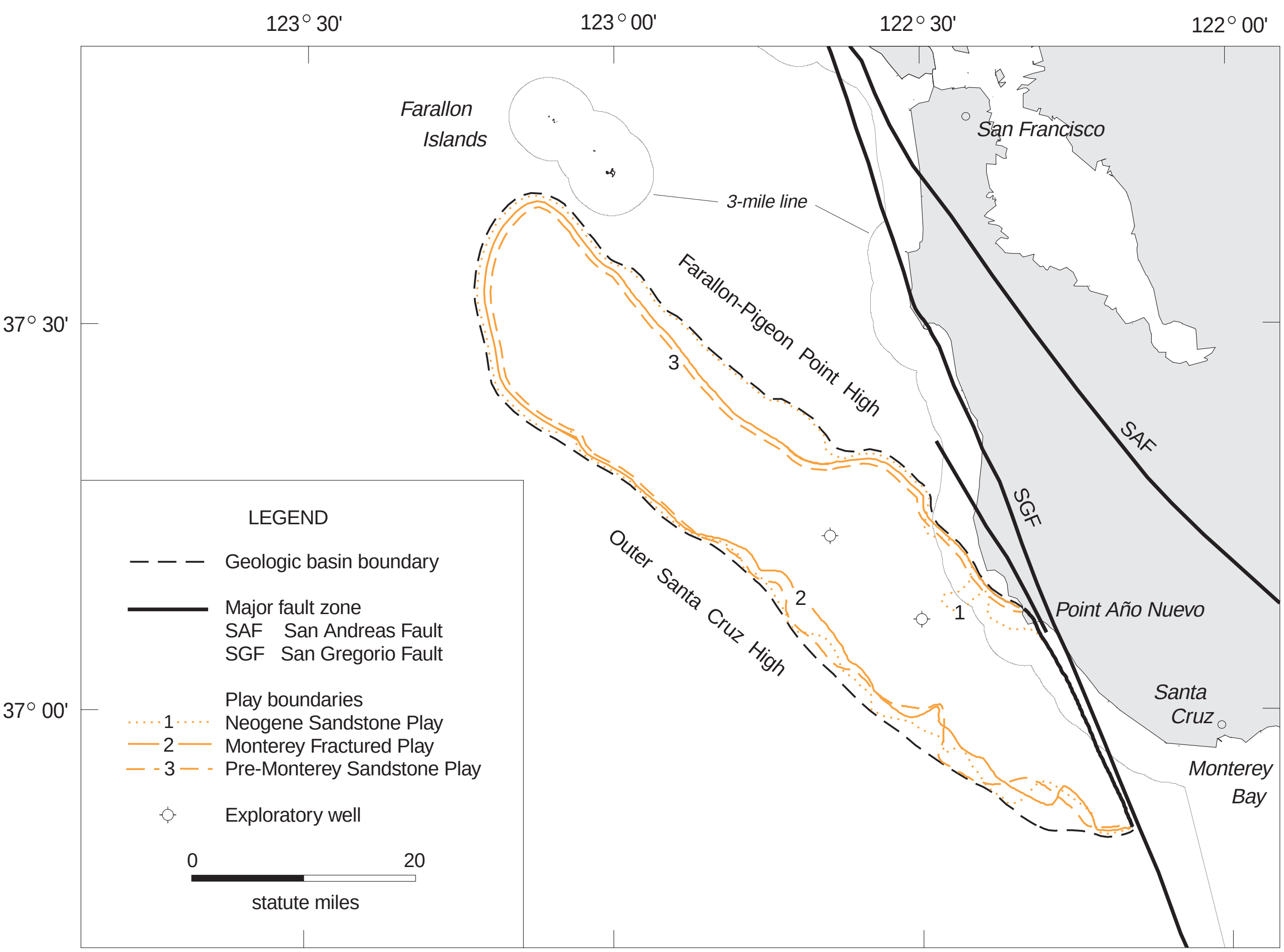

Figure 52. *Map of the Año Nuevo Basin assessment area showing petroleum geologic plays and wells.*

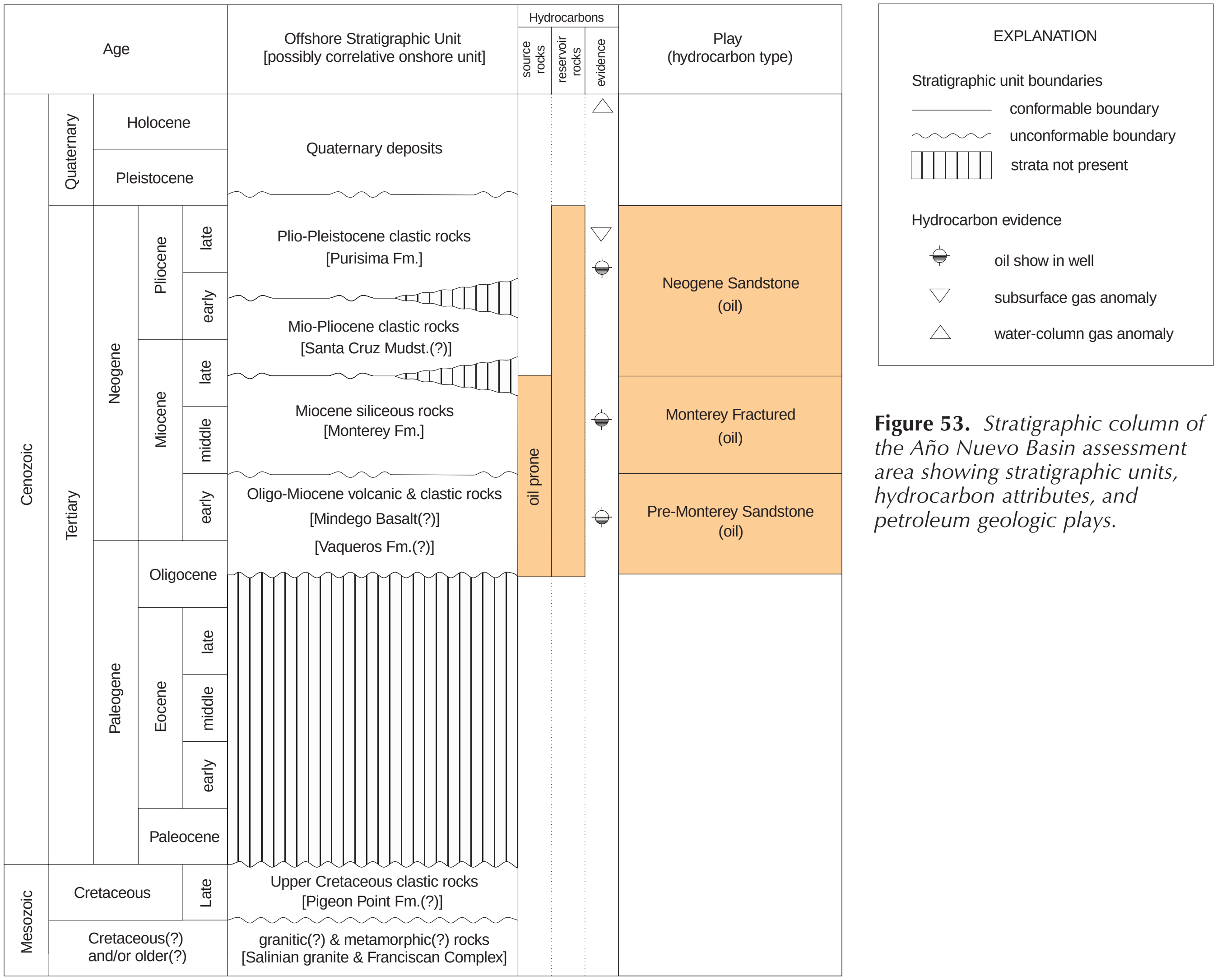

Figure 53. *Stratigraphic column of the Año Nuevo Basin assessment area showing stratigraphic units, hydrocarbon attributes, and petroleum geologic plays.*

submarine fan deposits similar (and possibly correlative[8]) to those exposed onshore at Point Año Nuevo (fig. 53). The age and character of basement rocks underlying the Upper Cretaceous strata onshore are unknown. Offshore, the Upper Cretaceous strata probably overlie Cretaceous and/or older rocks of the Salinia terrane (McCulloch, 1989), including granitic rocks (Hoskins and Griffiths, 1971) and metamorphic rocks of the Franciscan Complex (Silver and others, 1971; Mullins and Nagle, 1981); however, the spatial distribution of these dissimilar basement rocks is poorly understood. The initial subsidence and formation of the Año Nuevo basin proper may be recorded by the Upper Cretaceous strata; alternatively, these strata may be a local remnant of a larger body of Cretaceous and Paleogene strata (i.e., including strata in the Point Arena and adjacent Bodega basins) that were deposited, uplifted, and eroded prior to the formation of the basin. Following an episode of Paleogene uplift and erosion (or nondeposition of Paleocene to Oligocene strata), an episode of late Oligocene to early Miocene subsidence occurred, during which interbedded volcanic and marine clastic strata of early Miocene and possibly Oligocene age were deposited; the volcanic rocks are lithologically and temporally similar to those in other California coastal basins

[8] Strata penetrated in the offshore wells of the Año Nuevo basin were initially described by Hoskins and Griffiths (1971) and have been subsequently described by Zieglar and Cassell (1978) and McCulloch (1987b). Webster and Yenne (1987) assigned onshore formation names to the offshore strata based on lithologic and biostratigraphic (i.e., benthic foraminiferal) data from offshore well samples (fig. 53); however, given the limited number of wells and samples in the offshore Año Nuevo basin and the lack of demonstrated physical continuity between the offshore and onshore strata, these assignments and onshore-offshore correlations are uncertain. Therefore, the onshore-offshore correlations cited here and in figure 53 are considered to be possible correlations (and in some cases, possible partial correlations).

and may record a middle Tertiary extensional event that produced volcanism along the continental margin (McCulloch, 1987b). The bulk of the Año Nuevo basin fill consists of a thick sequence of middle to upper Miocene marine clastic, siliceous, and siliciclastic rocks that record a middle Miocene transgression, subsequent subsidence, and hemipelagic siliceous deposition. Some of the siliceous deposits appear to have been uplifted and eroded during the late Miocene and early Pliocene. The uneroded siliceous rocks are overlain by Pliocene and Pleistocene marine clastic rocks and semiconsolidated Quaternary marine deposits. These major Tertiary stratigraphic sequences, which were deposited in marine shelf and slope settings, are separated by boundaries that are evident on seismic-reflection profiles. The boundaries are generally unconformable along the uplifted margins of the basin and are locally unconformable at intrabasinal highs.

The structural axis and many faults and folds in the basin are predominantly northwest-trending and subparallel (or at low angles) to the San Andreas fault zone; this suggests that the origin and early deformational history of the basin may have been largely controlled by this right-lateral strike-slip fault (Wilcox and others, 1973; Blake and others, 1978). However, the variable orientation of many fold and fault trends suggests that some structural features may be genetically related to the San Gregorio fault and/or late Cenozoic compression.

Petroleum Geology

Knowledge of the petroleum geology of the basin has been garnered from two offshore exploratory wells (OCS-P 0035 #1 (south) and OCS-P 0036 #1 (north)) and a moderately dense grid of high-quality, seismic-reflection profiles across all but the northwesternmost portion of the basin; data from onshore wells and outcrops and published sources were also considered. The primary petroleum source rocks for all plays in the basin are presumed to be rocks of the Miocene Monterey Formation (fig. 53), by analogy with several California coastal basins. Although organic geochemical data are lacking for Monterey rocks in the Año Nuevo basin, the presence of organic-rich, thermally mature source rocks is strongly indicated by shows in Monterey and other strata in the basin. Structurally anomalous reflectors on seismic-reflection profiles, density contrasts on well logs, and mineralogic compositions of well samples suggest that diagenetic alteration of opal-CT-phase silica to quartz-phase silica has occurred at burial depths of approximately 4,700 feet. If the temperature required for this mineralogic conversion is coincident with the onset of oil generation in Monterey rocks (as described in the Central California province discussion), thermally mature Monterey rocks may exist over much of the basin, and two locally thick areas in the central and southeast portions of the basin may be potential oil-generation centers.

Abundant oil shows in the offshore wells and subsurface seismic amplitude anomalies (i.e., "bright spots" interpreted to be gas) indicate that oil and gas have generated and migrated within the Año Nuevo basin (fig. 53). The existence of a viable petroleum system (i.e., in which petroleum has generated, migrated, and accumulated within traps) is further confirmed by the spatial coincidence of several water-column seismic anomalies (interpreted to be gas) with the crests of subsurface structural traps. The petroleum potential of the basin may be most prospective in the southeast portion, where the San Gregorio and other vertically continuous faults may have created migration pathways through potentially generative Monterey rocks, and where numerous structural traps exist.

Plays

Three petroleum geologic plays, defined on the basis of reservoir rock stratigraphy, have been assessed in the Federal offshore portion of the basin (figs. 52 and 53). These are (1) the Neogene Sandstone play (upper Miocene and Pliocene clastic reservoirs), (2) the Monterey Fractured play (middle and upper Miocene fractured siliceous reservoirs), and (3) the Pre-Monterey Sandstone play (lower Miocene and possibly Oligocene clastic reservoirs).

Neogene sedimentary and volcanic rocks that are stratigraphically similar (and possibly correlative) to some of the strata included in these plays exist in the State offshore and onshore areas of the basin. These adjacent rocks compose the Pescadero Oil play of the Central Coastal province, which has been described and assessed by the U.S. Geological Survey (Stanley, 1995b).

Resource Estimates

Undiscovered Conventionally Recoverable Resources

Play-specific estimates of undiscovered conventionally recoverable resources have been developed using the subjective assessment method, and these estimates have been statistically aggregated to estimate the total volume of resources in the assessment area. Select data used to develop the resource estimates are shown in appendix C.

As a result of this assessment, the total volume of undiscovered conventionally recoverable resources

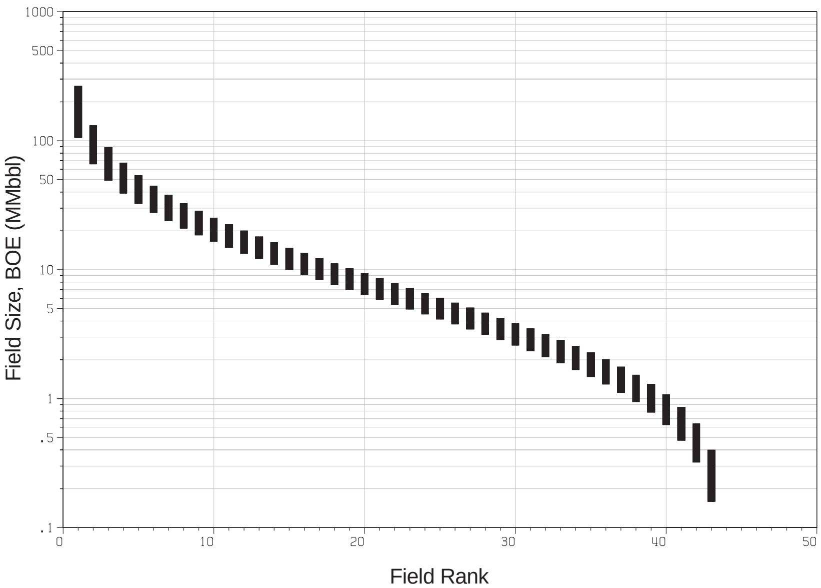

Figure 54. *Field-size rank plot of estimated undiscovered conventionally recoverable resources of the Año Nuevo Basin assessment area. Sizes of undiscovered fields are shown by bars; the top and bottom of a bar represent the 25th- and 75th-percentile values of a probability distribution, respectively.*

Table 18. *Estimates of undiscovered conventionally recoverable oil and gas resources in the Año Nuevo Basin assessment area as of January 1, 1995, by play. All estimates are risked values. The low, mean, and high estimates correspond to the 95th-percentile, mean, and 5th-percentile values of a probability distribution, respectively. Percentile values are not additive; some total mean values may not equal the sum of the component values due to independent rounding.*

Play	Oil (MMbbl)			Gas (Bcf)			BOE (MMbbl)		
	Low	Mean	High	Low	Mean	High	Low	Mean	High
Neogene Sandstone	0	81	184	0	95	219	0	98	222
Monterey Fractured	406	583	866	374	602	964	477	690	1,023
Pre-Monterey Sandstone	0	55	146	0	80	229	0	70	183
Total Assessment Area	*488*	*720*	*1,011*	*487*	*777*	*1,158*	*579*	*858*	*1,208*

Figure 55. *Cumulative probability plot of estimated undiscovered conventionally recoverable resources of the Año Nuevo Basin assessment area.*

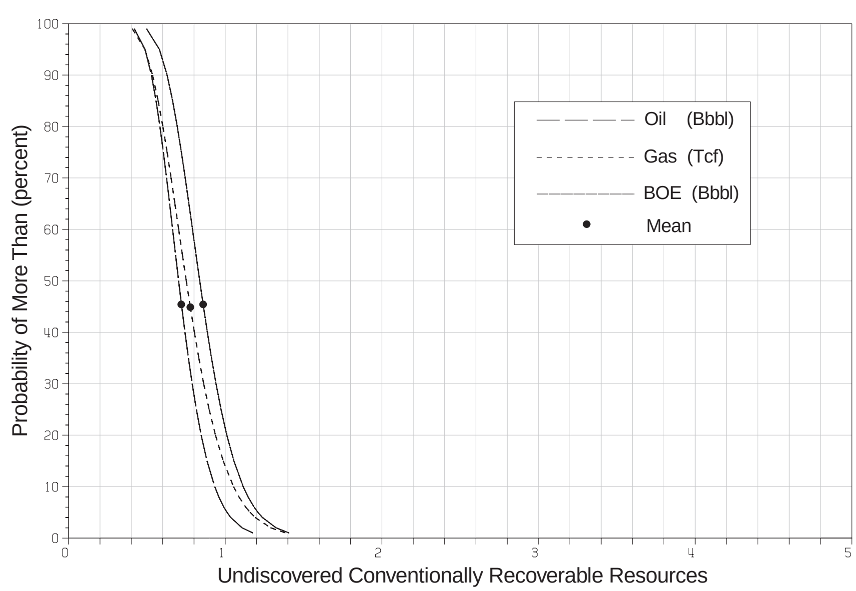

Table 19. *Estimates of undiscovered economically recoverable oil and gas resources in the Año Nuevo Basin assessment area as of January 1, 1995, by economic scenario. All estimates are risked mean values. The $18-per-barrel scenario is based on prices of $18 per bbl of oil and $2.11 per Mcf of gas; the $25-per-barrel scenario is based on prices of $25 per bbl of oil and $2.94 per Mcf of gas; the $50-per-barrel scenario is based on prices of $50 per barrel of oil and $5.87 per Mcf of gas.*

Economic Scenario	Oil (MMbbl)	Gas (Bcf)	BOE (MMbbl)
$18 per barrel	475	512	566
$25 per barrel	545	588	650
$50 per barrel	632	682	754

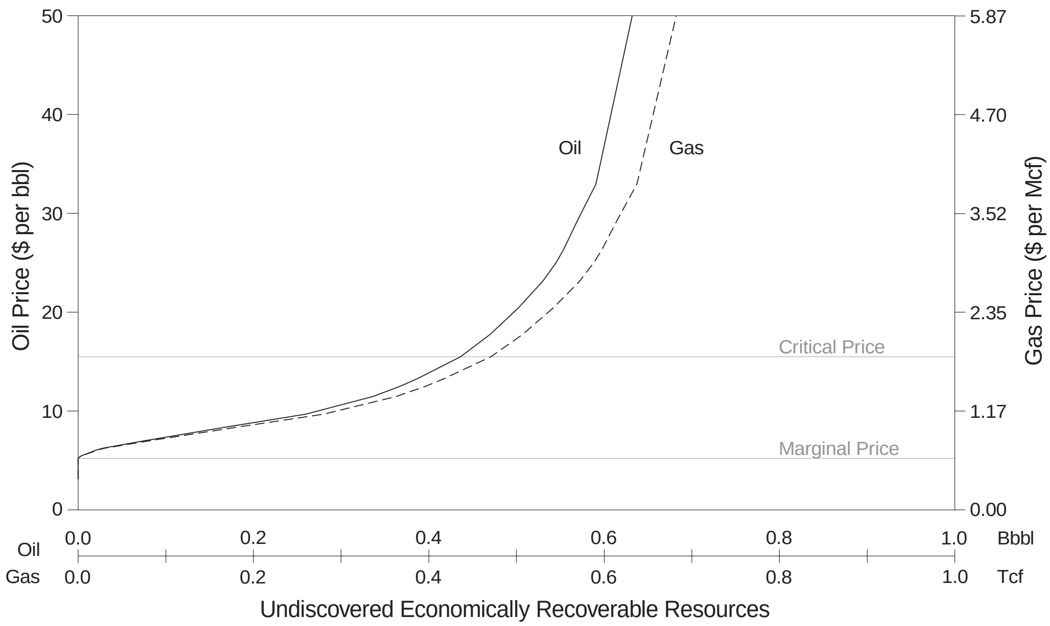

Figure 56. *Price-supply plot of estimated undiscovered economically recoverable resources of the Año Nuevo Basin assessment area.*

in the Año Nuevo Basin assessment area is estimated to be 720 MMbbl of oil and 777 Bcf of associated gas (mean estimates). This volume may exist in 43 fields with sizes ranging from approximately 160 Mbbl to 265 MMbbl of combined oil-equivalent resources (fig. 54). The majority of these resources (approximately 80 percent on a combined oil-equivalence basis) are estimated to exist in the Monterey Fractured play. The low, mean, and high estimates of resources in the assessment area are listed in table 18 and illustrated in figure 55.

Undiscovered Economically Recoverable Resources

Estimates of undiscovered conventionally recoverable resources in the assessment area that may be economically recoverable under various economic scenarios have been developed using the economic assessment method. Select data used to develop the resource estimates are shown in appendix D.

As a result of this assessment, 475 MMbbl of oil and 512 Bcf of associated gas are estimated to be economically recoverable from the Año Nuevo Basin assessment area under economic conditions existing as of this assessment (i.e., the $18-per-barrel economic scenario) (table 19). Larger volumes of resources are expected to be economically recoverable under increasingly favorable economic conditions (fig. 56).

Total Resource Endowment

No accumulations of resources have been discovered in the assessment area. Therefore, the aforementioned estimates of undiscovered conventionally recoverable resources compose the estimated total resource endowment of the area.

Acknowledgments

The author thanks Richard Stanley and James Crouch for sharing information and insight regarding the geology and petroleum potential of the central California coastal area and the Año Nuevo basin, James Cummings and Richard Hazen for assisting in preparing maps, Scott Drewry for preparing figures, and Margaret Kimbell-Drewry for initial data compilation.

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NEOGENE SANDSTONE PLAY

PLAY DEFINITION

The Neogene Sandstone play of the Año Nuevo Basin assessment area is defined to include accumulations of oil and associated gas in upper Miocene and Pliocene clastic rocks overlying the Monterey Formation. This basin-wide play encompasses an area of approximately 900 square miles (fig. 52) and exists at burial depths of approximately 1,000 to 3,000 feet.

PETROLEUM GEOLOGIC CHARACTERISTICS

Potential petroleum source rocks for the play are oil-prone Monterey rocks (fig. 53), which may be thermally mature throughout the basin; two areas in the central and southeast portions of the basin may be potential oil-generation centers. The oil is expected to be heavy (15 to 20 °API) and high in sulfur, by analogy with Monterey-sourced oils produced from several California coastal basins. Speculatively, reservoirs in this play may contain a greater proportion of gas due to selective upward migration of free associated gas from underlying generative Monterey rocks. No other potential source rocks are presumed to exist for this play.

Potential reservoir rocks consist of upper Miocene to lower Pliocene sandstones and siltstones (possibly correlative in part to the Santa Cruz Mudstone) and lower to upper Pliocene sandstones and siltstones (possibly correlative in part to the Purisima Formation) (fig. 53). Core and log analyses indicate that the rocks have fair to good reservoir quality.

Migration of oil and associated gas from underlying generative Monterey rocks is presumed to have occurred along fractures, faults, and unconformities.

Structural and stratigraphic traps are expected to exist in the play. Potential structural traps include anticlines, fault truncations, and faulted anticlines; although some of these have been mapped with seismic profiles, much of the post-Monterey section is relatively undeformed and lacks abundant and complex structural traps. Stratigraphic traps may exist at pinchouts of sandstone interbeds and where sandstones wedge out along the Outer Santa Cruz and Farallon-Pigeon Point highs. Seals may be provided by faults and unconformities and by Pliocene and Pleistocene mudstones and shales.

EXPLORATION

Two exploratory wells have penetrated the Federal offshore portion of this frontier play. No visible shows of oil were observed; however, a solvent show of oil was encountered in one well (OCS-P 0036 #1). Additionally, the presence of gas is strongly suggested by a well-imaged seismic amplitude anomaly (bright spot) in the southern part of the play.

RESOURCE ESTIMATES

Undiscovered Conventionally Recoverable Resources

Estimates of undiscovered conventionally recoverable resources in the Federal offshore portion of the play have been developed using the subjective

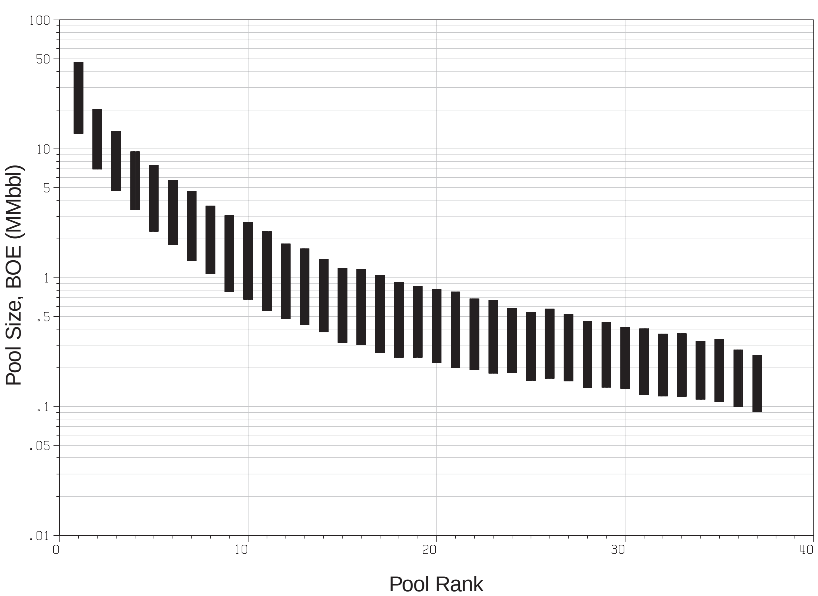


Figure 57. *Pool-size rank plot of estimated undiscovered conventionally recoverable resources of the Neogene Sandstone play, Año Nuevo Basin assessment area. Sizes of undiscovered pools are shown by bars; the top and bottom of a bar represent the 25th- and 75th-percentile values of a probability distribution, respectively.*

assessment method. Select data used to develop the resource estimates are shown in appendix C.

Structural information from seismic profiles and stratigraphic information from the exploratory wells were used to estimate the volume and number of pools. The oil recovery factor (oil yield) was estimated by analogy with several producing fields in the Pico-Repetto Sandstone play of the Santa Barbara-Ventura basin; the solution gas-to-oil ratio was estimated by analogy with select Monterey-producing fields in the onshore and offshore portions of the Santa Maria basin. The viability of this play (play chance) is estimated to be excellent; the probability that at least one undiscovered accumulation exists is predicted to be 95 percent. However, many prospects are expected to lack adequate fill (i.e., the volume of generated hydrocarbons may be insufficient to fill all traps), reservoir rocks, and/or seal. Therefore, the prospect success ratio (conditional prospect chance) is estimated to be poor; only 30 percent of the prospects are predicted to be pools.

As a result of this assessment, the Federal offshore portion of the play is estimated to contain 81 MMbbl of oil and 95 Bcf of associated gas (mean estimates). This volume of undiscovered conventionally recoverable resources may exist in as many as 37 pools with sizes ranging from approximately 90 Mbbl to 50 MMbbl of combined oil-equivalent resources (fig. 57). The low, mean, and high estimates of resources in the play are listed in table 18.

Monterey Fractured Play

Play Definition

The Monterey Fractured play of the Año Nuevo Basin assessment area is defined to include accumulations of oil and associated gas in middle and upper Miocene fractured siliceous rocks of the Monterey Formation. This basin-wide play encompasses an area of approximately 800 square miles (fig. 52) and exists at burial depths of approximately 3,000 to 6,000 feet.

Petroleum Geologic Characteristics

Potential petroleum source rocks for the play are oil-prone Monterey rocks (fig. 53), which may be thermally mature throughout the basin; two areas in the central and southeast portions of the basin may be potential oil-generation centers. The oil is expected to be heavy (15 to 20 °API) and high in sulfur, by analogy with Monterey-sourced oils produced from several California coastal basins. Speculatively, reservoirs in the upper portion of this play may contain lighter, gas-enriched oil due to selective upward migration of higher-viscosity oil and free associated gas.

Potential reservoir rocks consist of middle to upper Miocene fractured siliceous shales and cherts of the Monterey Formation (fig. 53). Mineralogic compositions of well samples indicate that the original biogenic (opal-A) silica in these rocks has been diagenetically altered to opal-CT and quartz. Core and log analyses indicate that the rocks have good to excellent reservoir quality, and that the best potential reservoir rocks may exist below the opal-CT-to-quartz diagenetic boundary, where fracture density and porosity may be enhanced. Multidirectional migration of oil and associated gas from in situ generative Monterey rocks is presumed to have occurred along fractures and faults, some of which breach the diagenetic boundary.

Predominantly structural traps are expected to exist in the play and to include anticlines, fault truncations, and simple to complexly faulted anticlines. Several potential structural traps have been mapped with seismic profiles; the majority of these exist within a northwest-trending zone along the eastern margin of the basin. Speculatively, some stratigraphic traps formed by pinchouts of siliciclastic interbeds may exist in the play. Seals may be provided by fractures, faults, and unconformities; by an inferred “tar accumulation zone” at the diagenetic boundary; and by mudstones and shales of the overlying Pliocene section.

Exploration

Two exploratory wells have penetrated the Federal offshore portion of this frontier play. Abundant shows of free tarry oil, tar stains on fractures, and pieces of viscous and dry tar were encountered throughout the Monterey section in both wells.

Resource Estimates

Undiscovered Conventionally Recoverable Resources

Estimates of undiscovered conventionally recoverable resources in the Federal offshore portion of the play have been developed using the subjective assessment method. Select data used to develop the resource estimates are shown in appendix C.

Structural information from seismic profiles and stratigraphic information from the exploratory wells were used to estimate the volume and number of pools. The oil recovery factor (oil yield) and solution gas-to-oil ratio were estimated by analogy with select Monterey-producing fields in the Federal

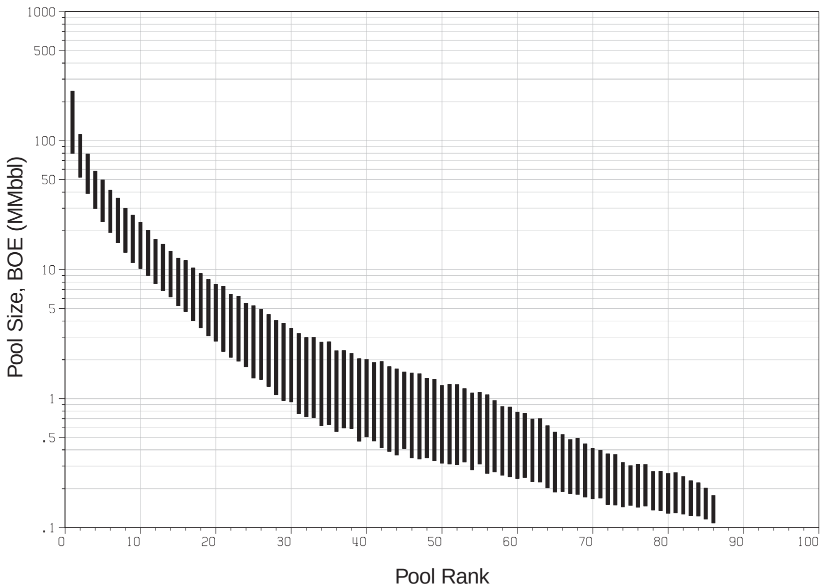


Figure 58. *Pool-size rank plot of estimated undiscovered conventionally recoverable resources of the Monterey Fractured play, Año Nuevo Basin assessment area. Sizes of undiscovered pools are shown by bars; the top and bottom of a bar represent the 25th- and 75th-percentile values of a probability distribution, respectively.*

offshore portion of the Santa Maria and Santa Barbara-Ventura basins. The viability of this play (play chance) is estimated to be assured; the probability that at least one undiscovered accumulation exists is predicted to be 100 percent. However, some prospects are expected to lack adequate fill (i.e., the volume of generated hydrocarbons may be insufficient to fill all traps), reservoir rocks, and/or seal. Therefore, the prospect success ratio (conditional prospect chance) is estimated to be good; 60 percent of the prospects are predicted to be pools.

As a result of this assessment, the Federal offshore portion of the play is estimated to contain 583 MMbbl of oil and 602 Bcf of associated gas (mean estimates). This volume of undiscovered conventionally recoverable resources may exist in as many as 86 pools with sizes ranging from approximately 110 Mbbl to 245 MMbbl of combined oil-equivalent resources (fig. 58). The low, mean, and high estimates of resources in the play are listed in table 18.

Pre-Monterey Sandstone Play

Play Definition

The Pre-Monterey Sandstone play of the Año Nuevo Basin assessment area is defined to include accumulations of oil and associated gas in lower Miocene and possibly Oligocene clastic rocks underlying the Monterey Formation. This basin-wide play encompasses an area of approximately 800 square miles (fig. 52) and exists at burial depths of approximately 5,000 to 8,000 feet.

Petroleum Geologic Characteristics

The primary potential petroleum source rocks for the play are oil-prone Monterey rocks (fig. 53), which may be thermally mature throughout the basin; two areas in the central and southeast portions of the basin may be potential oil-generation centers. The oil is expected to be heavy (15 to 20 °API) and high in sulfur, by analogy with Monterey-sourced oils produced from several California coastal basins. Other potential source rocks may exist in pre-Monterey clastic rocks of this play; however, the generative potential of these in situ source rocks is considered less prospective than the overlying Monterey rocks. Oil from pre-Monterey rocks, if generated, is expected to have higher gravity (25 to 45 °API), lower sulfur content, and a greater proportion of dissolved gas, based on analogy with Paleogene-sourced oils produced from the Santa Barbara-Ventura and onshore La Honda basins.

Potential reservoir rocks consist of lower Miocene and possibly Oligocene sandstones and siltstones (possibly correlative in part to the Mindego Basalt and Vaqueros Formation) (fig. 53). Core and log analyses suggest that these rocks may have fair reservoir quality, but that porosity and permeability may be diminished by the presence of volcaniclastic clays, compaction, and cementation. Migration of oil and associated gas from overlying generative

Monterey rocks (and generative pre-Monterey rocks, if they exist) is presumed to have occurred along fractures, faults, and unconformities.

Structural and stratigraphic traps are expected to exist in the play. Potential structural traps include anticlines, fault truncations, and simple to complexly faulted anticlines. Several potential structural traps have been mapped with seismic profiles; the majority of these exist within a northwest-trending zone along the eastern margin of the basin. Stratigraphic traps may exist at pinchouts of sandstone interbeds and where sandstones wedge out along the Outer Santa Cruz and Farallon-Pigeon Point highs. Seals may be provided by faults and unconformities, volcanic rocks and shales of this play, and siliceous shales and cherts of the overlying Miocene and Pliocene sections.

Exploration

Two exploratory wells have penetrated the Federal offshore portion of this frontier play. Visible oil shows were observed in one well (OCS-P 0035 #1) and some solvent shows were observed in the other well (OCS-P 0036 #1).

Resource Estimates

Undiscovered Conventionally Recoverable Resources

Estimates of undiscovered conventionally recoverable resources in the Federal offshore portion of the play have been developed using the subjective assessment method. Select data used to develop the resource estimates are shown in appendix C.

Structural information from seismic profiles and stratigraphic information from the exploratory wells were used to estimate the volume and number of pools. The oil recovery factor (oil yield) was estimated by analogy with select producing fields in the Sespe-Alegria-Vaqueros Sandstone play in the Santa Barbara-Ventura basin. This analog data set and field data from fractured Monterey reservoirs in the onshore and offshore Santa Maria basin were jointly considered in estimating the solution gas-to-oil ratio of this play, to account for the possibility of multiple (pre-Monterey and Monterey) sourcing. The viability of this play (play chance) is estimated to be good; the probability that at least one undiscovered accumulation exists is predicted to be 60 percent. However, many prospects are expected to lack adequate fill (i.e., the volume of generated hydrocarbons may be insufficient to fill all traps), reservoir rocks, and/or seal. Therefore, the prospect success ratio (conditional prospect chance) is estimated to be poor; 30 percent of the prospects are predicted to be pools.

As a result of this assessment, the Federal offshore portion of the play is estimated to contain 55 MMbbl of oil and 80 Bcf of associated gas (mean estimates). This volume of undiscovered conventionally recoverable resources may exist in as many as 54 pools with sizes ranging from approximately 50 Mbbl to 40 MMbbl of combined oil-equivalent resources (fig. 59). The low, mean, and high estimates of resources in the play are listed in table 18.

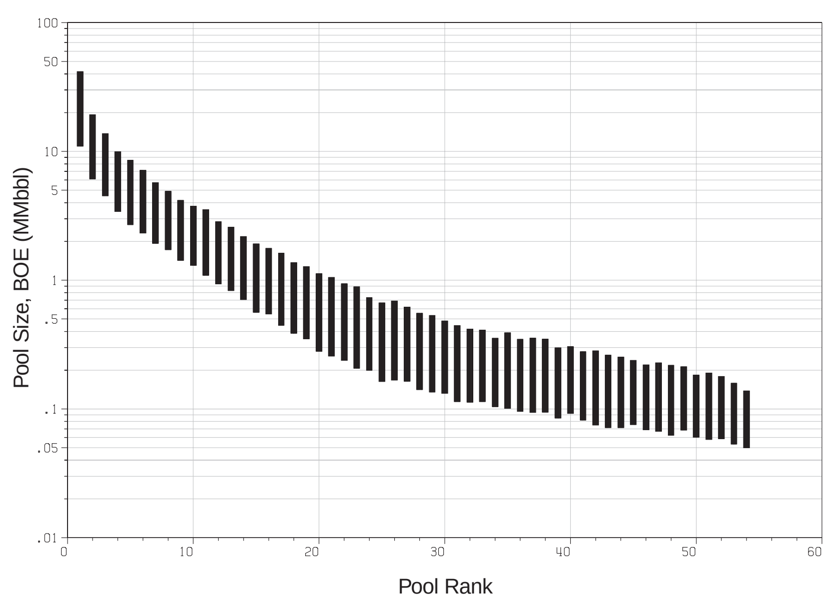


Figure 59. *Pool-size rank plot of estimated undiscovered conventionally recoverable resources of the Pre-Monterey Sandstone play, Año Nuevo Basin assessment area. Sizes of undiscovered pools are shown by bars; the top and bottom of a bar represent the 25th- and 75th-percentile values of a probability distribution, respectively.*

SANTA MARIA-PARTINGTON BASIN

by Drew Mayerson

Location

The Santa Maria basin and the Partington basin (or "Sur Basin," as described by McCulloch (1987b)) are the southernmost assessed basins in the Central California province (fig. 33). Both are northwest-trending basins with fault-bounded eastern limits and structural highs on the north and south.

The Santa Maria basin proper is informally subdivided along the Hosgri fault zone into onshore and offshore subareas (fig. 60). The offshore Santa Maria basin is bounded on the west by the Santa Lucia Bank fault as far north as approximately Point Piedras Blancas. North of that point, a northeast-trending structural discontinuity (referred to as the "San Martin structural discontinuity" by McCulloch (1987b)) separates west-dipping, highly deformed basement strata of the offshore Santa Maria basin from lesser-deformed, east-dipping basement strata of the Partington basin. The northeast-trending "Amberjack high" forms the boundary between the offshore Santa Maria basin and the Santa Barbara-Ventura basin. The offshore Santa Maria basin is approximately 100 miles long and 25 miles wide, and occupies an area of approximately 2,500 square miles. Water depths range from 300 feet near Point Sal to 3,500 feet in the southwest part of the basin.

The northern boundary of the Partington basin is defined by the structurally high Sur platform offshore Point Sur. Exposed basement strata define the western limit of the basin; to the east, the basin is bounded by the Hosgri fault zone. The Partington basin is

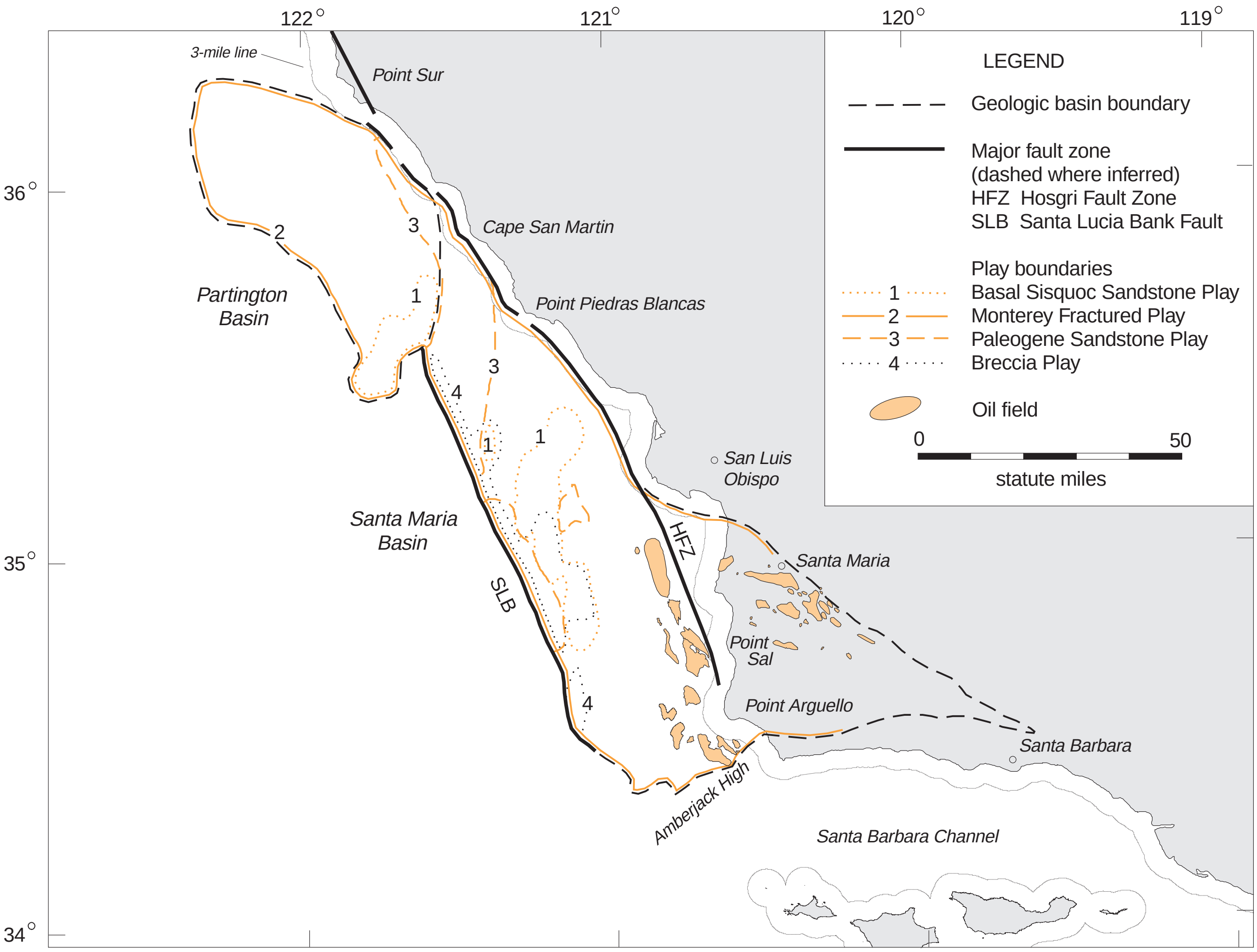


Figure 60. *Map of the Santa Maria-Partington Basin assessment area showing petroleum geologic plays and fields.*

approximately 25 miles wide and 65 miles long and encompasses an area of approximately 1,300 square miles. Water depths range from 500 to 8,000 feet.

For the purpose of this assessment, the Federal offshore portions of the Santa Maria and Partington basins have been combined into a single assessment area based on the interbasinal continuity of Neogene strata. The composite Santa Maria-Partington Basin assessment area is approximately 165 miles long and 25 mile wide and occupies an area of approximately 3,800 square miles. Water depths range from 300 feet near Point Sal to 8,000 feet in the northwest part of the assessment area.

Geologic Setting

Regional extension during the early Miocene caused the rapid subsidence of the Santa Maria basin. Offshore seismic-reflection profiles depict westward-tilted, normal-faulted, basement blocks that formed Miocene and Pliocene subbasins that are filled with volcanic rocks and biogenic and clastic sediments. Uplift and structural inversion of the basin began in the early Pliocene, resulting in reactivation of the normal faults and folding of Miocene and Pliocene strata into anticlines that are the traps for much of the oil in the basin today.

The Partington basin appears to have undergone a somewhat different tectonic history. In contrast to the complex folding in the offshore Santa Maria basin, Partington basin strata have been only minimally deformed. Basement topography dips uniformly east-northeast and terminates against or is thrust under the Hosgri fault zone.

More than 50 exploratory wells have been drilled in the southern and central portions of the offshore Santa Maria basin; the northern portion of the basin and all of the Partington basin remain undrilled. Most exploratory wells bottomed in Jurassic rocks of the Franciscan Complex; however, some wells bottomed in rocks of Cretaceous age or never reached basement; at least one well encountered Jurassic ophiolite. Similar basement rocks probably exist in the northern portion of the Santa Maria basin and in the Partington basin.

Paleogene rocks are missing in most of the wells and are presumed to be absent throughout most of the offshore Santa Maria basin. However, recent interpretation of seismic profiles indicates that a large body of strata—possibly a remnant of Paleogene age—exists along the Santa Lucia Bank fault and extends northward into the Partington basin. The strata have a maximum thickness in excess of 10,000 feet.

Neogene strata of the Lospe, Point Sal, Monterey, Sisquoc, Foxen, and Careaga Formations overlie basement rocks in the offshore Santa Maria and Partington basins (fig. 61). Lower to middle Miocene volcanics are also present throughout much of the offshore Santa Maria basin. The total thickness of these Neogene strata exceeds 10,000 feet in the depocenters and thins to 2,000 feet over the numerous intrabasinal uplifts in the offshore Santa Maria basin. Near Point Piedras Blancas, erosion and nondeposition have thinned the Neogene stratigraphic section to less than 1,000 feet. In many areas, the Monterey and underlying formations have been entirely eroded, leaving a thin shell of Sisquoc Formation in direct contact with basement rocks.

Exploration and Discovery Status

The first exploratory well (OCS-P 0060 #1) in the offshore Santa Maria basin was drilled in 1964 about 15 miles northwest of Point Sal. Although the well had abundant shows of oil in the Monterey Formation, it was not tested. However, the Monterey Formation has been the primary exploration target in the basin since the discovery well (OCS-P 0316 #1) at the Point Arguello field was drilled in 1980; the well was drilled as a result of OCS Lease Sale 48, which was held in 1979. Three subsequent lease sales that included the offshore Santa Maria basin have been held (Sale 53 in 1981, Sale RS-2 in 1982, and Sale 73 in 1983). As a result of those sales, 78 OCS blocks have been leased, more than 50 exploratory wells have been drilled, and 12 additional fields have been discovered. Two of the thirteen fields in the offshore Santa Maria basin (Point Arguello and Point Pedernales fields) were in production as of this assessment.

Seismic-reflection data coverage in the offshore Santa Maria and Partington basins is dense; the average trackline spacing in southern and central offshore Santa Maria basin is less than one-half mile. Toward the west and north into Partington basin, the coverage thins to approximately 1-mile spacing. For this assessment, a seismic data set of multiple surveys with a grid density of approximately 1-mile spacing was interpreted.

Plays

Four petroleum geologic plays, defined on the basis of reservoir rock stratigraphy, have been assessed in the Santa Maria-Partington Basin assessment area (fig. 61). These include two plays from which petroleum production has been established in the Santa Maria basin: the Basal Sisquoc Sandstone play, which is established only onshore and is considered frontier offshore, and the Monterey Fractured play,

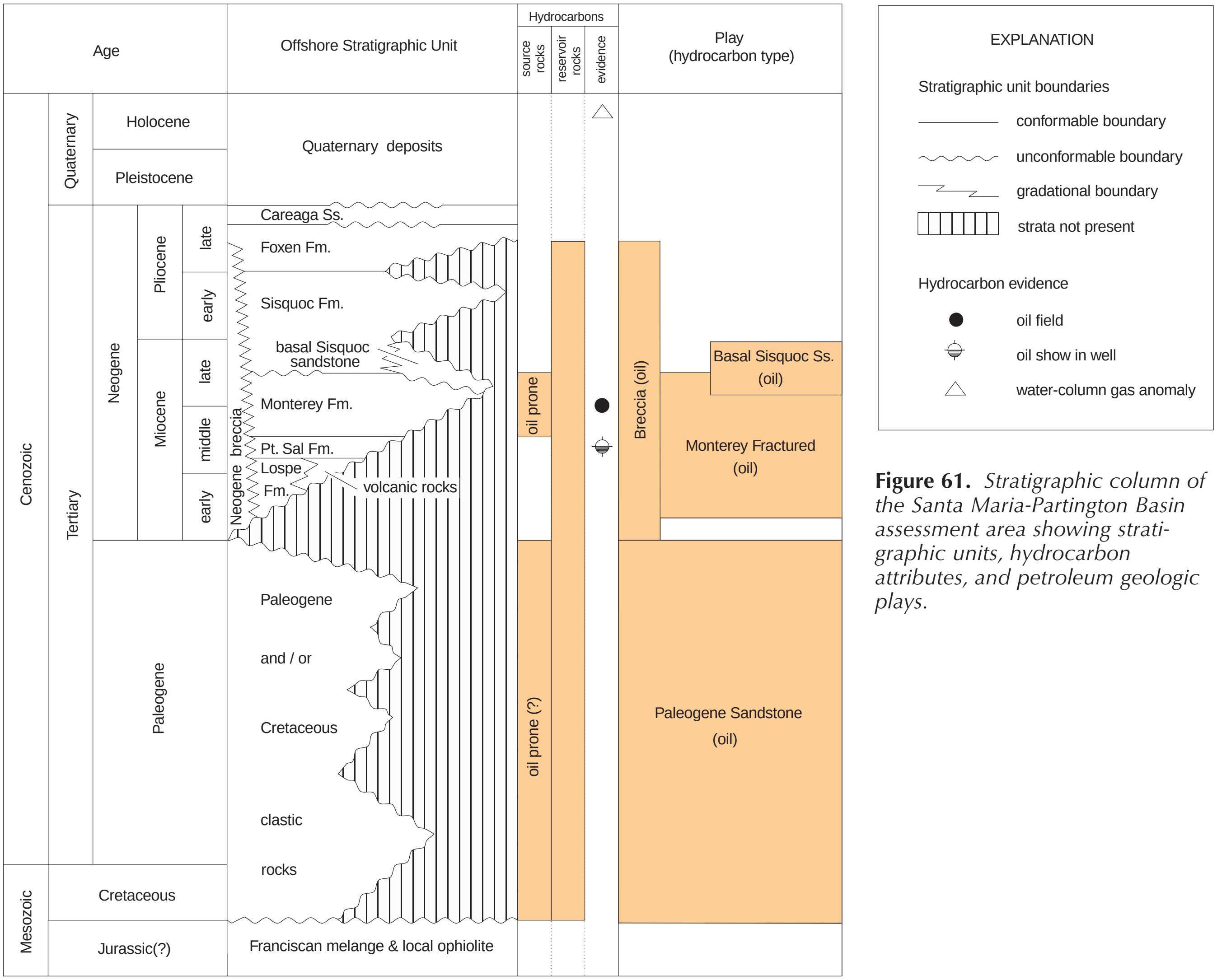


Figure 61. *Stratigraphic column of the Santa Maria-Partington Basin assessment area showing stratigraphic units, hydrocarbon attributes, and petroleum geologic plays.*

which is established offshore and onshore. Additionally, two conceptual plays have been assessed. The Paleogene Sandstone play is defined by seismic character and the presence of a thick section of continuous reflectors below the Monterey Formation in the Partington basin and in the outer portion of the offshore Santa Maria basin. The Breccia play is defined by proximity to large expanses of uplifted and eroded basement; accumulations in this play are presumed to be similar to breccia reservoirs in the onshore Los Angeles basin.

The primary petroleum source rocks for three of these four plays are organic-rich shales and phosphatic rocks of the Monterey Formation. Although Monterey rocks may be a source for the Paleogene Sandstone play where the two units are juxtaposed, the extreme thickness of the Paleogene(?) section in the Partington basin necessitates an additional source to charge Paleogene reservoirs in that basin. Therefore, a Paleogene source analogous to Paleogene strata in the Santa Barbara-Ventura basin is assumed to exist in the offshore Santa Maria and Partington basins.

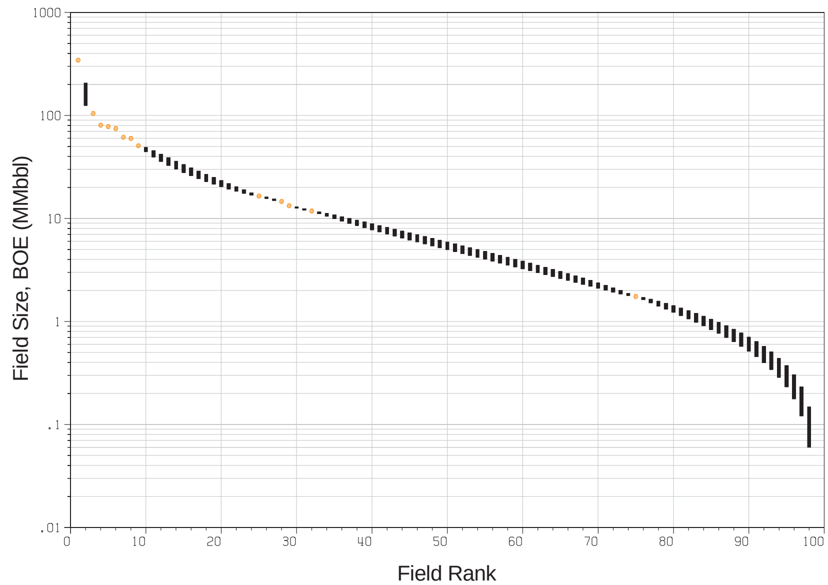
Mesozoic and Tertiary clastic and siliceous rocks, some of which are stratigraphically similar (and partly correlative) to the strata included in these plays, exist in the State offshore and onshore areas of the Santa Maria basin and in the State offshore area of the Partington basin. These adjacent rocks compose the Anticlinal Trends, Basin Margin, and Diagenetic plays of the Santa Maria Basin province, which has been described and assessed by the U.S. Geological Survey (Tennyson, 1995).

RESOURCE ESTIMATES

Undiscovered Conventionally Recoverable Resources

Play-specific estimates of undiscovered conventionally recoverable resources have been developed using the subjective assessment and discovery

Figure 62. *Field-size rank plot of estimated conventionally recoverable resources of the Santa Maria-Partington Basin assessment area. Sizes of discovered fields are shown by dots. Sizes of undiscovered fields are shown by bars; the top and bottom of a bar represent the 25th- and 75th-percentile value of a probability distribution, respectively.*



assessment methods, and these estimates have been statistically aggregated to estimate the total volume of resources in the assessment area. Select data used to develop the resource estimates are shown in appendix C.

As a result of this assessment, the total volume of undiscovered conventionally recoverable resources in the Santa Maria-Partington Basin assessment area is estimated to be 782 MMbbl of oil and 738 Bcf of associated gas (mean estimates). This volume may exist in 85 fields with sizes ranging from approximately 60 Mbbl to 205 MMbbl of combined oil-equivalent resources (fig. 62). The majority of these resources (approximately 88 percent on a combined oil-equivalence basis) are estimated to exist in the Monterey Fractured play. The low, mean, and high estimates of resources in the assessment area are listed in table 20 and illustrated in figure 63.

Undiscovered Economically Recoverable Resources

Estimates of undiscovered conventionally recoverable resources in the assessment area that may be economically recoverable under various economic scenarios have been developed using the economic assessment method. Select data used to develop the resource estimates are shown in appendix D.

As a result of this assessment, 189 MMbbl of oil and 178 Bcf of associated gas are estimated to be economically recoverable from the Santa Maria-Partington Basin assessment area under economic conditions existing as of this assessment (i.e., the $18-per-barrel economic scenario) (table 21). Larger volumes of resources are expected to be economically recoverable under increasingly favorable economic conditions (fig. 64).

Table 20. *Estimates of undiscovered conventionally recoverable oil and gas resources in the Santa Maria-Partington Basin assessment area as of January 1, 1995, by play. All estimates are risked values. The low, mean, and high estimates correspond to the 95th-percentile, mean, and 5th-percentile values of a probability distribution, respectively. Percentile values are not additive; some total mean values may not equal the sum of the component values due to independent rounding.*

Play	Oil (MMbbl)			Gas (Bcf)			BOE (MMbbl)		
	Low	Mean	High	Low	Mean	High	Low	Mean	High
Basal Sisquoc Sandstone	47	80	140	45	80	140	56	94	163
Monterey Fractured	629	687	787	561	629	752	729	799	921
Paleogene Sandstone	0	7	36	0	21	141	0	10	60
Breccia	0	8	56	0	8	61	0	10	67
Total Assessment Area	*678*	*782*	*895*	*598*	*738*	*897*	*787*	*913*	*1,051*

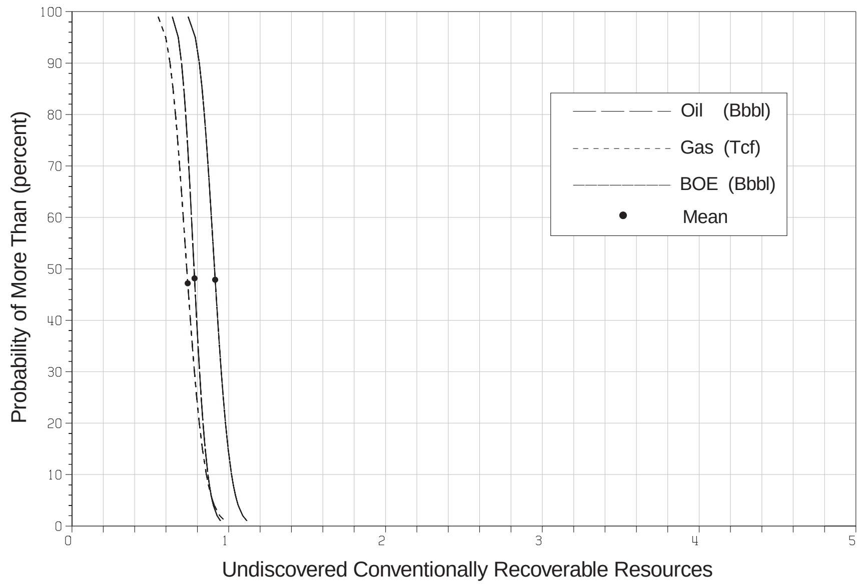


Figure 63. *Cumulative probability plot of estimated undiscovered conventionally recoverable resources of the Santa Maria-Partington Basin assessment area.*

Table 21. *Estimates of undiscovered economically recoverable oil and gas resources in the Santa Maria-Partington Basin assessment area as of January 1, 1995, by economic scenario. All estimates are risked mean values. The $18-per-barrel scenario is based on prices of $18 per bbl of oil and $2.11 per Mcf of gas; the $25-per-barrel scenario is based on prices of $25 per bbl of oil and $2.94 per Mcf of gas; the $50-per-barrel scenario is based on prices of $50 per barrel of oil and $5.87 per Mcf of gas.*

Economic Scenario	Oil (MMbbl)	Gas (Bcf)	BOE (MMbbl)
$18 per barrel	189	178	220
$25 per barrel	275	259	321
$50 per barrel	497	469	581

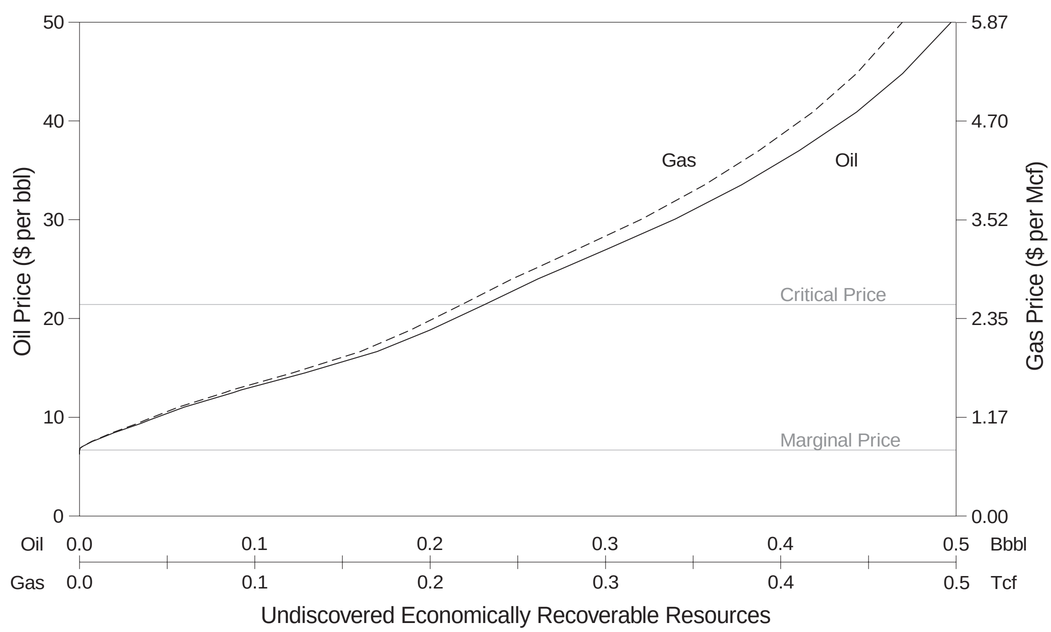


Figure 64. *Price-supply plot of estimated undiscovered economically recoverable resources of the Santa Maria-Partington Basin assessment area.*

Total Resource Endowment

As of this assessment, cumulative production from the assessment area was 118 MMbbl of oil and 43 Bcf of gas; remaining reserves were estimated to be 667 MMbbl of oil and 659 Bcf of gas. These discovered resources (all of which are from the Monterey Fractured play) and the aforementioned undiscovered conventionally recoverable resources collectively compose the area's estimated total resource endowment of 1.57 Bbbl of oil and 1.44 Tcf of gas (table 22).

Acknowledgments

The author gratefully acknowledges James K. Crouch and Marilyn Tennyson for providing their ideas and insights into the assessment of the Santa Maria basin. Special thanks go to William Kou for researching many of the analogs used for this assessment and spending countless hours at the computer helping to model the distributions. I would also like to extend thanks to Dale Julander, Ron Heck, Ed Edwards, and Chris Sorlien for their review of the play concepts and providing valuable input into this assessment. Finally, this author would like to acknowledge Cathie Dunkel for her unbridled enthusiasm and guidance on this project, her valuable input into the analog analysis for many of the plays, and her excellent editorial skills.

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Hoskins and Griffiths, 1971
Isaacs, 1984
McCulloch, 1989
McLean and Wiley, 1987
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Table 22. *Estimates of the total endowment of oil and gas resources in the Santa Maria-Partington Basin assessment area. Estimates of discovered resources (including cumulative production and remaining reserves) and undiscovered resources are as of January 1, 1995. Estimates of undiscovered conventionally recoverable resources are risked mean values. Some total values may not equal the sum of the component values due to independent rounding.*

Resource Category	Oil (Bbbl)	Gas (Tcf)	BOE (Bbbl)
Cumulative Production	0.12	0.04	0.13
Remaining Reserves	0.67	0.66	0.78
Undiscovered Conventionally Recoverable Resources	0.78	0.74	0.91
Total Resource Endowment	*1.57*	*1.44*	*1.82*

Basal Sisquoc Sandstone Play

Play Definition

The Basal Sisquoc Sandstone play of the Santa Maria-Partington Basin assessment area is defined to include stratigraphic and structural accumulations of oil and associated gas in Pliocene clastic sediments at the base of the Sisquoc Formation. This play is established (i.e., proven to exist) in the onshore Santa Maria basin where Monterey Formation strata have been uplifted and eroded around the basin margin and redeposited as coarse clastic sediments atop the Monterey Formation (e.g., Thomas and Brooks Sands in the Cat Canyon field, Basal Sisquoc Sand in the Guadalupe field). In the offshore Santa Maria basin, this play has not been tested. This play occurs in both the offshore Santa Maria and Partington basins where the Monterey has been uplifted, eroded, and redeposited on the flanks of the uplift. The interbasinal play covers an area of approximately 450 square miles and occurs at burial depths generally less than 3,000 feet (fig. 60).

Petroleum Geologic Characteristics

Potential petroleum source rocks for the play are oil-prone, middle to upper Miocene Monterey rocks stratigraphically below the Sisquoc Formation. Maximum Monterey thickness exceeds 2,000 feet in the basins; however, in areas where this play is present, the Monterey has been eroded and may be significantly less than 1,000 feet thick. Additionally, Monterey rocks within the area of this play may not be thermally mature unless they have been buried to depths greater than about 3,000 feet. Monterey rocks buried in synclines adjacent to the play are probably thermally mature and fractures may provide pathways for migration of petroleum into the play area. A similar situation exists in the onshore Santa Maria basin where petroleum has migrated several miles from the Santa Maria Valley syncline into stratigraphic traps in the Santa Maria Valley field.

Potential reservoir rocks include Pliocene sandstones that are composed of sediments shed from uplifted and eroded Monterey and older strata. Analysis of similar strata in traps of the Cat Canyon, Guadalupe, and Santa Maria Valley fields indicates that the strata have net thicknesses from 45 to 600 feet, porosities from 10 to 40 percent, and permeabilities from 200 to 3,350 millidarcies.

Traps in this play are generally stratigraphic; but the potential for structural accumulations cannot be discarded. Two areas of potential structural and stratigraphic traps have been mapped with seismic data. The largest of the two is located atop a large uplift that extends northward from near the western margin of the central offshore Santa Maria basin to the northern area of the basin approximately 15 miles west of Point Estero. The second area is located atop a northeast-trending uplift 15 to 20 miles west of Point Piedras Blancas in the Partington basin. In both areas, the Monterey has been partially or completely eroded, and detrital material has been shed down the flanks of the uplift and possibly accumulated in contact with Monterey strata below. Seals may be provided by mudstones and shales within the Sisquoc or younger formations, but may not be effective because the strata are generally thin.

EXPLORATION

No offshore wells have tested this conceptual play. In the onshore Santa Maria basin, petroleum is produced from basal Sisquoc sandstones in several areas (e.g., East and Sisquoc areas of the Cat Canyon field; Guadalupe field; and Clark, Bradley, and Southeast areas of the Santa Maria Valley field). Although seismic data have been used to delineate this play in the offshore, no bright spots or other hydrocarbon indicators have been observed on the interpreted seismic profiles.

RESOURCE ESTIMATES

Undiscovered Conventionally Recoverable Resources

Estimates of undiscovered conventionally recoverable resources in the Federal offshore portion of the play have been developed using the subjective assessment method. Select data used to develop the resource estimates are shown in appendix C.

Volumetric parameters for the play (i.e., pool area, net-pay thickness, and oil recovery factor) were estimated from onshore Santa Maria basin field analogs. Areas of likely traps were identified using the seismic data, but individual trap outlines were not mapped. The number of pools in the play was estimated by areal comparison to the onshore Santa Maria basin. The solution gas-to-oil ratio was estimated using Monterey Formation ratios from the offshore Santa Maria basin.

As a result of this assessment, the Federal offshore portion of the play is estimated to contain 80 MMbbl of oil and 80 Bcf of associated gas (mean estimates). This volume of undiscovered conventionally recoverable resources may exist in 15 pools with sizes ranging from approximately 235 Mbbl to 35 MMbbl of combined oil-equivalent resources (fig. 65). The low, mean, and high estimates of resources in the play are listed in table 20.

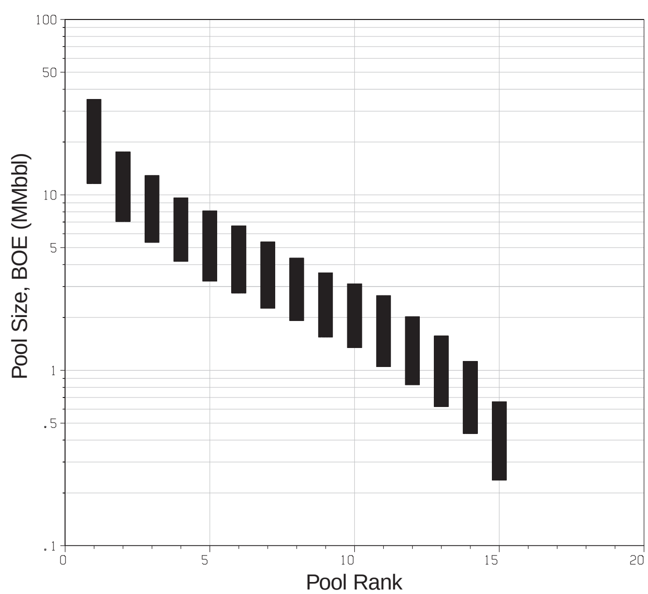

Figure 65. *Pool-size rank plot of estimated undiscovered conventionally recoverable resources of the Basal Sisquoc Sandstone play, Santa Maria-Partington Basin assessment area. Sizes of undiscovered pools are shown by bars; the top and bottom of a bar represent the 25th- and 75th-percentile values of a probability distribution, respectively.*

MONTEREY FRACTURED PLAY

PLAY DEFINITION

The Monterey Fractured play of the Santa Maria-Partington Basin assessment area is an established play that includes oil and associated gas accumulations in fractured siliceous and dolomitic rocks of the middle and upper Miocene Monterey Formation. For this assessment, the play also includes lower and middle Miocene sandstones in the Point Sal and Lospe Formations. The play encompasses an area of approximately 3,800 square miles and occurs at burial depths of approximately 0 (seafloor) to 11,000 feet (fig. 60).

PETROLEUM GEOLOGIC CHARACTERISTICS

The Monterey Formation is its own source and reservoir rock. Using surface samples from the Santa Barbara coastal area and core samples from the onshore Santa Maria basin, Isaacs (1984) calculated an average total organic carbon (TOC) content of approximately 5 percent; maximum TOC values are as high as 17 percent. Crain and others (1985) report average TOC values of 3 percent in the Point Arguello field. Other geochemical data (i.e., hydrogen-carbon and oxygen-carbon ratios) from the Santa Barbara coast and Pismo basin indicate that organic matter in the Monterey Formation contains type II kerogen (Isaacs and others, 1983). Oil gravities from offshore drill-stem tests range from less than 5 to 35 ^{o}API (the median value is 14 ^{o}API). The source for petroleum in the Point Sal Formation is also the Monterey Formation.

Reservoir rocks in this play include fractured siliceous and dolomitic rocks of the Monterey Formation, as well as sandstones in the Point Sal and Lospe Formations. Reservoir quality in the Monterey Formation ranges from poor to excellent, depending on the diagenetic grade of the siliceous strata. Many researchers believe that the best potential Monterey reservoir rocks are those in which the siliceous strata have been diagenetically altered from opal-CT to quartz, due to the increased fracture density associated with quartz-phase strata (see Central California province discussion). Mineralogic analyses of well samples from six wells in the offshore Santa Maria basin indicate that diagenetic alteration of opal-CT to quartz has occurred in all of the analyzed wells. Further, the stratigraphic position of this diagenetic boundary has been correlated with an anomalous, often cross-cutting seismic reflector that can be traced throughout much of the offshore Santa Maria basin. On the Piedras Blancas antiform in northern Santa Maria basin, the diagenetic reflector is absent, possibly because burial has been insufficient to convert opal-CT to quartz. The absence of the diagenetic reflector in the Partington basin may be attributed to other factors because the depth of burial appears sufficient to have converted opal-CT to quartz. Migration of fluids into the Monterey structures occurs along fractures and faults, some of which cross the diagenetic boundary. Migration into structures in the Point Sal and Lospe Formations may generally occur where sandstones in these formations lie in updip contact with Monterey source rocks.

Traps in the drilled areas of the offshore Santa Maria basin are primarily structural and generally occur in faulted and/or fault-bounded anticlines. The Hosgri, Purisima, and Lompoc fault zones bound the eastern offshore Santa Maria basin and trend northwest from near Point Arguello to approximately 10 miles north of Point Sal. The Hosgri fault zone continues northward through the Partington basin. Many of the fields discovered in the central offshore Santa Maria basin are related to the faulting associated with these zones. In the undrilled areas of the basins, traps have been identified along the northern extension of the Hosgri fault zone and along uplifts and faulted uplifts in the middle and western parts of the southern and central offshore Santa Maria basin. Subthrust traps may exist along the Hosgri fault zone in the northern offshore Santa Maria basin and in Partington basin. Stratigraphic traps have been identified in the west-central and northwest part of the offshore Santa Maria basin and the southwest part of the Partington basin where the Monterey has been eroded on the crests of basement highs but may be trapped below capping mudstones of the Sisquoc Formation on the flanks of the uplifts. Traps are noticeably sparse in the Partington basin due to the lack of structural disruption. The Point Sal Formation was not mapped for this assessment but is expected to have similar trap styles as the Monterey Formation. Seals are generally provided by capping mudstones of the Sisquoc Formation or by faults, fractures, and unconformities. The diagenetic boundary between opal-CT and quartz may also trap petroleum on the flanks of anticlines and homoclines. Traps identified atop the Piedras Blancas antiform may lack the requisite overburden to provide an effective seal.

Exploration and Discovery Status

The Monterey Formation has been the primary exploration target in the offshore Santa Maria basin since the discovery well (OCS-P 0316 #1) at the Point Arguello field was drilled in 1980. Since that time, 12 additional fields have been discovered. The Monterey Formation is the primary reservoir in all of the fields. Field sizes range from approximately 2 MMbbl to 324 MMbbl of combined oil-equivalent resources.

Although the exploration success ratio in the offshore Santa Maria basin is relatively high, some dry holes have been drilled. One such well (OCS-P 0496 #1) was drilled on top of a large, northeast-trending uplift in the south-central portion of the basin where the Monterey section is very thin and may never have been buried sufficiently to convert opal-CT to quartz. Additionally, a large anticline that breaches the seafloor in the west-central portion of the basin was drilled and found to be dry; although the well (OCS-P 0411 #1) penetrated more than 2,000 feet of Monterey section, no hydrocarbons were encountered. Mineralogic analyses subsequently revealed that siliceous strata in the lower half of the Monterey section are in the quartz phase; the single drill-stem test in the well was performed in opal-CT strata located 200 to 400 feet above the diagenetic boundary.

Resource Estimates

Undiscovered Conventionally Recoverable Resources

Estimates of undiscovered conventionally recoverable resources in the Federal offshore portion of the play have been developed using the discovery assessment method. Select data used to develop the resource estimates are shown in appendix C.

Pool-size data from 13 discovered fields in the offshore portion of the play were used to develop the pool-size distribution. The largest pool in the play is assumed to be the Point Arguello field (original recoverable reserves are estimated to be 324 MMbbl of combined oil-equivalent resources). The second-largest discovered pool is the Rocky Point field (original recoverable reserves are estimated to be 99 MMbbl of combined oil-equivalent resources). Based on the assumption that an undiscovered pool larger than Rocky Point may exist (through remapping and combination of two existing smaller fields, or a new field discovery), a gap in the lognormal pool-size distribution (between the Point Arguello and Rocky Point fields) for this play has been modeled. Additionally, to aid in estimating the total number of pools that may exist, the number of undiscovered pools with a mean pool size in excess of 10 MMbbl of combined oil-equivalent resources is estimated to be 20. The resulting estimated total number of pools is 90.

As a result of this assessment, the Federal offshore portion of the play is estimated to contain 687 MMbbl of oil and 629 Bcf of associated gas (mean estimates). This volume of undiscovered conventionally recoverable resources may exist in 77 pools with sizes ranging from approximately 60 Mbbl to 200 MMbbl of combined oil-equivalent resources (fig. 66). The low, mean, and high estimates of resources in the play are listed in table 20.

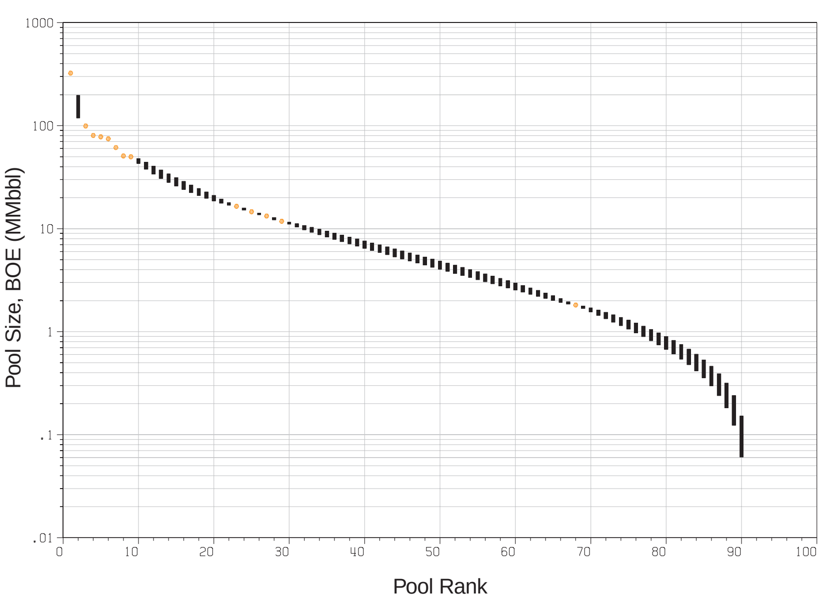

Figure 66. *Pool-size rank plot of estimated conventionally recoverable resources of the Monterey Fractured play, Santa Maria-Partington Basin assessment area. Sizes of discovered pools are shown by dots. Sizes of undiscovered pools are shown by bars; the top and bottom of a bar represent the 25th- and 75th-percentile values of a probability distribution, respectively.*

Paleogene Sandstone Play

Play Definition

The Paleogene Sandstone play of the Santa Maria-Partington Basin assessment area is defined to include structural and stratigraphic accumulations of oil and associated gas in undifferentiated Paleogene clastic reservoirs. This play is conceptual because large volumes of Paleogene strata have not been previously identified in the Santa Maria or Partington basins[9]. Recent interpretation of seismic-reflection profiles indicates that a thick section of strata exists below the Monterey Formation in the western offshore Santa Maria basin and in the Partington basin. This seismic-stratigraphic unit appears as a narrow belt of strata lying unconformably below the Monterey Formation in the western offshore Santa Maria basin; the unit is bounded on the west by the Santa Lucia Bank fault and on the east by basement highs. It is traceable northwestward to the latitude of Morro Bay where it widens substantially and extends northward between flanking basement uplifts into the Partington basin. Between Point Estero and Cape San Martin, the unit narrows and extends northwestward along the Hosgri fault zone to about 12 miles northwest of Lopez Point. In Partington basin, the western limit of the play is defined solely by seismic character; over 10,000 feet of subparallel reflectors below the Monterey Formation terminate diffusely against chaotic basement reflectors, presumably of the Franciscan Complex. The play encompasses an area of approximately 500 square miles and occurs at burial depths generally greater than 8,000 feet (fig. 60).

Petroleum Geologic Characteristics

Potential petroleum source rocks for this play are estimated to be analogous to Paleogene source rocks in the Santa Barbara-Ventura basin (i.e., Anita and Cozy Dell Shales) and in the onshore La Honda basin. The Monterey Formation may be a secondary source where favorable migration conditions exist.

Potential reservoir rocks for this play are estimated to be analogous to Paleogene reservoirs in the Santa Barbara-Ventura basin and pre-Monterey sandstones in the Año Nuevo basin. The most probable sediment types are fine- to coarse-grained sandstones deposited in shelf and slope systems; however, the presence of deep-water turbidite sandstones cannot be discounted due to the great thickness (more than 10,000 feet) of deposits in the Partington basin.

No traps in this play have been mapped because the seismic data do not display much structural disruption within the seismic-stratigraphic unit that defines the play. Stratigraphic traps are the most likely trap type where the Paleogene strata abut basement highs in the western offshore Santa Maria basin and in the north-trending corridor from the Santa Maria basin to the Partington basin. In the Partington basin, where strata of this play abut the Hosgri fault zone, subthrust stratigraphic and structural traps may exist; however, individual traps are not identifiable on the seismic data. Seals may be provided by shales within this play, by siliceous rocks of the overlying Monterey Formation, and by faults and unconformities.

Exploration

No exploratory wells have penetrated this play. Thin sections of Paleogene strata have been reported in wells drilled in the southeastern part of the offshore Santa Maria basin; however, no hydrocarbon shows have been reported. The play is considered most prospective along the Hosgri fault zone where the section is thick and structural and stratigraphic traps may exist.

Resource Estimates

Undiscovered Conventionally Recoverable Resources

Estimates of undiscovered conventionally recoverable resources in the Federal offshore portion of the play have been developed using the subjective assessment method. Select data used to develop the resource estimates are shown in appendix C.

The pool area was estimated by analogy to the Año Nuevo basin based on similar fault-bound basin margins. Net-pay thickness was estimated by analogy with Paleogene strata in the Año Nuevo and other offshore central California basins. The number of prospects was estimated by areal comparison to the Año Nuevo basin. The oil recovery factor (oil yield) and solution gas-to-oil ratio were

[9] The existence of this play presumes that the strata identified using seismic data are of Paleogene age. The possibility exists that the strata are of Cretaceous age and, therefore, may be less prospective; this possibility has been considered in estimating the probability of success of the play. If the strata are of Cretaceous age, this finding may be important in determining the offset along the Hosgri fault zone, because Cretaceous strata crop out on the east side of the fault along the coast as far south as Cayucos Point. Further mapping is necessary to confirm this possibility; but, based on mapping for this project, right-lateral offset of approximately 30 miles is feasible.

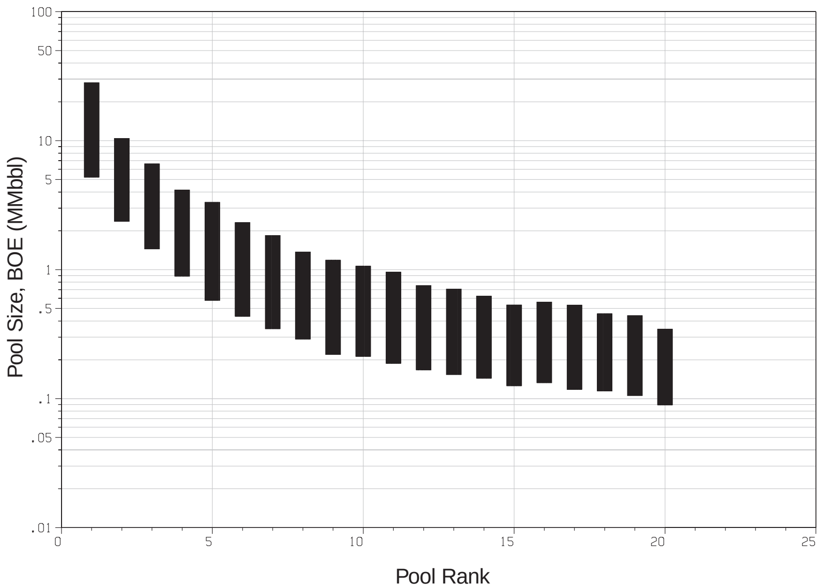

Figure 67. *Pool-size rank plot of estimated undiscovered conventionally recoverable resources of the Paleogene Sandstone play, Santa Maria-Partington Basin assessment area. Sizes of undiscovered pools are shown by bars; the top and bottom of a bar represent the 25th- and 75th-percentile values of a probability distribution, respectively.*

estimated by analogy to Paleogene reservoirs in the Santa Barbara-Ventura basin. The probability of success of this play (play chance) is estimated to be poor (20 percent), primarily because of the uncertainty regarding the age and lithologic character of the strata. If the play exists, the dearth of structural traps and only suspected stratigraphic traps resulted in a predicted prospect success ratio (conditional prospect chance) of 20 percent.

As a result of this assessment, the Federal offshore portion of the play is estimated to contain 7 MMbbl of oil and 21 Bcf of associated gas (mean estimates). This volume of undiscovered conventionally recoverable resources may exist in as many as 20 pools with sizes ranging from approximately 90 Mbbl to 30 MMbbl of combined oil-equivalent resources (fig. 67). The low, mean, and high estimates of resources in the play are listed in table 20.

BRECCIA PLAY

PLAY DEFINITION

The Breccia play of the Santa Maria-Partington Basin assessment area is defined to include stratigraphic and fault-trapped accumulations of oil and associated gas in brecciated basement rocks along the Santa Lucia Bank fault and other nearby basement highs (fig. 60). This play is conceptual because the breccia has not been drilled and is inferred to exist based solely on seismic-reflection data. The "breccia" seismic-stratigraphic unit appears as a narrow zone of disrupted reflectors that are confined to the hanging-wall block of the Santa Lucia Bank fault and basement highs immediately east of the fault. In the offshore Santa Maria basin, the Santa Lucia Bank fault juxtaposes Monterey and younger strata, and possibly Paleogene strata, against uplifted and eroded Franciscan basement. The zone of disruption exists along the entire trace of the fault. The existence of breccia on the eastern flanks of the basement highs is only postulated based on seismic evidence that Franciscan basement has been uplifted and eroded and is covered by a thin veneer of Pliocene(?) and younger strata. The play covers an area of approximately 275 square miles and occurs at burial depths from 500 to 2,500 feet (2,500 to 4,500 feet below sea level).

PETROLEUM GEOLOGIC CHARACTERISTICS

Potential source rocks for this play are organic-rich shales of the Monterey Formation where they are in contact with the breccia zone. The oil is likely to be low gravity and high in sulphur, similar to Monterey oils found in tests and production to the east.

Potential reservoir rocks for this play are brecciated basement rocks of the Franciscan Complex. Seismic profiles across the Santa Lucia Bank fault indicate that uplifted Franciscan basement in the foot-wall block to the west has been eroded and possibly redeposited eastward, forming a zone of chaotic reflectors that extend eastward away from the fault for distances up to 7,000 feet. Additionally, eroded basement highs immediately east of the fault at the latitude of Point Sal and Morro Bay may have shed detrital material in all directions. The reservoir quality of this play may vary; porosities of analogous breccias onshore range from 12 to 31 percent.

Stratigraphic traps may exist against basement highs east of the Santa Lucia Bank fault; but, seismic data indicate that fault traps are the predominant trap type in this play. No specific traps have been mapped using the seismic data; however, a zone where traps are likely to exist has been delineated. The potential for effective sealing against the Santa Lucia Bank fault is very uncertain because the fault may have been active since its inception in the early to middle Miocene.

EXPLORATION

No exploratory wells have drilled this play in the offshore Santa Maria basin.

RESOURCE ESTIMATES

Undiscovered Conventionally Recoverable Resources

Estimates of undiscovered conventionally recoverable resources in the play have been developed using the subjective assessment method. Select data used to develop the resource estimates are shown in appendix C.

The pool area, net-pay thickness, number of prospects, and oil recovery factor (oil yield) of this play were estimated by comparison to the San Onofre Breccia play in the Los Angeles Basin assessment area. The solution gas-to-oil ratio was estimated to be identical to the ratio for the Monterey Fractured play in the Santa Maria-Partington Basin assessment area. The probability of success of the play (play chance) is estimated to be very poor (15 percent) because the existence of the breccia is postulated solely on the basis of seismic data. If the play exists, the uncertainty regarding the effectiveness of a seal along the Santa Lucia Bank fault resulted in a predicted prospect success ratio (conditional prospect chance) of 15 percent.

As a result of this assessment, the play is estimated to contain 8 MMbbl of oil and 8 Bcf of associated gas (mean estimates). This volume of undiscovered conventionally recoverable resources may exist in as many as 17 pools with sizes ranging from approximately 290 Mbbl to 35 MMbbl of combined oil-equivalent resources (fig. 68). The low, mean, and high estimates of resources in the play are listed in table 20.

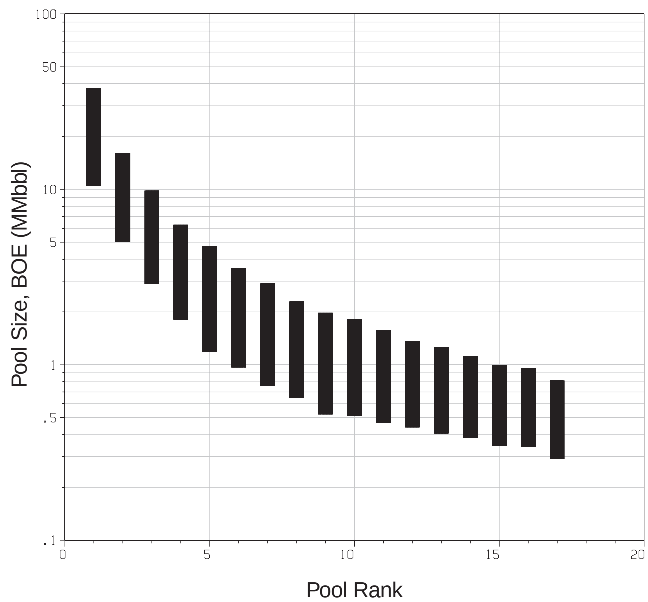

Figure 68. *Pool-size rank plot of estimated undiscovered conventionally recoverable resources of the Breccia play, Santa Maria-Partington Basin assessment area. Sizes of undiscovered pools are shown by bars; the top and bottom of a bar represent the 25th- and 75th-percentile values of a probability distribution, respectively.*

SANTA BARBARA-VENTURA BASIN PROVINCE

by James M. Galloway

LOCATION

The Santa Barbara-Ventura Basin province is located offshore southern California (fig. 69). This Federal offshore assessment province is within the western portion of the Transverse Ranges geomorphic province (which is so named because its east-west orientation runs counter to the predominant north-northwest grain of the region's major structural trends) and the western portion of the Santa Barbara-Ventura basin proper.

The depositional basin is bounded to the north by the Santa Ynez and related faults; to the east by the San Gabriel fault; to the south by a series of thrusts and lateral faults related to the Malibu Coast-Santa Monica fault zone, the Santa Cruz Island fault, and the Santa Rosa fault; and to the west by a poorly defined basement trend ("Amberjack high" of Crain and others (1985)). The basin extends in an east-west direction approximately 160 miles and in a north-south direction approximately 40 miles. The offshore portion of the basin is referred to commonly and herein as the Santa Barbara Channel.

The Santa Barbara-Ventura Basin province comprises only the submerged portion of the basin that lies seaward of the Federal-State boundary. As such, the assessment province is bounded to the north, east, and south by the 3-mile line. It is approximately 90 miles long and 20 miles wide and encompasses an area of about 1,800 square miles. Water depth in the assessment province ranges from 100 to 1,800 feet.

GEOLOGIC SETTING

The oldest known sedimentary rocks in the basin date from the Early Cretaceous(?) (fig. 70). These basinal sedimentary formations are deposited on a probable metamorphic or metasedimentary basement complex. Mesozoic- and Paleogene-aged rocks in the modern Santa Barbara-Ventura basin were originally deposited in a forearc setting. This sequence of Cretaceous to lower Oligocene, predominantly marine sedimentary rocks, is well known from outcrops and boreholes. The composite section is remarkably complete; however, erosion (resulting in local unconformities) and structural complications have

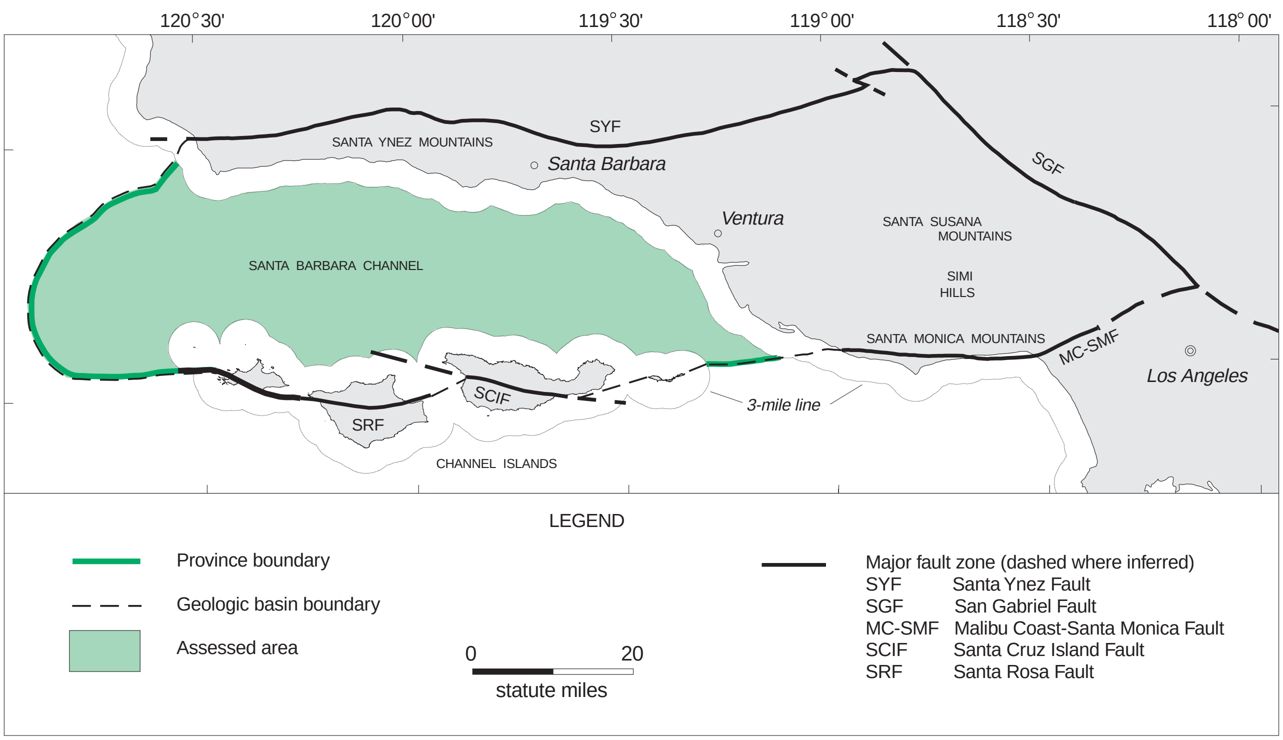

Figure 69. *Map of the Santa Barbara-Ventura Basin province showing assessed area.*

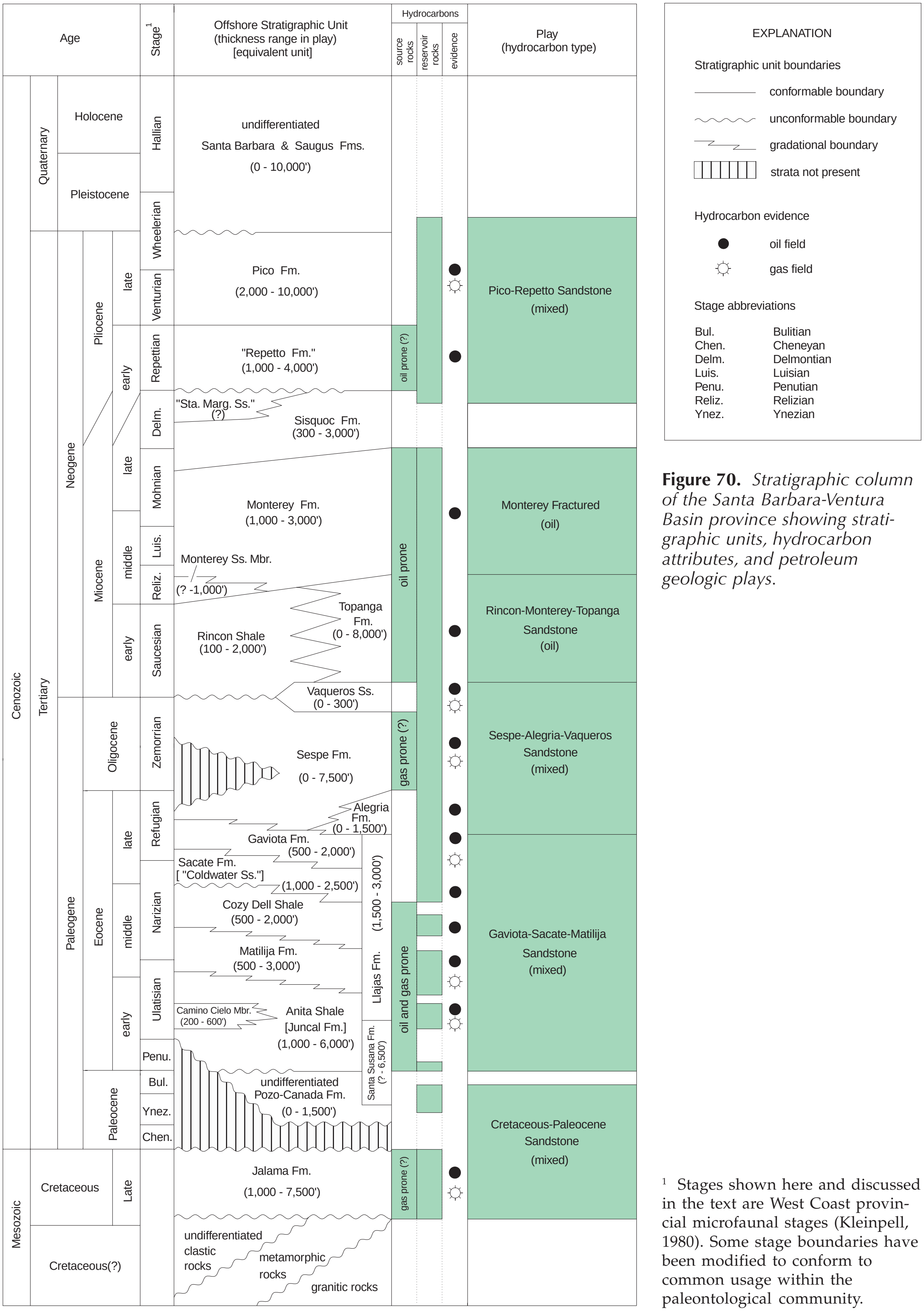

Figure 70. *Stratigraphic column of the Santa Barbara-Ventura Basin province showing stratigraphic units, hydrocarbon attributes, and petroleum geologic plays.*

[1] Stages shown here and discussed in the text are West Coast provincial microfaunal stages (Kleinpell, 1980). Some stage boundaries have been modified to conform to common usage within the paleontological community.

removed significant rock volumes in many areas. Major regional unconformities exist in the mid-Upper Cretaceous, Paleocene, and Oligocene sections.

The Cretaceous-Paleogene forearc basin bordered the paleosubduction zone in an elongate, north-south direction. The forearc basin predominantly filled from highland sediment sources to the east. In the Santa Barbara Channel and Outer Borderland areas (see Victor, this report), isochoral maps suggest thinning to paleosouth (present-day west). Bathyal paleobathymetric microfossil indicators are common. During the Eocene, however, changes to shallower water depths due to basin filling, lateral facies changes, and continued sediment influx from the continental highlands produced important stratigraphic variations (Ingle, 1981).

Shallow marine and nonmarine Oligocene sedimentary rocks mark the end of the forearc basin and the beginning of a fundamental reorganization of the regional structure. Paleomagnetic data suggest that the Santa Barbara-Ventura basin has rotated clockwise up to 120 degrees since the Eocene (Kamerling and Luyendyk, 1979). Significant episodes of rotation continued, possibly as late as the late Miocene or early Pliocene (Hornafius and others, 1986). Structural analyses (Yeats and others, 1994) and Global Positioning System telemetry suggest that rotation and basin compression continue today.

Rotation accompanied late Oligocene(?) to early Miocene regional extension and a rapid subsidence of the basin. In the Santa Barbara Channel, upper bathyal to middle bathyal foraminifera are common throughout the Miocene and show a quick transition from nonmarine to bathyal marine (>600 feet water depth) depositional environments. Shoaling by the late Miocene to early Pliocene is apparent (Ingle, 1981).

Late Pliocene and Quaternary tectonics within the basin, expressed as large-scale thrust faults and rapid deformation of young sediments, suggest significant crustal shortening. Most of the mapped structural trends reflect the latest regional diastrophism (fig. 71).

Stratigraphy

The stratigraphic terminology within the basin is complicated (fig. 70). This stems from complex structural geology, common facies changes within formations, the time-transgressive nature of many stratigraphic units, and widely scattered exposures that led to multiple names for rock units with lithostratigraphic similarities. Additionally, provincial terms were imported from other basins and applied to Ventura basin strata.

Basement rocks beneath much of the basin were likely deposited in a subduction complex. These rocks are typically Jurassic(?) to Cretaceous metasediments and metavolcanics and are referred to as the Franciscan Complex. They are exposed in the upturned basin flanks and penetrated by the relatively few exploratory wells that reached basement. Mesozoic plutonic rocks whose tectonic origin is uncertain have been observed on Santa Cruz Island (Gordon and Weigand, 1994).

A thick (>40,000 feet) composite sedimentary section, ranging in age from Cretaceous to Holocene, exists within the basin. Most of the section is of marine origin. One significant nonmarine section and several volcanic units are also present.

Cretaceous-aged rocks are prominently exposed in the Santa Ynez Mountains, Santa Monica Mountains, Simi Hills, and on the Channel Islands. These rocks have also been penetrated in boreholes, particularly along some of the major anticlinal trends (fig. 71). Most Cretaceous strata observed in the Santa Barbara Channel are referred to for this assessment as Jalama Formation. These rocks lie directly on basement or are separated from older Cretaceous rocks by a regional unconformity. The total Cretaceous section may exceed 6,500 feet in thickness.

Paleocene-aged rocks are not well represented in the basin. On the Channel Islands, rocks assigned to the Pozo and Canada Formations may be analogous to similarly aged rocks (Ynezian to Bulitian Stages) in offshore boreholes. In many places within the basin, the Paleocene is absent. The Channel Islands section may be as much as 1,500 feet thick. Offshore, the section partially penetrated by boreholes measures at least 1,000 feet thick.

Eocene-aged rocks are well represented in outcrop and in the subsurface. In the west and central portions of the Santa Barbara Channel, Eocene strata are found unconformably overlying basement, Cretaceous, or Paleocene rocks. The formations penetrated offshore include the lithologic and temporal equivalents to the Anita Shale (Juncal Formation), Matilija Formation, Cozy Dell Shale, Sacate Formation ("Coldwater Sandstone"), and Gaviota Formation. Although minor nonmarine and volcanic units have been noted, the Eocene section here generally represents a marine forearc environment with a gradual shallowing-upward tendency. Significant sand-rich sections, some of which are quite massive, are intercalated with prominent shaley units.

In the eastern portion of the Santa Barbara Channel, the Anita Shale grades into the Juncal Formation (which contains the sandy Camino Cielo Member). Farther east, the lithological distinctions between the members and formations fade, and the name "Llajas Formation" has been applied to the Eocene

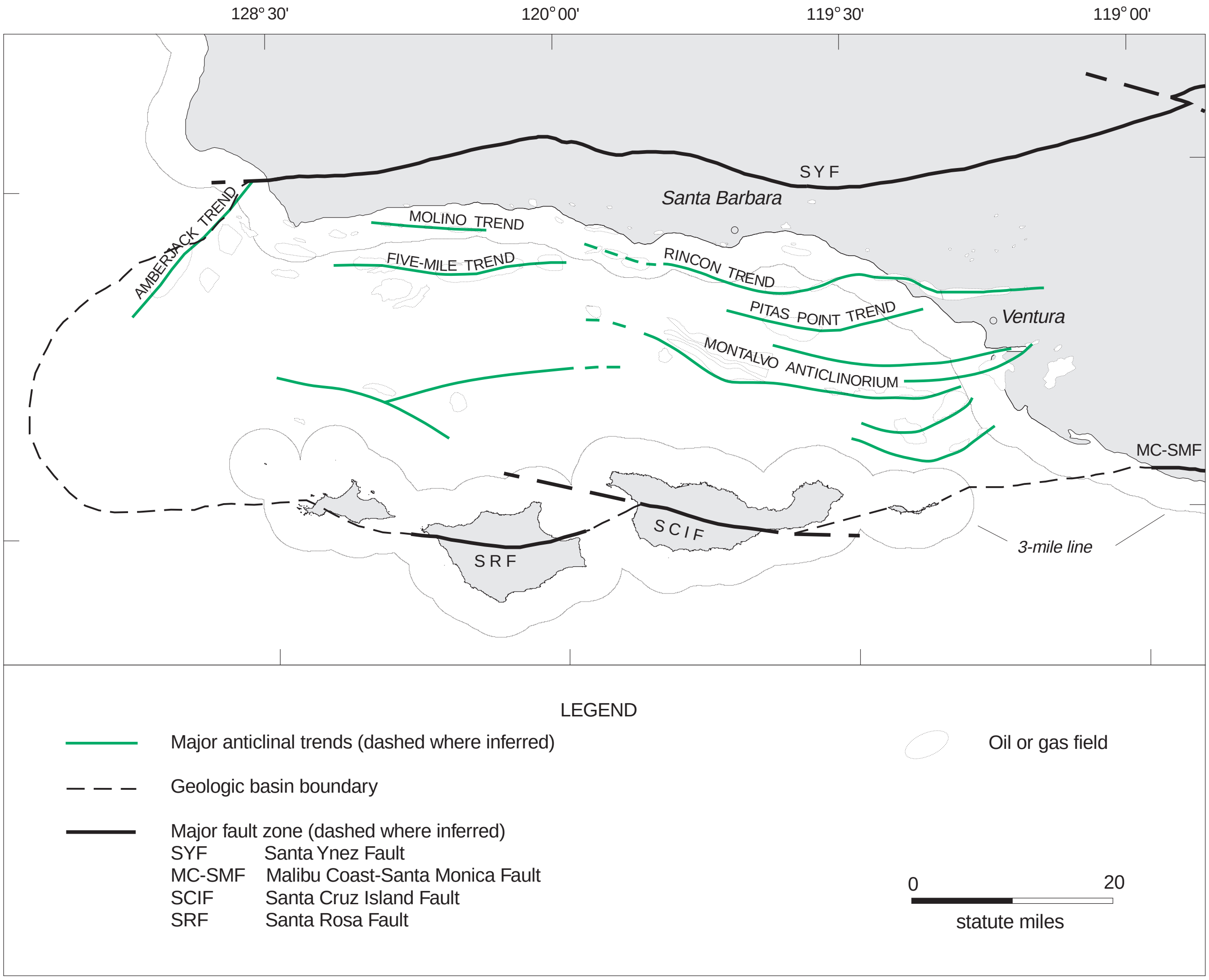

Figure 71. *Map of the Santa Barbara-Ventura basin showing anticlinal trends and select fields.*

section. The Eocene section, as interpreted on common-depth-point seismic-reflection profiles, may exceed 15,000 feet in thickness.

The Oligocene section is represented by the primarily nonmarine to shallow marine Sespe Formation and the shallow marine Alegria Formation. Analysis of the Sespe Formation suggests that it records numerous depositional environments; these include braided streams, meandering rivers, and fan deltas. The Sespe Formation is unique and easily recognized in outcrop and in well cuttings due to its variegated sandstones, conglomerates, and claystones. The Alegria Formation consists primarily of sandstone and siltstone. In some parts of the basin, the Sespe-Alegria (undifferentiated) strata conformably or paraconformably overlie the Eocene section. Elsewhere, this contact is a distinct angular unconformity.

Likewise, the upper contact of the Sespe with the overlying Neogene unit varies from gradational and conformable to a strong angular unconformity. The entire Oligocene section may exceed 7,500 feet in thickness within parts of the basin. In the Santa Barbara Channel, the section averages 3,000 to 4,000 feet thick. The nonmarine Oligocene section apparently thins toward the west and is entirely replaced by marine sedimentary rocks in the Point Conception area. (Detailed descriptions of the Paleogene sequence stratigraphy may be found in Campion and others (1994).)

The Miocene-aged section in the Santa Barbara Channel is composed of the Vaqueros Sandstone, Rincon Shale, Monterey Formation, and Sisquoc Formation (“Santa Margarita Sandstone”, locally). This sequence marks a sudden subsidence of the basin in the late Oligocene (late Zemorrian) (Campion and others, 1994) or early Miocene (early Saucesian) (Stanley and others, 1992), followed by almost 20 million years of deposition in basin-plain, slope, banktop, and shelf environments. With the exception of the Vaqueros Sandstone, which is a coarse- to fine-grained, shallow-water sandstone, and the relatively restricted, Relizian(?)-aged Hueneme Sandstone, the other units are primarily composed of fined-grained and bioclastic claystones, siliceous shales, porcelanites, diatomites, and siltstones (see Garrison and Douglas (1981) and Isaacs and Garrison (1983) for more detail). Locally important volcanic units are intercalated with the Rincon and Monterey Formations. The maximum thickness of the Miocene section may exceed 8,000 feet.

The Pliocene-aged section is represented by the "Repetto"[10] and Pico Formations. The Repetto Formation unconformably or paraconformably overlies the Sisquoc Formation. As is implied by the name, the Repetto Formation is coincident with the Repettian Stage. Conformably above the Repetto Formation is the Pico Formation. Both formations indicate bathyal to neritic, turbidite and fan environments. The Repetto consists of thin, rhythmically interbedded, medium- to fine-grained, generally nonchannelized sandstones and shales; whereas, the Pico commonly consists of arkosic sandstones and gravels, often found within channels and other lenticular bodies.

Pliocene paleobathymetric indicators suggest a generally shallowing-upward sequence in the Santa Barbara Channel. Much of the Pliocene section has been stripped away on the crest of the prominent anticlinal trends within the Channel area (fig. 71). However, in the basin's Pliocene depocenter, near the City of Ventura, the Pliocene section is in excess of 14,000 feet thick.

STRATIGRAPHIC OCCURRENCE OF PETROLEUM

Oil and natural gas reservoirs have been identified in nearly every formation (Cretaceous through Pleistocene) in the Santa Barbara-Ventura basin (fig. 70). As ranked by volume of oil and condensate produced (onshore and offshore) to date, the most important reservoir formations include (1) Pliocene Pico and Repetto turbidite sandstones; (2) Oligocene-Miocene Sespe and Vaqueros nonmarine to shallow-marine, coarse clastics; (3) middle Miocene Modelo sandstones; and (4) middle Miocene Monterey fractured biogenic siliceous shales.

Minor oil production has also been obtained from lower Miocene sandstones of the Topanga Formation, Rincon Formation, and Hueneme Sandstone and from Eocene sandstones of the Gaviota Formation, Sacate Formation, Cozy Dell Shale, and Matilija Formation. Insignificant production has been obtained from Cretaceous reservoirs in the basin.

Important dry gas accumulations have been identified in the Pliocene and Oligocene-Miocene reservoirs. Wet gas (with condensate) accumulations have been found predominantly in the Eocene reservoirs.

With the exception of the Modelo reservoirs (which are found in the eastern onshore portion of the basin and are not considered a play in the Santa Barbara Channel) and the small Cretaceous reservoirs, the established reservoir groups in the offshore part of the basin have provided the basis for the definition of plays and assessment of the undiscovered resource potential.

EXPLORATION HISTORY

Petroleum seeping to the Earth's surface has been exploited in this basin since prehistoric times. Distilleries and refineries were built in the 1850's and 1860's to process and refine seepage oil and tar. As early as 1861, "oil tunnels" (adits) were driven into the flanks of Sulphur Mountain, near Santa Paula, to tap the reservoir strata that fed the seeps. Indeed, the oldest fields were developed under rules adopted by "petroleum mining districts." Some of the earliest-discovered fields are still in production today. A few individual wells and oil tunnels have produced for over 100 years.

Since 1861, at least 155 oil and gas fields have been discovered in the greater Santa Barbara-Ventura basin. Of these, 33 were discovered before 1901. However, of these 33 shallow fields, only 4 (Bardsdale, Silverthread, Tar Creek-Topatopa, and Torrey Canyon) may ultimately produce over 10 MMbbl of oil; all 4 fields were augmented by later-discovered deep production.

The Summerland field, discovered in 1890, played an important role in the petroleum development history of the basin. It was there in 1894 that the first offshore oil wells in North America were drilled. Oil wells were drilled from piers through caissons driven into the seafloor. The subsequent development and haphazard abandonment of the field not only modified the exploration paradigm (to include offshore potential) but also began to shape the aesthetic and environmental mores that continue to cause conflict to this day.

It was not until the post-World War II advent of modern offshore exploration technology that the Federal offshore area was explored in earnest. Extensive bottom sampling, coring, and seismic programs have been conducted in the area since

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[10] The U.S. Geological Survey has abandoned the term "Repetto" (originally used to describe rocks that were deposited during the Repettian Stage) (Keroher and others, 1966); however, the term is widely used by the geological community and is used in this report.

then. The first Federal lease in the Santa Barbara Channel (on the western end of the Carpinteria field) was not issued until 1966, more than 100 years after petroleum development began in the basin.

Advances in exploration and development technology over the past 135 years have continued to further the search for petroleum into heretofore unreachable locations. As a result of this search, at least 12 fields that will ultimately produce in excess of 100 MMbbl of combined oil-equivalent resources (MMBOE) have been discovered; this estimate includes the supergiant (>1,000 MMBOE) Ventura-San Miguelito-Rincon field.

Considerable unleased, undrilled, and unexplored acreage exists in the Santa Barbara Channel. Furthermore, prospective to highly prospective areas throughout the basin have been precluded from exploration by the creation of parks, wilderness areas, and marine sanctuaries. These areas nevertheless contribute to the undiscovered petroleum potential of the basin.

Plays

Based on reservoir rock stratigraphy and the exploration and production history of the Santa Barbara-Ventura basin, six petroleum geologic plays were defined for analysis (fig. 70). With the exception of the Cretaceous-Paleocene Sandstone play, which has only three known accumulations in the basin, all of the plays were assessed to estimate their volume of undiscovered conventionally recoverable resources. These five assessed plays consist of (1) Pico-Repetto Sandstone play (Pliocene turbidite sandstones), (2) Monterey Fractured play (Miocene fractured siliceous shales), (3) Rincon-Monterey-Topanga Sandstone play (lower Miocene channel and fan sandstones), (4) Sespe-Alegria-Vaqueros Sandstone play (Oligocene shallow- to nonmarine coarse clastics), and (5) Gaviota-Sacate-Matilija Sandstone play (Eocene channel and fan sandstones).

These plays, described in the following parts of this section, are broadly related to plays in the State offshore and onshore portions of the basin, which have been described and assessed by the U.S. Geological Survey (Keller, 1995).

Resource Estimates

Undiscovered Conventionally Recoverable Resources

Original recoverable reserves were estimated for all known accumulations in the entire (onshore and offshore) basin[11]. Field reserves estimates were subdivided on a play basis. Public and private sources of information were used to develop the data base. If existing sources of data were insufficient, production and reserves were estimated. Reserves estimates of partially or wholly undeveloped fields are highly speculative.

Play-specific estimates of undiscovered conventionally recoverable resources have been developed using the discovery assessment method. For each assessed play, a pool-size distribution of the entire play area (including discovered and undiscovered pools, onshore and offshore) was developed. Estimates of undiscovered conventionally recoverable resources in the Federal offshore portion of each play were subsequently calculated using a subjective area proportionality factor. These play-specific estimates have been statistically aggregated to estimate the total volume of undiscovered conventionally recoverable resources in the Federal offshore portion of the basin (i.e., the Santa Barbara-Ventura Basin province). Select data used to develop the resource estimates are shown in appendix C.

As a result of this assessment, the total volume of undiscovered conventionally recoverable resources in the Santa Barbara-Ventura Basin province is estimated to be 1.85 Bbbl of oil (including oil and condensate) and 4.62 Tcf of gas (including associated and non-associated gas) (mean estimates). This volume may exist in 174 fields with sizes ranging from approximately 70 Mbbl to 215 MMbbl of combined oil-equivalent resources (fig. 72). A large proportion of these resources (approximately 46 percent on a combined oil-equivalence basis) is estimated to exist in the Monterey Fractured play. The low, mean, and high estimates of resources in the province are listed in table 23 and illustrated in figure 73.

Undiscovered Economically Recoverable Resources

Estimates of undiscovered conventionally recoverable resources in the province that may be economically recoverable under various economic scenarios have been developed using the economic assessment method. Select data used to develop the resource estimates are shown in appendix D.

As a result of this assessment, 1.17 Bbbl of oil (including oil and condensate) and 2.91 Tcf of gas (including associated and nonassociated gas) are estimated to be economically recoverable from the Santa Barbara-Ventura Basin province under economic conditions existing as of this assessment (i.e., the $18-per-barrel economic scenario) (table 24). Larger volumes of resources are expected to be

[11] The author is solely responsible for the accuracy of the production and reserves data used in this analysis.

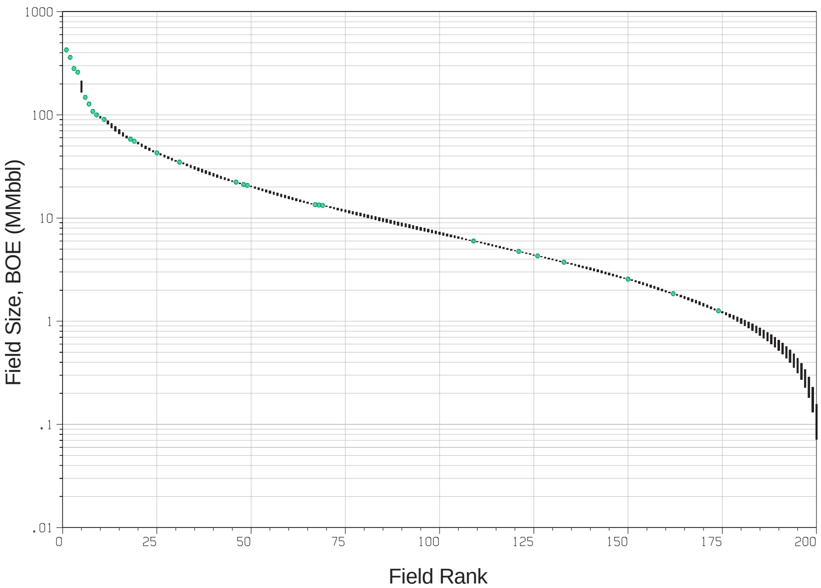

Figure 72. *Field-size rank plot of estimated conventionally recoverable resources of the Santa Barbara-Ventura basin province. Sizes of discovered fields are shown by dots. Sizes of undiscovered fields are shown by bars; the top and bottom of a bar represent the 25th- and 75th-percentile value of a probability distribution, respectively.*

Table 23. *Estimates of undiscovered conventionally recoverable oil and gas resources in the Santa Barbara-Ventura Basin province as of January 1, 1995, by play. All estimates are risked values. The low, mean, and high estimates correspond to the 95th-percentile, mean, and 5th-percentile values of a probability distribution, respectively. Percentile values are not additive; some total mean values may not equal the sum of the component values due to independent rounding.*

Play	Oil (MMbbl)			Gas (Bcf)			BOE (MMbbl)		
	Low	Mean	High	Low	Mean	High	Low	Mean	High
Pico-Repetto Sandstone	216	299	400	617	1,244	2,168	323	521	782
Monterey Fractured	959	1,004	1,050	1,129	1,201	1,277	1,162	1,218	1,276
Rincon-Monterey-Topanga Sandstone	140	144	149	249	259	269	185	191	196
Sespe-Alegria-Vaqueros Sandstone	263	277	291	1,227	1,338	1,454	489	515	542
Gaviota-Sacate-Matilija Sandstone	117	122	127	541	572	605	215	224	233
Cretaceous-Paleocene Sandstone					not assessed				
Total Province	*1,744*	*1,847*	*1,953*	*3,840*	*4,615*	*5,481*	*2,432*	*2,668*	*2,918*

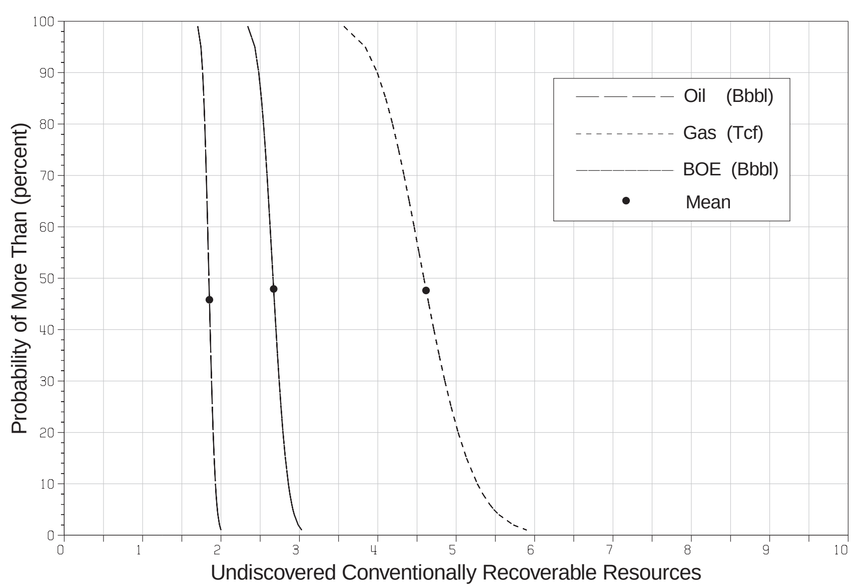

Figure 73. *Cumulative probability plot of estimated undiscovered conventionally recoverable resources of the Santa Barbara-Ventura Basin province.*

Table 24. *Estimates of undiscovered economically recoverable oil and gas resources in the Santa Barbara-Ventura Basin province as of January 1, 1995, by economic scenario. All estimates are risked mean values. The $18-per-barrel scenario is based on prices of $18 per bbl of oil and $2.11 per Mcf of gas; the $25-per-barrel scenario is based on prices of $25 per bbl of oil and $2.94 per Mcf of gas; the $50-per-barrel scenario is based on prices of $50 per barrel of oil and $5.87 per Mcf of gas.*

Economic Scenario	Oil (MMbbl)	Gas (Bcf)	BOE (MMbbl)
$18 per barrel	1,166	2,913	1,684
$25 per barrel	1,370	3,425	1,980
$50 per barrel	1,644	4,108	2,375

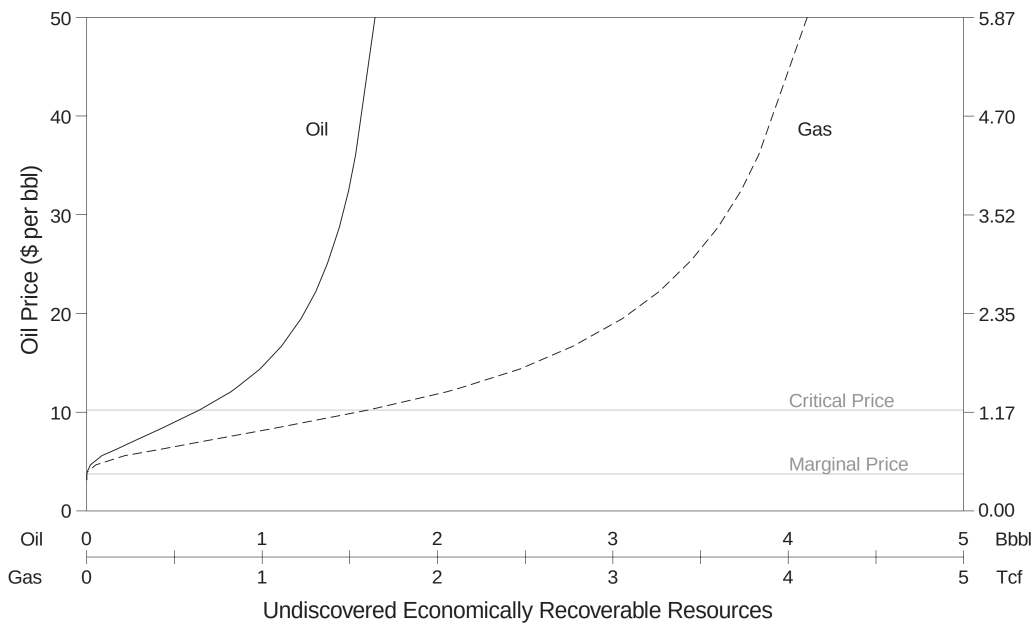

Figure 74. *Price-supply plot of estimated undiscovered economically recoverable resources of the Santa Barbara-Ventura Basin province.*

economically recoverable under increasingly favorable economic conditions (fig. 74).

Total Resource Endowment

As of this assessment, original recoverable reserves in 26 fields in the province were estimated to be 1.14 Bbbl of oil and 2.39 Tcf of gas. These discovered resources and the aforementioned undiscovered conventionally recoverable resources collectively compose the province's estimated total resource endowment of 2.99 Bbbl of oil and 7.01 Tcf of gas (table 25).

Table 25. *Estimates of the total endowment of oil and gas resources in the Santa Barbara-Ventura Basin province. Estimates of discovered resources (including cumulative production and remaining reserves) and undiscovered resources are as of January 1, 1995. Estimates of undiscovered conventionally recoverable resources are risked mean values. Some total values may not equal the sum of the component values due to independent rounding.*

Resource Category	Oil (Bbbl)	Gas (Tcf)	BOE (Bbbl)
Cumulative Production	0.49	0.67	0.61
Remaining Reserves	0.65	1.72	0.96
Undiscovered Conventionally Recoverable Resources	1.85	4.61	2.67
Total Resource Endowment	*2.99*	*7.01*	*4.24*

ACKNOWLEDGMENTS

During the course of the 4 years this project has been underway, a great many professionals provided critical input and peer review. The author has been able to draw upon many years, and sometimes decades, of experience regarding the Santa Barbara-Ventura basin, which the following individuals have provided: J.P. Chauvel and Greg Cavette (UNOCAL), James Crouch (J.K. Crouch and Associates, Inc.), Dennis Giovannetti (Vastar Resources), Ron Heck and Ed Edwards (Heck & Associates), Tom Hopps (Rancho Energy Consultants), Marc Kamerling and Chris Sorlien (University of California Santa Barbara, Institute of Crustal Studies), Margaret Keller (U.S. Geological Survey), Pat Kinnear and Steve Fields (California Division of Oil, Gas, and Geothermal Resources). Cathie Dunkel, Michael Brickey, Ken Piper, Scott Drewry, and Margaret Keller provided their valuable editing skills. To these people, and to many others who have provided helpful suggestions and criticism, the author offers his profound thanks.

ADDITIONAL REFERENCES

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Conservation Committee of California Oil Producers, 1961
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PICO-REPETTO SANDSTONE PLAY

PLAY DEFINITION

The Pico-Repetto Sandstone play of the Santa Barbara-Ventura Basin province includes known and prospective oil and gas accumulations in Pliocene- and early Pleistocene-aged reservoirs. This is an established play; original recoverable reserves in onshore and offshore fields exceed 1.94 Bbbl of oil and condensate and 3.28 Tcf of associated and nonassociated gas.

Pliocene strata are distributed throughout the basin; however, this play is limited to the central and eastern portions of the basin (fig. 75) where the reservoir sandstones are known to be abundant and where the depositional thickness of the play exceeds 2,000 feet. The Federal offshore portion of the play is limited to the eastern part of the Santa Barbara Channel; it encompasses an area of about 400 square miles.

PETROLEUM GEOLOGIC CHARACTERISTICS

Reservoir rocks of this play are primarily sandstones of the Repetto and Pico Formations (fig. 70). Thin-bedded, glauconitic, turbidite sandstones deposited in a bathyal environment are typical of the Repetto Formation. Arkosic sandstones, gravels, and sandy siltstones deposited in an upper bathyal to inner neritic environment are characteristic of the Pico Formation. Sandstones often compose over 50 percent of the rock volume in parts of the play area. The Repetto Formation exceeds a thickness of 4,000 feet. The Pico Formation has a maximum thickness of over 10,000 feet in the basin's Pliocene depocenter.

The source rocks for the oil and gas reservoired in the Pico and Repetto Formations are probably the Miocene Monterey Formation (fig. 70). It is possible that deeply buried, lower Pliocene claystones and mudstones are an additional petroleum source; although, geochemical data suggest that much of the Pliocene section is thermally immature (Yeats and Taylor, 1990).

Traps within this play will be predominantly anticlines, faulted anticlines, and fault blocks. Less-common traps include unconformities on the flanks of folds and permeability barriers. Important structural trends have been identified in the play area, but some trapping mechanisms have not been adequately tested offshore. In particular, primary stratigraphic traps and subthrust accumulations are statistically underrepresented in the known fields.

DISCOVERIES

The largest productive accumulations in the play (based on original recoverable reserves) include the Ventura-San Miguelito-Rincon field (discovered 1919; 1,770 MMBOE), Dos Cuadras field (1968; 281 MMBOE), Carpinteria field (1966; 129 MMBOE), and the Saticoy-South Mountain (Bridge Pool) field (1955; 86 MMBOE). The first production from this play was obtained from oil tunnels at the Santa Paula field as early as 1861. For the purpose of resource assessment, it was assumed that the largest accumulation in the play has been discovered.

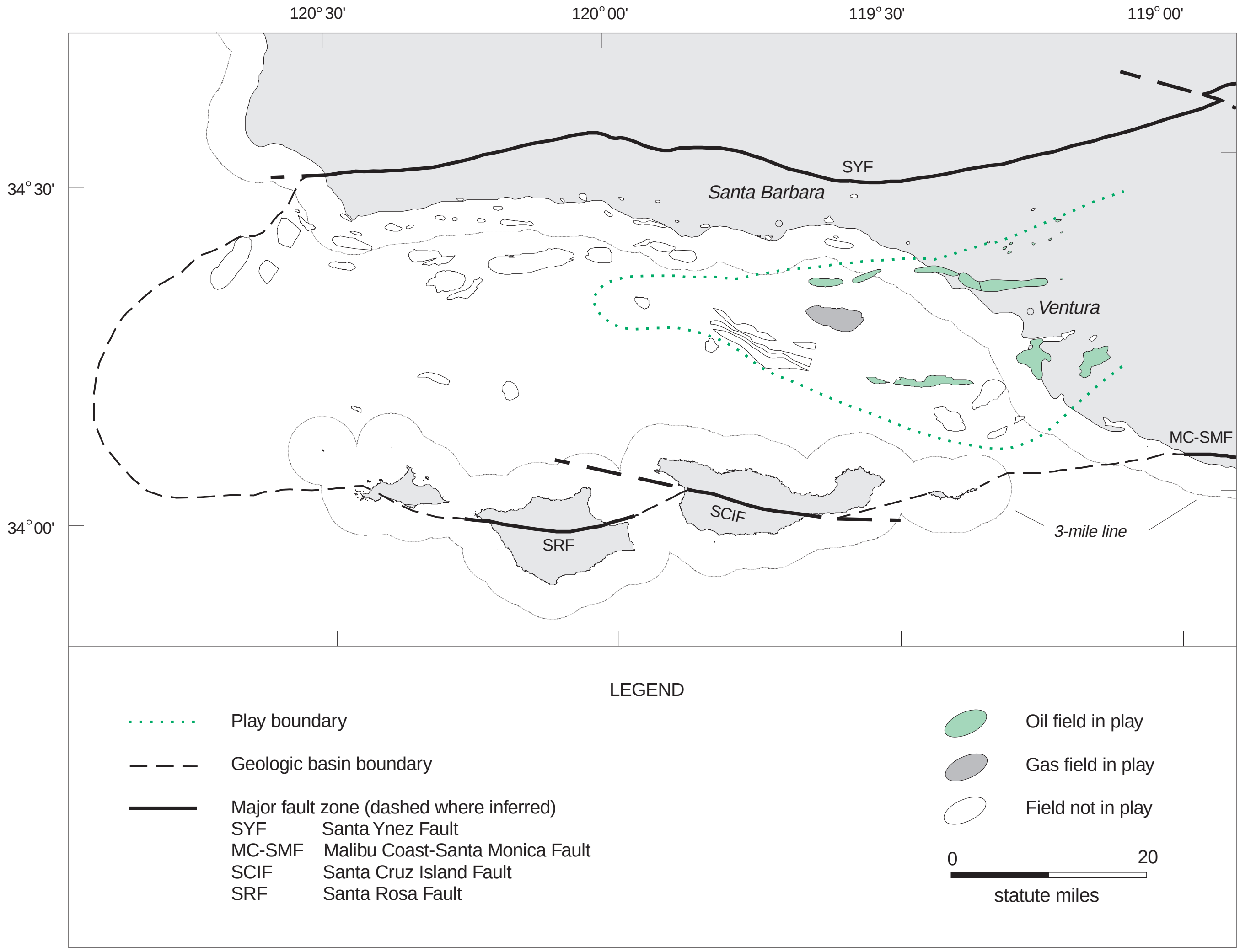

Figure 75. *Map of the Pico-Repetto Sandstone play, Santa Barbara-Ventura basin showing select fields.*

Resource Estimates

Undiscovered Conventionally Recoverable Resources

Estimates of undiscovered conventionally recoverable resources in the entire play have been developed using the discovery assessment method with pool-size data from 26 onshore and offshore discovered accumulations in the play. Estimates of undiscovered resources in the Federal offshore portion of the play were subsequently calculated using a subjective area-proportionality factor. Select data used to develop the resource estimates are shown in appendix C.

As a result of this assessment, the entire play is estimated to contain 748 MMbbl of oil (including oil and condensate) and 3.11 Tcf of gas (including associated and nonassociated gas) (mean estimates). This volume of undiscovered conventionally recoverable resources may exist in 54 pools with sizes ranging from approximately 4 Mbbl to 795 MMbbl of combined oil-equivalent resources (fig. 76). Of these, 3 pools may exceed 100 MMBOE and an additional 11 pools may exceed 10 MMBOE. Analysis of the discovered pools (each with original recoverable reserves in excess of 10 MBOE) suggests that the undiscovered pools will contain primarily oil and associated gas and that some nonassociated gas pools are probable.

The Federal offshore portion of the play is estimated to contain approximately 40 percent of these undiscovered conventionally recoverable resources, which is 299 MMbbl of oil (including oil and condensate) and 1.24 Tcf of gas (including associated and nonassociated gas) (mean estimates). The low, mean, and high estimates of resources in the Federal offshore portion of the play are listed in table 23.

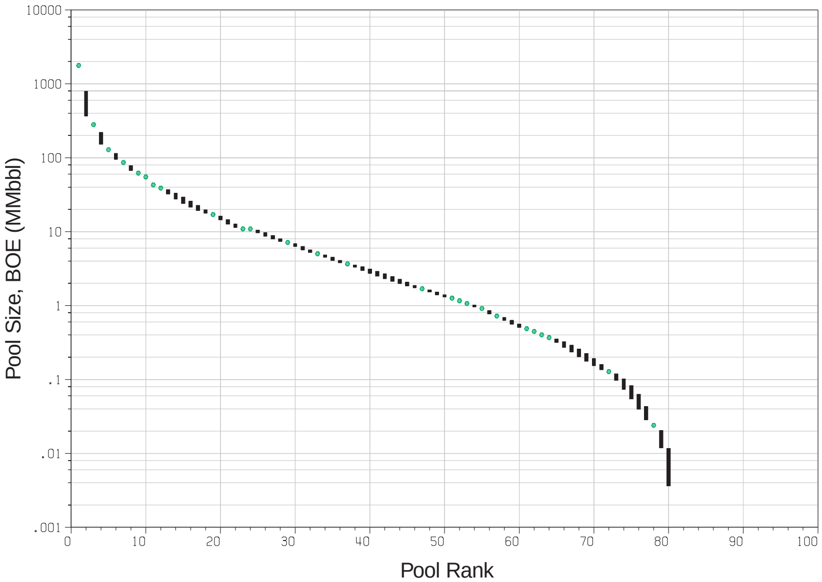

Figure 76. *Pool-size rank plot of estimated conventionally recoverable resources of the Pico-Repetto Sandstone play, Santa Barbara-Ventura basin. Sizes of discovered pools are shown by dots. Sizes of undiscovered pools are shown by bars; the top and bottom of a bar represent the 25th- and 75th-percentile values of a probability distribution, respectively.*

MONTEREY FRACTURED PLAY

PLAY DEFINITION

The Monterey Fractured play of the Santa Barbara-Ventura Basin province includes known and prospective oil accumulations in middle to late Miocene-aged reservoirs of the Monterey Formation. These reservoirs characteristically have secondary fracture porosity. This is an established play; original recoverable reserves in onshore and offshore fields exceed 1.09 Bbbl of oil and 1.74 Tcf of associated gas.

The Monterey Formation is distributed throughout the Santa Barbara-Ventura basin (fig. 77). In the eastern part of the basin east of the Ojai field, sandy Monterey strata are known as the Modelo Formation. (The Modelo Formation has not been assessed herein because these facies are primarily found in the onshore part of the basin.) The Monterey Formation is exposed on the north flank of the basin in seacliffs and on the seafloor. On the south flank of the basin, the Monterey Formation and coeval volcaniclastics are exposed on the Channel Islands and on the seafloor. The Federal offshore portion of the play encompasses an area of about 1,500 square miles.

PETROLEUM GEOLOGIC CHARACTERISTICS

Reservoir rocks of this play are fractured zones within the Monterey Formation (fig. 70). Silica diagenesis (which causes the rock mass to become increasingly brittle) coupled with late Neogene compressional tectonics have formed these reservoirs. If either component is missing, a highly prospective fractured reservoir will not form.

The Monterey Formation is a self-sourcing rock unit (fig. 70). In the Santa Barbara-Ventura basin, the Monterey is known to be highly petroliferous and is estimated to have expelled 10 to 20 Bbbl of oil. Much of the Monterey Formation is now within the main zone of oil generation (“oil window”). The generation of Monterey-sourced crude oils is much debated. Empirical evidence suggests that the Monterey Formation is capable of producing oils with a wide range of physical properties and characteristics (e.g., gravity, sulphur content, and viscosity).

Traps within this play are predominantly complexly faulted anticlines. Less-common traps will include normal- and thrust-faulted blocks. Primary stratigraphic traps and stratigraphic components of combination traps are not well recognized or understood in the Monterey Formation, but they may provide important trapping mechanisms for future discoveries within the basin.

DISCOVERIES

The largest productive accumulations in Monterey fractured rocks of this play (based on original recoverable reserves) include the Hondo field (discovered 1969; 393 MMBOE), Pescado field (1970; 127 MMBOE), and South Ellwood Offshore field (1969; 62 MMBOE). Other large, undeveloped accumulations have been identified offshore. The earliest recognized production from “fractured shales” of the Monterey Formation in the Santa Barbara-Ventura basin was obtained in 1917 at the North Sulphur Mountain area

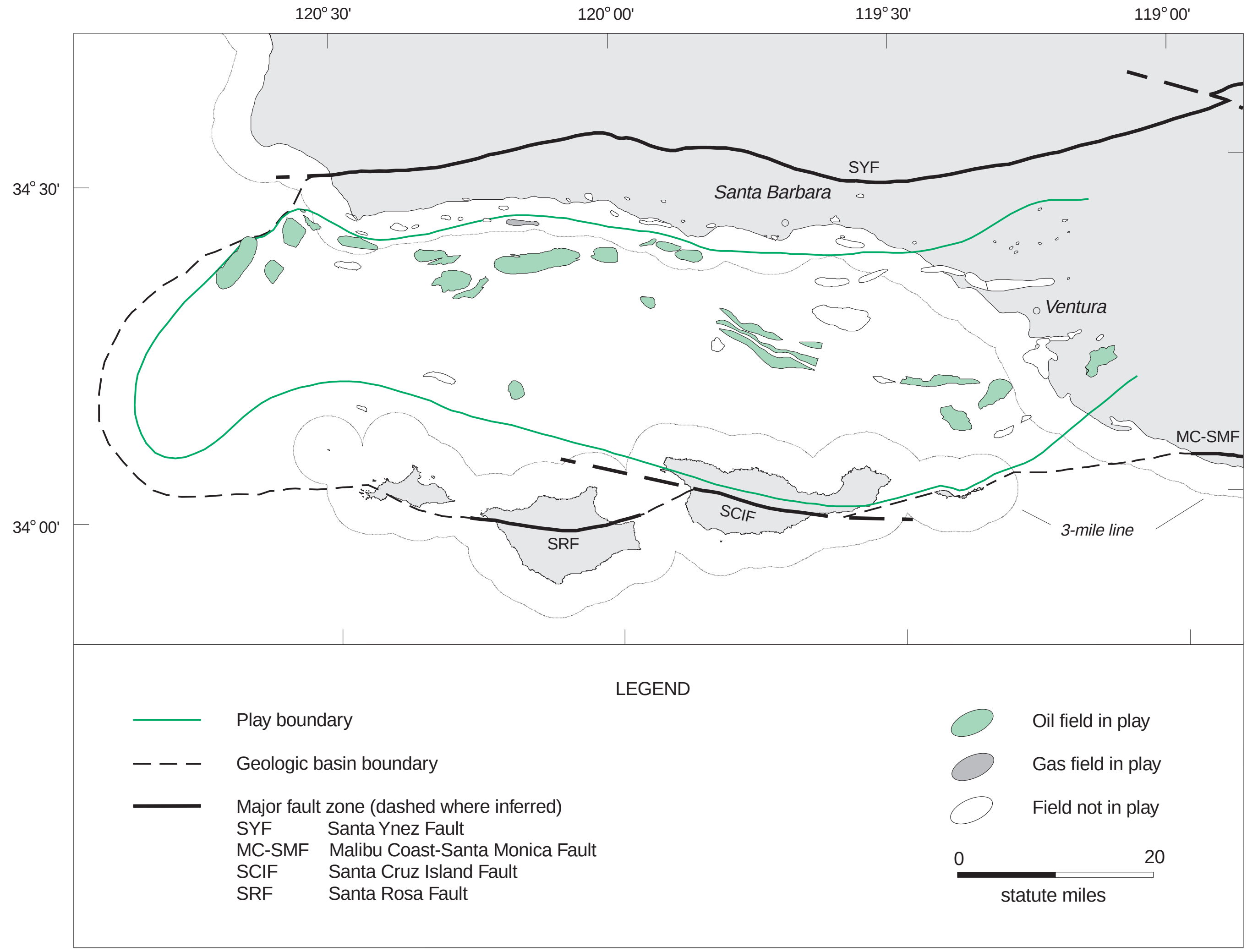

Figure 77. *Map of the Monterey Fractured play, Santa Barbara-Ventura basin showing select fields.*

of the Ojai field. For the purpose of resource assessment, it was assumed that the largest accumulation in the play has been discovered.

Resource Estimates

Undiscovered Conventionally Recoverable Resources

Estimates of undiscovered conventionally recoverable resources in the entire play have been developed using the discovery assessment method with pool-size data from 26 onshore and offshore discovered accumulations in the play. Estimates of undiscovered resources in the Federal offshore portion of the play were subsequently calculated using a subjective area-proportionality factor. Select data used to develop the resource estimates are shown in appendix C.

As a result of this assessment, the entire play is estimated to contain 1.34 Bbbl of oil (including oil and condensate) and 1.60 Tcf of gas (including associated and nonassociated gas) (mean estimates). This volume of undiscovered conventionally recoverable resources may exist in 104 pools with sizes ranging from approximately 205 Mbbl to 225 MMbbl of combined oil-equivalent resources (fig. 78). Of these, 3 pools may exceed 100 MMBOE and an additional 35 pools may exceed 10 MMBOE. Analysis of the discovered pools suggests that the undiscovered pools will contain primarily oil and associated gas.

The Federal offshore portion of the play is estimated to contain approximately 75 percent of these undiscovered conventionally recoverable resources, which is 1.00 Bbbl of oil (including oil and condensate) and 1.20 Tcf of gas (including associated and nonassociated gas) (mean estimates). The low, mean, and high estimates of resources in the Federal offshore portion of the play are listed in table 23.

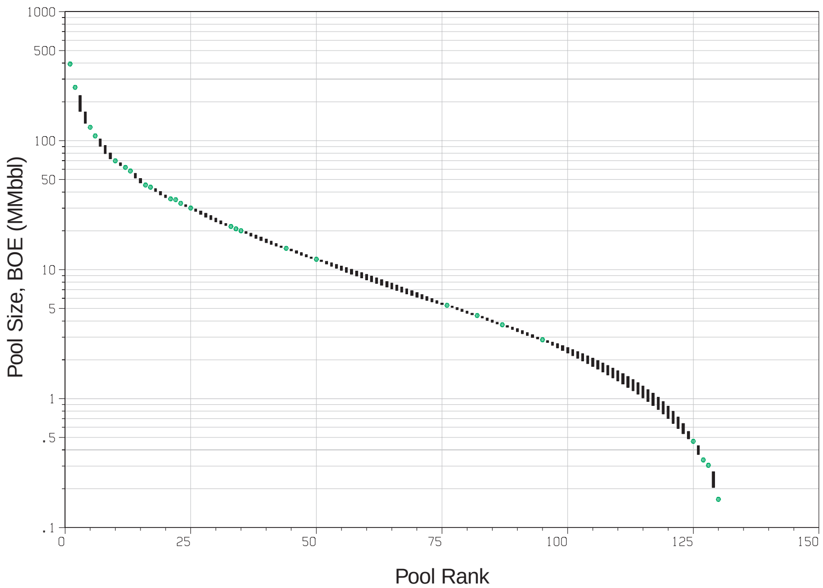

Figure 78. *Pool-size rank plot of estimated conventionally recoverable resources of the Monterey Fractured play, Santa Barbara-Ventura basin. Sizes of discovered pools are shown by dots. Sizes of undiscovered pools are shown by bars; the top and bottom of a bar represent the 25th- and 75th-percentile values of a probability distribution, respectively.*

RINCON-MONTEREY-TOPANGA SANDSTONE PLAY

PLAY DEFINITION

The Rincon-Monterey-Topanga Sandstone play of the Santa Barbara-Ventura Basin province includes known and prospective oil and associated gas accumulations in early Miocene- to middle Miocene-aged reservoirs. This is an established play; original recoverable reserves in onshore and offshore fields exceed 156 MMbbl of oil and 188 Bcf of associated gas.

This play is limited to two noncontiguous areas in the basin (fig. 79). Lower Miocene (Saucesian) Rincon sandstones and middle Miocene (Relizian to Luisian) lower Monterey sandstones are present in the north-central part of the Santa Barbara Channel. Strata assigned to the lower to middle Miocene Topanga Formation, the lower to middle Miocene San Onofre Breccia, and the lower Miocene (Saucesian to Relizian) Hueneme Sandstone are exposed in outcrop and in boreholes in the southeastern Santa Barbara Channel, along the Oakridge trend, in the Santa Monica Mountains, and on the Channel Islands. The Federal offshore portion of the play encompasses an area of about 160 square miles.

PETROLEUM GEOLOGIC CHARACTERISTICS

Reservoir rocks of this play, as identified in oil fields, are primarily sandstones deposited in deep-water fans and channels. The sandstone reservoirs in the northern subarea of the play have good porosity (20 to 30 percent) and good permeability (400 to 600 millidarcies). Stacked sand bodies are as thick as 150 feet, and the sandy zones may have a gross thickness in excess of 1,000 feet. The sandstone reservoirs in the southeastern subarea of the play vary in porosity and permeability. The Topanga sandstones have good porosity (20 to 30 percent) and fair to very good permeability (200 to 1,000 millidarcies). The Hueneme Sandstone has very good porosity (30 to 35 percent) and good to excellent permeability (500 to 1,500 millidarcies).

Multiple source rocks are likely for this play. Reservoirs containing medium- to low-gravity, sulphurous, asphaltic oil are probably sourced from the Monterey Formation. Locally, particularly in the northern subarea, fine-grained clay shales of the Rincon Formation may also be a significant source of petroleum (Stanley and others, 1992). The deposition of lower to middle Miocene volcanics in the area of this play may have altered the thermal maturation history of potential source strata.

Traps within this play are predominantly structural but contain important stratigraphic components. The majority of the discovered fields in this play are in faulted anticlines. In some of the fields, particularly in the northern subarea, lenticular, sinuous channel sandstones complicate the reservoir geometry. The basal transgressive Hueneme Sandstone commonly occupies depressions incised into the underlying Sespe Formation, and as such, pinchouts may be an important trapping mechanism in future discoveries.

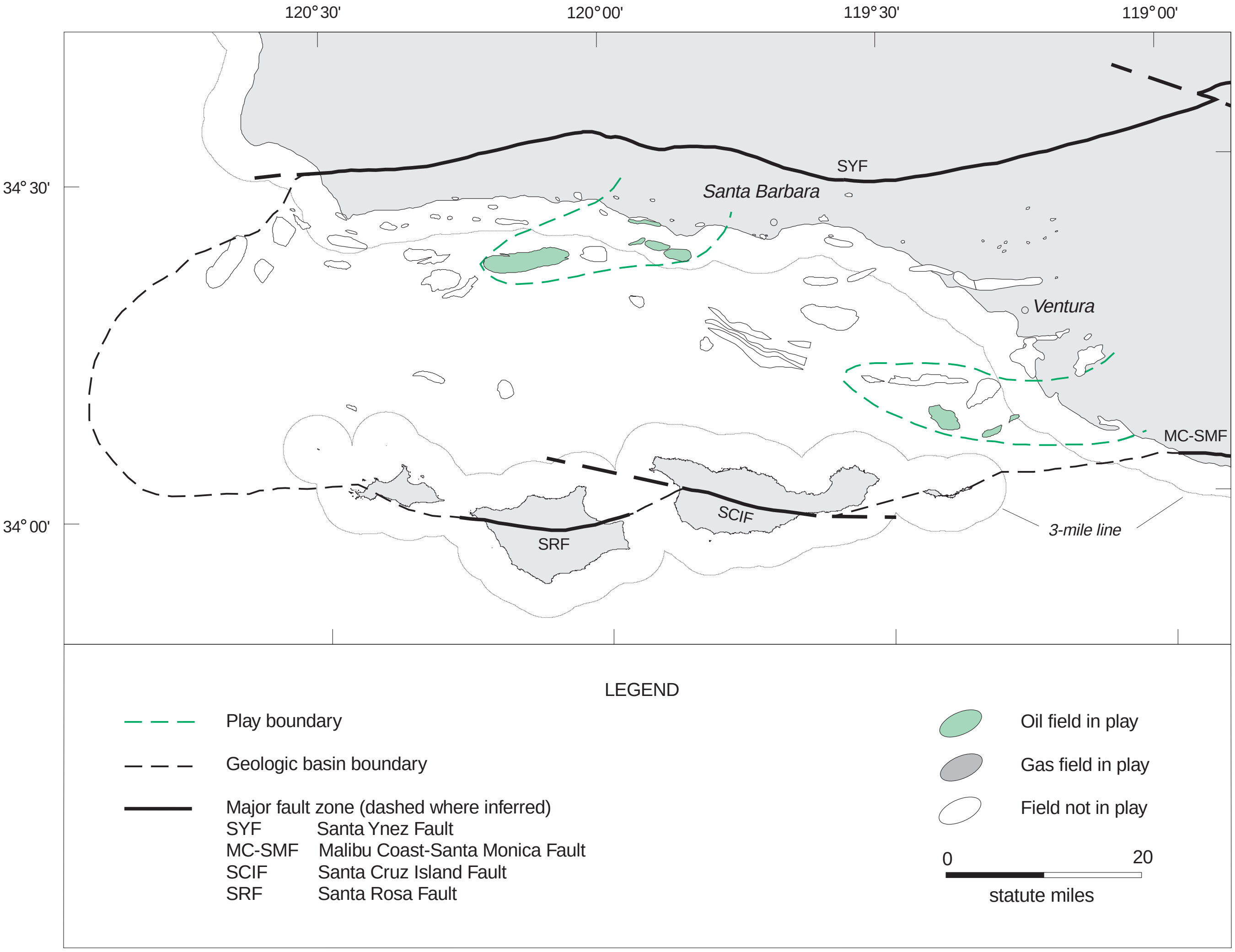

Figure 79. *Map of the Rincon-Monterey-Topanga Sandstone play, Santa Barbara-Ventura basin showing select fields.*

Discoveries

The largest productive accumulations in the play (based on original recoverable reserves) include the Oakridge field (Lower Monterey/Topanga/Vaqueros zone; discovered 1952; 24 MMBOE), Hueneme field (Hueneme/Sespe zones; 1969; 17 MMBOE), Sockeye field ("Upper Topanga" zone; 1970; 14 MMBOE), and South Ellwood Offshore field (Rincon zone; 1965; 7 MMBOE). Additional undeveloped discoveries in this play have been made at the Coal Oil Point Offshore field, "Embarcadero Offshore" field, and Hondo field (Lower Monterey Sands zone). Significant additional, undeveloped reserves are estimated for South Ellwood Offshore field. The earliest known oil production from reservoirs in this play occurred in 1931 at the Ellwood field. It is unclear from the old records whether the production was obtained from fractured shales or sandstone stringers within the Rincon Formation.

For the purpose of resource assessment, it was assumed that the largest accumulation in the play has been discovered. However, giant accumulations in nearby analogous basins (e.g., Kettleman North Dome field (Temblor zone; 725 MMBOE) in the San Joaquin basin and San Ardo field (540 MMBOE) in the Salinas basin) in strata equivalent to this play suggest that this assumption may be conservative.

Resource Estimates

Undiscovered Conventionally Recoverable Resources

Estimates of undiscovered conventionally recoverable resources in the entire play have been developed using the discovery assessment method with pool-size data from eight onshore and offshore discovered accumulations in the play. Estimates of undiscovered resources in the Federal offshore portion of the play were subsequently calculated using a subjective

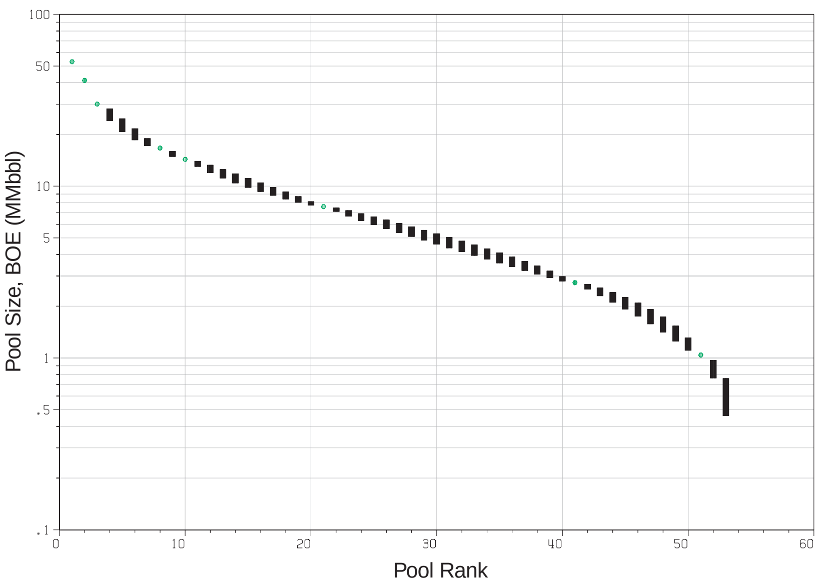

Figure 80. *Pool-size rank plot of estimated conventionally recoverable resources of the Rincon-Monterey-Topanga Sandstone play, Santa Barbara-Ventura basin. Sizes of discovered pools are shown by dots. Sizes of undiscovered pools are shown by bars; the top and bottom of a bar represent the 25th- and 75th-percentile values of a probability distribution, respectively.*

area-proportionality factor. Select data used to develop the resource estimates are shown in appendix C.

As a result of this assessment, the entire play is estimated to contain 241 MMbbl of oil (including oil and condensate) and 432 Bcf of gas (including associated and nonassociated gas) (mean estimates). This volume of undiscovered conventionally recoverable resources may exist in 45 pools with sizes ranging from approximately 460 Mbbl to 30 MMbbl of combined oil-equivalent resources (fig. 80). Analysis of the discovered pools suggests that the undiscovered pools will contain primarily medium- to low-gravity oil and associated gas.

The Federal offshore portion of the play is estimated to contain approximately 60 percent of these undiscovered conventionally recoverable resources, which is 144 MMbbl of oil (including oil and condensate) and 259 Bcf of gas (including associated and nonassociated gas) (mean estimates). The low, mean, and high estimates of resources in the Federal offshore portion of the play are listed in table 23.

SESPE-ALEGRIA-VAQUEROS SANDSTONE PLAY

PLAY DEFINITION

The Sespe-Alegria-Vaqueros Sandstone play of the Santa Barbara-Ventura Basin province includes known and prospective accumulations of oil and associated gas and of non-associated gas in late Eocene- and Oligocene- to early Miocene-aged reservoirs. This is an established play; original recoverable reserves in onshore and offshore fields exceed 580 MMbbl of oil and condensate, and over 1.58 Tcf of associated and nonassociated gas.

Formations in this play are exposed in the Santa Ynez Mountains on the north flank of the basin, on the Channel Islands on the south flank of the basin, and in prominent structural trends (such as the Montalvo Anticlinorium) within the basin (fig. 71). The formations are also penetrated by numerous boreholes offshore. On the basis of these exposures and interpretation of seismic-reflection profiles, it is presumed that these strata are present throughout the offshore portion of the basin (fig. 81). The shallow-marine Alegria Formation is coeval with and replaces the nonmarine to shallow-marine Sespe Formation in the western portion of the basin. The distribution of the Vaqueros Sandstone is less certain. The Federal offshore portion of the play encompasses an area of about 1,700 square miles.

PETROLEUM GEOLOGIC CHARACTERISTICS

Reservoir rocks of this play are primarily coarse clastics. Nonmarine "red beds" within the Sespe Formation are interpreted to represent braided and meandering fluvial systems. Conglomerate, sandstone, siltstone, and mudstone are the predominant lithologies. Sandy and silty facies suggestive of a fan-delta deposit, dating from the late Eocene, may mark the oldest Sespe. Shallow-marine sandstones of the lower Oligocene Alegria Formation are coeval with parts of the Sespe and have been referred to as "marine Sespe." Much of the middle Zemorrian Stage is absent from the section above lower

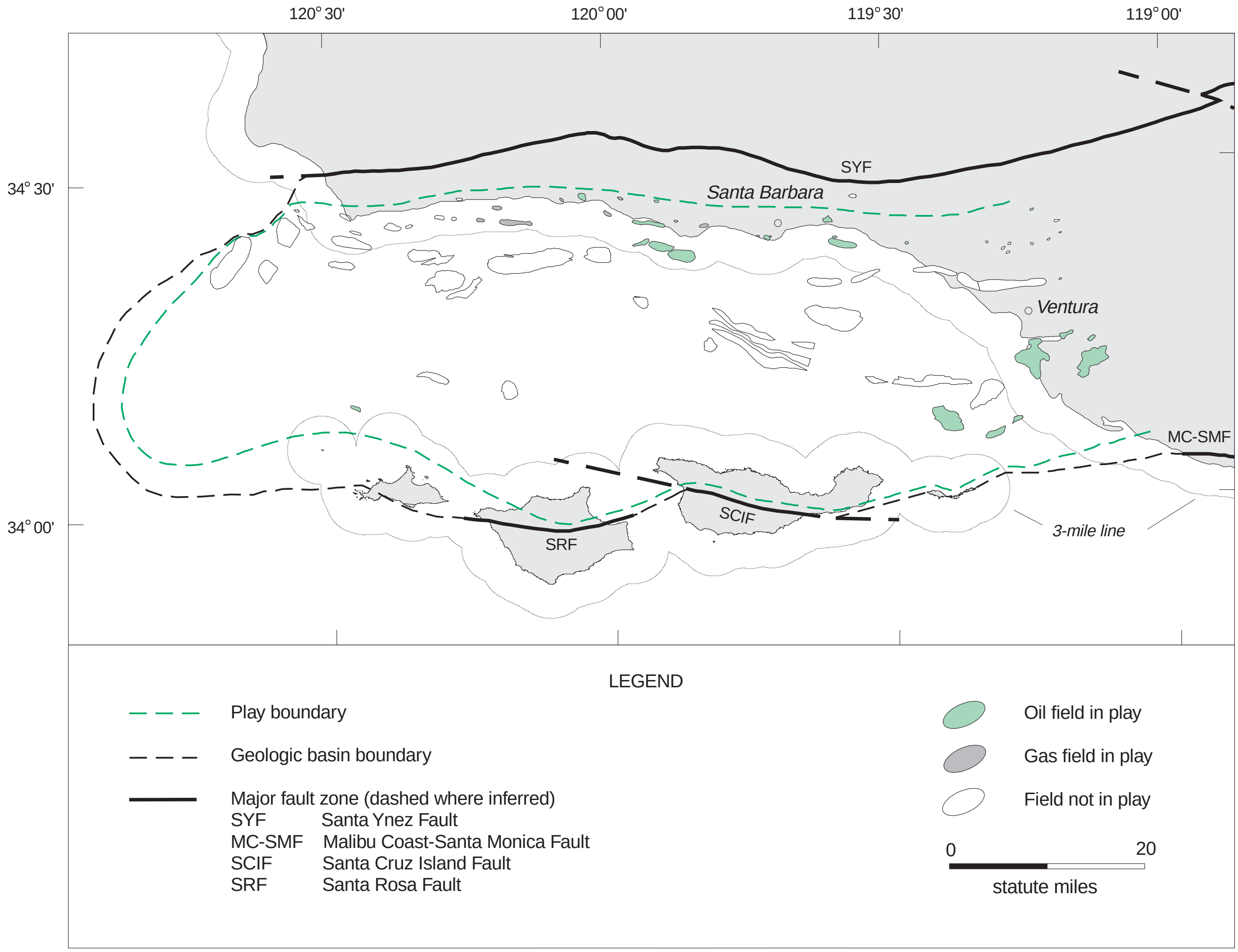

Figure 81. *Map of the Sespe-Alegria-Vaqueros Sandstone play, Santa Barbara-Ventura basin showing select fields*

Sespe/Alegria strata (Howard, 1988; Campion and others, 1994).

The upper portion of the Sespe Formation, like the lower portion, is easily recognizable in outcrop and well cuttings by its variegated nature. It too is dominated by sand-rich fluvial facies. The shallow-marine Vaqueros Sandstone, where present, represents a nearshore to shelf deposit, which locally may also represent submarine canyon fill. The entire Sespe-Alegria-Vaqueros section may be more than 7,500 feet thick in parts of the basin, but averages 3,000 to 4,000 feet thick in the Santa Barbara Channel.

The formations in this play are not generally considered to be prospective source rocks for oil. Likely oil sources include Eocene deep-water shales and overlying Miocene formations. The anomalous number of nonassociated gas fields in the play (relative to the other plays in the basin) may suggest that a local dry-gas source rock exists within the play. If so, the gas could be sourced from land-derived woody or coaly debris in the shallow-marine or continental-marine transitional section.

Important trapping mechanisms within this play include both structural and stratigraphic components. Based on analysis of existing fields within the play, anticlines, faulted anticlines, and fault blocks may provide the most common traps. Stratigraphic traps and combination (stratigraphic-structural) traps are also present.

Discoveries

The largest productive accumulations in the play include the South Mountain field, (Sespe zones; discovered 1916; 153 MMBOE), Ellwood field (Vaqueros zone; 1928; 125 MMBOE), Tar Creek-Topatopa area of the Sespe field (Vaqueros and Sespe zones; 1887; 56 MMBOE), and Molino Offshore gas field

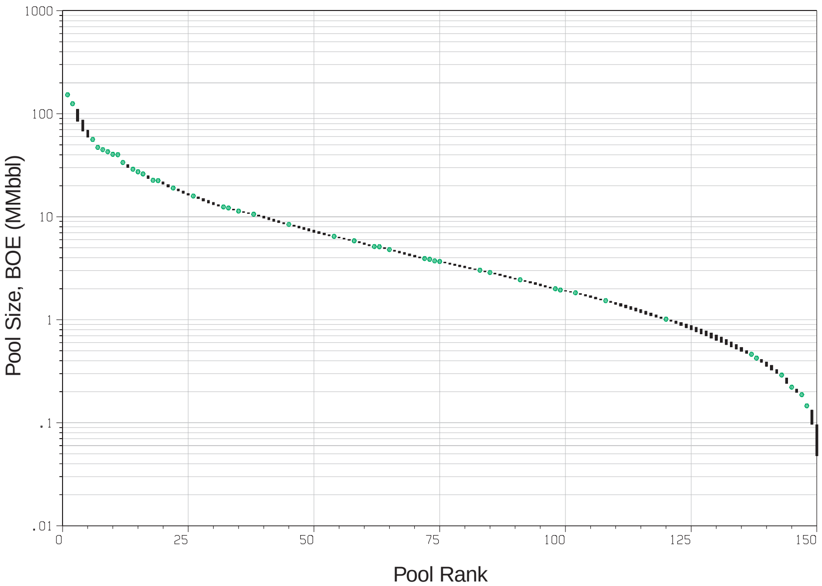

Figure 82. *Pool-size rank plot of estimated conventionally recoverable resources of the Sespe-Alegria-Vaqueros Sandstone play, Santa Barbara-Ventura basin. Sizes of discovered pools are shown by dots. Sizes of undiscovered pools are shown by bars; the top and bottom of a bar represent the 25th- and 75th-percentile values of a probability distribution, respectively.*

(Vaqueros and Sespe zones; 1962; 47 MMBOE). The earliest production in the play was obtained from the fields in Sespe Canyon in 1887. For the purpose of resource assessment, it was assumed that the largest accumulation in the play has been discovered.

RESOURCE ESTIMATES

Undiscovered Conventionally Recoverable Resources

Estimates of undiscovered conventionally recoverable resources in the entire play have been developed using the discovery assessment method with pool-size data from 44 onshore and offshore discovered accumulations in the play. Estimates of undiscovered resources in the Federal offshore portion of the play were subsequently calculated using a subjective area-proportionality factor. Select data used to develop the resource estimates are shown in appendix C.

As a result of this assessment, the entire play is estimated to contain 413 MMbbl of oil (including oil and condensate) and 2.00 Tcf of gas (including associated and nonassociated gas) (mean estimates). This volume of undiscovered conventionally recoverable resources may exist in 106 pools with sizes ranging from approximately 45 Mbbl to 110 MMbbl of combined oil-equivalent resources (fig. 82). Of these, 20 pools may exceed 10 MMBOE. Analysis of the discovered pools suggests that undiscovered pools will contain primarily oil and that some nonassociated gas pools are probable.

The Federal offshore portion of the play is estimated to contain approximately 67 percent of these undiscovered conventionally recoverable resources, which is 277 MMbbl of oil (including oil and condensate) and 1.34 Tcf of gas (including associated and nonassociated gas) (mean estimates). The low, mean, and high estimates of resources in the Federal offshore portion of the play are listed in table 23.

GAVIOTA-SACATE-MATILIJA SANDSTONE PLAY

PLAY DEFINITION

The Gaviota-Sacate-Matilija Sandstone play of the Santa Barbara-Ventura Basin province includes known and prospective accumulations of oil and associated gas and of nonassociated gas in Eocene- to early Oligocene(?)-aged reservoirs. This is an established play; original recoverable reserves in onshore and offshore fields exceed 130 MMbbl of oil and condensate and 840 Bcf of associated and nonassociated gas.

Eocene and lower Oligocene strata are known from exposures in the Santa Ynez Mountains on the north flank of the basin and from similar exposures on the Channel Islands. Many exploratory and production wells have also penetrated these rocks offshore. From these exposures and interpretation of seismic-reflection profiles, Eocene and lower Oligocene formations are assumed to be distributed throughout the basin (fig. 83). It is suspected that the reservoirs degrade in quality with increasing depth of burial; therefore, these rocks are not considered prospective beneath the basin's Pliocene depocenter in the eastern part of the Santa Barbara Channel and adjacent onshore area. The Federal

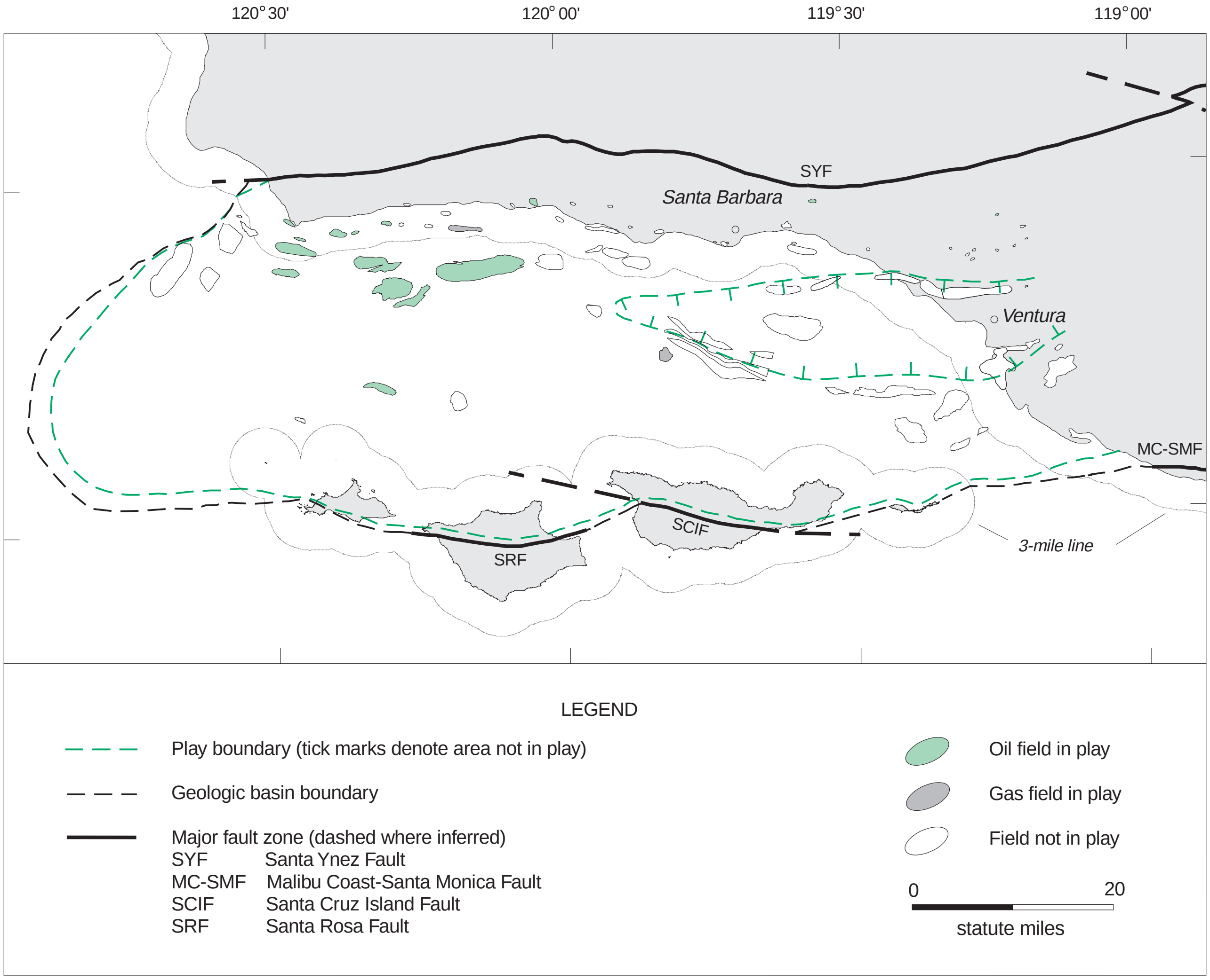

Figure 83. *Map of the Gaviota-Sacate-Matilija Sandstone play, Santa Barbara-Ventura basin showing select fields.*

offshore portion of the play encompasses an area of about 1,500 square miles.

Petroleum Geologic Characteristics

Reservoir rocks of this play are primarily fine- to coarse-grained sandstones. Varied depositional environments are exhibited in the reservoirs of this play. Reservoir rocks representative of deep-water turbidites, slope to shelf fans and channels, nearshore bars, and continental and deltaic deposits have been identified. In the most general sense, deep-water facies are more likely to exist in the central and south-central portions of the modern basin. Facies representative of shallow-marine to nonmarine depositional environments are more likely to be found in the north and east parts of the basin.

Relatively few offshore wells penetrate completely through the Eocene section, so its true thickness is not well constrained. The thickest section in this play is estimated (from well correlations and seismic profiles) to exceed 15,000 feet. More commonly, the section ranges from 3,000 to 8,000 feet thick.

The oil and gas reservoired in this play are from multiple sources. Likely source rocks include organic-rich, fine-grained sequences within the Anita Shale (Juncal Formation) and Cozy Dell Shale. These rocks are probably the source of high-gravity, low-sulphur, paraffinic-naphthenic oils. Cretaceous(?)- and Eocene-aged rocks are a probable source of wet gas and condensate in this play. Oils typical of Miocene source rocks (medium to low gravity, sulphur-rich, and asphaltic) also exist in some reservoirs of this play. It is likely that mixed-source accumulations exist as well.

Most petroleum accumulations in this play have been discovered in reservoirs of the Gaviota, Sacate, and Matilija Formations. A few accumulations are

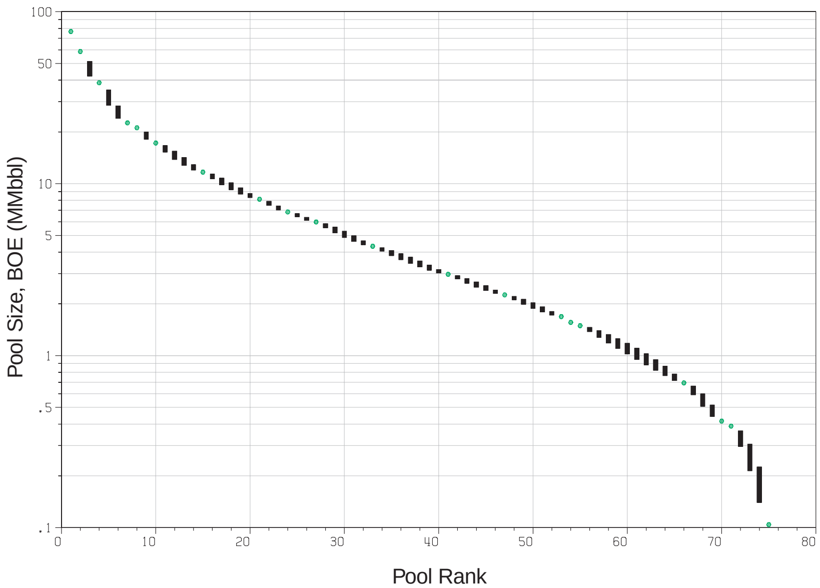

Figure 84. *Pool-size rank plot of estimated conventionally recoverable resources of the Gaviota-Sacate-Matilija Sandstone play, Santa Barbara-Ventura basin. Sizes of discovered pools are shown by dots. Sizes of undiscovered pools are shown by bars; the top and bottom of a bar represent the 25th- and 75th-percentile values of a probability distribution, respectively.*

also known from the sandy Camino Cielo Member of the Juncal Formation, sandstones within the Cozy Dell Shale, and the Llajas Formation. Surficial seepage of oil and gas from these rocks occurs at several locations onshore.

Based on analysis of known accumulations, traps within this play are predominantly anticlines, faulted anticlines, and fault blocks. Entrapment may occur less commonly along permeability barriers and angular unconformities.

DISCOVERIES

Relatively few fields in the Santa Barbara-Ventura basin contain petroleum in only Eocene to lower Oligocene reservoirs; most of these accumulations occur in conjunction with other (most typically Sespe-Alegria-Vaqueros Sandstone) plays. The largest productive accumulations in the play include the Molino Offshore gas field ("Matilija" zone; discovered 1983; 39 MMBOE), Bardsdale field (Llajas zone; 1936; 12 MMBOE), Shiells Canyon field (Llajas zone; 1959; 6 MMBOE), and Capitan field (Gaviota zone; 1945; 4 MMBOE). Other undeveloped accumulations exist in this play, some of which have been identified offshore. Two of these undeveloped onshore accumulations may exceed the Molino Offshore gas field ("Matilija" zone) in size. The earliest production of oil from this play, at Toro Canyon, occurred in the 1880's.

For the purpose of resource assessment, it was assumed that the largest accumulation in the play has been discovered. However, this is a conservative assumption given the minimal exploration history of this play in the Santa Barbara Channel. For example, Eocene sandstones are the primary reservoir at the Rio Vista gas field (>550 MMBOE) in the Sacramento basin and the Coalinga East Extension oil field (>540 MMBOE) in the San Joaquin basin.

RESOURCE ESTIMATES

Undiscovered Conventionally Recoverable Resources

Estimates of undiscovered conventionally recoverable resources in the entire play have been developed using the discovery assessment method with pool-size data from 20 onshore and offshore discovered accumulations in the play. Estimates of undiscovered resources in the Federal offshore portion of the play were subsequently calculated using a subjective area-proportionality factor. Select data used to develop the resource estimates are shown in appendix C.

As a result of this assessment, the entire play is estimated to contain 187 MMbbl of oil (including oil and condensate) and 880 Bcf of gas (including associated and nonassociated gas) (mean estimates). This volume of undiscovered conventionally recoverable resources may exist in 55 pools with sizes ranging from approximately 140 Mbbl to 50 MMbbl of combined oil-equivalent resources (fig. 84). Of these, 10 pools may exceed 10 MMBOE.

The Federal offshore portion of the play is estimated to contain approximately 65 percent of these undiscovered conventionally recoverable resources, which is 122 MMbbl of oil (including oil and condensate) and 572 Bcf of gas (including associated and nonassociated gas) (mean estimates). The low, mean, and high estimates of resources in the Federal offshore portion of the play are listed in table 23.

Cretaceous-Paleocene Sandstone Play

Play Definition

The Cretaceous-Paleocene Sandstone play of the Santa Barbara-Ventura Basin province is an established play in which oil, associated gas, and nonassociated gas have been discovered. However, there is a paucity of geologic information regarding the play, and its location and petroleum geologic characteristics are poorly understood. Nevertheless, interest continues in this play, which has an important, gas-prone analog in the Sacramento basin.

Discoveries

A total of 673 Mbbl of oil and 388 MMcf of associated gas have been produced from two fields in the onshore part of the basin. Additionally, an estimated 480 Mbbl of condensate and 12 Bcf of nonassociated gas have been discovered at the Santa Rosa gas field in the Federal offshore area.

Geologically Analogous Areas

The Cretaceous and Paleogene rocks of the Sacramento, San Joaquin, and Santa Barbara-Ventura basins of California were once part of a continuous forearc basin along the west coast of the North American continent. Because of wide-ranging depositional and sedimentological similarities, these rocks have been collectively termed the "Great Valley Sequence."

The Sacramento basin contains over 100 known gas and high-gravity oil accumulations in formations analogous to this play of the Santa Barbara-Ventura basin. The Grimes gas field (discovered 1960; 660 Bcf), Willows-Beehive Bend gas field (1938; 380 Bcf), and Lindsey Slough gas field (1962; 300 Bcf) represent large, structural and stratigraphic accumulations in Paleocene and Cretaceous reservoirs. The Brentwood field (1962; 9.5 MMbbl and 60 Bcf) is the largest oil accumulation in the Sacramento basin.

Elsewhere in California, outside of the Sacramento basin, a few small oil, condensate, and gas discoveries have been made in Cretaceous- and Paleocene-aged reservoirs. The Helm oil field (1941) in the San Joaquin basin may ultimately produce about 10 MMbbl of oil and condensate and about 60 Bcf of gas from Cretaceous and Paleocene zones. The Oil City area of the Coalinga field (1885; 2.5 MMbbl) was the first area from which petroleum was produced from Great Valley Sequence formations.

Resource Assessment

This play was not formally assessed. It is not unreasonable to speculate that accumulations similar to or larger than those found in the Sacramento and San Joaquin basins might exist in this largely unexplored play of the Santa Barbara Channel.

LOS ANGELES BASIN PROVINCE

by Scott D. Drewry

LOCATION

The Los Angeles Basin province is located offshore southern California from Point Dume (on the north) to Dana Point (on the south) (fig. 85). This Federal offshore assessment province is bounded on the north and east by the 3-mile line, on the west by the Palos Verdes fault zone, and on the south by the Dana Point sill (a basement high); it is approximately 70 miles long and 10 miles wide. The Palos Verdes Peninsula subdivides the province and its constituent plays into two noncontiguous subareas (one in the vicinity of Santa Monica Bay and one in the vicinity and south of San Pedro Bay), which together encompass an area of about 300 square miles. Water depth in the province ranges from about 100 to 2,000 feet.

GEOLOGIC SETTING

The province comprises the Federal offshore portion of the Los Angeles basin proper, a structurally controlled basin from which numerous oil fields produce onshore (fig. 86). The basin is considered to have formed by the clockwise rotation of the western Transverse Ranges. Rifting began in the early Miocene and resulted in relatively high heat flow and local isostatic uplift of basement blocks of the Catalina Schist.

Granitic rocks exposed east of the basin were a source of voluminous coarse clastic sediments that were deposited by late Miocene and early Pliocene fan systems (Puente and "Repetto"[12] Formations) in the basin (fig. 87). Much of the sediments were diverted into the southern (San Pedro Bay) subarea by uplifted basement blocks that effectively dammed the fans and modified their morphology. Numerous episodic pulses of fan deposition resulted in rapid burial and good reservoir potential. A regionally continuous basal organic shale ("nodular shale") is a prolific source of high-sulphur, low-gravity oil onshore; this unit (and possibly interbedded organic shales of the Puente Formation) may provide a rich petroleum source for the clastic fan reservoirs and the underlying breccia and schist reservoirs offshore. Neogene strata in the Federal offshore portion of the Los Angeles basin have a maximum thickness of approximately 11,000 feet southeast of the Palos Verdes Peninsula and thin to the southeast.

The structural grain of the offshore part of the Los Angeles basin is dominated by the Palos Verdes and Newport-Inglewood fault zones. These northwest-trending fault zones appear to control the distribution of petroleum accumulations onshore and are presumed to be important migration paths and trapping mechanisms for accumulations offshore.

EXPLORATION AND DISCOVERY STATUS

Seismic-reflection data coverage is moderately dense to dense throughout the province; however, exploratory drilling has been restricted due to limited oil and gas leasing opportunities in State and Federal waters. In the northern (Santa Monica Bay) subarea, only two exploratory boreholes have been drilled; data from these boreholes—together with some data from approximately 20 boreholes in adjacent State waters—were considered for this assessment. Approximately 40 boreholes (including shallow coreholes and deeper wells) have been drilled in the southern (San Pedro Bay) subarea; approximately 50 boreholes have been drilled in adjacent State waters.

Although numerous oil fields exist in the onshore part of the Los Angeles basin, only two fields (Beta and its northwest extension) have been discovered in the Federal offshore area. Production from the Beta field began in 1981 and was ongoing as of this assessment with portions of the field under waterflood.

PLAYS

Two petroleum geologic plays have been defined and assessed in the province (figs. 86 and 87). The Puente Fan Sandstone play is an established play that includes middle Miocene to lower Pliocene sandstone reservoirs (Puente and Repetto Formations). The San Onofre Breccia play is a frontier play that includes lower to middle Miocene clastic reservoirs and underlying Cretaceous fractured schist reservoirs. Together, these plays essentially compose the Federal offshore extension of the onshore and State offshore Southwestern Shelf play, which has been defined and assessed by the U.S. Geological Survey (Beyer, 1995).

[12] The U.S. Geological Survey has abandoned the term "Repetto" (originally used to describe rocks that were deposited during the Repettian Stage) (Keroher and others, 1966); however, the term is widely used by the geological community and is used in this report.

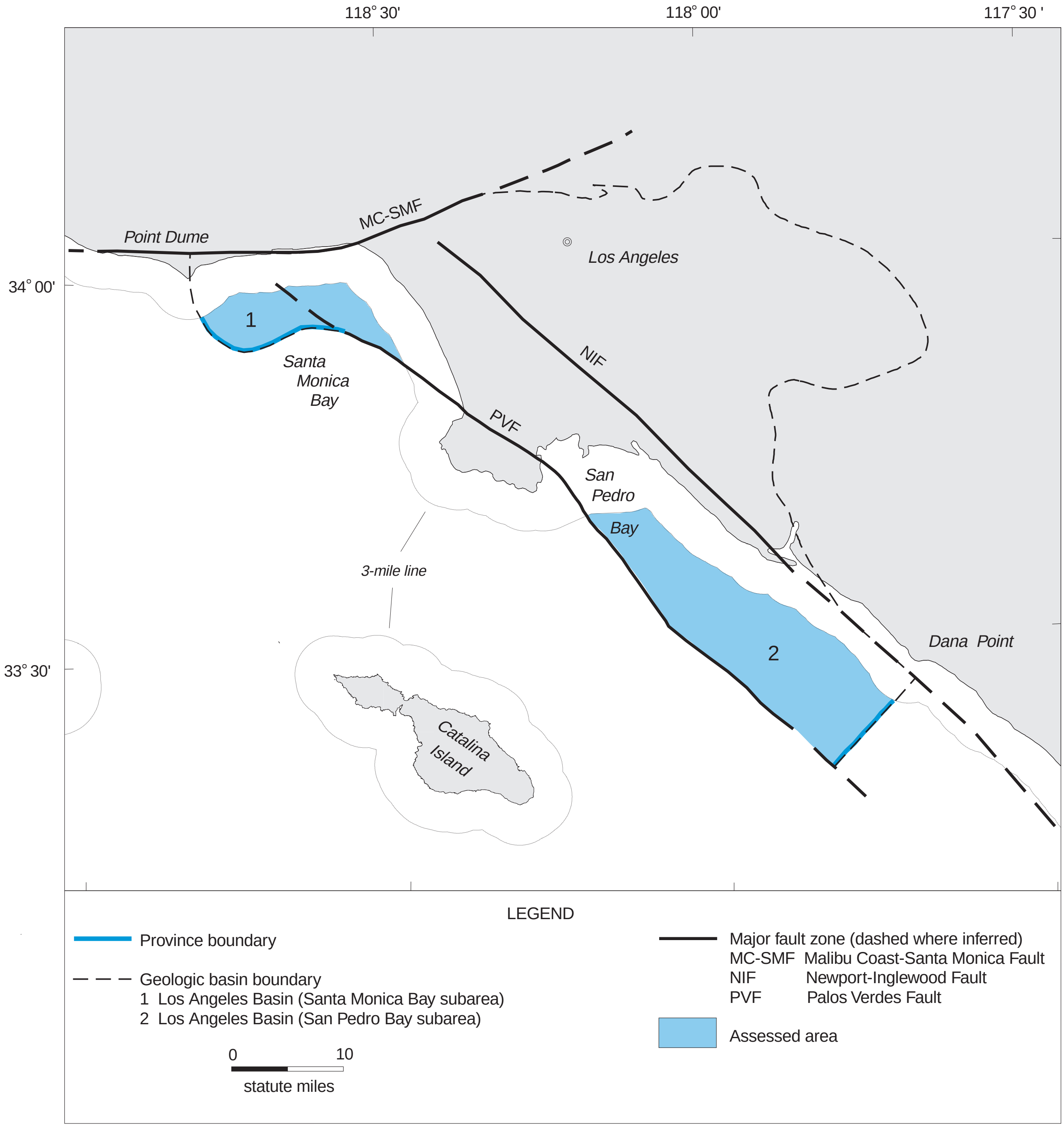

Figure 85. *Map of the Los Angeles Basin province showing the geologic basin and assessed area.*

Resource Estimates

Undiscovered Conventionally Recoverable Resources

Play-specific estimates of undiscovered conventionally recoverable resources have been developed using the subjective assessment method, and these estimates have been statistically aggregated to estimate the total volume of resources in the province. Select data used to develop the resource estimates are shown in appendix C.

As a result of this assessment, the total volume of undiscovered conventionally recoverable resources in the Los Angeles Basin province is estimated to be 315 MMbbl of oil and 322 Bcf of associated gas

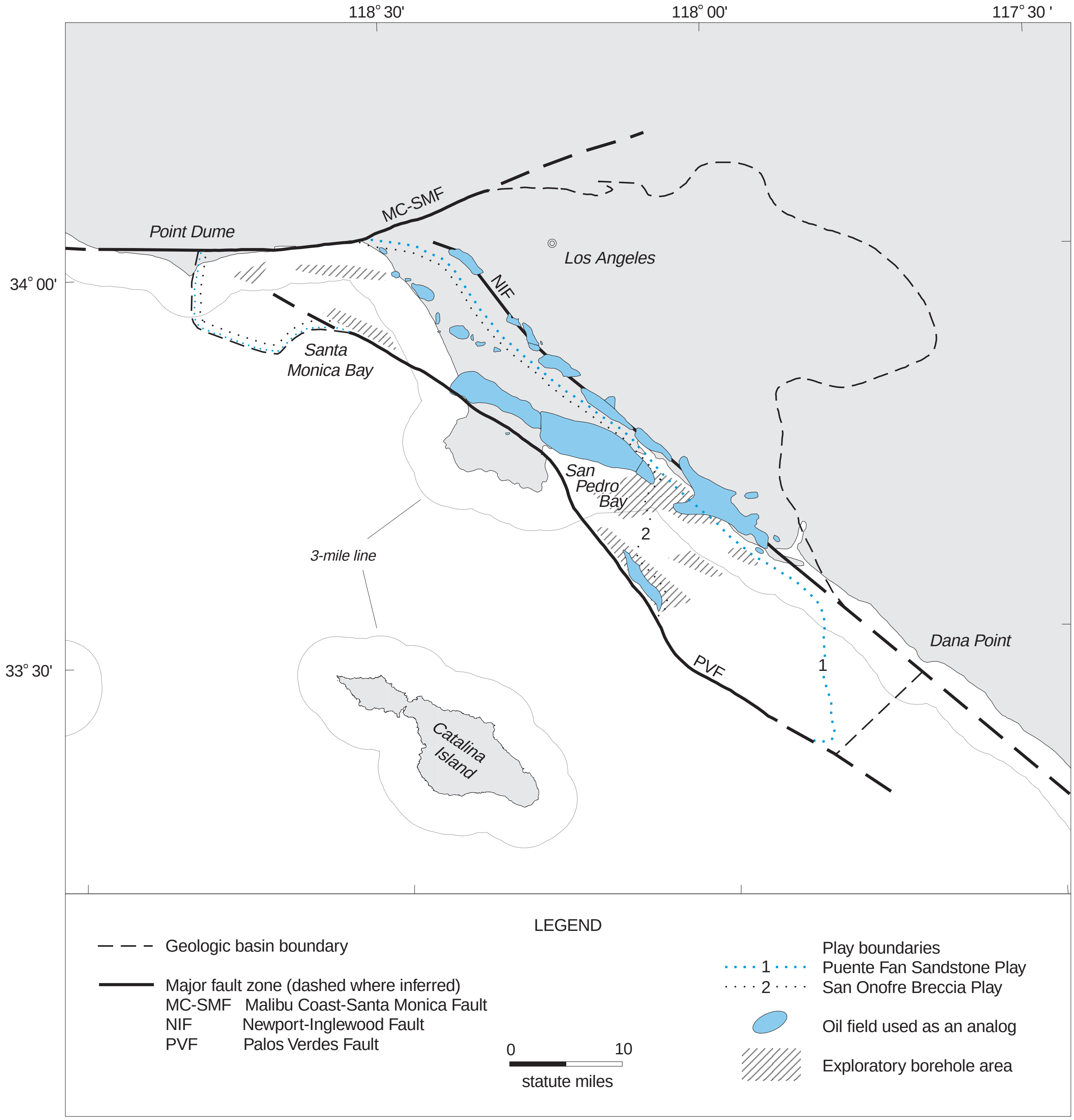

Figure 86. *Map of the Los Angeles Basin province showing petroleum geologic plays, select fields, and borehole areas.*

(mean estimates). This volume may exist in 21 fields with sizes ranging from approximately 380 Mbbl to 90 MMbbl of combined oil-equivalent resources (fig. 88). The majority of these resources (approximately 89 percent on a combined oil-equivalence basis) are estimated to exist in the Puente Fan Sandstone play. The low, mean, and high estimates of resources in the province are listed in table 26 and illustrated in figure 89.

Undiscovered Economically Recoverable Resources

Estimates of undiscovered conventionally recoverable resources in the province that may be economically recoverable under various economic scenarios have been developed using the economic assessment method. Select data used to develop the resource estimates are shown in appendix D.

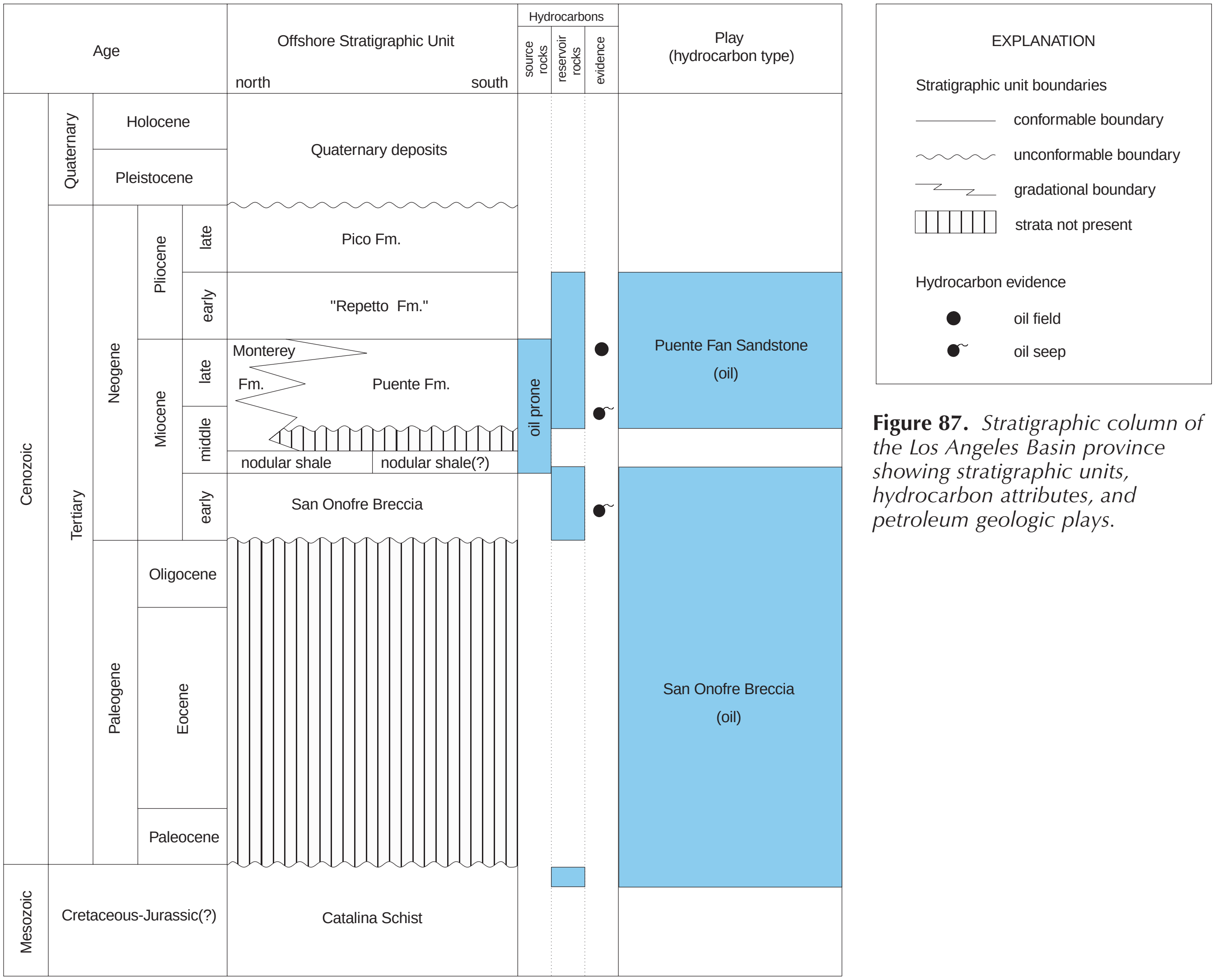

Figure 87. *Stratigraphic column of the Los Angeles Basin province showing stratigraphic units, hydrocarbon attributes, and petroleum geologic plays.*

As a result of this assessment, 209 MMbbl of oil and 213 Bcf of associated gas are estimated to be economically recoverable from the Los Angeles Basin province under economic conditions existing as of this assessment (i.e., the $18-per-barrel economic scenario) (table 27). Larger volumes of resources are expected to be economically recoverable under increasingly favorable economic conditions (fig. 90).

Total Resource Endowment

As of this assessment, cumulative production from the province was 67 MMbbl of oil and 22 Bcf of gas; remaining reserves were estimated to be 55 MMbbl of oil and 11 Bcf of gas. These discovered resources (all from the Puente Fan Sandstone play) and the aforementioned undiscovered conventionally recoverable resources collectively compose the province's estimated total resource endowment of 437 MMbbl of oil and 355 Bcf of gas (table 28).

Acknowledgments

This assessment of the Los Angeles Basin province was significantly enhanced by the contributions of many persons; most notably, Larry Beyer, Thane McCulloh, and Tom Wright gave generously of their time and experience. Acknowledgment is also due to Dennis Tayman and Scott Cranswick who performed the seismic interpretive mapping of the area.

Additional References

Beyer, 1988
Crouch, 1990
Crouch, Bachman, and Associates, Inc., 1989a
Crouch and Suppe, 1993
Redin, 1991
Wright, 1991

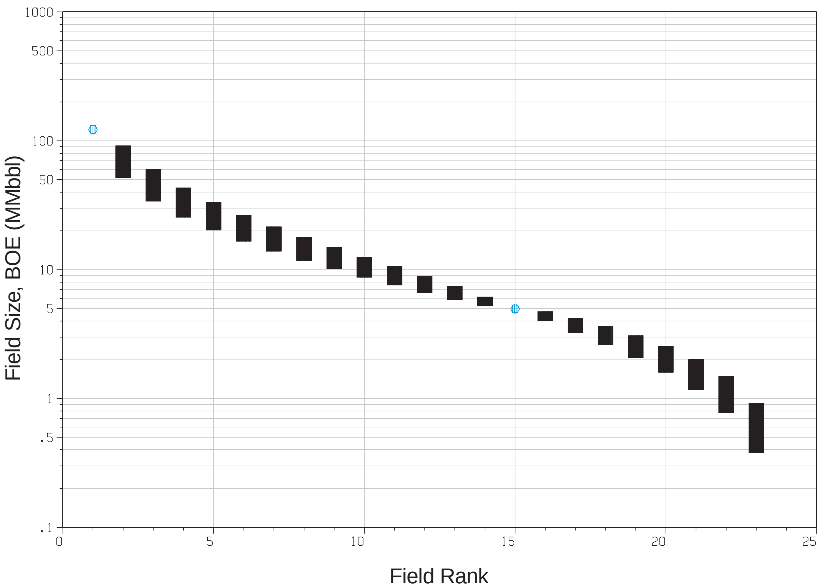

Figure 88. *Field-size rank plot of estimated conventionally recoverable resources of the Los Angeles Basin province. Sizes of discovered fields are shown by dots. Sizes of undiscovered fields are shown by bars; the top and bottom of a bar represent the 25th- and 75th-percentile value of a probability distribution, respectively.*

Table 26. *Estimates of undiscovered conventionally recoverable oil and gas resources in the Los Angeles Basin province as of January 1, 1995, by play. All estimates are risked values. The low, mean, and high estimates correspond to the 95th-percentile, mean, and 5th-percentile values of a probability distribution, respectively. Percentile values are not additive; some total mean values may not equal the sum of the component values due to independent rounding.*

Play	Oil (MMbbl)			Gas (Bcf)			BOE (MMbbl)		
	Low	Mean	High	Low	Mean	High	Low	Mean	High
Puente Fan Sandstone	171	277	447	161	306	516	202	331	531
San Onofre Breccia	0	38	96	0	16	44	0	41	104
Total Province	*186*	*315*	*489*	*173*	*322*	*534*	*220*	*372*	*578*

Figure 89. *Cumulative probability plot of estimated undiscovered conventionally recoverable resources of the Los Angeles Basin province.*

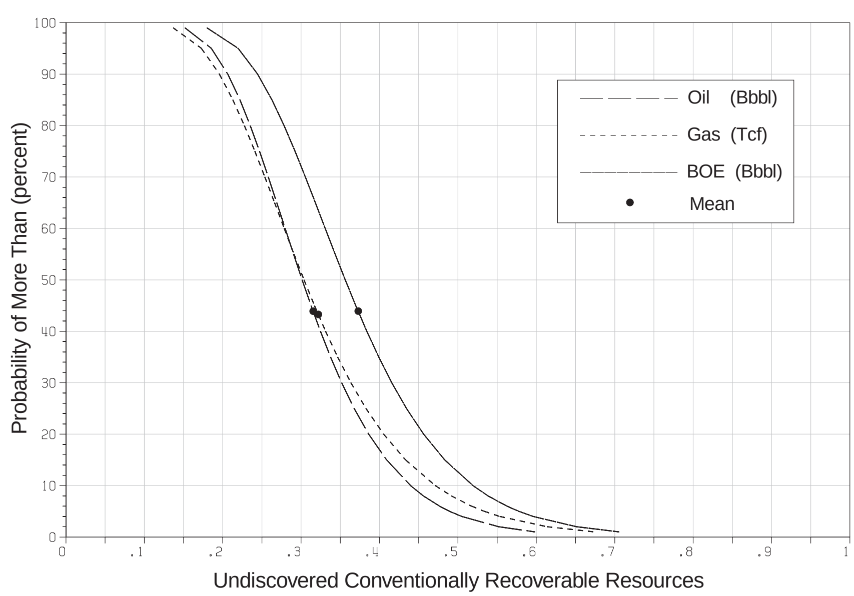

Table 27. *Estimates of undiscovered economically recoverable oil and gas resources in the Los Angeles Basin province as of January 1, 1995, by economic scenario. All estimates are risked mean values. The $18-per-barrel scenario is based on prices of $18 per bbl of oil and $2.11 per Mcf of gas; the $25-per-barrel scenario is based on prices of $25 per bbl of oil and $2.94 per Mcf of gas; the $50-per-barrel scenario is based on prices of $50 per barrel of oil and $5.87 per Mcf of gas.*

Economic Scenario	Oil (MMbbl)	Gas (Bcf)	BOE (MMbbl)
$18 per barrel	209	213	246
$25 per barrel	242	247	286
$50 per barrel	279	285	330

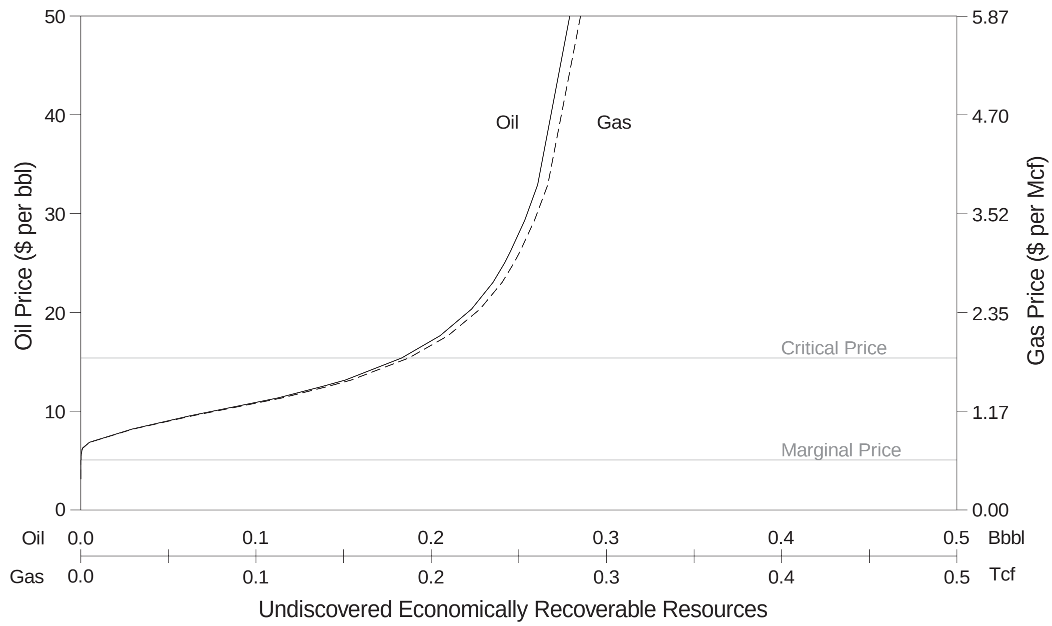

Figure 90. *Price-supply plot of estimated undiscovered economically recoverable resources of the Los Angeles Basin province.*

Table 28. *Estimates of the total endowment of oil and gas resources in the Los Angeles Basin province. Estimates of discovered resources (including cumulative production and remaining reserves) and undiscovered resources are as of January 1, 1995. Estimates of undiscovered conventionally recoverable resources are risked mean values. Some total values may not equal the sum of the component values due to independent rounding.*

Resource Category	Oil (Bbbl)	Gas (Tcf)	BOE (Bbbl)
Cumulative Production	0.07	0.02	0.07
Remaining Reserves	0.06	0.01	0.06
Undiscovered Conventionally Recoverable Resources	0.31	0.32	0.37
Total Resource Endowment	*0.44*	*0.36*	*0.50*

PUENTE FAN SANDSTONE PLAY

PLAY DEFINITION

The Puente Fan Sandstone play of the Los Angeles Basin province is defined to include accumulations of oil and associated gas in middle Miocene to lower Pliocene sandstones (Puente and Repetto Formations) in a variety of structural traps. The play exists west of the Newport-Inglewood fault zone and extends from Point Dume to the Dana Point sill (fig. 86). The Federal offshore portion of the play encompasses a total area of approximately 275 square miles. Depth to the main reservoir section (Puente Formation) ranges from 2,000 to 3,000 feet below the seafloor in the northern subarea; in the southern subarea, reservoir depths average from 4,000 to 5,000 feet below the seafloor.

The petroleum potential of the onshore and State offshore portions of this play has been assessed as part of the Southwestern Shelf play by the U.S. Geological Survey (Beyer, 1995).

PETROLEUM GEOLOGIC CHARACTERISTICS

Petroleum source rocks for this play include the lower middle Miocene "nodular shale" and interbedded middle Miocene pelagic mudstones and shales of the Puente Formation (fig. 87). Onshore, these rocks are rich in marine-derived kerogen; total organic carbon content averages 4 percent and is as high as 10 and 16 percent in the "nodular shale" and Puente Formation, respectively (Jeffrey and others, 1991). High heat flow in the Los Angeles basin has generated oil from these kerogens at depths as shallow as 8,000 feet; the oil typically has moderately low gravity (less than 25 °API) and high sulphur content (greater than 1 percent). Oil gravity often increases with depth; this underscores the importance of identifying traps with possible migration pathways to deeper generative centers onshore (a limited migration distance).

Reservoir rocks for this play are middle Miocene to lower Pliocene sandstones of the Puente and Tarzana fans (Puente and Repetto Formations) (fig. 87). The structurally confined nature of the Los Angeles basin (i.e., bounded on the west by the Palos Verdes high) and the prolific granitic source combined to make these "distal" fan sandstones good to very good reservoir rocks; porosities in producing reservoirs offshore (Beta field) and onshore range from 17 to 33 percent (Crouch, 1990; Sorensen and others, 1993).

Traps in this play are predominantly faults and faulted anticlines along the Palos Verdes fault zone. Seals may be provided by interbedded pelagic and hemipelagic siltstones and shales.

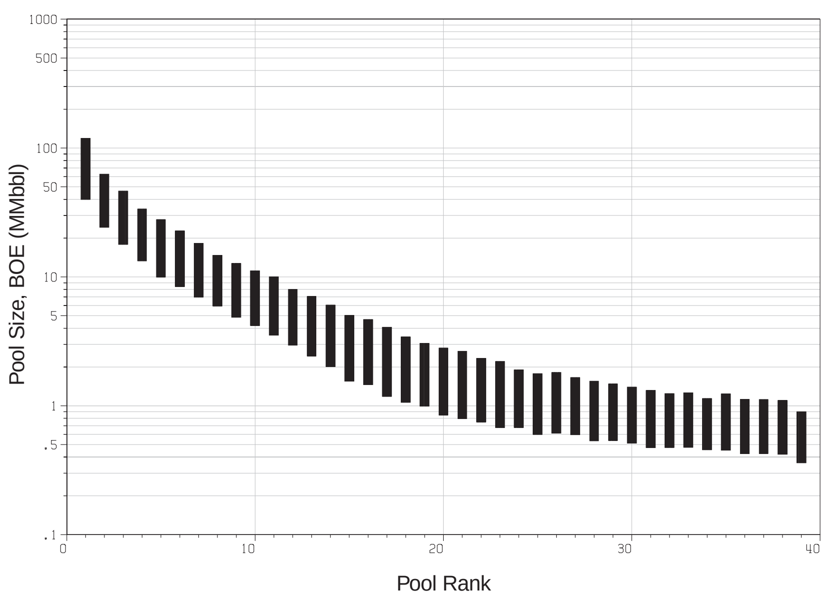

Figure 91. *Pool-size rank plot of estimated undiscovered conventionally recoverable resources of the Puente Fan Sandstone play, Los Angeles Basin province. Sizes of undiscovered pools are shown by bars; the top and bottom of a bar represent the 25th- and 75th-percentile values of a probability distribution, respectively.*

Exploration and Discovery Status

Both of the coreholes drilled in the northern subarea penetrated rocks of this play; gas shows were noted in one corehole and tar was encountered in the other. Offshore oil seeps in the northern subarea suggest that onshore productive trends extend offshore. Most of the wells and coreholes in the southern subarea penetrated and encountered oil shows in rocks of this play.

Two fields (Beta and its northwest extension) have been discovered in the southern subarea of this established play. Production from the Beta field began in 1981 and was ongoing as of this assessment with portions of the field under waterflood. Numerous fields have been discovered in the adjacent State offshore and onshore areas; as of this assessment, approximately 8 Bbbl of oil have been produced from geologically analogous reservoir rocks in these fields.

Resource Estimates

Undiscovered Conventionally Recoverable Resources

Estimates of undiscovered conventionally recoverable resources in the Federal offshore portion of the play have been developed using the subjective assessment method with play-specific (Beta field) data and adjusted onshore analogs. Select data used to develop the resource estimates are shown in appendix C.

As a result of this assessment, the Federal offshore portion of the play is estimated to contain 277 MMbbl of oil and 306 Bcf of associated gas (mean estimates). This volume of undiscovered conventionally recoverable resources may exist in as many as 39 pools with sizes ranging from approximately 360 Mbbl to 120 MMbbl of combined oil-equivalent resources (fig. 91). The low, mean, and high estimates of resources in the play are listed in table 26.

San Onofre Breccia Play

Play Definition

The San Onofre Breccia play of the Los Angeles Basin province is defined to include accumulations of oil and associated gas in stratigraphic and structural traps of the fractured Catalina Schist, schist-derived San Onofre Breccia, and overlying "nodular shale." The play exists west of the Newport-Inglewood fault zone in the northern two-thirds of the basin and extends from Point Dume to about 10 miles south of the Palos Verdes Peninsula (fig. 86). The Federal offshore portion of the play encompasses a total area of approximately 100 square miles. Depth to the reservoir section ranges from 2,000 to 7,000 feet below the seafloor in the northern subarea and from 7,000 to 11,000 feet in the southern subarea.

The petroleum potential of the onshore and State offshore portions of this play has been assessed as part of the Southwestern Shelf play by the U.S. Geological Survey (Beyer, 1995). Reservoir rocks equivalent to those included in this play are presumed to extend west of this play and have been assessed as the San Onofre Breccia play of the Santa Monica-San Pedro assessment area (see this report).

Petroleum Geologic Characteristics

The petroleum source rock for this play is the lower middle Miocene "nodular shale" (fig. 87). Onshore, these rocks are rich in marine-derived kerogen; total organic carbon content averages 4 percent and is as high as 10 percent (Jeffrey and others, 1991). High heat flow in the Los Angeles basin has generated oil from these kerogens at depths as shallow as 8,000 feet. The oil typically has moderately low gravity (less than 25 °API) and high sulphur content (greater than 1 percent). Oil gravity often increases with depth; this underscores the importance of identifying traps with possible migration pathways to deeper generative centers onshore (a limited migration distance).

The primary reservoir rocks for this play are lower Miocene sandstones and breccias of the San Onofre Breccia (Catalina Schist eroded from the Palos Verdes paleohigh) and locally fractured Cretaceous and possibly Jurassic rocks of the Catalina Schist. The lowermost and possibly fractured portion of the "nodular shale" may contain potential reservoir rocks and is also included in this play (fig. 87). Reservoir quality may be variable; porosities of analogous reservoirs onshore range from 12 to 31 percent.

Faults and pinchouts against local basement irregularities may produce many traps in this play; however, the traps must be located within the "sediment halo" of the Palos Verdes paleohigh to be considered viable targets. The overlying "nodular shale" may provide a seal as well as a petroleum source for the traps. The traps are expected to be small; the productive area of onshore analog fields ranges from 15 to 600 acres.

EXPLORATION AND DISCOVERY STATUS

Both of the coreholes drilled in the northern subarea penetrated rocks of this play; gas shows were noted in one corehole and tar was encountered in the other. Offshore oil seeps in this area may indicate that onshore productive trends (e.g., El Segundo, Playa Del Rey, and Venice Beach fields) extend offshore. Many of the wells and coreholes drilled in the southern subarea penetrated rocks of this frontier play; shows were encountered in a few of these boreholes.

RESOURCE ESTIMATES

Undiscovered Conventionally Recoverable Resources

Estimates of undiscovered conventionally recoverable resources in the Federal offshore portion of the play have been developed using the subjective assessment method with adjusted onshore analogs (e.g., El Segundo, Playa Del Rey, and Venice Beach fields). Select data used to develop the resource estimates are shown in appendix C.

As a result of this assessment, the Federal offshore portion of the play is estimated to contain 38 MMbbl of oil and 16 Bcf of associated gas (mean estimates). This volume of undiscovered conventionally recoverable resources may exist in as many as 13 pools with sizes ranging from approximately 290 Mbbl to 30 MMbbl of combined oil-equivalent resources (fig. 92). The low, mean, and high estimates of resources in the play are listed in table 26.

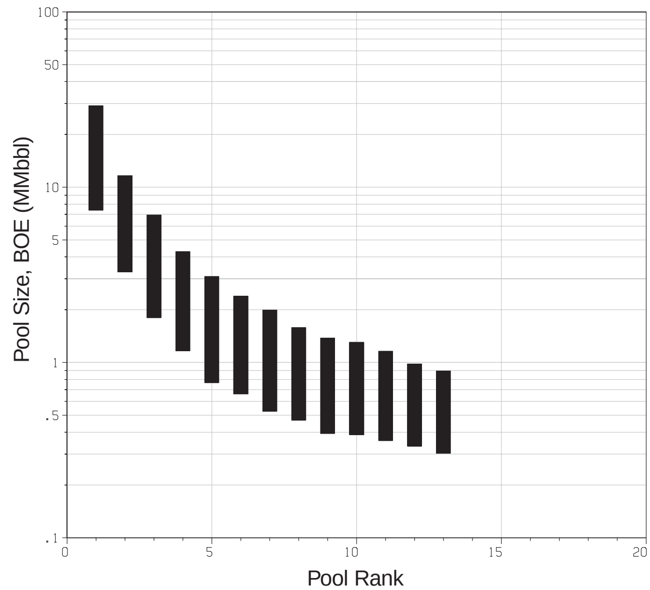

Figure 92. *Pool-size rank plot of estimated undiscovered conventionally recoverable resources of the San Onofre Breccia play, Los Angeles Basin province. Sizes of undiscovered pools are shown by bars; the top and bottom of a bar represent the 25th- and 75th-percentile values of a probability distribution, respectively.*

INNER BORDERLAND PROVINCE

by Scott D. Drewry and Frank W. Victor

Location

The Inner Borderland province is located offshore southern California from the Anacapa ridge and the Malibu Coast-Santa Monica fault (on the north) to the U.S.-Mexico maritime boundary (on the south) (fig. 93). This assessment province is bounded on the west by the Santa Cruz-Catalina ridge and the Thirtymile bank; to the east, by the Palos Verdes fault zone, and to the southeast by the southern and eastern boundary of the Oceanside-Capistrano basin.

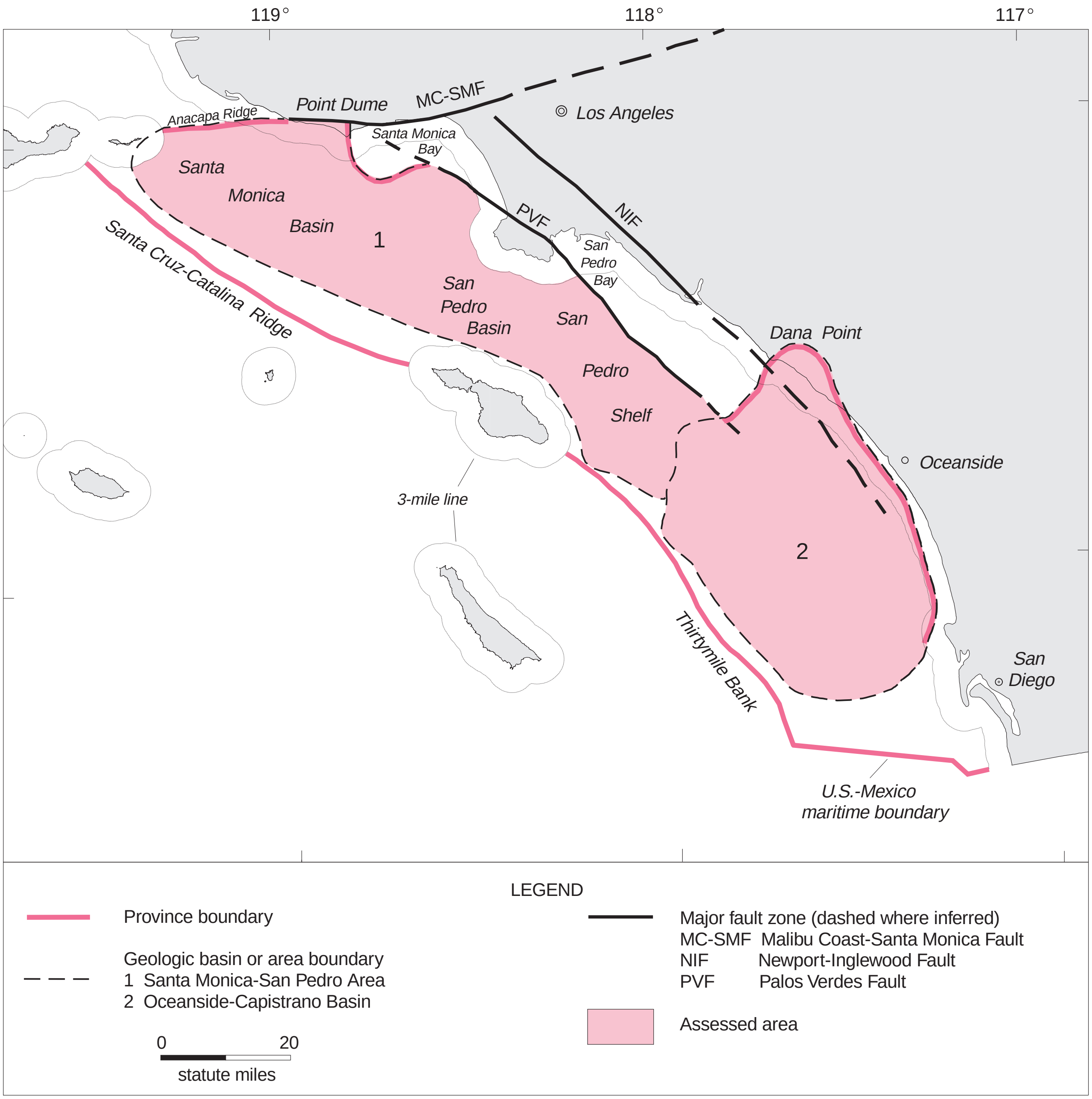

Figure 93. *Map of the Inner Borderland province showing geologic basins and areas, and assessed areas.*

The province encompasses four depositional subareas: Santa Monica basin, San Pedro basin, San Pedro shelf, and the Oceanside-Capistrano basin. The Santa Monica basin, San Pedro basin, and San Pedro shelf have been combined as a single assessment area due to the nearly continuous extent of Neogene strata. The Oceanside-Capistrano basin is depositionally distinct from the Santa Monica-San Pedro assessment area. These assessment areas and the plays defined within them are described in the following summaries.

The Inner Borderland province and its constituent assessment areas differ from other provinces and assessment areas in the Pacific OCS Region in that they include State offshore and onshore areas that are adjacent to the Federal offshore area (fig. 93); other provinces and assessment areas in the Region comprise only Federal offshore areas. The State offshore and onshore areas of the Inner Borderland province were included in this study to facilitate their assessment, which was based in part on information from the Federal offshore area[13].

GEOLOGIC SETTING

The general structure of the province is the result of early Miocene extension and late Pliocene compression. The extension was due to rifting and clockwise rotation of the western Transverse Ranges crustal block (Crouch and Suppe, 1993). In the late Pliocene, a change in microplate geometry resulted

[13] By agreement between the MMS and USGS, the State offshore and onshore areas of the Inner Borderland province were assessed by the MMS rather than the USGS.

Table 29. *Estimates of undiscovered conventionally recoverable oil and gas resources in the Inner Borderland province as of January 1, 1995, by assessment area. All estimates are risked values. The low, mean, and high estimates correspond to the 95th-percentile, mean, and 5th-percentile values of a probability distribution, respectively. Percentile values are not additive; some total mean values may not equal the sum of the component values due to independent rounding.*

Assessment Area	Oil (Bbbl)			Gas (Tcf)			BOE (Bbbl)		
	Low	Mean	High	Low	Mean	High	Low	Mean	High
Santa Monica-San Pedro Area[1]	0.23	0.68	1.47	0.25	0.77	1.68	0.28	0.82	1.76
Oceanside-Capistrano Basin[1]	0	1.11	2.21	0	1.30	3.17	0	1.34	2.70
Total Province[1]	*0.87*	*1.79*	*3.18*	*0.79*	*2.07*	*4.19*	*1.04*	*2.16*	*3.85*

[1] Includes a small area and volume of resources in the State offshore and onshore area adjacent to the Federal offshore area.

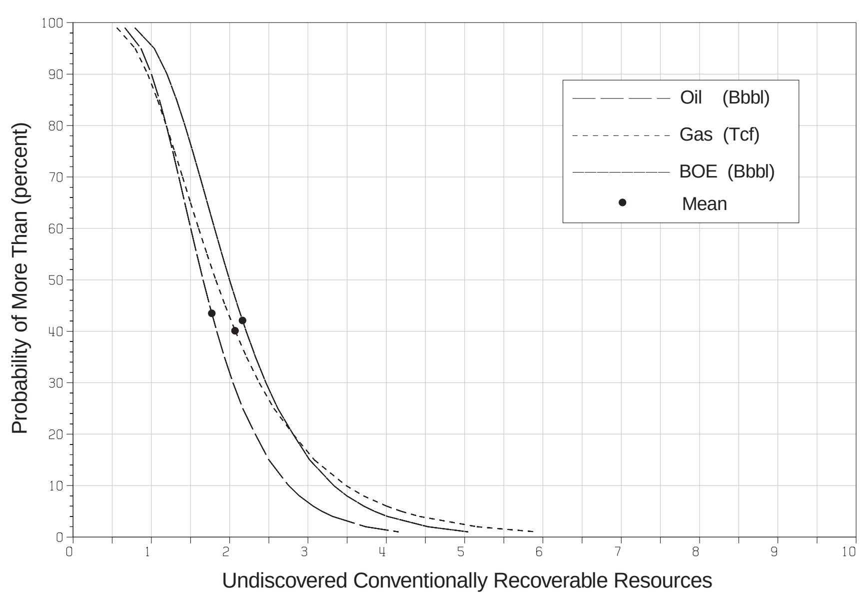

Figure 94. *Cumulative probability plot of estimated undiscovered conventionally recoverable resources of the Inner Borderland province.*

in a change to northwest-trending, right-lateral wrenching with a component of northeast-oriented compression. This history has resulted in a combination of extensional and compressional features.

The Palos Verdes and Newport-Inglewood fault zones dominate the structural style of the eastern part of the province. The Newport-Inglewood fault zone is a wrench zone along which several giant oil fields exist onshore and in State waters. A number of medium- to large-scale compressional structures in the Oceanside-Capistrano basin are associated with the fault zone.

Cretaceous and Neogene strata are present throughout the province. Some Paleogene strata exist in the eastern one-third of the Oceanside-Capistrano basin; however, they are missing in much of the province due to the early Miocene rifting.

EXPLORATION AND DISCOVERY STATUS

Two small fields have been discovered in the onshore portion of the Oceanside-Capistrano Basin assessment area and some petroleum shows have been noted in the Santa Monica-San Pedro assessment area. Offshore exploratory drilling has been restricted due to limited oil and gas leasing opportunities in State and Federal waters.

RESOURCE ESTIMATES

Undiscovered Conventionally Recoverable Resources

Estimates of the total volume of undiscovered conventionally recoverable resources in the province have been developed by statistically aggregating the constituent assessment area estimates. Estimates of the volume of resources in the Federal offshore, State offshore, and onshore portions of the province were subsequently calculated by summing the estimated volume of resources in the respective portions of the constituent assessment areas.

As a result of this assessment, the total volume of undiscovered conventionally recoverable resources in the Inner Borderland province is estimated to be 1.79 Bbbl of oil and 2.07 Tcf of associated gas (mean estimates). The low, mean, and high estimates of resources in the province are listed in table 29 and illustrated in figure 94.

The Federal offshore portion of the province is expected to contain the majority of these resources, or approximately 1.71 Bbbl of oil and 1.97 Tcf of associated gas (table 30). The State offshore portion of the province is estimated to contain approximately 84 MMbbl of oil and 102 Bcf of associated gas. A negligible volume of resources is expected to exist in the onshore portion of the province.

Table 30. *Estimates of undiscovered conventionally recoverable oil and gas resources in the Inner Borderland province as of January 1, 1995, by area. All estimates are risked mean values. Some total values may not equal the sum of the component values due to independent rounding.*

Area	Oil (Bbbl)	Gas (Tcf)	BOE (Bbbl)
Onshore		negligible	
State Offshore	0.08	0.10	0.19
Federal Offshore	1.71	1.97	2.06
Total	*1.79*	*2.07*	*2.16*

Undiscovered Economically Recoverable Resources

Estimates of the total volume of undiscovered conventionally recoverable resources in the province that may be economically recoverable under various economic scenarios have been developed by statistically aggregating the constituent assessment area estimates.

As a result of this assessment, 1.19 Bbbl of oil and 1.37 Tcf of associated gas are estimated to be economically recoverable from the Inner Borderland province under economic conditions existing as of this assessment (i.e., the $18-per-barrel economic scenario) (table 31). Larger volumes of resources are expected to be economically recoverable under increasingly favorable economic conditions (fig. 95).

The majority of undiscovered economically recoverable resources in the province are expected to exist in the Federal offshore portion of the province.

Total Resource Endowment

As of this assessment, cumulative production from the province was 4.6 Mbbl of oil and 11 MMcf of gas; remaining reserves were estimated to be negligible. These discovered resources (all of which are from the onshore portion of the Oceanside-Capistrano basin) and the aforementioned undiscovered conventionally recoverable resources collectively compose the province's estimated total resource endowment of 1.79 Bbbl of oil and 2.07 Tcf of gas (table 32).

Table 31. *Estimates of undiscovered economically recoverable oil and gas resources in the Inner Borderland province as of January 1, 1995 for three economic scenarios, by assessment area. All estimates are risked mean values. The $18-per-barrel scenario is based on prices of $18 per bbl of oil and $2.11 per Mcf of gas; the $25-per-barrel scenario is based on prices of $25 per bbl of oil and $2.94 per Mcf of gas; the $50-per-barrel scenario is based on prices of $50 per barrel of oil and $5.87 per Mcf of gas. Some total values may not equal the sum of the component values due to independent rounding.*

Assessment Area	$18-per-barrel Scenario			$25-per-barrel Scenario			$50-per-barrel Scenario		
	Oil (Bbbl)	Gas (Tcf)	BOE (Bbbl)	Oil (Bbbl)	Gas (Tcf)	BOE (Bbbl)	Oil (Bbbl)	Gas (Tcf)	BOE (Bbbl)
Santa Monica-San Pedro Area[1]	0.44	0.50	0.53	0.50	0.57	0.60	0.59	0.66	0.71
Oceanside-Capistrano Basin[1]	0.74	0.87	0.90	0.88	1.03	1.07	1.02	1.19	1.23
Total Province[1]	*1.19*	*1.37*	*1.43*	*1.39*	*1.60*	*1.67*	*1.61*	*1.85*	*1.94*

[1] Includes a small area and volume of resources in the State offshore and onshore area adjacent to the Federal offshore area.

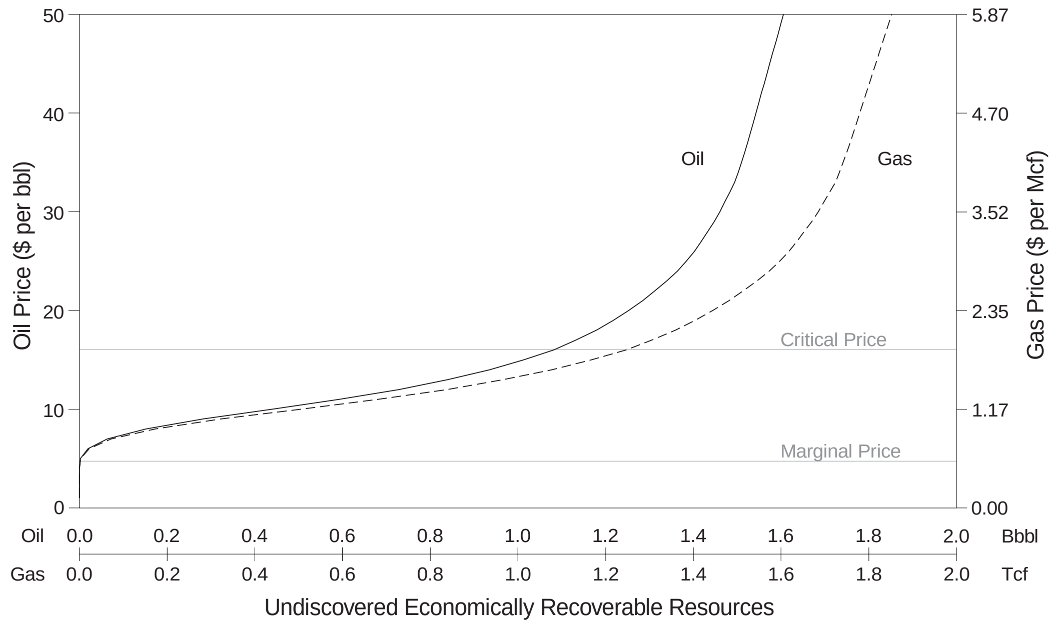

Figure 95. *Price-supply plot of estimated undiscovered economically recoverable resources of the Inner Borderland province.*

Table 32. *Estimates of the total endowment of oil and gas resources in the Inner Borderland province, by assessment area. Estimates of discovered resources (including cumulative production and remaining reserves) and undiscovered resources are as of January 1, 1995. Estimates of undiscovered conventionally recoverable resources are risked mean values. Some total values may not equal the sum of the component values due to independent rounding.*

Assessment Area	Discovered Resources (Reserves)						Undiscovered Conventionally Recoverable Resources			Total Resource Endowment		
	Cumulative Production			Remaining Reserves								
	Oil (Bbbl)	Gas (Tcf)	BOE (Bbbl)	Oil (Bbbl)	Gas (Tcf)	BOE (Bbbl)	Oil (Bbbl)	Gas (Tcf)	BOE (Bbbl)	Oil (Bbbl)	Gas (Tcf)	BOE (Bbbl)
Santa Monica-San Pedro Area[1]	0	0	0	0	0	0	0.68	0.77	0.82	0.68	0.77	0.82
Oceanside-Capistrano Basin[1]	<0.01	<0.01	<0.01		negligible		1.11	1.30	1.34	1.11	1.30	1.34
Total Province[1]	*<0.01*	*<0.01*	*<0.01*		*negligible*		*1.79*	*2.07*	*2.16*	*1.79*	*2.07*	*2.16*

[1] Includes a small area and volume of resources in the State offshore and onshore area adjacent to the Federal offshore area.

SANTA MONICA-SAN PEDRO AREA

by Scott D. Drewry

Location

The Santa Monica-San Pedro assessment area occupies the northern portion of the Inner Borderland province (fig. 93). The assessment area extends from the Anacapa ridge (on the north) to the Dana Point sill (on the south); it is bounded on the west by the Santa Cruz-Catalina ridge and on the east by the Palos Verdes fault zone (fig. 96). It encompasses three depositional subareas: Santa Monica basin, San

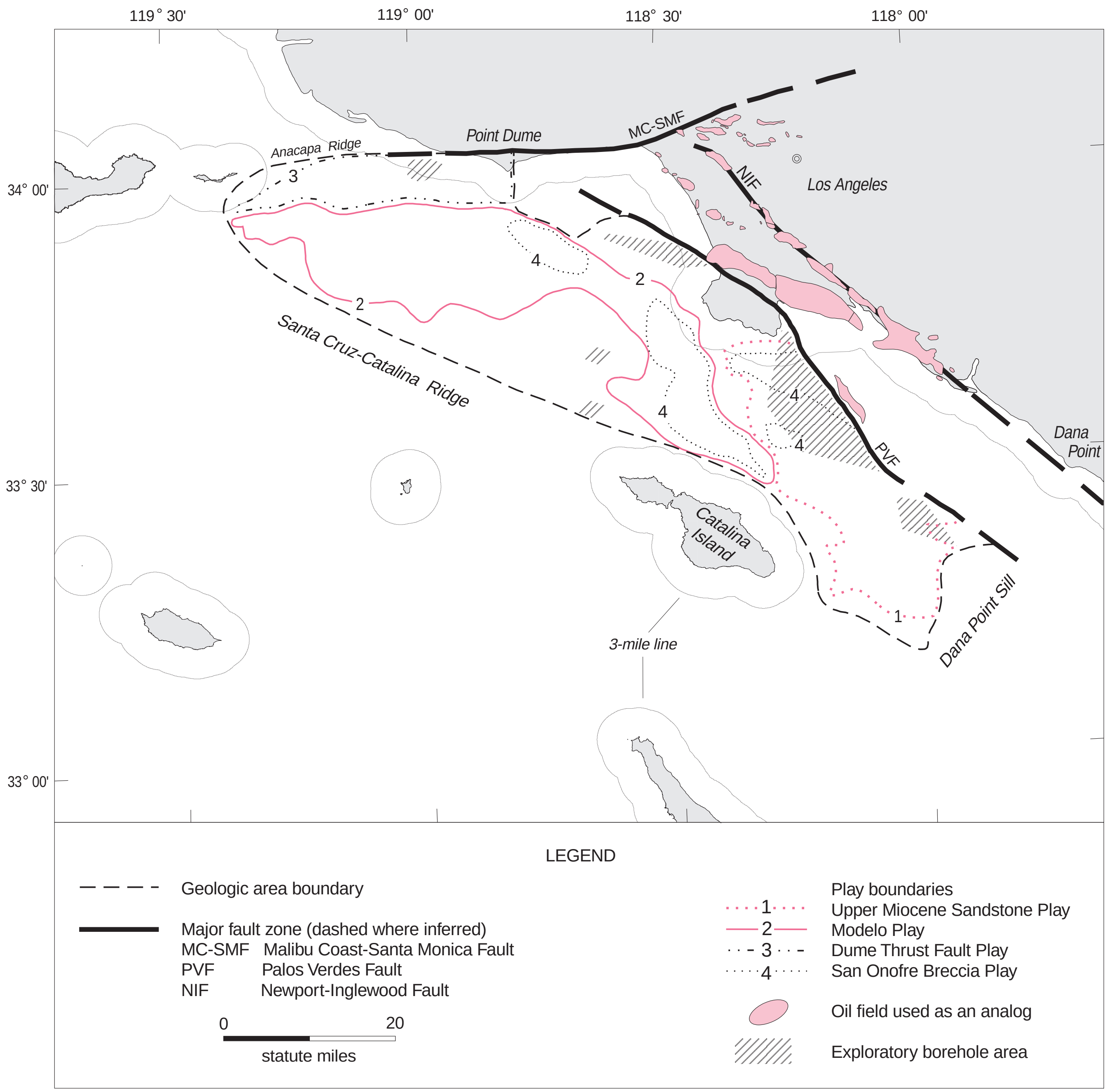

Figure 96. *Map of the Santa Monica-San Pedro assessment area showing petroleum geologic plays, select adjacent fields, and borehole areas.*

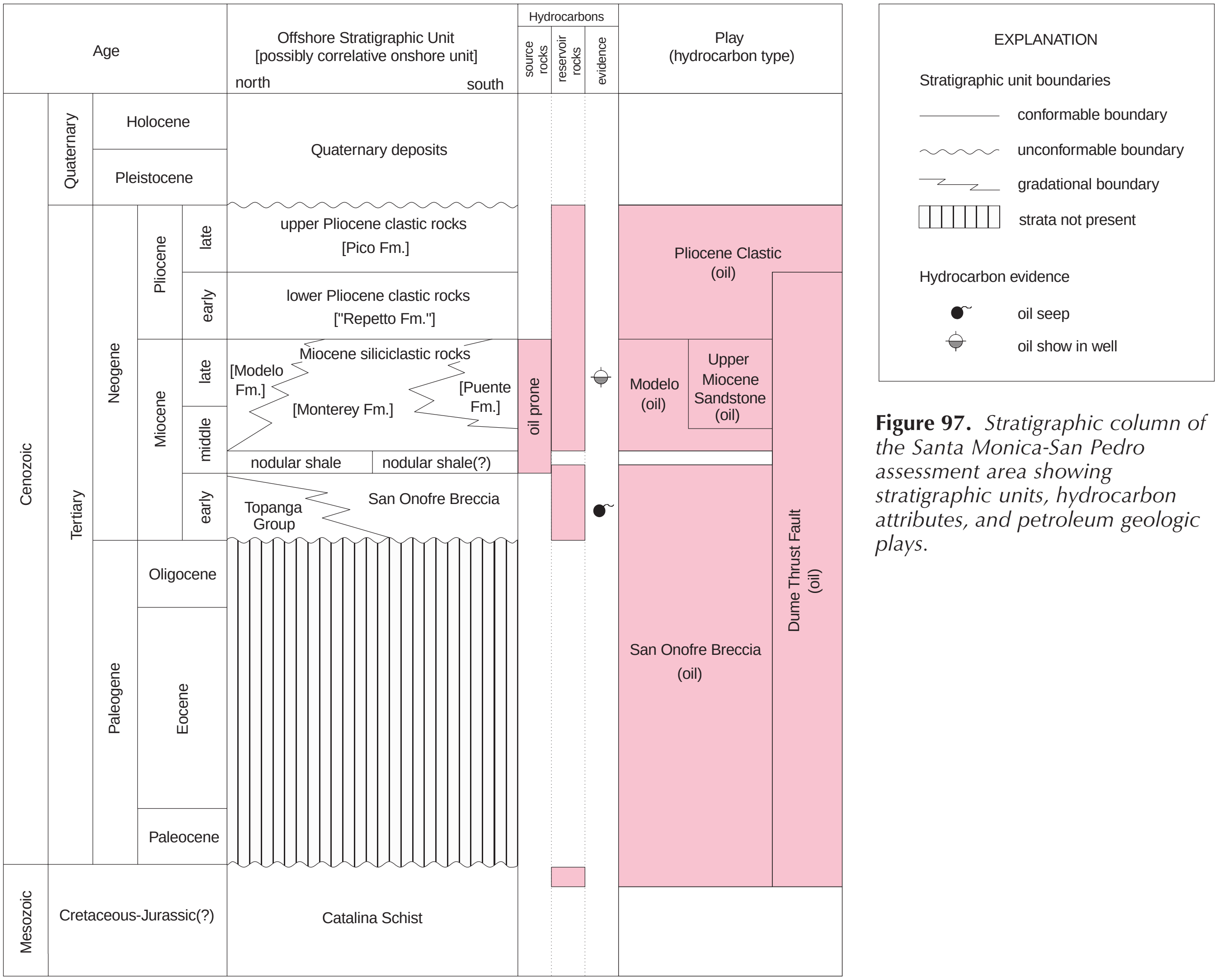

Figure 97. *Stratigraphic column of the Santa Monica-San Pedro assessment area showing stratigraphic units, hydrocarbon attributes, and petroleum geologic plays.*

Pedro basin, and San Pedro shelf. This elongate, northwest-trending assessment area is about 90 miles long and 12 to 40 miles wide and covers an area of about 1,300 square miles. Water depth in the area is as great as 2,000 feet on the San Pedro shelf and 3,000 feet in the Santa Monica and San Pedro basins.

Although the majority of the assessment area is in the Federal offshore area (which is the focus of this study), it includes some adjacent State offshore and onshore areas (fig. 96). These adjacent areas were included in this study to facilitate their assessment, which was based in part on information from the Federal offshore area.

GEOLOGIC SETTING

This geologic area is the seaward extension of the triangular Los Angeles rift basin, which formed by the clockwise rotation of the western Transverse Ranges crustal block. Early Miocene rifting of this block resulted in relatively high heat flow and local isostatic uplift of basement blocks of the Catalina Schist.

Paleogene strata are missing in the area due to the early Miocene rifting. The Neogene stratigraphic section consists primarily of lower Miocene volcanics, local schist-basement debris, middle to upper Miocene organic shales and cherts, and interbedded upper Miocene to lower Pliocene fine-grained clastic rocks (distal facies of the Puente and Tarzana fans of the Los Angeles basin) (fig. 97). These clastic strata are volumetrically concentrated on the eastern and northern perimeters of the assessment area. Upper Pliocene to Holocene fine-grained clastic rocks cover most of the area but are not of sufficient thickness to have appreciable petroleum potential.

Exploration

More than 40 exploratory boreholes (of widely varying depths) have been drilled in several offshore areas (fig. 96); however, no significant accumulations of hydrocarbons have been discovered. Nearly all of the boreholes are located on the periphery of the area; none are located in the central parts of the Santa Monica or San Pedro basins (fig. 96). Most of the boreholes are clustered along the eastern edge of the San Pedro shelf leaving much of the area undrilled. Most of the offshore area, with the exception of the structurally complex nearshore area west of Point Dume, is traversed by a dense grid of seismic-reflection profiles. Offshore exploratory drilling has been restricted due to limited oil and gas leasing opportunities in State and Federal waters.

Plays

Five petroleum geologic plays were defined in the assessment area (fig. 97). Three plays were defined on the basis of reservoir rock stratigraphy; these include Cretaceous schist and overlying Miocene clastic reservoirs (San Onofre Breccia play), middle to upper Miocene clastic and chert reservoirs (Modelo play), and middle to upper Miocene clastic reservoirs (Upper Miocene Sandstone play). The Dume Thrust Fault play was defined on the basis of the structural nature of traps along the Malibu Coast fault and the Dume thrust fault. Additionally, a conceptual play of Pliocene clastic reservoirs (Pliocene Clastic play) was defined but not formally assessed.

All of the assessed plays in the Santa Monica-San Pedro assessment area extend into State waters and one of these (Dume Thrust Fault play) extends onshore. Three plays (Upper Miocene Sandstone, Modelo, and San Onofre Breccia plays) are presumed to contain a negligible volume of oil and gas resources in the State offshore area, and only the Federal offshore portion of these plays has been assessed. However, the entire (Federal offshore, State offshore, and onshore) Dume Thrust Fault play has been assessed.

Resource Estimates

Undiscovered Conventionally Recoverable Resources

Play-specific estimates of undiscovered conventionally recoverable resources have been developed using the subjective assessment method with adjusted on-shore fields as analogs, and these estimates have been statistically aggregated to estimate the total volume of resources in the assessment area. Select data used to develop the resource estimates are shown in appendix C. Estimates of the volume of resources in the Federal offshore, State offshore, and onshore portions of the Dume Thrust Fault play were subsequently calculated using a subjective area-proportionality factor, and the area-specific play estimates have been summed to estimate the total volume of resources in the respective portions of the assessment area.

As a result of this assessment, the total volume of undiscovered conventionally recoverable resources in the Santa Monica-San Pedro assessment area is estimated to be 683 MMbbl of oil and 769 Bcf of associated gas (mean estimates). This volume may exist in 37 fields with sizes ranging from approximately 95 Mbbl to 320 MMbbl of combined oil-equivalent resources (fig. 98). The majority of these

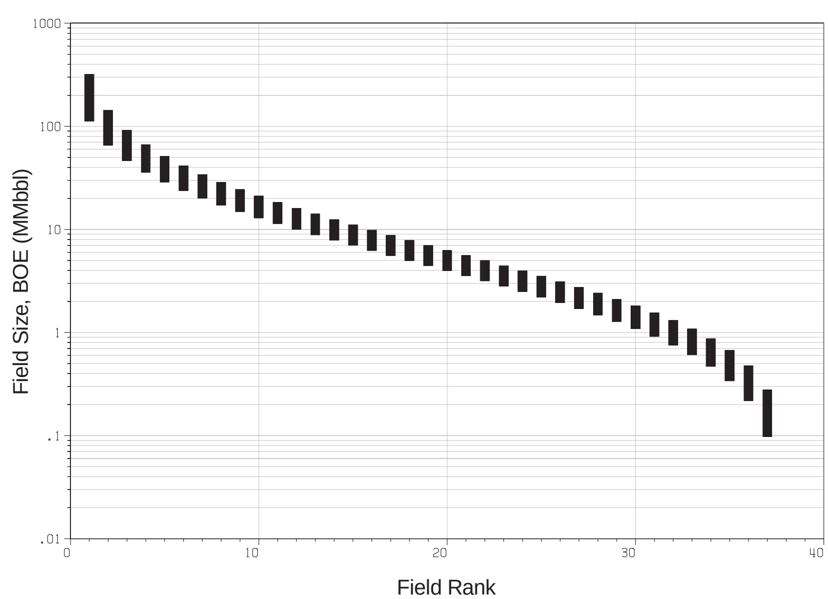

Figure 98. *Field-size rank plot of estimated undiscovered conventionally recoverable resources of the Santa Monica-San Pedro assessment area. Sizes of undiscovered fields are shown by bars; the top and bottom of a bar represent the 25th- and 75th-percentile value of a probability distribution, respectively.*

Table 33. *Estimates of undiscovered conventionally recoverable oil and gas resources in the Santa Monica-San Pedro assessment area as of January 1, 1995, by play. All estimates are risked values. The low, mean, and high estimates correspond to the 95th-percentile, mean, and 5th-percentile values of a probability distribution, respectively. Percentile values are not additive; some total mean values may not equal the sum of the component values due to independent rounding.*

Play	Oil (MMbbl)			Gas (Bcf)			BOE (MMbbl)		
	Low	Mean	High	Low	Mean	High	Low	Mean	High
Pliocene Clastic					not assessed				
Upper Miocene Sandstone	0	39	85	0	16	34	0	42	91
Modelo	0	245	736	0	291	879	0	297	877
Dume Thrust Fault[1]	0	367	853	0	448	1,079	0	446	1,037
San Onofre Breccia	0	32	90	0	14	40	0	35	97
Total Assessment Area[1]	*230*	*683*	*1,472*	*252*	*769*	*1,680*	*278*	*820*	*1,763*

[1] Includes a small area and volume of resources in the State offshore and onshore area adjacent to the Federal offshore area.

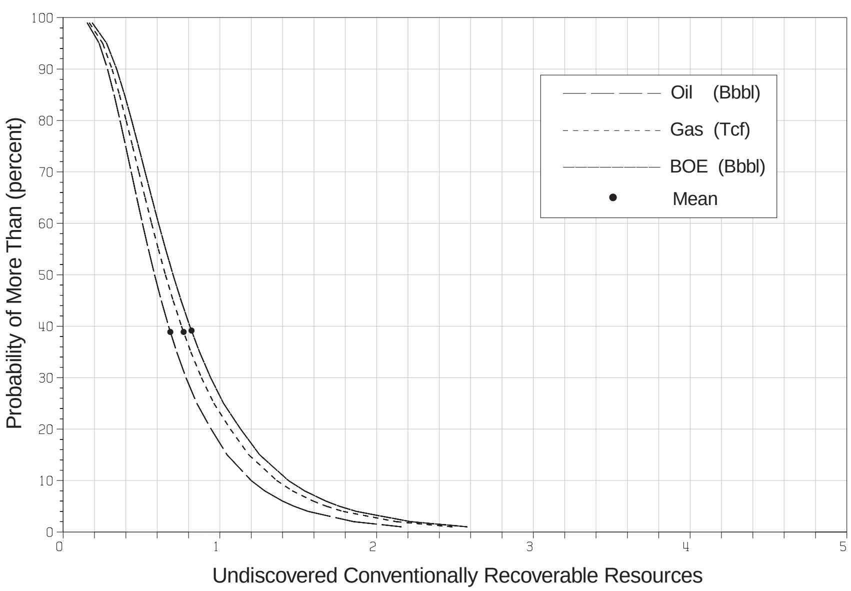

Figure 99. *Cumulative probability plot of estimated undiscovered conventionally recoverable resources of the Santa Monica-San Pedro assessment area.*

resources (approximately 91 percent on a combined oil-equivalence basis) are estimated to exist in the Modelo and Dume Thrust Fault plays. The low, mean, and high estimates of resources in the assessment area are listed in table 33 and illustrated in figure 99.

The Federal offshore portion of the assessment area is expected to contain the majority of these fields and resources, or approximately 646 MMbbl of oil and 724 Bcf of associated gas (table 34). The State offshore portion of the assessment area is estimated to contain approximately 37 MMbbl of oil and 45 Bcf of associated gas. A negligible volume of resources is expected to exist in the onshore portion of the assessment area.

Undiscovered Economically Recoverable Resources

Estimates of undiscovered conventionally recoverable resources in the assessment area that may be economically recoverable under various economic scenarios have been developed using the economic assessment method. Select data used to develop the resource estimates are shown in appendix D.

As a result of this assessment, 442 MMbbl of oil and 498 Bcf of associated gas are estimated to be economically recoverable from the Santa Monica-San Pedro assessment area under economic conditions existing as of this assessment (i.e., the $18-per-barrel economic scenario) (table 35). Larger volumes of resources are expected to be economically recoverable under increasingly favorable economic conditions (fig. 100).

Table 34. *Estimates of undiscovered conventionally recoverable oil and gas resources in the Santa Monica-San Pedro assessment area as of January 1, 1995, by area. All estimates are risked mean values. Some total values may not equal the sum of the component values due to independent rounding.*

Area	Oil (Bbbl)	Gas (Tcf)	BOE (Bbbl)
Onshore		negligible	
State Offshore	0.04	0.05	0.05
Federal Offshore	0.65	0.72	0.78
Total Assessment Area	*0.68*	*0.77*	*0.82*

The majority of undiscovered economically recoverable resources in the assessment area are expected to exist in the Federal offshore portion of the area.

Total Resource Endowment

No accumulations of resources have been discovered in the assessment area. Therefore, the aforementioned estimates of undiscovered conventionally recoverable resources compose the estimated total resource endowment of the area.

ACKNOWLEDGMENTS

This assessment of the Santa Monica-San Pedro area was significantly enhanced by the contributions of several persons, including Larry Beyer, Jim Crouch, Thane McCulloh, and Tom Wright. Their experience, patience, and generous cooperation was very helpful. Acknowledgment is also due to Scott Cranswick and Dennis Tayman who performed the seismic interpretative mapping of the area.

ADDITIONAL REFERENCES

Crouch, Bachman, and Associates, Inc., 1989a
Crouch, Bachman, and Associates, Inc., 1989b
Crouch and Suppe, 1993
Vedder, 1987

Table 35. *Estimates of undiscovered economically recoverable oil and gas resources in the Santa Monica-San Pedro assessment area[1] as of January 1, 1995, by economic scenario. All estimates are risked mean values. The $18-per-barrel scenario is based on prices of $18 per bbl of oil and $2.11 per Mcf of gas; the $25-per-barrel scenario is based on prices of $25 per bbl of oil and $2.94 per Mcf of gas; the $50-per-barrel scenario is based on prices of $50 per barrel of oil and $5.87 per Mcf of gas.*

Economic Scenario	Oil (MMbbl)	Gas (Bcf)	BOE (MMbbl)
$18 per barrel	442	498	531
$25 per barrel	503	565	603
$50 per barrel	591	664	709

[1] Includes a small area and volume of resources in the State offshore and onshore area adjacent to the Federal offshore area.

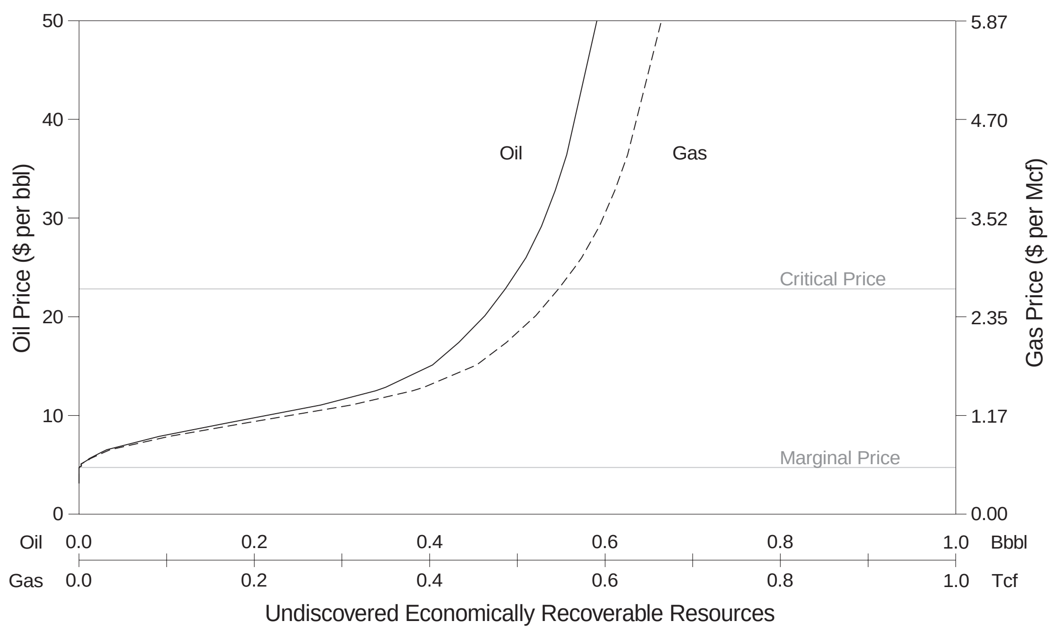

Figure 100. *Price-supply plot of estimated undis-covered economically recoverable resources of the Santa Monica-San Pedro assessment area.*

PLIOCENE CLASTIC PLAY

PLAY DEFINITION

The Pliocene Clastic play of the Santa Monica-San Pedro assessment area is defined to include accumulations of oil and associated gas in Pliocene clastic strata. The area of this conceptual play is estimated to be similar to that of the Modelo play (fig. 96); however, rocks of this play may extend farther west on the Santa Cruz-Catalina ridge.

PETROLEUM GEOLOGIC CHARACTERISTICS

This play is not considered to have an internal (Pliocene) petroleum source. It may, however, be sourced from underlying Miocene strata.

Potential reservoir rocks of this play include Pliocene sandstones, siltstones, and mudstones of the "Repetto"[14] and Pico Formations (fig. 97). However, these strata may be of relatively poor reservoir quality and may lack sufficient seal.

The majority of traps in this play are expected to be large stratigraphic pinchouts against the Santa Cruz-Catalina ridge. Some structural and fault traps may exist in the central and eastern portions of the play.

EXPLORATION

No exploratory wells have been drilled in this play.

RESOURCE ASSESSMENT

This play was not formally assessed due to significant uncertainties regarding source rocks, reservoir rocks, and traps.

UPPER MIOCENE SANDSTONE PLAY

PLAY DEFINITION

The Upper Miocene Sandstone play of the Santa Monica-San Pedro assessment area is defined to include accumulations of oil and associated gas in distal Puente Fan sandstones in fault traps on the San Pedro shelf. This play is fundamentally similar to the Puente Fan Sandstone play of the Los Angeles Basin province; however, there are sufficient differences to warrant the frontier status of this play. These include (1) the presence of finer grained reservoir rocks (deposited in more distal environments), (2) the presence of a thinner section of overburden (i.e., deposition of overlying Pliocene strata was confined by the Palos Verdes paleohigh), and (3) the possible presence of a larger volume of "Monterey" rocks in this play.

This play extends over most of the San Pedro shelf from the Palos Verdes fault west toward Catalina Island and from the Palos Verdes Peninsula south to the Dana Point sill (fig. 96). The Federal offshore portion of the play is approximately 30 miles long and 8 to 10 miles wide and covers an area of approximately 240 square miles. The depth to reservoir rocks in the play ranges from 600 to 5,000 feet and averages 3,000 feet below the seafloor.

PETROLEUM GEOLOGIC CHARACTERISTICS

Petroleum source rocks for this play include the lower middle Miocene "nodular shale" and interbedded middle Miocene pelagic mudstones and shales of the Puente Formation (fig. 97). In the onshore Los Angeles basin, these rocks are rich in marine-derived kerogen; total organic carbon content averages 4 percent and is as high as 10 and 16 percent in the "nodular shale" and Puente Formation, respectively (Jeffrey and others, 1991). High heat flow in the Los Angeles basin has generated oil from these kerogens at depths as shallow as 8,000 feet; the oil typically has moderately low gravity (less than 25 °API) and high sulphur content (greater than 1 percent). However, the relatively thin Neogene section on the San Pedro shelf (average thickness is 3,000 feet and maximum thickness is 7,000 feet) probably precludes significant oil generation in this area; therefore, migration from source rocks outside this play may be required. Long-distance migration from proven areas east of the Palos Verdes fault zone is unlikely due to the presence of a number of fault barriers; this is suggested by the fact that all five exploratory wells drilled in the most prospective areas of this play have been dry. Migration from source rocks in the San Pedro basin is similarly dubious.

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[14] The U.S. Geological Survey has abandoned the term "Repetto" (originally used to describe rocks that were deposited during the Repettian Stage) (Keroher and others, 1966); however, the term is widely used by the geological community and is used in this report.

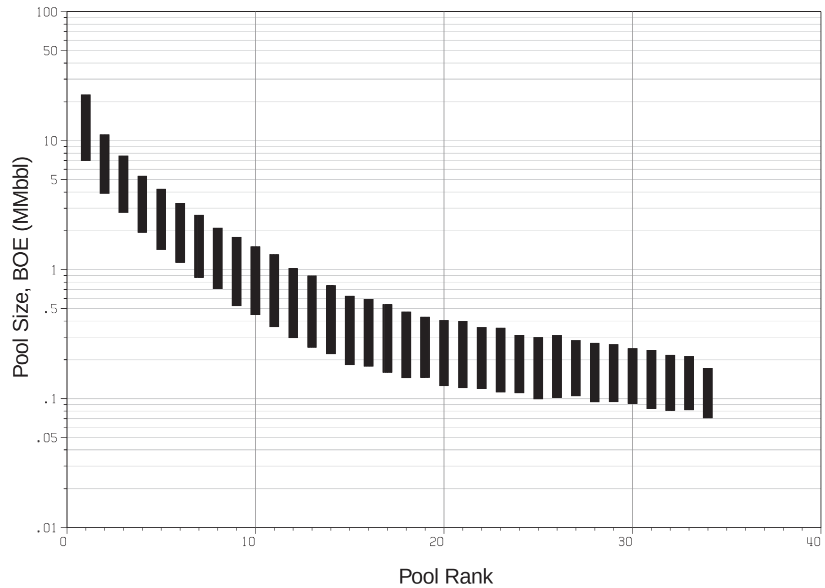


Figure 101. *Pool-size rank plot of estimated undiscovered conventionally recoverable resources of the Upper Miocene Sandstone play, Santa Monica-San Pedro assessment area. Sizes of undiscovered pools are shown by bars; the top and bottom of a bar represent the 25th- and 75th-percentile values of a probability distribution, respectively.*

Reservoir rocks of this play are composed of distal Puente Fan sands that have "spilled" over the Palos Verdes paleofault at bathymetric lows south of the Palos Verdes high (north of the Beta field). Although the thickness of the section is less than half of that east of the fault (average thickness of 3,000 feet) and the rocks are undoubtedly finer grained, sufficient reservoir section does exist.

Reservoir parameters for this play were significantly reduced from those of the Puente Fan Sandstone play of the Los Angeles Basin province. As stated above, oil migration into reservoir sandstones of this play is expected to have been limited due to the presence of a dense network of faults that are normal to (and presumably an impediment to) migration paths.

The network of northwest-trending faults that may have impeded Puente Fan sediments and oil migration from the east does provide a wealth of potential fault traps in the play. Many anticlinal and turbidite sandstone channel traps may also exist. Interbedded siltstones, mudstones, and shales may provide seals, and additional sealing may be provided by overlying upper Pliocene siltstones and mudstones.

Exploration

Five offshore exploratory wells, which are clustered along the eastern edge of the San Pedro shelf, have been drilled in this play. No significant accumulations of hydrocarbons have been discovered.

Resource Estimates

Undiscovered Conventionally Recoverable Resources

Estimates of undiscovered conventionally recoverable resources in the Federal offshore portion of the play have been developed using the subjective assessment method with adjusted onshore analogs from the Los Angeles basin. Select data used to develop the resource estimates are shown in appendix C.

As a result of this assessment, the Federal offshore portion of the play is estimated to contain 39 MMbbl of oil and 16 Bcf of associated gas (mean estimates). This volume of undiscovered conventionally recoverable resources may exist in as many as 34 pools with sizes ranging from approximately 70 Mbbl to 25 MMbbl of combined oil-equivalent resources (fig. 101). The low, mean, and high estimates of resources in the play are listed in table 33.

MODELO PLAY

PLAY DEFINITION

The Modelo play of the Santa Monica-San Pedro assessment area is defined to include accumulations of oil and associated gas in structural and fault traps of the Modelo and Monterey Formations[15]. This conceptual play exists in the Santa Monica and San Pedro basins from the Dume thrust fault south to Catalina Island and from the Palos Verdes high to the Santa Cruz-Catalina ridge (fig. 96). This irregularly shaped play extends for almost 50 miles from its northwest to southeast margins and covers an area of about 350 square miles. Reservoir rock depths in the play range from 0 to 15,000 feet below the seafloor.

[15] Middle to upper Miocene strata of the Modelo and Monterey Formations exist as interfingered facies in the Santa Monica-San Pedro assessment area. The Modelo Formation consists of fine-grained clastic strata that were deposited in distal environments; whereas, the Monterey Formation consists of a combination of fine-grained clastic strata and chert that were deposited predominantly by pelagic rain. Although these middle to upper Miocene strata include a mixture of facies, the predominant facies is presumed to be clastic. Therefore, all middle to upper Miocene strata exclusive of the Puente Formation have been included in the Modelo play, and reservoir rocks in the play are assumed to have characteristics similar to clastic Modelo reservoirs in the onshore Santa Barbara-Ventura basin.

PETROLEUM GEOLOGIC CHARACTERISTICS

Petroleum source rocks for this play include the lower middle Miocene “nodular shale” and interbedded middle to upper Miocene pelagic mudstones and shales of the Monterey Formation (fig. 97). In the onshore Los Angeles basin, these rocks are rich in marine-derived kerogen and have an average total organic carbon content of about 4 percent (Jeffrey and others, 1991; Philippi, 1975). High heat flow in the Los Angeles basin has generated oil from “nodular shale” kerogens at depths as shallow as 8,000 feet; the oil typically has moderately low gravity (less than 25 °API) and high sulphur content (greater than 1 percent). A fairly large “oil kitchen” may exist in the northwest portion of the Santa Monica basin, which has as much as 12,000 feet of Pliocene overburden; a much smaller “kitchen” may exist in the central portion of the San Pedro basin, where 8,000 feet of overburden exists.

Reservoir rocks of this play include middle to upper Miocene clastic strata of the Modelo Formation and fractured shales and cherts of the Monterey Formation (fig. 97); rocks of both of these reservoir types exist in coastal outcrops north of the play. Cherts with minimal clastic contamination may be good fractured reservoirs; however, the location and

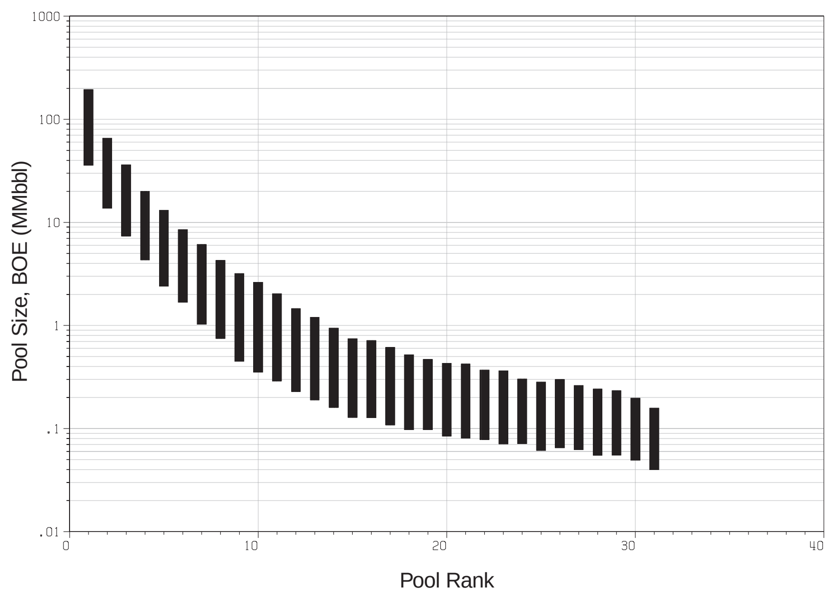


Figure 102. *Pool-size rank plot of estimated undiscovered conventionally recoverable resources of the Modelo play, Santa Monica-San Pedro assessment area. Sizes of undiscovered pools are shown by bars; the top and bottom of a bar represent the 25th- and 75th-percentile values of a probability distribution, respectively.*

degree of clastic contamination in the area are unknown. Most of the reservoir potential in the play is assumed to be in fine-grained clastic Modelo rocks, which may have fair to good reservoir quality.

Anticlinal and fault traps are expected in this play, although strata are relatively undeformed compared to other plays in the area. As a result, fewer but potentially larger (area) traps may exist. Interbedded siltstones, mudstones, and shales may provide seals, and additional sealing may be provided by overlying lower Pliocene siltstones and mudstones.

Exploration

No exploratory wells have been drilled in this play.

Resource Estimates

Undiscovered Conventionally Recoverable Resources

Estimates of undiscovered conventionally recoverable resources in the Federal offshore portion of the play have been developed using the subjective assessment method with clastic Modelo analogs from the onshore Santa Barbara-Ventura basin (see discussion above). Select data used to develop the resource estimates are shown in appendix C.

As a result of this assessment, the Federal offshore portion of the play is estimated to contain 245 MMbbl of oil and 291 Bcf of associated gas (mean estimates). This volume of undiscovered conventionally recoverable resources may exist in as many as 31 pools with sizes ranging from approximately 40 Mbbl to 195 MMbbl of combined oil-equivalent resources (fig. 102). The low, mean, and high estimates of resources in the play are listed in table 33.

Dume Thrust Fault Play

Play Definition

The Dume Thrust Fault play of the Santa Monica-San Pedro assessment area is defined to include accumulations of oil and associated gas in fault traps along the Dume thrust fault and the Malibu Coast fault. This frontier play exists onshore and offshore (in Federal and State waters) at the northern margin of the area (fig. 96). The play extends approximately 25 miles westward from Point Dume to the area south of Anacapa ridge and encompasses a total area of about 160 square miles. Reservoir rock depths in the play range from 0 to 15,000 feet below the seafloor.

Petroleum Geologic Characteristics

Petroleum source rocks for this play include the lower middle Miocene “nodular shale” and interbedded middle to upper Miocene mudstones and shales of the Monterey Formation (fig. 97). In the onshore Los Angeles basin, these rocks are rich in marine-derived kerogen and have an average total organic carbon content of about 4 percent (Jeffrey and others, 1991; Philippi, 1975). High heat flow in the Los Angeles basin has generated oil from “nodular shale” kerogens at depths as shallow as 8,000 feet; the oil typically has moderately low gravity (less than 25 °API) and high sulphur content (greater than 1 percent). A fairly large “oil kitchen” may exist in the northwest portion of the Santa Monica basin, which has as much as 12,000 feet of Pliocene overburden.

This play has a variety of potential reservoir rocks including Catalina Schist basement; clastic rocks of the Topanga Group, San Onofre Breccia, Modelo Formation, and Repetto Formation; and fractured rocks of the Monterey Formation and “nodular shale” (fig. 97). Monterey strata in this play have been penetrated by one exploratory well and a few coreholes. Repetto strata (which have not been drilled) are predicted to exist based on extrapolation of a presumably equivalent seismic-stratigraphic unit from Santa Monica Bay. Outcrops in the adjacent coastal area further suggest that Topanga, Modelo, and Monterey strata exist in the offshore area; however, seismic data quality in State waters west of Point Dume is poor. The presence of laumontite (which exists in coastal outcrops) may reduce reservoir quality to an unknown degree.

The primary trapping mechanisms in this play are faults of the Dume thrust fault and Malibu Coast fault zones. Subthrust accumulations may also exist. The presence and effectiveness of seals are uncertain. Some seals may be provided by interbedded siltstones, mudstones, and shales.

Exploration

Two exploratory wells have been drilled in the Federal offshore area of this play; tar was observed in the cuttings from one of the wells. Five wells have been drilled in State waters, and visible shows of oil were observed in the cuttings from one of these wells.

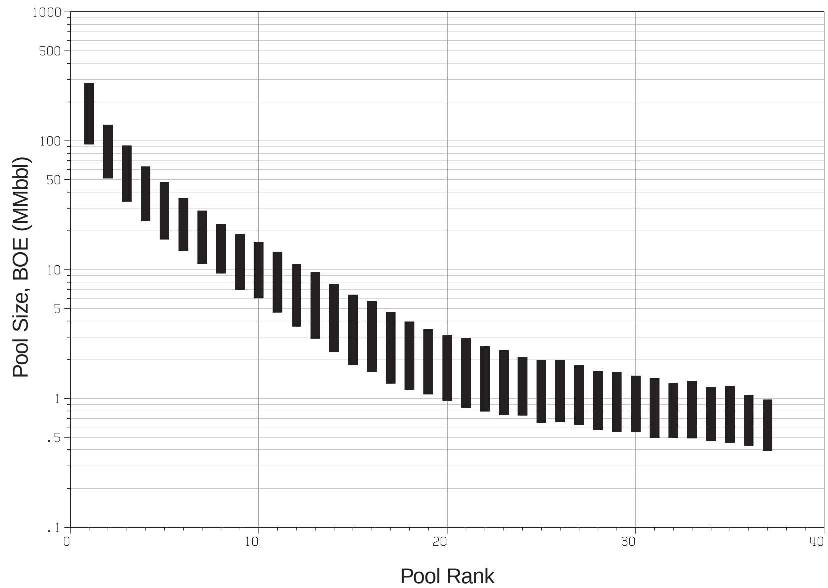


Figure 103. *Pool-size rank plot of estimated undiscovered conventionally recoverable resources of the Dume Thrust Fault play, Santa Monica-San Pedro assessment area. Sizes of undiscovered pools are shown by bars; the top and bottom of a bar represent the 25th- and 75th-percentile values of a probability distribution, respectively.*

RESOURCE ESTIMATES

Undiscovered Conventionally Recoverable Resources

Estimates of undiscovered conventionally recoverable resources in the play have been developed using the subjective assessment method. Select data used to develop the resource estimates are shown in appendix C.

As a result of this assessment, the play is estimated to contain 367 MMbbl of oil and 448 Bcf of associated gas (mean estimates). This volume of undiscovered conventionally recoverable resources may exist in as many as 37 pools with sizes ranging from approximately 395 Mbbl to 280 MMbbl of combined oil-equivalent resources (fig. 103). The low, mean, and high estimates of resources in the play are listed in table 33.

The majority of these pools and resources, or approximately 330 MMbbl of oil and 403 Bcf of associated gas, are expected to exist in the Federal offshore portion of the play. The remaining pools and resources, or approximately 37 MMbbl of oil and 45 Bcf of associated gas, are expected to exist in the State offshore portion of the play. A negligible volume of resources is expected to exist in the onshore portion of the play.

SAN ONOFRE BRECCIA PLAY

PLAY DEFINITION

The San Onofre Breccia play of the Santa Monica-San Pedro assessment area is defined to include accumulations of oil and associated gas in stratigraphic and structural traps of the fractured Catalina Schist, the schist-derived San Onofre Breccia, and overlying "nodular shale." This conceptual play exists in four noncontiguous subareas which cover a total area of approximately 175 square miles (fig. 96). Depth to the reservoir section ranges from 2,000 to 9,000 feet below the seafloor.

Catalina Schist of the Palos Verdes paleohigh was the primary sediment source for reservoir rocks of this play, which were deposited within a "sediment halo" adjacent to the high. This "halo" has been subsequently dissected by erosion (e.g., Redondo Canyon), resulting in four noncontiguous subareas of reservoir rock. An extensive body of potentially analogous debris-fan strata along the east margin of the Santa Cruz-Catalina ridge has not been included in this play due to the unknown lithologic character (schist debris or volcaniclastics) of the strata.

Reservoir rocks equivalent to those included in this play extend eastward and have been assessed as the San Onofre Breccia play of the Los Angeles Basin province (see this report). Similarly, equivalent rocks are presumed to extend farther eastward into the State offshore and onshore portions of the Los Angeles basin where they have been assessed as part of the Southwestern Shelf play by the U.S. Geological Survey (Beyer, 1995).

Petroleum Geologic Characteristics

The petroleum source rock for this play is the lower middle Miocene “nodular shale” (fig. 97). In the onshore Los Angeles basin, this unit is rich in marine-derived kerogen and has an average total organic carbon content of 3 to 4 percent (Jeffrey and others, 1991). High heat flow in the Los Angeles basin has generated oil from these kerogens at depths as shallow as 8,000 feet; the oil typically has moderately low gravity (less than 25 °API) and high sulphur content (greater than 1 percent). Oil gravity often increases with depth; this underscores the importance of identifying traps with possible migration pathways to deeper generative centers onshore (a limited migration distance).

The primary reservoir rocks for this play are lower Miocene sandstones and breccias of the San Onofre Breccia (Catalina Schist eroded from the Palos Verdes paleohigh) and locally fractured Cretaceous (and possibly Jurassic) rocks of the Catalina Schist. The lowermost, possibly fractured, portion of the “nodular shale” may contain potential reservoir rocks and is also included in this play (fig. 97). Reservoir quality may be variable; porosities of analogous reservoirs in the onshore Los Angeles basin range from 12 to 31 percent.

Faults and pinchouts against local basement irregularities may produce many traps in the area; however, only traps located within the “sediment halo” of the Palos Verdes paleohigh are considered viable targets in this play. The overlying “nodular shale” may provide a seal (as well as a petroleum source and reservoir rock) for the traps. The traps are expected to be small; productive areas of analog fields in the onshore Los Angeles basin range from 15 to 600 acres.

Exploration

Four offshore exploratory wells have been drilled in this play. Tar was observed in the sidewall cores from one of the wells. Offshore oil seeps south of the Palos Verdes Peninsula are of unknown affinity but are likely leaking from the San Onofre Breccia where the strata offlap the Palos Verdes high.

Resource Estimates

Undiscovered Conventionally Recoverable Resources

Estimates of undiscovered conventionally recoverable resources in the Federal offshore portion of the play have been developed using the subjective assessment method with adjusted analogs from the onshore Los Angeles basin (e.g., El Segundo, Playa Del Rey, and Venice Beach fields). Select data used to develop the resource estimates are shown in appendix C.

As a result of this assessment, the Federal offshore portion of the play is estimated to contain 32 MMbbl of oil and 14 Bcf of associated gas (mean estimates). This volume of undiscovered conventionally recoverable resources may exist in as many as 14 pools with sizes ranging from approximately 300 Mbbl to 30 MMbbl of combined oil-equivalent resources (fig. 104). The low, mean, and high estimates of resources in the play are listed in table 33.

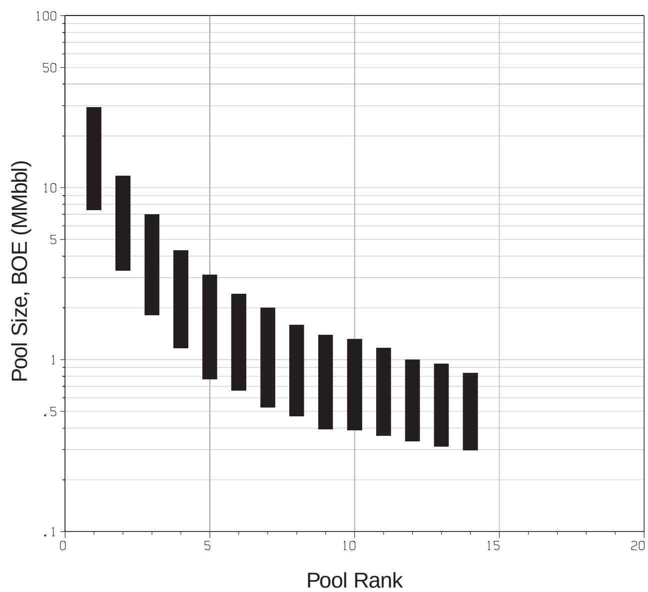


Figure 104. *Pool-size rank plot of estimated undiscovered conventionally recoverable resources of the San Onofre Breccia play, Santa Monica-San Pedro assessment area. Sizes of undiscovered pools are shown by bars; the top and bottom of a bar represent the 25th- and 75th-percentile values of a probability distribution, respectively.*

OCEANSIDE-CAPISTRANO BASIN

by Frank W. Victor

LOCATION

The Oceanside-Capistrano Basin assessment area is the southernmost area in the Inner Borderland province (fig. 93). Most of the basin is located offshore; however, a small, partly exhumed portion of the basin exists onshore near Dana Point (fig. 105). This onshore area of the basin is referred to as the Capistrano syncline; it is bounded on the north by the Coast Ranges and extends about 10 miles in width from the San Joaquin Hills eastward to a generally north-south-trending boundary along which Cretaceous strata are exposed in outcrop. Offshore, the basin is bounded on the northwest by the Dana Point sill and extends southerly about 50 miles to the vicinity of La Jolla; it is bounded to the west by the Thirtymile bank and extends about 30 miles east into State waters. The entire basin is about 50 miles long and averages 30 miles in width and occupies an area of about 1,500 square miles. Water depth in the basin ranges from 0 (coastline) to about 3,000 feet.

Although the majority of the assessment area is in the Federal offshore area (which is the focus of this study), it includes some adjacent State offshore and onshore areas (fig. 105). These adjacent areas were included in this study to facilitate their assessment, which was based in part on information from the Federal offshore area.

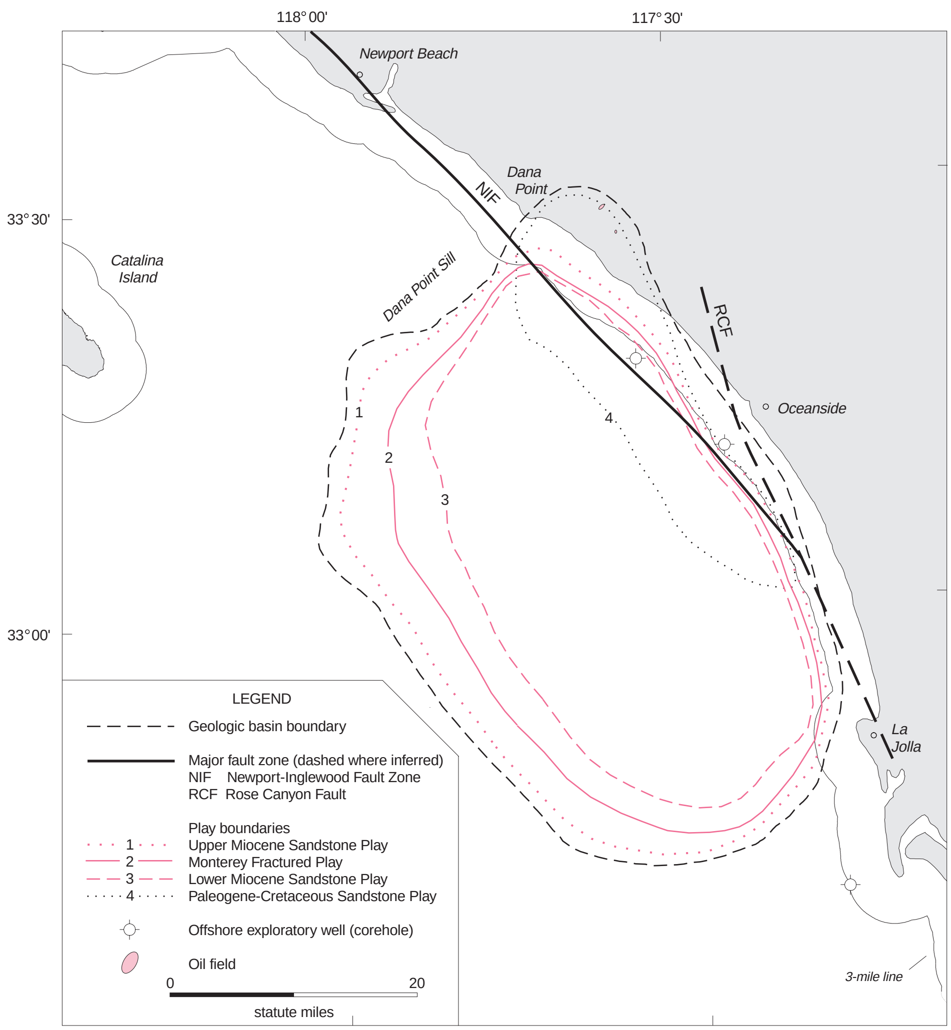


Figure 105. *Map of the Oceanside-Capistrano Basin assessment area showing petroleum geologic plays, offshore wells, and fields.*

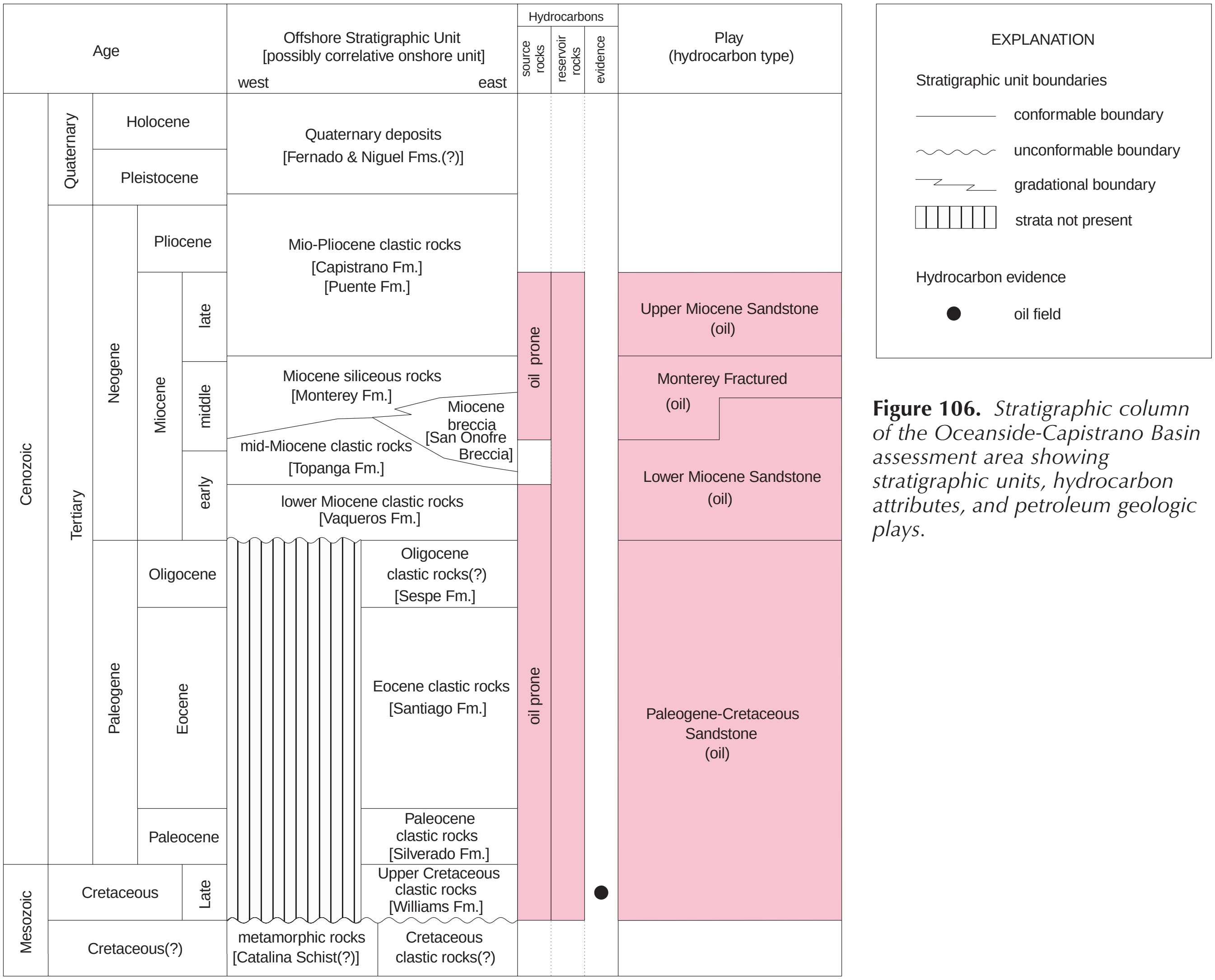


Figure 106. *Stratigraphic column of the Oceanside-Capistrano Basin assessment area showing stratigraphic units, hydrocarbon attributes, and petroleum geologic plays.*

Geologic Setting

The Oceanside-Capistrano basin is an asymmetrical structural trough filled with up to 11,000 feet of Cretaceous and Tertiary marine and nonmarine rocks (fig. 106). The northwest-trending Newport-Inglewood fault zone lies offshore near the eastern margin of the basin (fig. 105); the fault has been a major feature in the tectonic and structural evolution of the basin. Large, compressional, fault-bounded anticlines, faulted homoclines, and stratigraphic pinchouts west of the fault zone are evident on seismic-reflection profiles. Most of these structures are located in the Federal offshore area, but a few extend into the State offshore area; these structures are numerous and large enough to contain significant quantities of oil and gas. The Newport-Inglewood structural trend has major petroleum significance in the Oceanside-Capistrano basin since this is the same fault and structural trend along which several prolific oil fields exist in the onshore Los Angeles basin.

The Capistrano syncline is a flat-bottomed, north-south-trending structural trough formed by downwarping of the eastern part of the San Joaquin Hills on the west and down-to-the-west displacement of the Cristianitos fault zone on the east. The syncline is separated from the Los Angeles basin proper by the structurally high San Joaquin Hills and its northward extension into the subsurface. Up to 3,700 feet of middle and upper Miocene marine rocks overlie schist breccia and Paleogene and Cretaceous strata within the syncline (Wright, 1991).

Exploration

Exploration within the offshore part of the basin has been limited. Only two boreholes (the Mobil San Clemente #1 and Shell Oceanside #1 coreholes) have been drilled offshore. The coreholes were drilled as stratigraphic tests in the 1960's and did not encounter any oil or gas. The Mobil San Clemente corehole penetrated Pliocene and Miocene rocks (presumably of the Capistrano and Monterey Formations, and the San Onofre Breccia). The Shell Oceanside corehole penetrated Pliocene rocks (presumably of the Capistrano Formation). No deep exploratory wells have been drilled in the basin.

A number of high-quality seismic-reflection surveys have been recorded offshore. Many of the profiles from these surveys extend into State waters.

Onshore, more than 60 exploratory wells have been drilled from the early 1950's to 1984. Two fields—the San Clemente and Cristianitos Creek fields—have been discovered. Collectively, these fields produced a very small quantity (less than 5 Mbbl) of high-gravity (45 to 54 °API) oil from the Upper Cretaceous Williams Formation in the late 1950's. Both fields were considered to be subcommercial and have been abandoned. One of the last wells was drilled in 1981 as an extension to the San Clemente field, and it was dry.

PLAYS

Four petroleum geologic plays within the basin have been defined; the plays are defined on the basis of reservoir rock stratigraphy (fig. 106). The plays (and corresponding reservoir rock formations) are (1) the Upper Miocene Sandstone play (Capistrano Formation), (2) the Monterey Fractured play (Monterey Formation), (3) the Lower Miocene Sandstone play (San Onofre Breccia and Topanga and Vaqueros Formations), and (4) the Paleogene-Cretaceous Sandstone play (Williams, Silverado, Santiago, and Sespe(?) Formations).

The Upper Miocene Sandstone, Monterey Fractured, and Lower Miocene Sandstone plays are restricted to the offshore area of the basin; these plays are considered to be conceptual plays based on the absence of directly detected hydrocarbons. The Paleogene-Cretaceous Sandstone play exists onshore and offshore and is an established play because hydrocarbon accumulations have been discovered in the play onshore.

RESOURCE ESTIMATES

Undiscovered Conventionally Recoverable Resources

Play-specific estimates of undiscovered conventionally recoverable resources have been developed using the subjective assessment method, and these estimates have been statistically aggregated to estimate the total volume of resources in the assessment area. Select data used to develop the resource estimates are shown in appendix C. Estimates of the volume of resources in the Federal offshore, State offshore, and onshore portions of each play were subsequently calculated using a subjective area-proportionality factor, and the area-specific play estimates have been summed to estimate the total volume of resources in the respective portions of the assessment area.

As a result of this assessment, the total volume of undiscovered conventionally recoverable resources in the Oceanside-Capistrano Basin assessment area is estimated to be 1.11 Bbbl of oil and 1.30 Tcf of associated gas (mean estimates). This volume may exist in 51 fields with sizes ranging from approximately 95 Mbbl to 450 MMbbl of combined oil-

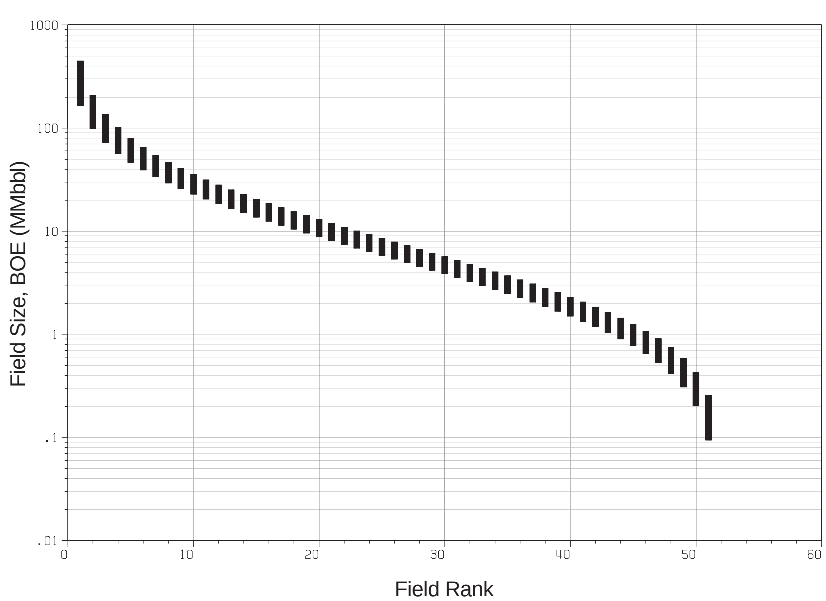


Figure 107. *Field-size rank plot of estimated undiscovered conventionally recoverable resources of the Oceanside-Capistrano Basin assessment area. Sizes of undiscovered fields are shown by bars; the top and bottom of a bar represent the 25th- and 75th-percentile value of a probability distribution, respectively.*

equivalent resources (fig. 107). The low, mean, and high estimates of resources in the assessment area are listed in table 36 and illustrated in figure 108.

The Federal offshore portion of the assessment area is expected to contain the majority of these fields and resources, or approximately 1.07 Bbbl of oil and 1.25 Tcf of associated gas (table 37). The State offshore portion of the assessment area is estimated to contain approximately 47 MMbbl of oil and 57 Bcf of associated gas. A negligible volume of resources is expected to exist in the onshore portion of the assessment area.

Table 36. *Estimates of undiscovered conventionally recoverable oil and gas resources in the Oceanside-Capistrano Basin assessment area as of January 1, 1995, by play. All estimates are risked values. The low, mean, and high estimates correspond to the 95th-percentile, mean, and 5th-percentile values of a probability distribution, respectively. Percentile values are not additive; some total mean values may not equal the sum of the component values due to independent rounding.*

Play	Oil (MMbbl)			Gas (Bcf)			BOE (MMbbl)		
	Low	Mean	High	Low	Mean	High	Low	Mean	High
Upper Miocene Sandstone[1]	0	514	1,191	0	274	648	0	563	1,304
Monterey Fractured[1]	0	387	768	0	452	983	0	467	935
Lower Miocene Sandstone[1]	0	208	711	0	568	2,466	0	309	1,116
Paleogene-Cretaceous Sandstone[1]	0	3	14	0	8	39	0	4	21
Total Assessment Area[1]	*0*	*1,112*	*2,211*	*0*	*1,302*	*3,174*	*0*	*1,343*	*2,698*

[1] Includes a small area and volume of resources in the State offshore and onshore area adjacent to the Federal offshore area.

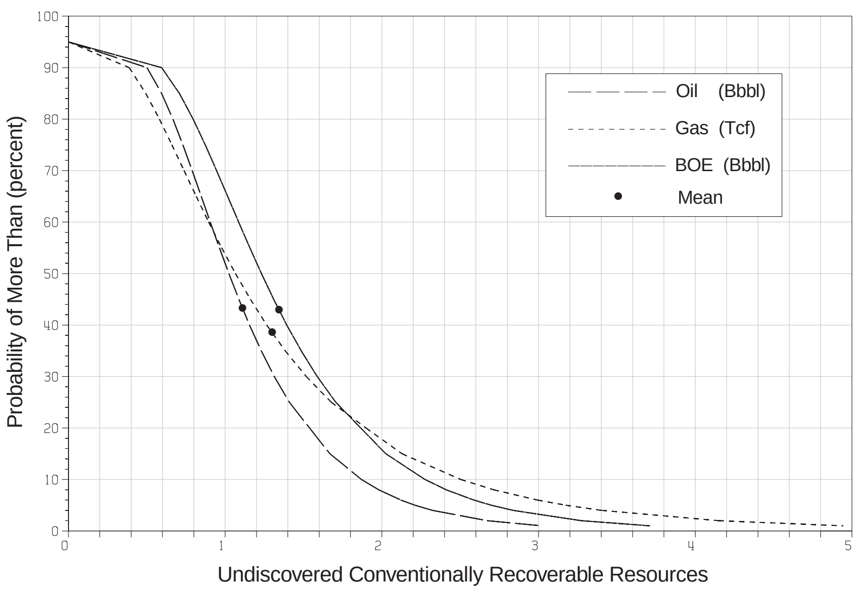


Figure 108. *Cumulative probability plot of estimated undiscovered conventionally recoverable resources of the Oceanside-Capistrano Basin assessment area.*

Table 37. *Estimates of undiscovered conventionally recoverable oil and gas resources in the Oceanside-Capistrano Basin assessment area as of January 1, 1995, by area. All estimates are risked mean values. Some total values may not equal the sum of the component values due to independent rounding.*

Area	Oil (Bbbl)	Gas (Tcf)	BOE (Bbbl)
Onshore		negligible	
State Offshore	0.05	0.06	0.06
Federal Offshore	1.07	1.25	1.29
Total Assessment Area	*1.11*	*1.30*	*1.34*

Undiscovered Economically Recoverable Resources

Estimates of undiscovered conventionally recoverable resources in the assessment area that may be economically recoverable under various economic scenarios have been developed using the economic assessment method. Select data used to develop the

Table 38. *Estimates of undiscovered economically recoverable oil and gas resources in the Oceanside-Capistrano Basin assessment area[1] as of January 1, 1995, by economic scenario. All estimates are risked mean values. The $18-per-barrel scenario is based on prices of $18 per bbl of oil and $2.11 per Mcf of gas; the $25-per-barrel scenario is based on prices of $25 per bbl of oil and $2.94 per Mcf of gas; the $50-per-barrel scenario is based on prices of $50 per barrel of oil and $5.87 per Mcf of gas.*

Economic Scenario	Oil (MMbbl)	Gas (Bcf)	BOE (MMbbl)
$18 per barrel	743	869	898
$25 per barrel	882	1,032	1,065
$50 per barrel	1,015	1,188	1,226

[1] Includes a small area and volume of resources in the State offshore and onshore area adjacent to the Federal offshore area.

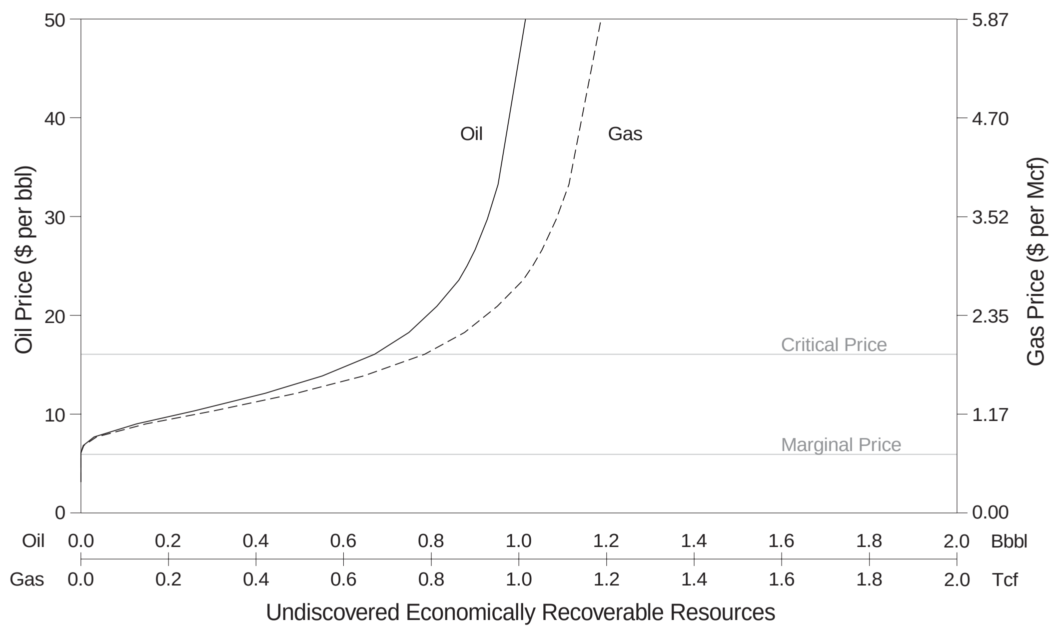


Figure 109. *Price-supply plot of estimated undiscovered economically recoverable resources of the Oceanside-Capistrano Basin assessment area.*

Table 39. *Estimates of the total endowment of oil and gas resources in the Oceanside-Capistrano Basin assessment area. Estimates of discovered resources (including cumulative production and remaining reserves) and undiscovered resources are as of January 1, 1995. Estimates of undiscovered conventionally recoverable resources are risked mean values. Some total values may not equal the sum of the component values due to independent rounding.*

Resource Category	Oil (Bbbl)	Gas (Tcf)	BOE (Bbbl)
Cumulative Production[1]	<0.01	<0.01	<0.01
Remaining Reserves[1]		negligible	
Undiscovered Conventionally Recoverable Resources[1]	1.11	1.30	1.34
Total Resource Endowment[1]	*1.11*	*1.30*	*1.34*

[1] Includes a small area and volume of resources in the State offshore and onshore area adjacent to the Federal offshore area.

resource estimates are shown in appendix D.

As a result of this assessment, 743 MMbbl of oil and 869 Bcf of associated gas are estimated to be economically recoverable from the Oceanside-Capistrano Basin assessment area under economic conditions existing as of this assessment (i.e., the $18-per-barrel economic scenario) (table 38). Larger volumes of resources are expected to be economically recoverable under increasingly favorable economic conditions (fig. 109).

The majority of undiscovered economically recoverable resources in the assessment area are expected to exist in the Federal and State offshore portions of the area.

Total Resource Endowment

As of this assessment, cumulative production from the onshore portion of the assessment area was 4.6 Mbbl of oil and 11 MMcf of gas; remaining reserves were estimated to be negligible. These discovered resources (all of which are from the Paleogene-Cretaceous Sandstone play) and the aforementioned undiscovered conventionally recoverable resources collectively compose the area's estimated total resource endowment of 1.11 Bbbl of oil and 1.30 Tcf of gas (table 39).

Acknowledgments

Jim Crouch is acknowledged for sharing his knowledge and insight regarding the Oceanside-Capistrano basin. Larry Beyer was helpful in providing onshore information. Acknowledgment is also due to Bill Kou who performed the seismic interpretive mapping of the offshore part of the basin.

Additional References

Crouch, 1993
Crouch, Bachman, and Associates, Inc., 1989a
Crouch and Suppe, 1993
Vedder, 1987

Upper Miocene Sandstone Play

Play Definition

The Upper Miocene Sandstone play of the Oceanside-Capistrano Basin assessment area is a conceptual play consisting of accumulations of oil and associated gas in upper Miocene sandstones of the Capistrano Formation. The play exists over most of the offshore portion of the basin (in Federal and State waters) but does not exist onshore (fig. 105). It encompasses an area of about 1,300 square miles; the depth to reservoir rocks in the play ranges from about 1,200 to 5,500 feet below the seafloor.

Petroleum Geologic Characteristics

The primary petroleum source rocks for this play are within the Monterey Formation (fig. 106). Mudstones and shales within the lower part of the Capistrano Formation may also have source potential for this play. The type and amount of organic matter within Monterey rocks of the Oceanside-Capistrano basin are largely unknown; however, Monterey rocks in other California coastal basins are rich in organic matter, and similar rocks are presumed to exist in the Oceanside-Capistrano basin. The depth at which thermal maturation may have occurred is also unknown. The Monterey is buried between 5,000 and 8,500 feet (corresponding to temperatures of about 185 to 270 °F, respectively) and, therefore, may have been buried sufficiently to permit petroleum generation.

Potential reservoir rocks in this play are upper Miocene channel and fan turbidite sandstones of the Capistrano Formation (fig. 106); these are probably stratigraphically equivalent to Puente Formation sandstones and lower "Repetto" strata in the Los Angeles basin (see Los Angeles Basin province summary). The Capistrano Formation contains very sand-rich units that are regionally extensive across the offshore part of the Oceanside-Capistrano basin; rocks of this formation are exposed in outcrops onshore from the San Joaquin Hills to south of San Clemente. The Mobil San Clemente corehole penetrated over 3,000 feet of this section, which is sand-rich and of potentially excellent reservoir quality. A number of channel and lobate features (interpreted to be fans) are imaged on offshore seismic-reflection profiles; similar features are exposed in coastal outcrops at Dana Point and San Clemente. Based on basin geometry, these channel and fan deposits were probably depositionally restricted to the basin trough where stacking of multiple reservoir sandstones is likely.

A large number of structural traps—including small to large anticlines and faulted anticlines—within the Capistrano Formation are evident from seismic mapping. The dominant structural trend is along the Newport-Inglewood fault zone. Channel and fan facies outside the Newport-Inglewood structural trend afford excellent opportunities for stratigraphic entrapment.

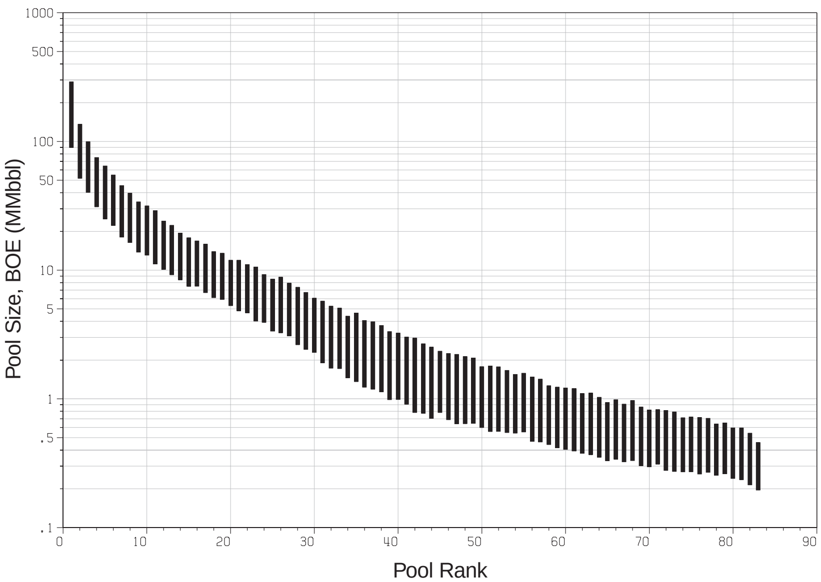


Figure 110. *Pool-size rank plot of estimated undiscovered conventionally recoverable resources of the Upper Miocene Sandstone play, Oceanside-Capistrano Basin assessment area. Sizes of undiscovered pools are shown by bars; the top and bottom of a bar represent the 25th- and 75th-percentile values of a probability distribution, respectively.*

EXPLORATION

Both of the coreholes drilled in the offshore part of the basin penetrated rocks of this play. No shows of hydrocarbons were encountered.

RESOURCE ESTIMATES

Undiscovered Conventionally Recoverable Resources

Estimates of undiscovered conventionally recoverable resources in the play have been developed using the subjective assessment method with a combination of play-specific and analog data. Select data used to develop the resource estimates are shown in appendix C.

The size and number of prospects in the play were estimated from seismic mapping. Conservatively modified analog data from Puente producing zones in the Los Angeles basin were used to estimate the net-pay thickness, oil recovery factor, and gas-to-oil ratio for this play.

As a result of this assessment, the play is expected to contain 514 MMbbl of oil and 274 Bcf of associated gas (mean estimates). This volume of undiscovered conventionally recoverable resources may exist in as many as 83 pools with sizes ranging from approximately 195 Mbbl to 290 MMbbl of combined oil-equivalent resources (fig. 110). The low, mean, and high estimates of resources in the play are listed in table 36.

The majority of these pools and resources, or approximately 494 MMbbl of oil and 263 Bcf of associated gas, are expected to exist in the Federal offshore portion of the play. The remaining pools and resources, or approximately 20 MMbbl of oil and 11 Bcf of associated gas, are expected to exist in the State offshore portion of the play.

MONTEREY FRACTURED PLAY

PLAY DEFINITION

The Monterey Fractured play of the Oceanside-Capistrano Basin assessment area is a conceptual play consisting of accumulations of oil and associated gas in middle to upper Miocene fractured rocks of the Monterey Formation. The play exists over most of the offshore portion of the basin (in Federal and State waters) but does not exist onshore (fig. 105). It encompasses an area of about 1,000 square miles; the depth to reservoir rocks in the play ranges from about 3,400 to 8,500 feet below the seafloor.

PETROLEUM GEOLOGIC CHARACTERISTICS

The Monterey Formation is considered to be both source rock and reservoir rock for this play (fig. 106) by analogy with Monterey rocks in the offshore Santa Barbara-Ventura and Santa Maria basins and the onshore San Joaquin basin. The type and amount of organic matter within Monterey rocks of the Oceanside-Capistrano basin are largely unknown; however, Monterey rocks in other California coastal basins are rich in organic matter, and similar rocks are presumed to exist in the Oceanside-Capistrano basin. The depth at which thermal maturation may have occurred is also unknown. The Monterey is buried between 5,000 and 8,500 feet (corresponding to temperatures of about 185 to 270 °F, respectively) and, therefore, may have been buried sufficiently to permit petroleum generation.

Potential reservoir rocks in this play include fractured shale, dolomitic limestone, sandstone, siltstone, and chert of the Monterey Formation (fig. 106). Monterey rocks in the offshore Oceanside-Capistrano basin have been penetrated by one corehole; the corehole and offshore seismic data suggest that the Monterey section is more than 1,500 feet thick in most of the play area. Onshore, Monterey strata outcrop along the coast from Newport Beach to Oceanside where they are described as calcareous, siliceous, and phosphatic (Crouch, 1993). The outcrop data indicate that Monterey rocks are much dirtier (clays and mudstones) than in the offshore Santa Barbara-Ventura and Santa Maria basins; therefore, porosity and permeability of Monterey reservoir rocks may be diminished in this basin.

The Newport-Inglewood fault zone has created a number of small to large anticlines, fault traps, and subthrust traps within the basin. The potential for stratigraphic entrapment in this play is considered to be minor.

EXPLORATION

One of the coreholes (Mobil San Clemente) drilled in the offshore part of the basin penetrated rocks of the Monterey Formation. No shows of hydrocarbons were encountered.

RESOURCE ESTIMATES

Undiscovered Conventionally Recoverable Resources

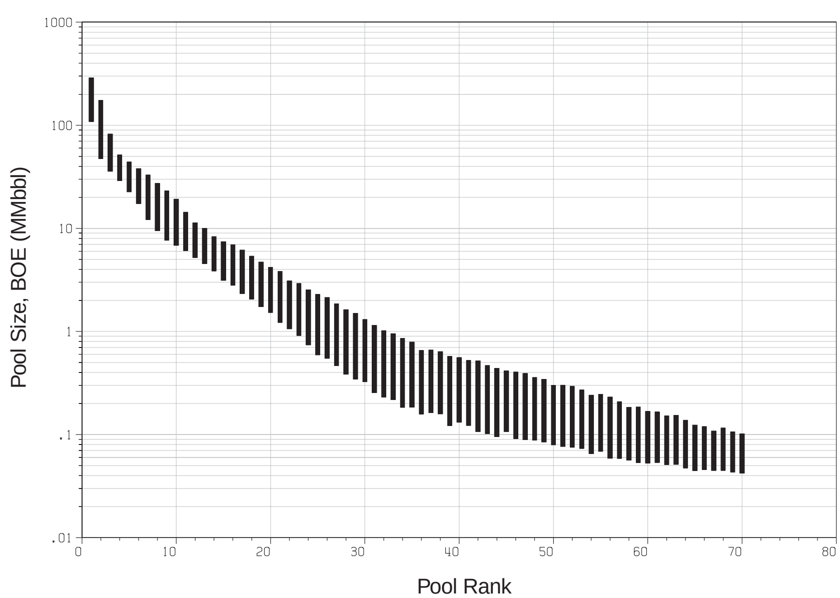
Estimates of undiscovered conventionally recoverable resources in the play have been developed using the subjective assessment method with a combination of play-specific and analog data. Select data used to develop the resource estimates are shown in appendix C.

The volume and number of prospects in the play were estimated from seismic mapping. Conservatively modified analog data from Monterey producing zones in the offshore Santa Barbara-Ventura and Santa Maria basins were used to estimate the oil recovery factor and gas-to-oil ratio for this play.

As a result of this assessment, the play is estimated to contain 387 MMbbl of oil and 452 Bcf of associated gas (mean estimates). This volume of undiscovered conventionally recoverable resources may exist in as many as 76 pools with sizes ranging from approximately 40 Mbbl to 290 MMbbl of combined oil-equivalent resources (fig. 111). The low, mean, and high estimates of resources in the play are listed in table 36.

The majority of these pools and resources, or approximately 371 MMbbl of oil and 435 Bcf of associated gas, are expected to exist in the Federal offshore portion of the play. The remaining pools and resources, or approximately 16 MMbbl of oil and 17 Bcf of associated gas, are expected to exist in the State offshore portion of the play.

Figure 111. *Pool-size rank plot of estimated undiscovered conventionally recoverable resources of the Monterey Fractured play, Oceanside-Capistrano Basin assessment area. Sizes of undiscovered pools are shown by bars; the top and bottom of a bar represent the 25th- and 75th-percentile values of a probability distribution, respectively.*



LOWER MIOCENE SANDSTONE PLAY

PLAY DEFINITION

The Lower Miocene Sandstone play of the Oceanside-Capistrano Basin assessment area is a conceptual play consisting of accumulations of oil and associated gas in lower to middle Miocene clastic rocks of the San Onofre Breccia, Topanga Formation, and Vaqueros Formation. The play exists offshore in the eastern two-thirds of the basin (in Federal and State waters) but does not exist onshore (fig. 105). It encompasses an area of about 700 square miles; the depth to reservoir rocks in the play ranges from about 5,200 to 9,800 feet below the seafloor.

PETROLEUM GEOLOGIC CHARACTERISTICS

Potential source rocks for this play are the Monterey Formation, lower Miocene shales in the Vaqueros Formation, and Eocene shales in the Santiago Formation(?) (fig. 106). The type and amount of organic matter within Monterey rocks of the Oceanside-Capistrano basin are largely unknown; however, Monterey rocks in other California coastal basins are rich in organic matter, and similar rocks are presumed to exist in the Oceanside-Capistrano basin. The Monterey is buried between 5,000 and 8,500 feet (corresponding to temperatures of about 185 to 270 ^{o}F, respectively) and, therefore, may have been buried sufficiently to permit petroleum generation.

Potential reservoir rocks in this play include sandstones, siltstones, and conglomerates of the Vaqueros and Topanga Formations and the San Onofre Breccia (fig. 106). Based on onshore wells and outcrops, the Vaqueros Formation consists of shallow-marine sandstone, siltstone, and conglomerate; the Topanga Formation consists of deep-marine turbidite sandstone, siltstone, conglomerate, breccia, and shale; and the San Onofre Breccia consists of conglomeratic breccia, conglomerate, and sandstones. The San Onofre Breccia exists in extremely lenticular bodies in coastal outcrops with coarse sandtones that were deposited in submarine fan channels. The medium- to coarse-grained sandstones within the San Onofre Breccia could be excellent reservoir rocks. Porosity and permeability should be preserved within these rocks due to the moderate depths of burial.

A number of small to large anticlines, fault traps, and subthrust traps within this play are evident from seismic mapping; most of these features exist along the Newport-Inglewood fault zone. Some potential for stratigraphic entrapment exists where strata pinch out along the western margin of the play.

EXPLORATION

The San Onofre Breccia was penetrated by one of the coreholes (Mobil San Clemente) drilled in the offshore part of the basin; however, no shows of hydrocarbons were encountered. The Vaqueros and Topanga Formations were not penetrated by either of the coreholes. Vaqueros strata are evident on seismic-reflection profiles and pinch out westerly across the basin.

The formations included in this play are productive in several areas of the onshore and offshore Los Angeles and Santa Barbara-Ventura basins. However, no hydrocarbons have been discovered in these formations in the onshore part of the Oceanside-Capistrano basin.

RESOURCE ESTIMATES

Undiscovered Conventionally Recoverable Resources

Estimates of undiscovered conventionally recoverable resources in the play have been developed using the subjective assessment method with a combination of play-specific and analog data. Select data used to develop the resource estimates are shown in appendix C.

The volume and number of prospects in the play were estimated from seismic mapping. Analog data from Vaqueros, Sespe, and Alegria producing zones in the offshore Santa Barbara-Ventura basin were used to estimate the net-pay thickness, oil recovery factor, and gas-to-oil ratio for this play.

As a result of this assessment, the play is estimated to contain 208 MMbbl of oil and 568 Bcf of associated gas (mean estimates). This volume of undiscovered conventionally recoverable resources may exist in as many as 74 pools with sizes ranging from approximately 60 Mbbl to 310 MMbbl of combined oil-equivalent resources (fig. 112). The low, mean, and high estimates of resources in the play are listed in table 36.

The majority of these pools and resources, or approximately 200 MMbbl of oil and 546 Bcf of associated gas, are expected to exist in the Federal offshore portion of the play. The remaining pools and resources, or approximately 8 MMbbl of oil and 22 Bcf of associated gas, are expected to exist in the State offshore portion of the play.

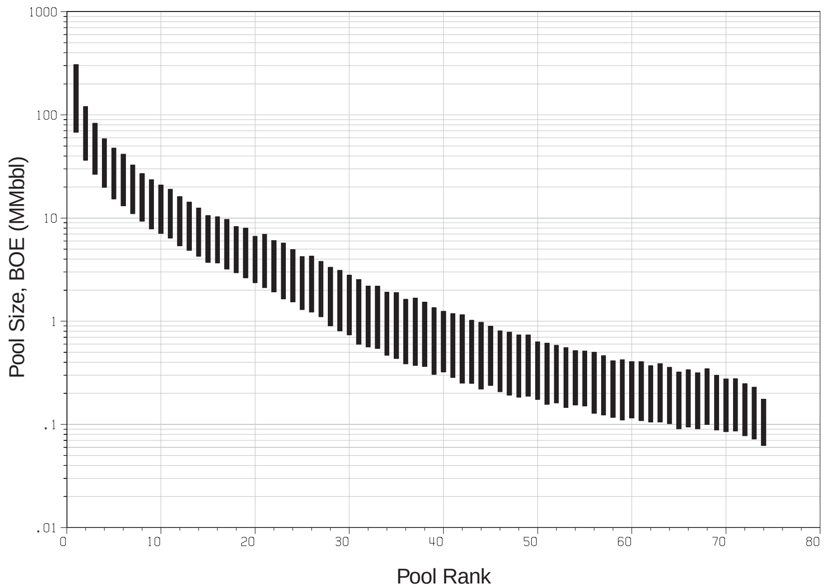


Figure 112. *Pool-size rank plot of estimated undiscovered conventionally recoverable resources of the Lower Miocene Sandstone play, Oceanside-Capistrano Basin assessment area. Sizes of undiscovered pools are shown by bars; the top and bottom of a bar represent the 25th- and 75th-percentile values of a probability distribution, respectively.*

Paleogene-Cretaceous Sandstone Play

Play Definition

The Paleogene-Cretaceous Sandstone play of the Oceanside-Capistrano Basin assessment area is an established play consisting of accumulations of oil and associated gas in Upper Cretaceous and Paleogene sandstones. The play exists onshore and offshore (in Federal and State waters) along the eastern margin of the basin (fig. 105). It encompasses an area of about 400 square miles. The depth to reservoir rocks in the play onshore ranges from about 2,000 to 5,000 feet below the surface; offshore, the depth to reservoir rocks ranges from about 8,000 to 10,500 feet below the seafloor.

Offshore strata included in this play are presumably equivalent to onshore strata of the Upper Cretaceous Williams Formation, Paleocene Silverado Formation, Eocene Santiago Formation, and Oligocene Sespe Formation (fig. 106). These strata outcrop onshore from San Clemente to La Jolla and have been penetrated by numerous exploratory wells in the Capistrano syncline. Oligocene strata are predicted to exist offshore based on extrapolation of onshore outcrop and well data southward using seismic-reflection profiles. The Cretaceous and Paleogene strata are depositionally restricted to the eastern area of the basin where they extend slightly west of the Newport-Inglewood fault zone.

Petroleum Geologic Characteristics

Potential petroleum source rocks for this play are Upper Cretaceous and Paleogene shales (fig. 106). Although the thermal history of these rocks should be sufficient to generate oil and gas, the volume of source rock may be lacking (the type and amount of organic matter are unknown); as a result, the amount of oil and gas generated from these rocks is expected to be small.

Potential reservoir rocks in this play include sandstones and conglomerates of the Williams, Silverado, Santiago, and Sespe Formations (fig. 106). Based on onshore wells and outcrops, the Williams Formation consists primarily of thin shallow-marine sandstone; the Silverado Formation consists of nonmarine sandstone and conglomerate; the Santiago Formation consists of marine sandstone, conglomerate, and mudstone; and the Sespe Formation consists of nonmarine sandstone, conglomerate, and mudstone. Sandstones of these units should have fair to good porosity and permeability, although the reservoirs are expected to be thin.

The dominant trap types in this play are small anticlinal folds and fault traps. Although seismic profiles have been used to determine the offshore extent of the play, the quality of the profiles in this deep section is very poor; therefore, the profiles are inconclusive for mapping structures and trends.

Exploration and Discovery Status

Two fields have been discovered in the onshore part of this play. Collectively, the San Clemente and Cristianitos Creek fields produced a very small quantity (less than 5 Mbbl) of high-gravity (45 to 54 °API) oil and gas from the Upper Cretaceous Williams Formation in the late 1950's. Both fields were considered to be subcommercial and have been abandoned.

Neither of the coreholes drilled in the offshore part of the basin penetrated rocks of this play.

Resource Estimates

Undiscovered Conventionally Recoverable Resources

Estimates of undiscovered conventionally recoverable resources in the play have been developed using the subjective assessment method with a combination of play-specific and analog data. Select data used to develop the resource estimates are shown in appendix C.

The volume and number of prospects in the play were estimated from seismic mapping. Analog data from Eocene and Oligocene producing zones in the offshore Santa Barbara-Ventura basin and the onshore Los Angeles and San Joaquin basins were used to estimate the net-pay thickness, oil recovery factor, and gas-to-oil ratio for this play.

As a result of this assessment, the play is estimated to contain 3 MMbbl of oil and 8 Bcf of associated gas (mean estimates). This volume of undiscovered conventionally recoverable resources may exist in as many as 27 pools with sizes ranging from approximately 40 Mbbl to 8 MMbbl of combined oil-equivalent resources (fig. 113). The low, mean, and high estimates of resources in the play are listed in table 36.

The majority of these pools and resources, or approximately 3 MMbbl of oil and 7 Bcf of associated gas, are expected to exist in the State offshore portion of the play. The remaining pools and resources, which are negligible, are expected to exist in the onshore and Federal offshore portions of the play.

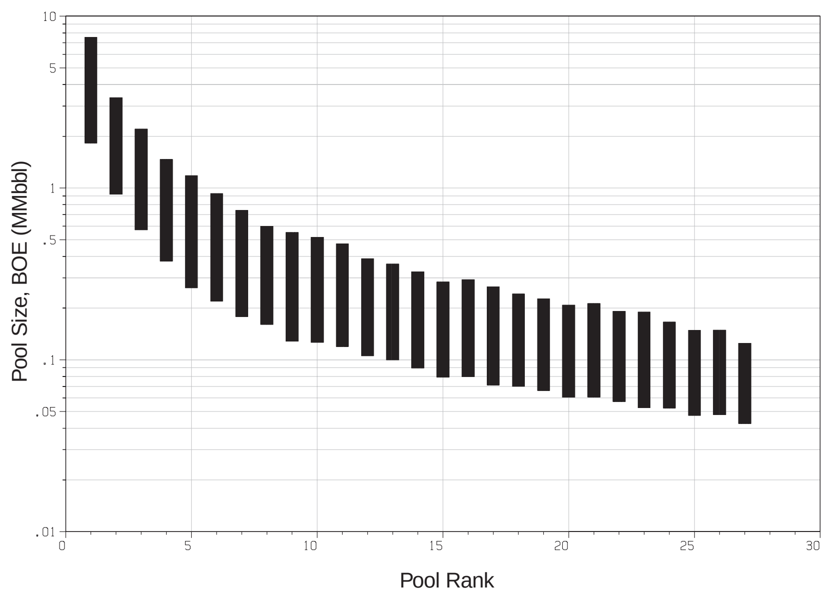


Figure 113. *Pool-size rank plot of estimated undiscovered conventionally recoverable resources of the Paleogene-Cretaceous Sandstone play, Oceanside-Capistrano Basin assessment area. Sizes of undiscovered pools are shown by bars; the top and bottom of a bar represent the 25th- and 75th-percentile values of a probability distribution, respectively.*

OUTER BORDERLAND PROVINCE

by Frank W. Victor

LOCATION

The Outer Borderland province is located offshore southern California from the Channel Islands (on the north) to the U.S.-Mexico maritime boundary (on the south). The province is bounded on the west by the approximate base of the continental slope; to the east, it is bounded by the Santa Cruz-Catalina ridge and the Thirtymile bank (fig. 114).

This Federal offshore assessment province encompasses several geologic basins and areas. Some of these areas contain appreciable sections of sedimentary rock and may have petroleum potential. These areas include the Santa Cruz basin, Santa Rosa area,

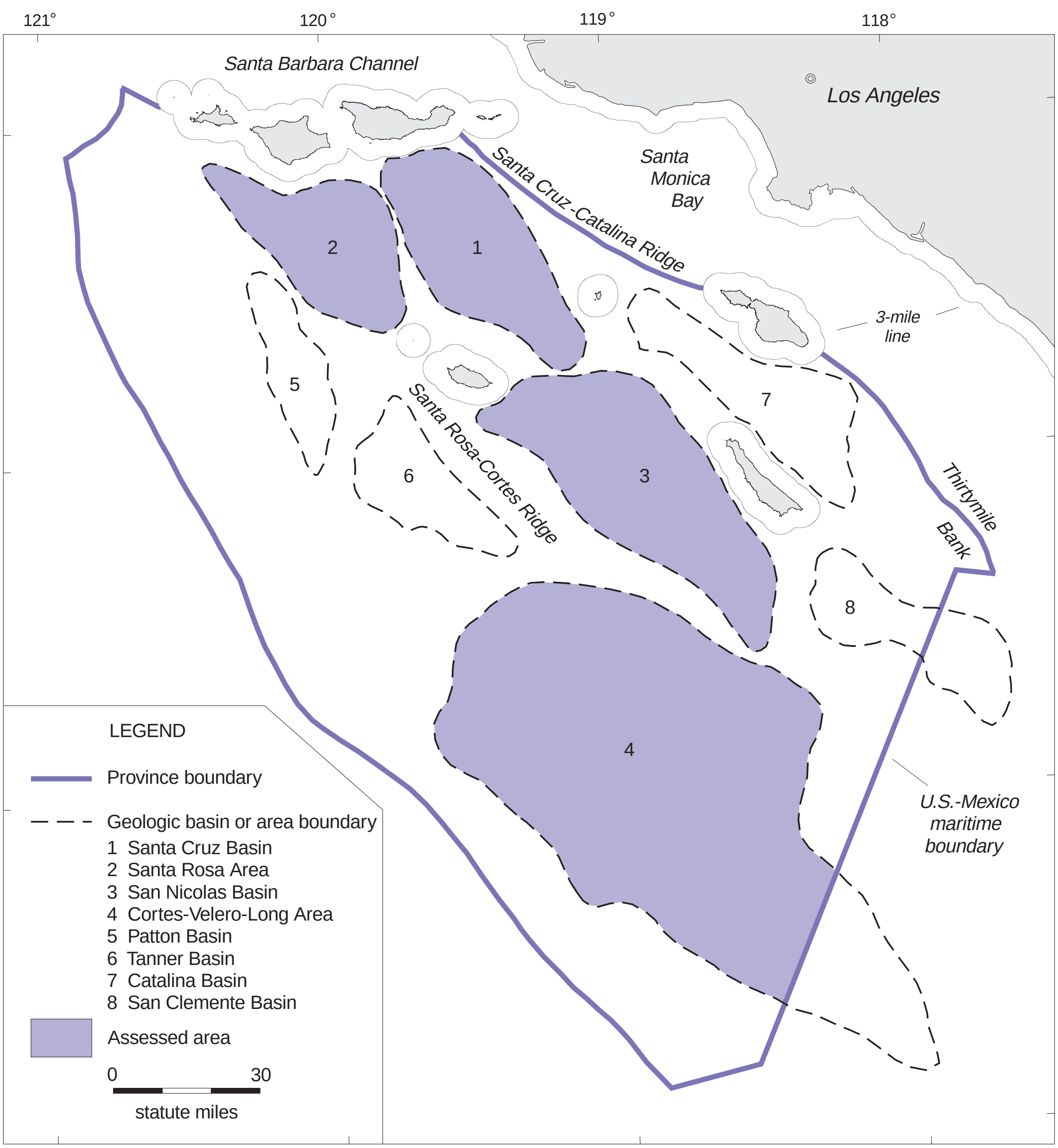


Figure 114. *Map of the Outer Borderland province showing geologic basins and areas, and assessed areas.*

San Nicolas basin, Cortes basin, Velero basin, and Long basin. The Santa Cruz basin and Santa Rosa area have been combined as a single assessment area due to the continuous extent of Paleogene and Cretaceous strata. Similarly, the Cortes, Velero, and Long basins have been combined as a single assessment area due to the nearly continuous extent of Paleogene strata and lack of definitive basin boundaries.

A number of the geologic basins and areas in the province lack an appreciable stratigraphic section and, therefore, probably lack sufficient petroleum source rock, thermal history, and reservoir rock; some of these areas are virtually devoid of traps. As a result, they are expected to have negligible petroleum potential and have not been formally assessed. These areas include the Patton basin, Tanner basin, Catalina basin, and San Clemente basin.

GEOLOGIC SETTING

Upper Cretaceous and Tertiary rocks are present in most of the geologic basins and areas in the province. Generally, these areas have been relatively "sediment starved" and contain much thinner Neogene stratigraphic sections than those in the Inner Borderland province.

Many of the basin geometries in this province formed during the Miocene as the result of extension and rotation of the continental borderland. The dominant structural trend in most of the basins is northwest-southeast. With the exception of the Santa Cruz and San Nicolas basins, in which late-stage compression has produced reverse faulting, most of the faults in the province are normal faults that developed in response to extension.

EXPLORATION

Although a number of seismic-reflection surveys have been recorded within the province, very limited exploratory drilling has taken place. A deep stratigraphic test well (OCS-CAL 75-70 No. 1) was drilled on Cortes bank in 1975 (Paul and others, 1976). In addition, nine exploratory oil and gas wells have been drilled from 1977 through 1983. They include one well south of Santa Rosa Island, one well on the Santa Cruz-Catalina ridge (northwest of Santa Barbara Island), and seven wells on Dall and Tanner banks (at the southern end of the Santa Rosa-Cortes ridge). Unfortunately, most of these wells are located in structurally uplifted areas and are of limited use in interpreting the nature of strata within the geologic basins and areas. No appreciable shows of hydrocarbons were encountered in the wells; however, weak indications of hydrocarbons (oil staining, minor fluorescence, and weak gas shows) were encountered in some of the wells.

RESOURCE ESTIMATES

Undiscovered Conventionally Recoverable Resources

Estimates of the total volume of undiscovered conventionally recoverable resources in the province have been developed by statistically aggregating the constituent assessment area estimates. As a result of this assessment, the total volume of undiscovered conventionally recoverable resources in the Outer Borderland province is estimated to be 1.40 Bbbl of oil and 2.79 Tcf of associated gas (mean estimates). The low, mean, and high estimates of resources in the province are listed in table 40 and illustrated in figure 115.

Undiscovered Economically Recoverable Resources

Estimates of the total volume of undiscovered conventionally recoverable resources in the province that may be economically recoverable under various economic scenarios have been developed by statistically aggregating the constituent assessment area estimates. As a result of this assessment, 62 MMbbl of oil and 104 Bcf of associated gas are estimated to be economically recoverable from the Outer Borderland province under economic conditions existing as of this assessment (i.e., the $18-per-barrel economic scenario) (table 41). Larger volumes of resources are expected to be economically recoverable under increasingly favorable economic conditions (fig. 116).

Total Resource Endowment

No accumulations of resources have been discovered in the province. Therefore, the aforementioned estimates of undiscovered conventionally recoverable resources compose the estimated total resource endowment of the province.

Table 40. *Estimates of undiscovered conventionally recoverable oil and gas resources in the Outer Borderland province as of January 1, 1995, by assessment area. All estimates are risked values. The low, mean, and high estimates correspond to the 95th-percentile, mean, and 5th-percentile values of a probability distribution, respectively. Percentile values are not additive; some total mean values may not equal the sum of the component values due to independent rounding.*

Assessment Area	Oil (Bbbl)			Gas (Tcf)			BOE (Bbbl)		
	Low	Mean	High	Low	Mean	High	Low	Mean	High
Santa Cruz-Santa Rosa Area	0	0.44	0.93	0	0.78	1.85	0	0.58	1.24
San Nicolas Basin	0	0.55	1.18	0	0.91	2.42	0	0.71	1.58
Cortes-Velero-Long Area	0	0.41	1.20	0	1.10	3.49	0	0.61	1.80
Total Province	*0.63*	*1.40*	*2.56*	*0.98*	*2.79*	*5.89*	*0.82*	*1.89*	*3.56*

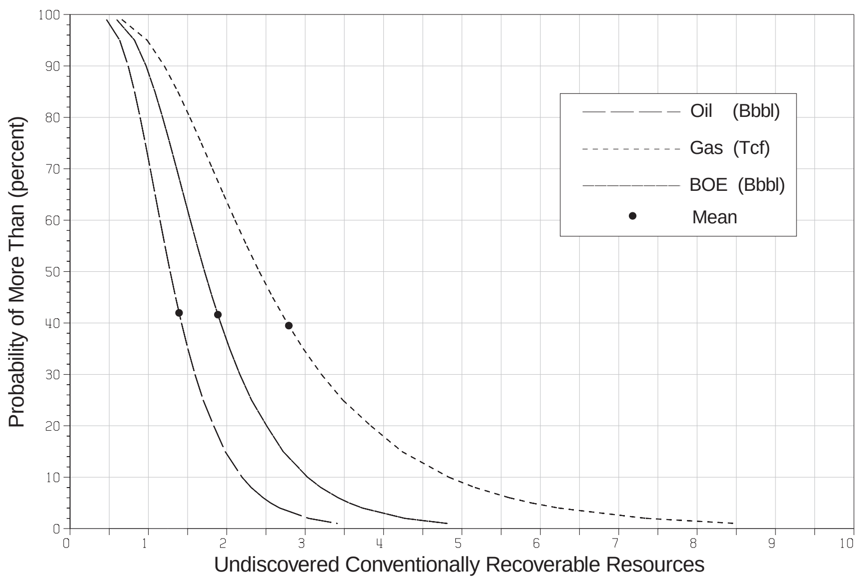


Figure 115. *Cumulative probability plot of estimated undiscovered conventionally recoverable resources of the Outer Borderland province.*

Acknowledgments

The extensive work of Jack Vedder was an important source of information for this assessment of the Outer Borderland province. Acknowledgment is also due to James Galloway, Bill Kou, Robert MacDonald, and Ken Piper who performed seismic interpretative mapping in various areas of the province.

Additional References

Crouch and Suppe, 1993
McLean and Wiley, 1987
Vedder, 1987

Table 41. *Estimates of undiscovered economically recoverable oil and gas resources in the Outer Borderland province as of January 1, 1995 for three economic scenarios, by assessment area. All estimates are risked mean values. The $18-per-barrel scenario is based on prices of $18 per bbl of oil and $2.11 per Mcf of gas; the $25-per-barrel scenario is based on prices of $25 per bbl of oil and $2.94 per Mcf of gas; the $50-per-barrel scenario is based on prices of $50 per barrel of oil and $5.87 per Mcf of gas. Some total values may not equal the sum of the component values due to independent rounding.*

Assessment Area	$18-per-barrel Scenario			$25-per-barrel Scenario			$50-per-barrel Scenario		
	Oil (Bbbl)	Gas (Tcf)	BOE (Bbbl)	Oil (Bbbl)	Gas (Tcf)	BOE (Bbbl)	Oil (Bbbl)	Gas (Tcf)	BOE (Bbbl)
Santa Cruz-Santa Rosa Area	<0.01	0.01	0.01	0.10	0.18	0.13	0.33	0.58	0.43
San Nicolas Basin	0.06	0.09	0.07	0.20	0.34	0.26	0.40	0.67	0.52
Cortes-Velero-Long Area	0	0	0	<0.01	<0.01	<0.01	0.21	0.57	0.31
Total Province	*0.06*	*0.10*	*0.08*	*0.30*	*0.52*	*0.40*	*0.94*	*1.83*	*1.27*

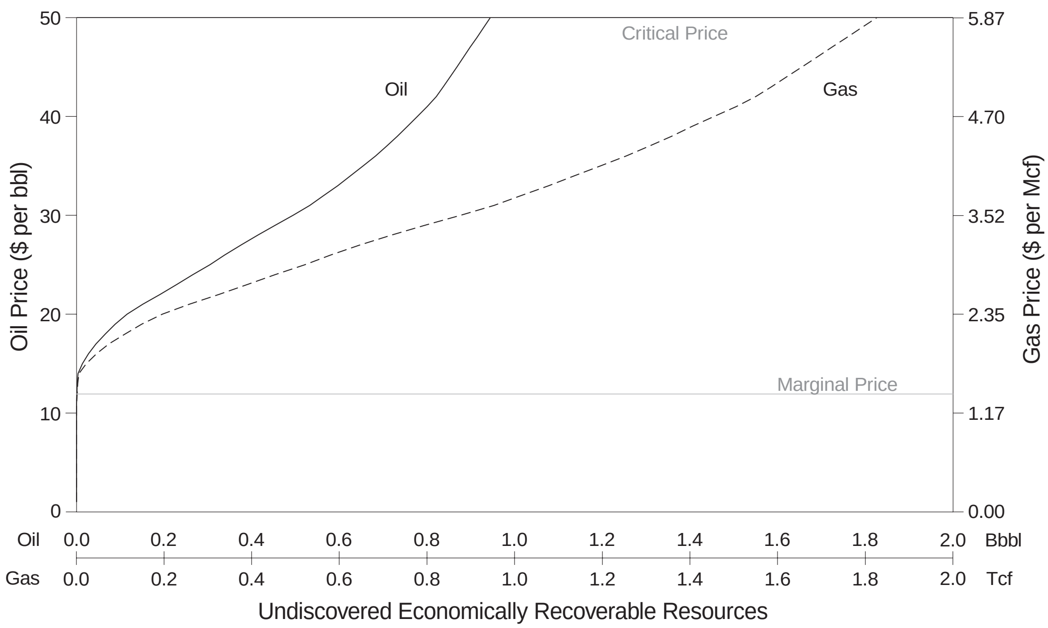


Figure 116. *Price-supply plot of estimated undiscovered economically recoverable resources of the Outer Borderland province.*

SANTA CRUZ-SANTA ROSA AREA

by Frank W. Victor

Location

The Santa Cruz-Santa Rosa assessment area occupies the northern portion of the Outer Borderland province (fig. 114). The assessment area comprises two geologic subareas, the Santa Cruz basin and the Santa Rosa area. These areas have been combined as a single assessment area due to the continuous extent of Paleogene and Cretaceous strata.

The Santa Cruz basin is located immediately south of Santa Cruz Island; it is bounded on the east by the Santa Cruz-Catalina ridge and on the west by an unnamed paleohigh that merges with the Santa Rosa-Cortes ridge to the south (fig. 117). This northwest-trending basin extends approximately 55 miles in length and averages 20 miles in width. It encompasses an area of approximately 1,000 square miles. Water depth within the basin averages about 3,000 feet.

The Santa Rosa area is located south of Santa Rosa Island. The area extends approximately 30 miles west from the Santa Cruz basin and extends south to Begg Rock (fig. 117). It is approximately 50 miles long and from 5 to 25 miles wide and encompasses an area of approximately 900 square miles. Water depth within the area ranges from 500 to 3,500 feet.

Geologic Setting

The Santa Cruz basin is an elongate, northwest-trending basin, which contains up to approximately 9,000 feet of Upper Cretaceous through Quaternary strata[16] (fig. 118). The basin is asymmetrical with the depocenter located in the eastern half of the basin. Post-Miocene compression, primarily from the west, has created a number of asymmetrical, reverse-fault-bounded anticlines in the eastern part of the basin. These structures are evident on seismic-reflection

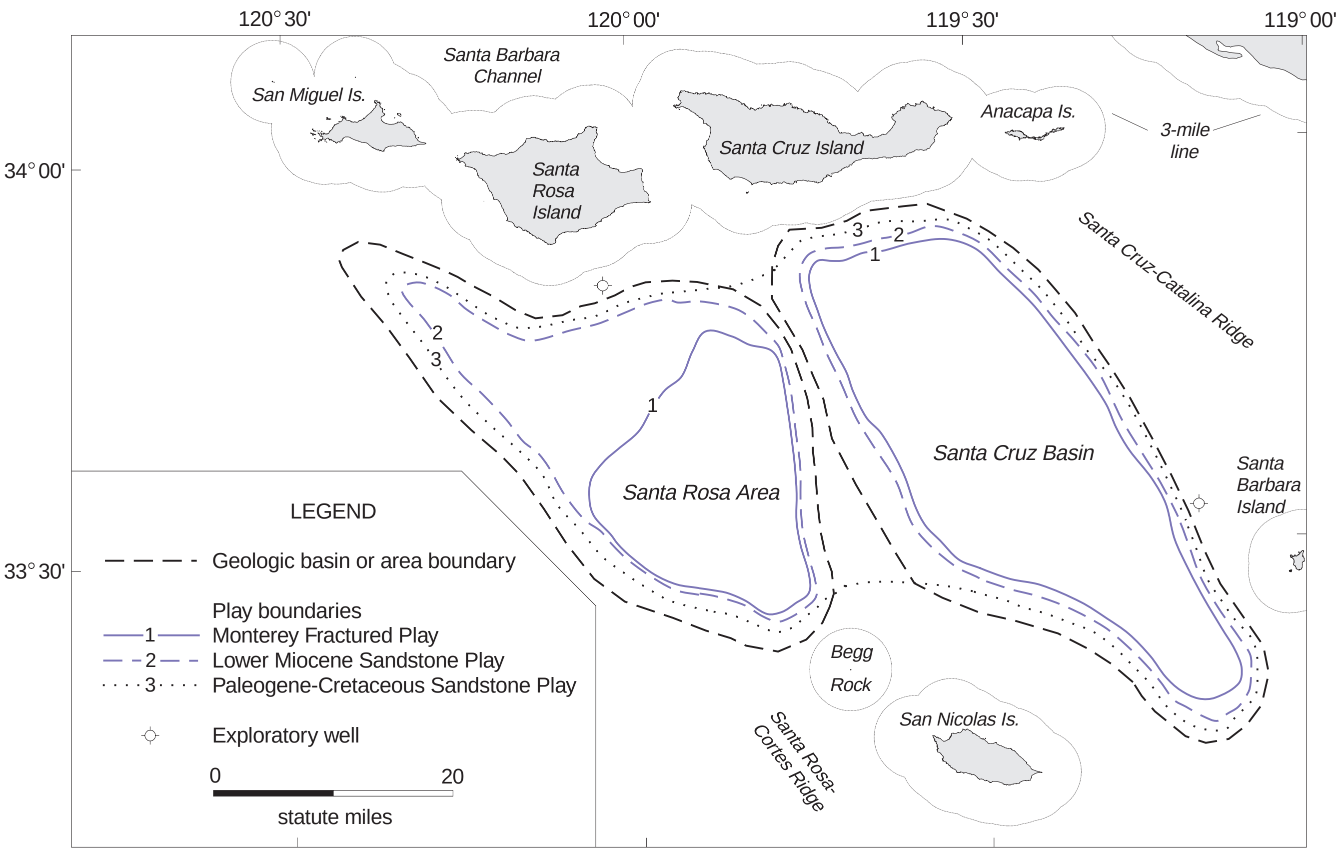


Figure 117. *Map of the Santa Cruz-Santa Rosa assessment area showing the geologic basin and area, petroleum geologic plays, and wells.*

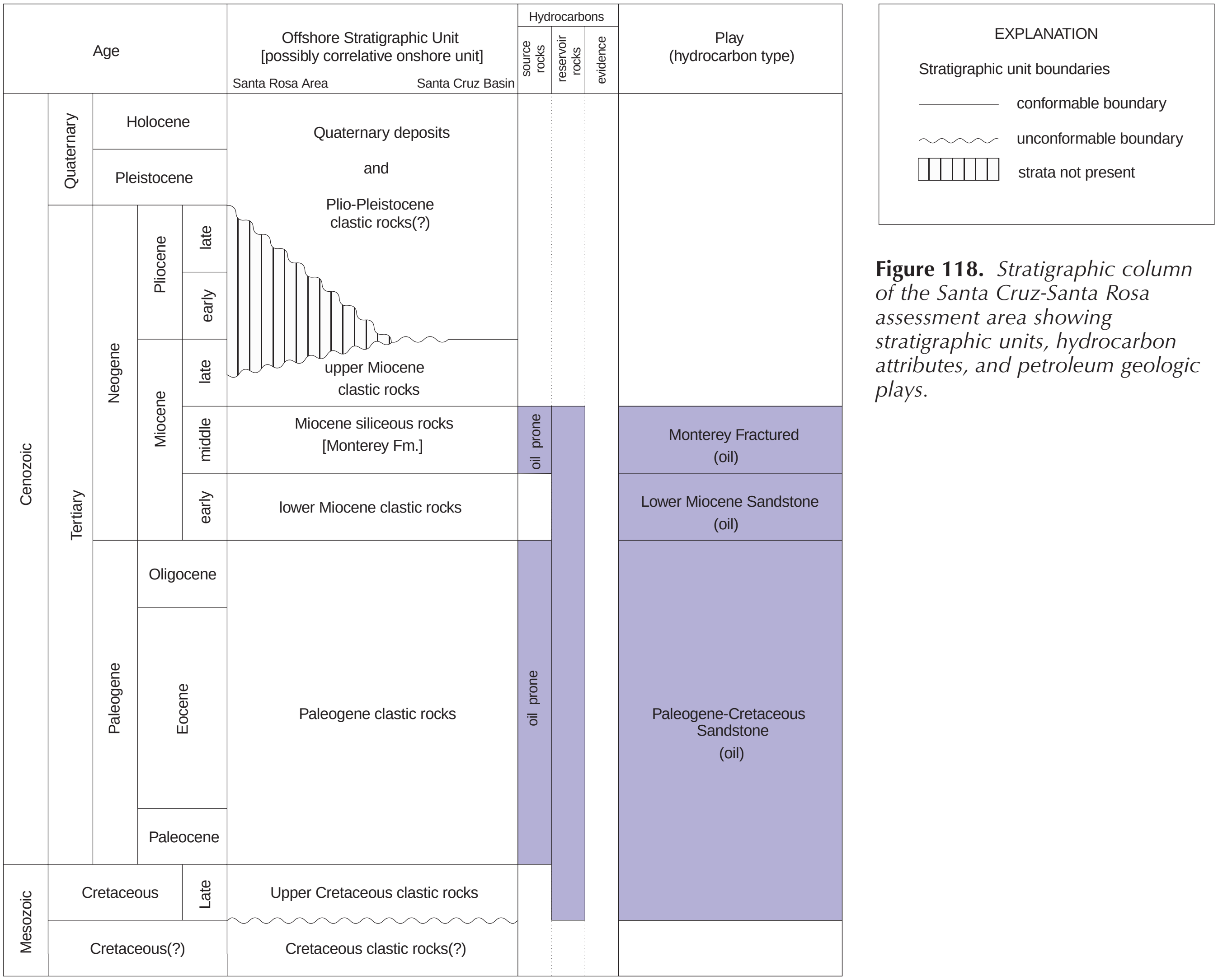


Figure 118. *Stratigraphic column of the Santa Cruz-Santa Rosa assessment area showing stratigraphic units, hydrocarbon attributes, and petroleum geologic plays.*

profiles and are numerous and large enough to trap significant quantities of oil and gas.

The Santa Rosa area is a broad depositional area (i.e., not a confined basin), which contains up to approximately 6,000 feet of Upper Cretaceous, Paleogene, and Miocene clastic strata[16] (fig. 118). Upper Miocene and younger strata are very thin or nonexistent within the area due to extremely low depositional rates and uplift and erosion. A number of relatively small, low-relief structures, which may contain oil and gas, exist in the area.

[16] Descriptions of the age and lithology of stratigraphic units in the Santa Cruz-Santa Rosa assessment area are based on inference (rather than direct evidence) because no wells have been drilled within the area. Individual stratigraphic units are inferred to exist based on seismic-stratigraphic extrapolation of units that have been penetrated in wells in the Outer Borderland province (see this report); analog data from these wells have been used in the assessment of plays in the Santa Cruz-Santa Rosa assessment area.

Exploration

No exploratory wells have been drilled within the Santa Cruz-Santa Rosa assessment area; one well (OCS-P 0289 #1) was drilled immediately east of the Santa Cruz basin, and another well (OCS-P 0245 #1) was drilled immediately north of the Santa Rosa area. In addition, a number of moderate- to high-quality seismic-reflection surveys have been recorded in both areas.

The adjacent wells penetrated lower Miocene, Paleogene, and Cretaceous strata. Most middle Miocene and younger strata have been eroded from the uplifted areas in which the wells were drilled; however, middle Miocene and younger strata are present in the Santa Cruz-Santa Rosa assessment

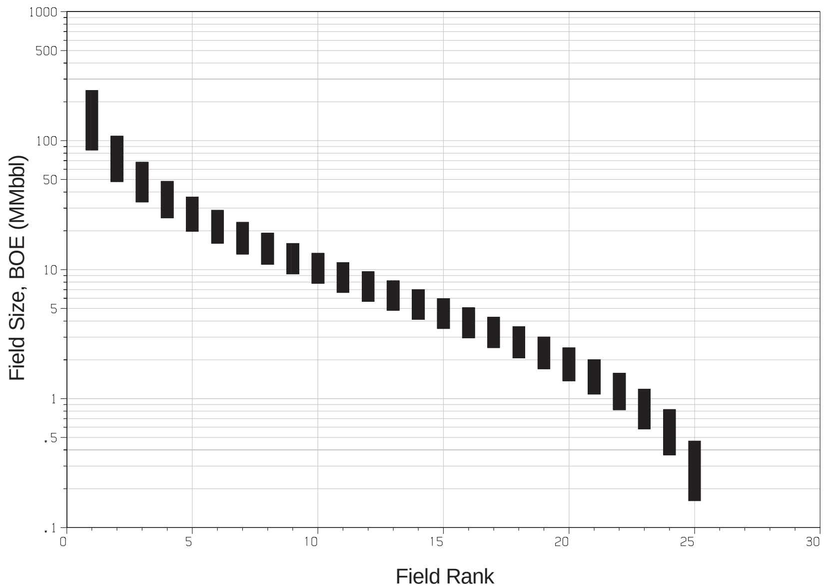


Figure 119. *Field-size rank plot of estimated undiscovered conventionally recoverable resources of the Santa Cruz-Santa Rosa assessment area. Sizes of undiscovered fields are shown by bars; the top and bottom of a bar represent the 25th- and 75th-percentile value of a probability distribution, respectively.*

area. The approximate geologic age of these undrilled stratigraphic units is estimated based on seismic-stratigraphic extrapolation of older strata penetrated by the wells.

No appreciable shows of oil or gas were encountered in either of the adjacent wells; however, weak indications of gas were encountered in one well.

PLAYS

Five petroleum geologic plays have been defined in the Santa Cruz-Santa Rosa assessment area (fig. 118). The plays were defined on the basis of reservoir rock stratigraphy. The plays (and corresponding reservoir rocks) consist of two Monterey Fractured plays (fractured siliceous rocks), two Lower Miocene Sandstone plays (clastic rocks), and one Paleogene-Cretaceous Sandstone play (clastic rocks).

The Monterey Fractured and Lower Miocene Sandstone plays are confined to the Santa Cruz basin proper and the Santa Rosa area proper and have been individually assessed in each area. The Paleogene-Cretaceous Sandstone play exists within and between both areas and has been assessed as a single play.

All of the plays in the Santa Cruz-Santa Rosa assessment area are considered to be conceptual plays based on the absence of directly detected hydrocarbons within the play areas. This is presumed to be a consequence of the location and limited number of the wells rather than a lack of geological conditions conducive to hydrocarbon accumulation.

RESOURCE ESTIMATES

Undiscovered Conventionally Recoverable Resources

Play-specific estimates of undiscovered conventionally recoverable resources have been developed using the subjective assessment method, and these estimates have been statistically aggregated to estimate the total volume of resources in the assessment area. Select data used to develop the resource estimates are shown in appendix C.

As a result of this assessment, the total volume of undiscovered conventionally recoverable resources in the Santa Cruz-Santa Rosa assessment area is estimated to be 438 MMbbl of oil and 782 Bcf of associated gas (mean estimates). This volume may exist in 25 fields with sizes ranging from approximately 160 Mbbl to 245 MMbbl of combined oil-equivalent resources (fig. 119). The majority of these resources (64 percent on a combined oil-equivalence basis) are estimated to exist in the Santa Cruz basin. The low, mean, and high estimates of resources in the assessment area are listed in table 42 and illustrated in figure 120.

Undiscovered Economically Recoverable Resources

Estimates of undiscovered conventionally recoverable resources in the assessment area that may be economically recoverable under various economic scenarios have been developed using the economic assessment method. Select data used to develop the resource estimates are shown in appendix D.

Table 42. *Estimates of undiscovered conventionally recoverable oil and gas resources in the Santa Cruz-Santa Rosa assessment area as of January 1, 1995, by play. All estimates are risked values. The low, mean, and high estimates correspond to the 95th-percentile, mean, and 5th-percentile values of a probability distribution, respectively. Percentile values are not additive; some total mean values may not equal the sum of the component values due to independent rounding.*

Play	Oil (MMbbl)			Gas (Bcf)			BOE (MMbbl)		
	Low	Mean	High	Low	Mean	High	Low	Mean	High
Santa Cruz Basin									
Monterey Fractured	0	194	445	0	227	555	0	234	540
Lower Miocene Sandstone	0	92	271	0	231	802	0	133	407
Santa Rosa Area									
Monterey Fractured	0	31	110	0	39	148	0	38	136
Lower Miocene Sandstone	0	30	132	0	79	440	0	44	213
Santa Cruz-Santa Rosa Area									
Paleogene-Cretaceous Sandstone	0	92	389	0	207	985	0	129	563
Total Assessment Area	*0*	*438*	*926*	*0*	*782*	*1,852*	*0*	*577*	*1,237*

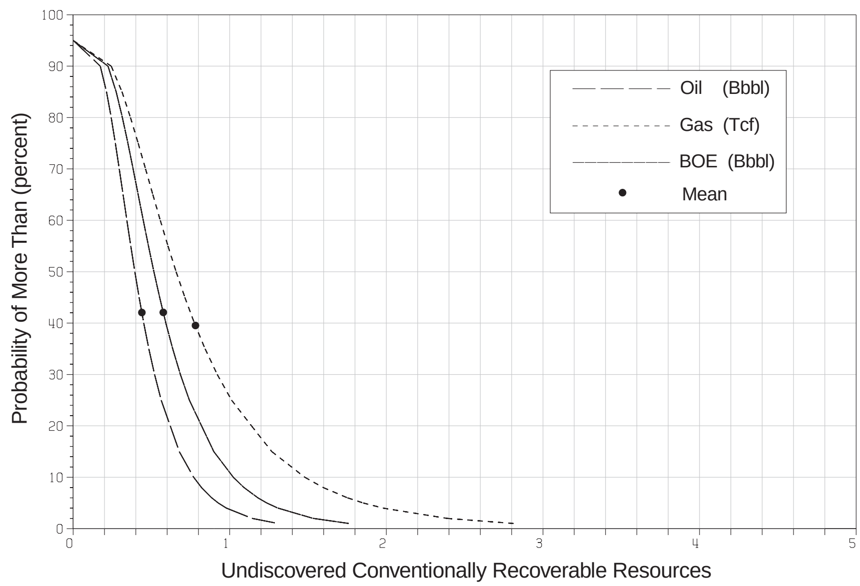


Figure 120. *Cumulative probability plot of estimated undiscovered conventionally recoverable resources of the Santa Cruz-Santa Rosa assessment area.*

As a result of this assessment, 7 MMbbl of oil and 13 Bcf of associated gas are estimated to be economically recoverable from the Santa Cruz-Santa Rosa assessment area under economic conditions existing as of this assessment (i.e., the $18-per-barrel economic scenario) (table 43). Larger volumes of resources are expected to be economically recoverable under increasingly favorable economic conditions (fig. 121).

Total Resource Endowment

No accumulations of resources have been discovered in the assessment area. Therefore, the aforementioned estimates of undiscovered conventionally recoverable resources compose the estimated total resource endowment of the area.

Table 43. *Estimates of undiscovered economically recoverable oil and gas resources in the Santa Cruz-Santa Rosa assessment area as of January 1, 1995, by economic scenario. All estimates are risked mean values. The $18-per-barrel scenario is based on prices of $18 per bbl of oil and $2.11 per Mcf of gas; the $25-per-barrel scenario is based on prices of $25 per bbl of oil and $2.94 per Mcf of gas; the $50-per-barrel scenario is based on prices of $50 per barrel of oil and $5.87 per Mcf of gas.*

Economic Scenario	Oil (MMbbl)	Gas (Bcf)	BOE (MMbbl)
$18 per barrel	7	13	10
$25 per barrel	98	176	130
$50 per barrel	327	584	431

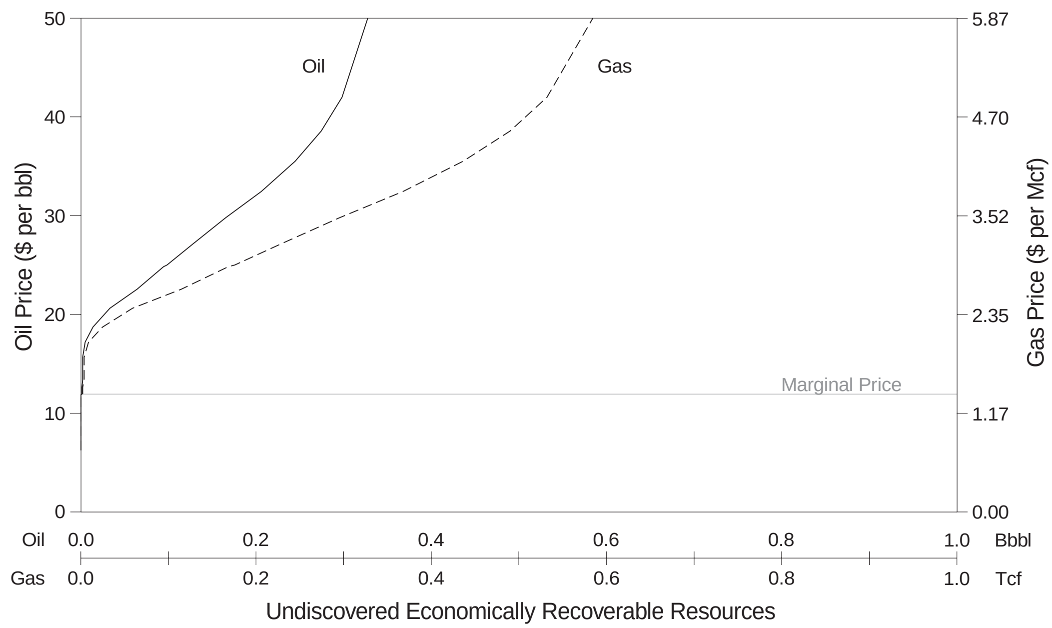


Figure 121. *Price-supply plot of estimated undiscovered economically recoverable resources of the Santa Cruz-Santa Rosa assessment area.*

MONTEREY FRACTURED PLAYS

PLAY DEFINITION

The Monterey Fractured plays of the Santa Cruz basin and the Santa Rosa area are conceptual plays consisting of accumulations of oil and associated gas in middle Miocene fractured siliceous rocks of the Monterey Formation. Because the plays are confined to the Santa Cruz basin proper and the Santa Rosa area proper (fig. 117), they have been individually assessed in each area.

The play exists over most of the Santa Cruz basin where it encompasses an area of about 700 square miles. The depth to reservoir rocks of the play in this basin ranges from 2,000 to 6,000 feet below the seafloor.

In the Santa Rosa area, the play is limited to the southeast part of the area, due to the limited original depositional extent and uplift and erosion of the Monterey Formation. The play encompasses an area of about 300 square miles; the depth to reservoir rocks of the play in this area ranges from 1,000 to 4,000 feet below the seafloor.

PETROLEUM GEOLOGIC CHARACTERISTICS

The Monterey Formation is considered to be both petroleum source rock and reservoir rock for these plays (fig. 118) by analogy with Monterey rocks in the offshore Santa Barbara-Ventura and Santa Maria basins and the onshore San Joaquin basin. The type and amount of organic matter within Monterey rocks of the Santa Cruz basin and the Santa Rosa area are unknown; however, Monterey rocks in other California coastal basins are rich in organic matter, and similar rocks are presumed to exist in the Santa Cruz basin and the Santa Rosa area. The depth at which thermal maturation may have occurred in the Santa Cruz basin and the Santa Rosa area is also unknown. Monterey rocks are buried no more than 4,000 feet in the Santa Rosa area and may not have been buried sufficiently to permit petroleum generation. Due to the moderately shallow depths of the potential reservoir rocks, the oil in these plays is predicted to be of moderate (less than 30 °API) gravity.

Potential reservoir rocks in these plays include middle Miocene fractured, siliceous and calcareous shales and cherts, and perhaps some basal clastic rocks of the Monterey Formation (fig. 118). Seismic profiles suggest that the Monterey section is thin in both the Santa Cruz basin and the Santa Rosa area; the thickness of these rocks is estimated to range from 300 to 1,000 feet. Diagenetic alteration, compression, and folding may have enhanced fracturing of the shales and cherts in the Santa Cruz basin. Monterey strata in these areas are expected to have reservoir characteristics similar to those in the offshore Santa Barbara-Ventura and Santa Maria basins.

The dominant trap type in these plays is expected to be the anticline.

EXPLORATION

Neither of the exploratory wells adjacent to the Santa Cruz-Santa Rosa assessment area penetrated rocks similar to those included in these plays. Middle Miocene strata presumably equivalent to the Monterey Formation are inferred to exist in both areas based on seismic-stratigraphic extrapolation of older strata from the adjacent wells and from the wells on Dall, Tanner, and Cortes banks.

RESOURCE ESTIMATES

Undiscovered Conventionally Recoverable Resources

Estimates of undiscovered conventionally recoverable resources in each play have been developed using the subjective assessment method with a combination of play-specific and analog data. Select data used to develop the resource estimates are shown in appendix C.

The area and number of prospects in each play were estimated from seismic mapping. Conservatively reduced analog data from Monterey producing zones in the offshore Santa Barbara-Ventura and Santa Maria basins were used to estimate the oil recovery factor and gas-to-oil ratio for both plays.

As a result of this assessment, the play in the Santa Cruz basin is estimated to contain 194 MMbbl of oil and 227 Bcf of associated gas (mean estimates). This volume of undiscovered conventionally recoverable resources may exist in as many as 46 pools with sizes ranging from approximately 230 Mbbl to 180 MMbbl of combined oil-equivalent resources (fig. 122). The low, mean, and high estimates of resources in the play are listed in table 42.

The play in the Santa Rosa area is estimated to contain 31 MMbbl of oil and 39 Bcf of associated gas

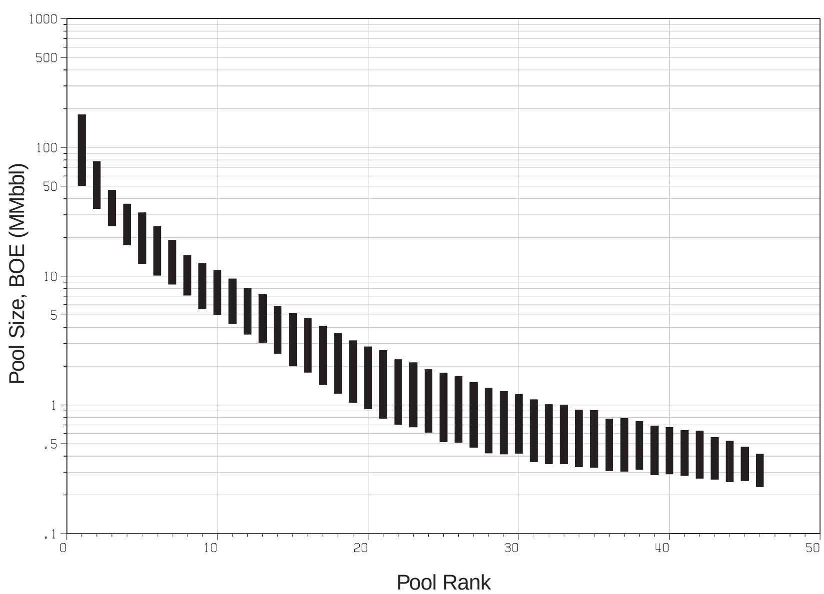


Figure 122. *Pool-size rank plot of estimated undiscovered conventionally recoverable resources of the Monterey Fractured play, Santa Cruz Basin subarea of the Santa Cruz-Santa Rosa assessment area. Sizes of undiscovered pools are shown by bars; the top and bottom of a bar represent the 25th- and 75th-percentile values of a probability distribution, respectively.*

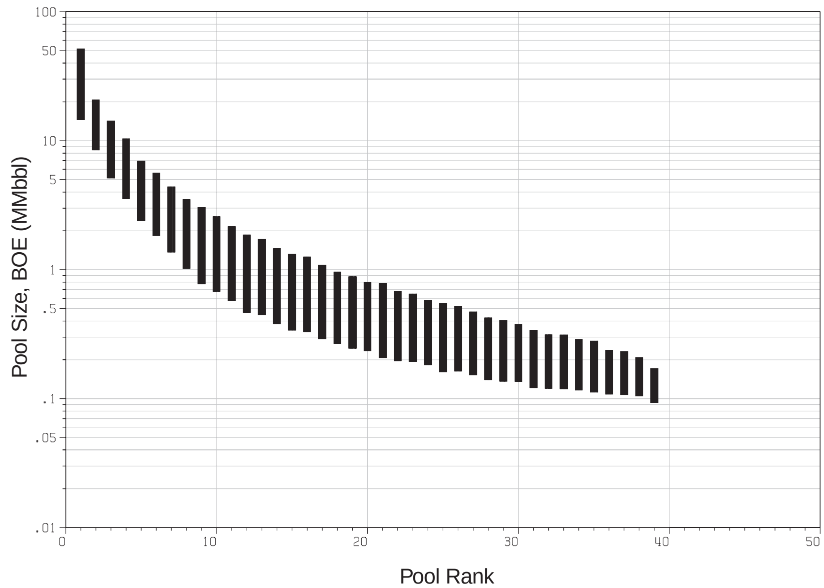


Figure 123. *Pool-size rank plot of estimated undiscovered conventionally recoverable resources of the Monterey Fractured play, Santa Rosa subarea of the Santa Cruz-Santa Rosa assessment area. Sizes of undiscovered pools are shown by bars; the top and bottom of a bar represent the 25th- and 75th-percentile values of a probability distribution, respectively.*

(mean estimates). This volume of undiscovered conventionally recoverable resources may exist in as many as 39 pools with sizes ranging from approximately 95 Mbbl to 50 MMbbl of combined oil-equivalent resources (fig. 123). The low, mean, and high estimates of resources in the play are listed in table 42.

Lower Miocene Sandstone Plays

Play Definition

The Lower Miocene Sandstone plays of the Santa Cruz basin and the Santa Rosa area are conceptual plays consisting of accumulations of oil and associated gas in lower Miocene clastic rocks. Because the plays are confined to the Santa Cruz basin proper and the Santa Rosa area proper, they have been individually assessed in each area.

The play exists over most of the Santa Cruz basin (fig. 117) where it encompasses an area of about 750 square miles. The depth to reservoir rocks in the play in this basin ranges from 3,000 to 6,500 feet below the seafloor.

The play also exists over most of the Santa Rosa area (fig. 117) where it encompasses an area of about 750 square miles. The depth to reservoir rocks in the play in this area ranges from 2,000 to 4,500 feet below the seafloor.

Petroleum Geologic Characteristics

The primary potential petroleum source rocks for these plays are Paleogene mudstones and shales (fig. 118). Oligocene and Eocene rocks of adequate to excellent source quality were penetrated by the deep stratigraphic test well (OCS-CAL 75-70 No. 1) on Cortes bank. The total organic carbon content of samples from this well is 3.3 to 4.3 weight percent in Oligocene rocks and 0.4 to 2.7 weight percent in Eocene rocks (Vedder, 1987). The geothermal gradient in this area is unknown; however, if a moderate (1.8 to 2.0 °F per 100 feet) geothermal gradient is assumed to have existed, petroleum generation may have occurred in these rocks under current burial conditions. Potential Paleogene source rocks are thin in the area, and the volume of generated oil and gas may therefore be small. Rocks of the Monterey Formation may be a secondary source of petroleum for reservoir rocks in the upper part of these plays.

Potential reservoir rocks in these plays are lower Miocene sandstones (fig. 118). Lower Miocene strata penetrated in the wells adjacent to the area

(OCS-P 0245 #1, OCS-P 0289 #1), and the wells on Dall, Tanner, and Cortes banks are described as porous and fine- to medium-grained sandstones with log-derived porosities ranging from 23 to 35 percent and with good permeability. Similar rocks of potentially good to excellent reservoir quality are presumed to exist in the Santa Cruz basin and the Santa Rosa area. Based on seismic mapping, rocks inferred to be of early Miocene age are areally extensive throughout the Santa Cruz basin and the Santa Rosa area; this stratigraphic unit has an average thickness of about 400 feet and a maximum thickness estimated to be 2,000 feet.

The dominant trap types in these plays are small to moderate anticlinal folds and associated reverse-fault traps.

EXPLORATION

Both of the exploratory wells adjacent to the Santa Cruz-Santa Rosa assessment area and most of the wells on Dall, Tanner, and Cortes banks penetrated rocks similar to those included in these plays; analog data from these wells have been used in the assessment of both plays.

No appreciable shows of hydrocarbons were encountered in any of the wells; however, weak indications of hydrocarbons (oil staining, minor fluorescence, and weak gas shows) were encountered in lower Miocene and other rocks in some of the wells.

RESOURCE ESTIMATES

Undiscovered Conventionally Recoverable Resources

Estimates of undiscovered conventionally recoverable resources in each play have been developed using the subjective assessment method with a combination of play-specific and analog data. Select data used to develop the resource estimates are shown in appendix C.

The area and number of prospects in each play were estimated from seismic mapping. Conservatively reduced analog data from Vaqueros, Sespe, and Alegria producing zones in the offshore Santa Barbara-Ventura basin were used to estimate the net-pay thickness, oil recovery factor, and gas-to-oil ratio for both plays.

As a result of this assessment, the play in the Santa Cruz basin is estimated to contain 92 MMbbl of oil and 231 Bcf of associated gas (mean estimates). This volume of undiscovered conventionally recoverable resources may exist in as many as 46 pools with sizes ranging from approximately 90 Mbbl to 105 MMbbl of combined oil-equivalent resources (fig. 124). The low, mean, and high estimates of resources in the play are listed in table 42.

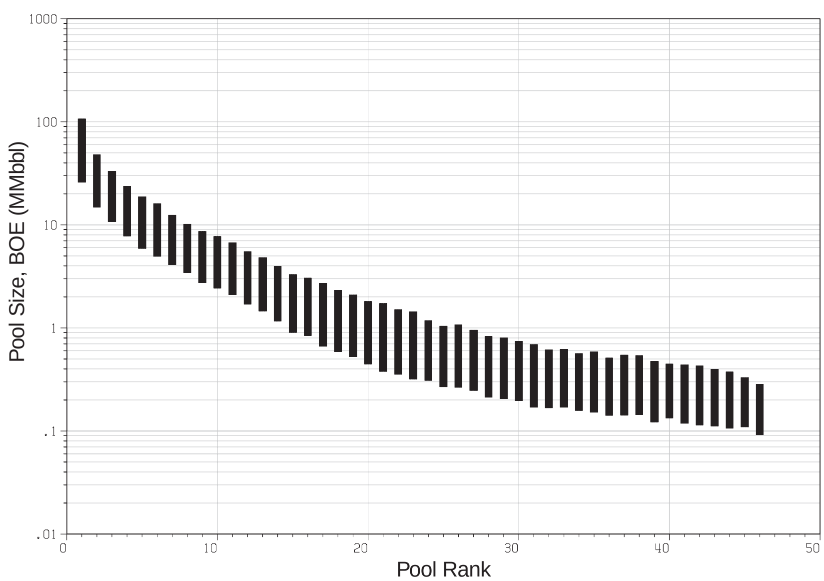


Figure 124. *Pool-size rank plot of estimated undiscovered conventionally recoverable resources of the Lower Miocene Sandstone play, Santa Cruz Basin subarea of the Santa Cruz-Santa Rosa assessment area. Sizes of undiscovered pools are shown by bars; the top and bottom of a bar represent the 25th- and 75th-percentile values of a probability distribution, respectively.*

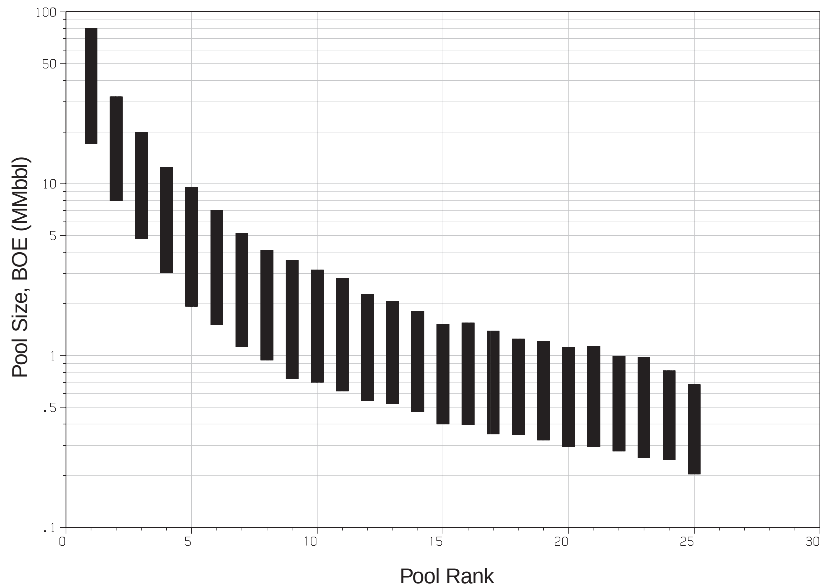


Figure 125. *Pool-size rank plot of estimated undiscovered conventionally recoverable resources of the Lower Miocene Sandstone play, Santa Rosa subarea of the Santa Cruz-Santa Rosa assessment area. Sizes of undiscovered pools are shown by bars; the top and bottom of a bar represent the 25th- and 75th-percentile values of a probability distribution, respectively.*

The play in the Santa Rosa area is estimated to contain 30 MMbbl of oil and 79 Bcf of associated gas (mean estimates). This volume of undiscovered conventionally recoverable resources may exist in as many as 25 pools with sizes ranging from approximately 205 Mbbl to 80 MMbbl of combined oil-equivalent resources (fig. 125). The low, mean, and high estimates of resources in the play are listed in table 42.

PALEOGENE-CRETACEOUS SANDSTONE PLAY

PLAY DEFINITION

The Paleogene-Cretaceous Sandstone play of the Santa Cruz-Santa Rosa assessment area is a conceptual play consisting of accumulations of oil and associated gas in Upper Cretaceous and Paleogene clastic rocks. This play exists within and between the Santa Cruz basin and the Santa Rosa area (fig. 117) and encompasses an area of about 2,000 square miles. The depth to reservoir rocks in the play ranges from 6,500 to 9,000 feet below the seafloor in the Santa Cruz basin and from 4,000 to 8,000 feet below the seafloor in the Santa Rosa area.

PETROLEUM GEOLOGIC CHARACTERISTICS

The primary potential petroleum source rocks for this play are Paleogene mudstones and shales (fig. 118). Oligocene and Eocene rocks of adequate to excellent source quality were penetrated by the deep stratigraphic test well (OCS-CAL 75-70 No. 1) on Cortes bank. The total organic carbon content of samples from this well is 3.3 to 4.3 weight percent in Oligocene rocks and 0.4 to 2.7 weight percent in Eocene rocks; Upper Cretaceous shales containing 0.4 to 0.6 percent total organic carbon are not considered to be potential source rocks (Vedder, 1987). The geothermal gradient in this area is unknown; however, if a moderate (1.8 to 2.0 °F per 100 feet) geothermal gradient is assumed to have existed, petroleum generation may have occurred in these rocks under current burial conditions. However, potential source rocks are thin in the area, and the volume of generated oil and gas may therefore be small.

Potential reservoir rocks in this play are Paleogene and Cretaceous sandstones (fig. 118). Paleogene strata in the wells on Dall, Tanner, and Cortes banks are described as porous and fine- to coarse-grained sandstones; log-derived porosities range from 23 to 30 percent in Oligocene samples, from 10 to 25 percent in Eocene samples, and from 6 to 14 percent in Upper Cretaceous samples. The proportion of sandstone within the total section is

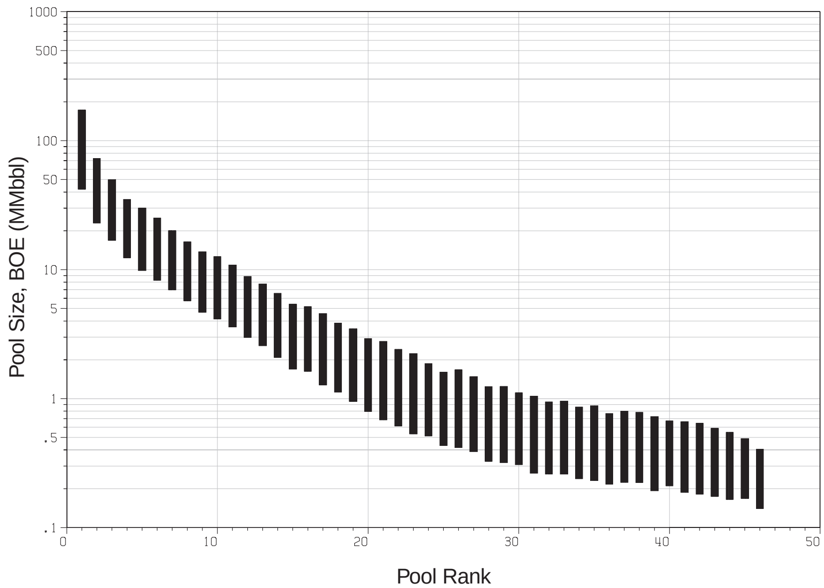


Figure 126. *Pool-size rank plot of estimated undiscovered conventionally recoverable resources of the Paleogene-Cretaceous Sandstone play, Santa Cruz-Santa Rosa assessment area. Sizes of undiscovered pools are shown by bars; the top and bottom of a bar represent the 25th- and 75th-percentile values of a probability distribution, respectively.*

quite high; on average, sandstone composes approximately 50 percent of the total Paleogene section. Similar rocks of potentially good to excellent reservoir quality are presumed to exist in the Santa Cruz basin and the Santa Rosa assessment area. Based on seismic mapping and well correlations, rocks inferred to be of Paleogene and Cretaceous age are areally extensive throughout the Santa Cruz-Santa Rosa area; this stratigraphic unit has an average thickness of about 1,000 feet and a maximum thickness estimated to be 3,000 feet.

The dominant trap types in this play are small to moderate anticlinal folds and associated reverse-fault traps.

EXPLORATION

Both of the exploratory wells adjacent to the Santa Cruz-Santa Rosa assessment area and most of the wells on Dall, Tanner, and Cortes banks penetrated rocks similar to those included in this play; analog data from these wells have been used in the assessment of this play.

No appreciable shows of hydrocarbons were encountered in any of the wells. However, weak indications of gas were encountered in Paleogene-Cretaceous strata in the well south of Santa Rosa Island; other weak indications of hydrocarbons were encountered in Paleogene, Cretaceous, and other rocks in some of the wells on Dall, Tanner, and Cortes banks.

RESOURCE ESTIMATES

Undiscovered Conventionally Recoverable Resources

Estimates of undiscovered conventionally recoverable resources in the play have been developed using the subjective assessment method with a combination of play-specific and analog data. Select data used to develop the resource estimates are shown in appendix C.

The area and number of prospects in the play were estimated from seismic mapping. Analog data from Cretaceous, Eocene, and Oligocene producing zones in the Santa Barbara-Ventura, Los Angeles, and San Joaquin basins were used to estimate the net-pay thickness, oil recovery factor, and gas-to-oil ratio for this play.

As a result of this assessment, the play is estimated to contain 92 MMbbl of oil and 207 Bcf of associated gas (mean estimates). This volume of undiscovered conventionally recoverable resources may exist in as many as 46 pools with sizes ranging from approximately 140 Mbbl to 175 MMbbl of combined oil-equivalent resources (fig. 126). The low, mean, and high estimates of resources in the play are listed in table 42.

SAN NICOLAS BASIN

by Frank W. Victor

LOCATION

The San Nicolas Basin assessment area is located immediately southeast of San Nicolas Island in the Outer Borderland province (fig. 114). The basin is bounded on the east by the San Clemente ridge and on the west by the Santa Rosa-Cortes ridge; it extends from an unnamed east-west paleohigh between San Nicolas and Santa Barbara Islands (on the north) to Santo Tomas and Blake knolls (on the south) (fig. 127). It extends approximately 70 miles in length and from 10 to 30 miles in width and encompasses an area of approximately 1,300 square miles. The water depth within the basin ranges from 3,000 to 5,000 feet and averages 3,500 feet.

GEOLOGIC SETTING

The San Nicolas basin is an elongate, northwest-trending basin, which contains up to approximately 12,000 feet of Upper Cretaceous through

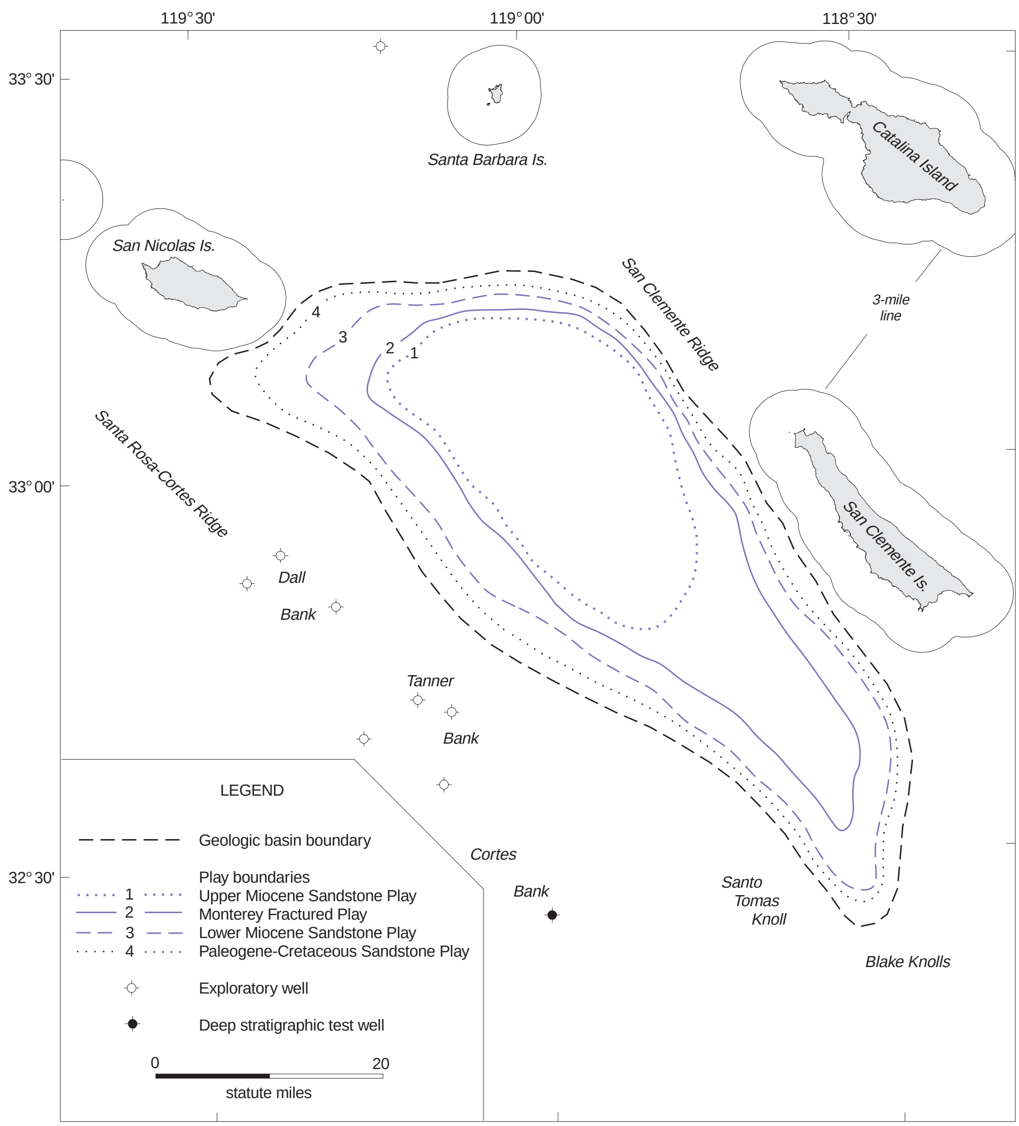
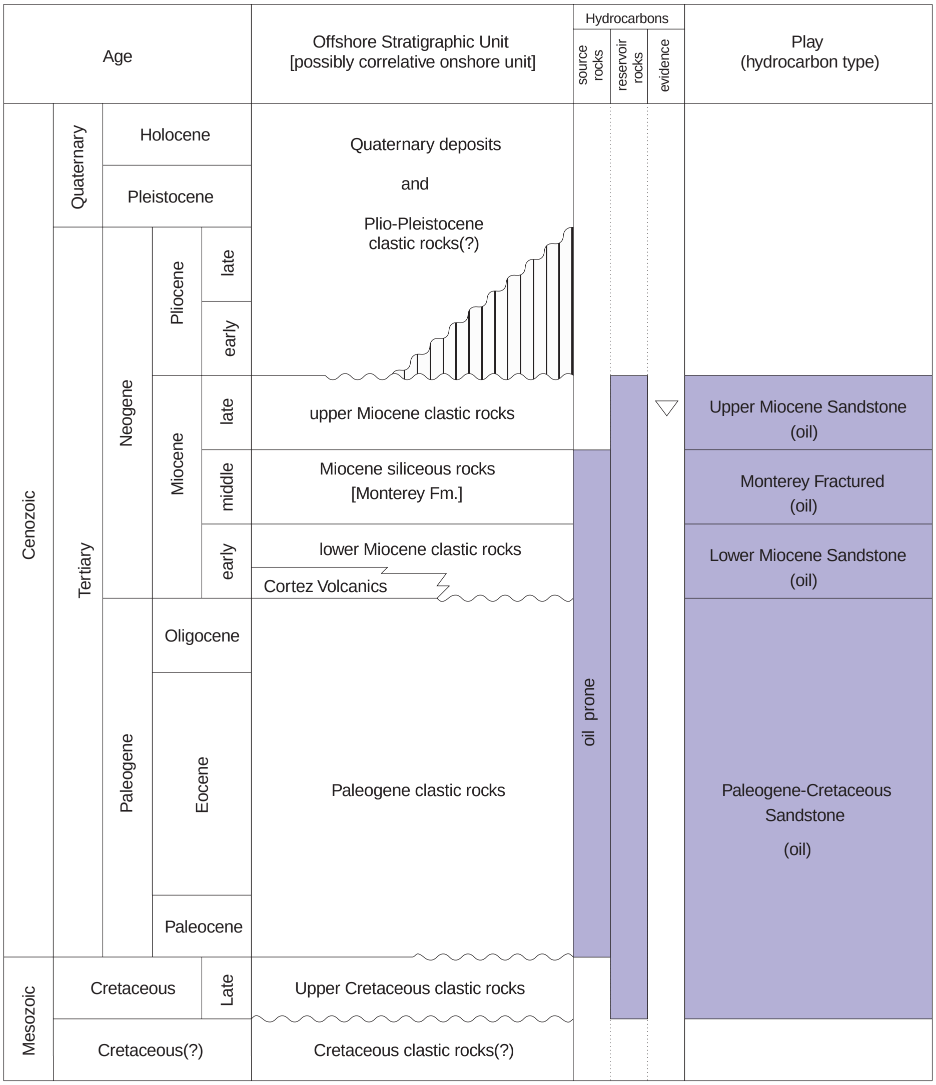


Figure 127. *Map of the San Nicolas Basin assessment area showing petroleum geologic plays and adjacent wells.*



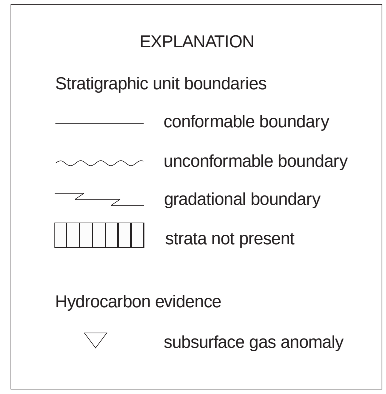


Figure 128. *Stratigraphic column of the San Nicolas Basin assessment area showing stratigraphic units, hydrocarbon attributes, and petroleum geologic plays.*

Quaternary strata[17] (fig. 128). The basin is asymmetrical, with the depocenter located in the northern third of the basin. Miocene compression, primarily from the west, has created a number of asymmetrical, reverse-fault-bounded anticlines in the eastern part of the basin. These structures are evident on seismic-reflection profiles and are numerous and large enough to trap significant quantities of oil and gas.

EXPLORATION

No exploratory wells have been drilled within the San Nicolas basin; however, a number of high-quality seismic-reflection surveys have been recorded. Eight wells were drilled immediately west of the basin on the southern end of the Santa Rosa-Cortes ridge. These include a deep stratigraphic test well (OCS-CAL 75-70 No. 1) on Cortes bank and seven exploratory oil and gas wells on Dall and Tanner banks.

These wells penetrated lower Miocene, Paleogene, and Cretaceous strata. Most middle Miocene and younger strata have been eroded from the uplifted banks on which the wells were drilled; however, middle Miocene and younger strata are present and relatively thick within the San Nicolas basin. The approximate geologic age of these undrilled stratigraphic units is based on seismic-stratigraphic extrapolation of older strata from the wells and on

[17] Descriptions of the age and lithology of stratigraphic units in the San Nicolas Basin assessment area are based on inference (rather than direct evidence) because no wells have been drilled within the area. Individual stratigraphic units are inferred to exist based on seismic-stratigraphic extrapolation of units that have been penetrated in wells on the Santa Rosa-Cortes ridge; analog data from these wells have been used in the assessment of plays in the San Nicolas Basin assessment area.

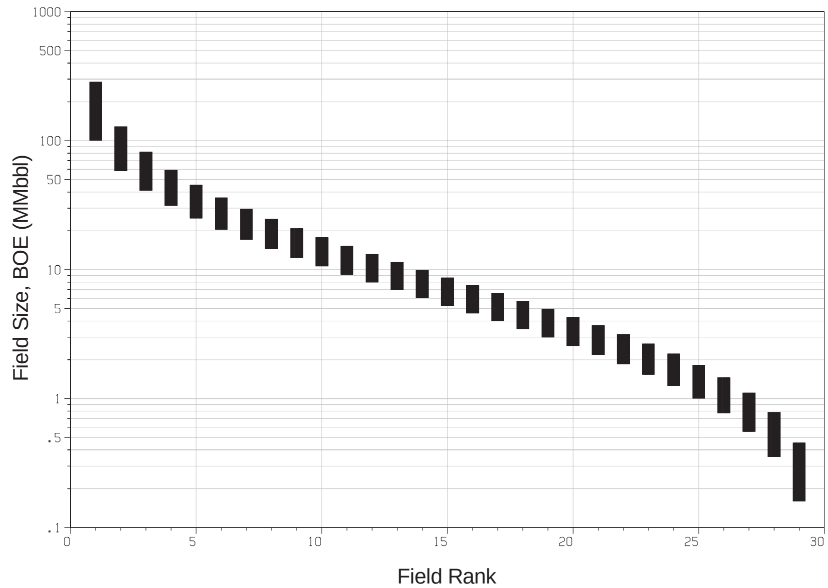


Figure 129. *Field-size rank plot of estimated undiscovered conventionally recoverable resources of the San Nicolas Basin assessment area. Sizes of undiscovered fields are shown by bars; the top and bottom of a bar represent the 25th- and 75th-percentile value of a probability distribution, respectively.*

the absence of significant unconformities within middle Miocene and younger strata in the basin.

No appreciable shows of oil or gas were encountered in the adjacent wells; however, weak indications of hydrocarbons (oil staining, minor fluorescence, and weak gas shows) were encountered in some of the wells. Possible gas-related amplitude anomalies within the upper Miocene stratigraphic section are present on seismic profiles.

Plays

Four petroleum geologic plays have been defined in the San Nicolas basin (fig. 128). The plays were defined on the basis of reservoir rock stratigraphy. The plays (and corresponding reservoir rocks) consist of the Upper Miocene Sandstone play (clastic rocks), the Monterey Fractured play (fractured rocks), the Lower Miocene Sandstone play (clastic rocks), and the Paleogene-Cretaceous Sandstone play (clastic rocks).

All of the plays in the basin are considered to be conceptual plays based on the absence of directly detected hydrocarbons within the play areas. This is presumed to be a consequence of the location and limited number of the wells rather than a lack of geological conditions conducive to hydrocarbon accumulation.

Resource Estimates

Undiscovered Conventionally Recoverable Resources

Play-specific estimates of undiscovered conventionally recoverable resources have been developed using the subjective assessment method, and these estimates have been statistically aggregated to estimate the total volume of resources in the basin. Select data used to develop the resource estimates are shown in appendix C.

As a result of this assessment, the total volume of undiscovered conventionally recoverable resources in the San Nicolas basin is estimated to be 545 MMbbl of oil and 909 Bcf of associated gas (mean estimates). This volume may exist in 29 fields with sizes ranging from approximately 160 Mbbl to 285 MMbbl of combined oil-equivalent resources (fig. 129). The low, mean, and high estimates of resources in the assessment area are listed in table 44 and illustrated in figure 130.

Undiscovered Economically Recoverable Resources

Estimates of undiscovered conventionally recoverable resources in the assessment area that may be economically recoverable under various economic scenarios have been developed using the economic assessment method. Select data used to develop the resource estimates are shown in appendix D.

As a result of this assessment, 55 MMbbl of oil and 91 Bcf of associated gas are estimated to be economically recoverable from the San Nicolas Basin assessment area under economic conditions existing as of this assessment (i.e., the $18-per-barrel economic scenario) (table 45). Larger volumes of resources are expected to be economically recoverable under increasingly favorable economic conditions (fig. 131).

Total Resource Endowment

No accumulations of resources have been discovered in the assessment area. Therefore, the aforementioned estimates of undiscovered conventionally recoverable resources compose the estimated total resource endowment of the area.

Table 44. *Estimates of undiscovered conventionally recoverable oil and gas resources in the San Nicolas Basin assessment area as of January 1, 1995, by play. All estimates are risked values. The low, mean, and high estimates correspond to the 95th-percentile, mean, and 5th-percentile values of a probability distribution, respectively. Percentile values are not additive; some total mean values may not equal the sum of the component values due to independent rounding.*

Play	Oil (MMbbl)			Gas (Bcf)			BOE (MMbbl)		
	Low	Mean	High	Low	Mean	High	Low	Mean	High
Upper Miocene Sandstone	0	73	269	0	38	149	0	80	295
Monterey Fractured	0	202	533	0	226	581	0	243	629
Lower Miocene Sandstone	0	159	570	0	364	1,319	0	224	818
Paleogene-Cretaceous Sandstone	0	110	416	0	281	1,241	0	161	628
Total Assessment Area	*0*	*545*	*1,176*	*0*	*909*	*2,417*	*0*	*707*	*1,576*

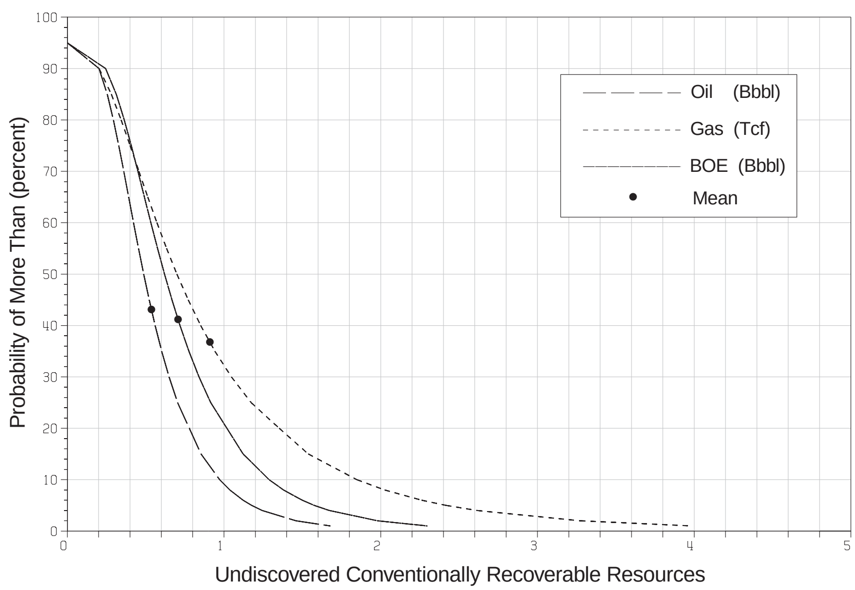


Figure 130. *Cumulative probability plot of estimated undiscovered conventionally recoverable resources of the San Nicolas Basin assessment area.*

Table 45. *Estimates of undiscovered economically recoverable oil and gas resources in the San Nicolas Basin assessment area as of January 1, 1995, by economic scenario. All estimates are risked mean values. The $18-per-barrel scenario is based on prices of $18 per bbl of oil and $2.11 per Mcf of gas; the $25-per-barrel scenario is based on prices of $25 per bbl of oil and $2.94 per Mcf of gas; the $50-per-barrel scenario is based on prices of $50 per barrel of oil and $5.87 per Mcf of gas.*

Economic Scenario	Oil (MMbbl)	Gas (Bcf)	BOE (MMbbl)
$18 per barrel	55	91	71
$25 per barrel	204	339	264
$50 per barrel	404	673	524

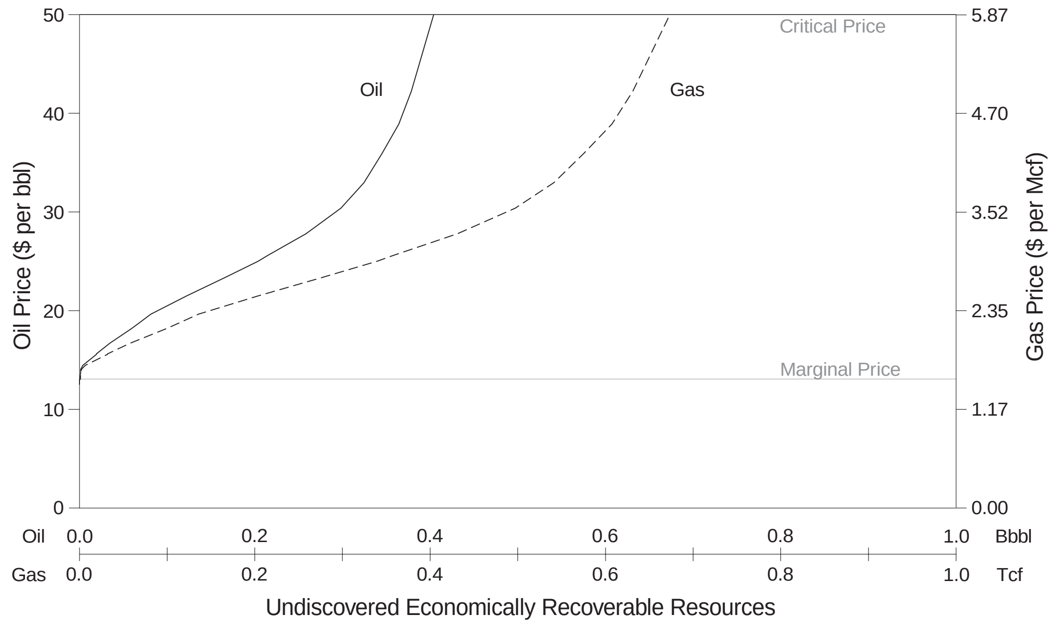


Figure 131. *Price-supply plot of estimated undiscovered economically recoverable resources of the San Nicolas Basin assessment area.*

Upper Miocene Sandstone Play

Play Definition

The Upper Miocene Sandstone play of the San Nicolas Basin assessment area is a conceptual play consisting of accumulations of oil and associated gas in upper Miocene sandstones. The play exists in the north-central part of the basin, where it encompasses an area of approximately 500 square miles (fig. 127). The depth to reservoir rocks in the play ranges from 1,000 to 5,000 feet below the seafloor.

Petroleum Geologic Characteristics

Potential petroleum source rocks for this play are middle Miocene shales of the Monterey Formation (fig. 128). The type and amount of organic matter within Monterey rocks of the San Nicolas basin are unknown; however, Monterey rocks in other California coastal basins are rich in organic matter, and similar rocks are presumed to exist in the San Nicolas basin. The geothermal gradient and the depth at which thermal maturation may have occurred in the San Nicolas basin are also unknown. The Monterey is buried no more than 6,000 feet and may not have been buried sufficiently to permit petroleum generation. However, the existence of "diagenetic reflectors" on seismic profiles suggests that temperatures conducive to silica diagenesis and possibly petroleum generation may have been attained in Monterey rocks. Due to the relatively shallow depths of the potential reservoir rocks, the oil in this play is predicted to be of low (less than 25 °API) gravity.

Potential reservoir rocks in this play include upper Miocene turbidite sandstones (fig. 128). Seismic profiles suggest that the upper Miocene section is thin in the San Nicolas basin; the average thickness of the unit is about 2,000 feet, and the maximum thickness is estimated to be about 4,000 feet. Potential reservoir sandstones should have good to excellent porosity and permeability based on burial depth and depositional history. However, based on the presence of relatively thin sections of lower Miocene strata in the wells adjacent to the basin, thin pay zones are expected in this play. Strata penetrated by the wells included fine- to medium-grained sandstones with log-derived porosities of 23 to 32 percent and good permeability.

The dominant trap type in this play is the relatively low-relief, simple anticlinal structure. The structural trend of prospects in the basin is northwest-southeast. However, there are very few structural prospects within the play area due to the lack of post-Miocene tectonic activity and absence of significant structural relief.

EXPLORATION

None of the exploratory wells adjacent to the San Nicolas basin penetrated rocks similar to those included in this play due to erosion of middle Miocene and younger strata from the uplifted banks on which the wells were drilled. Upper Miocene strata are inferred to exist in the basin based on seismic-stratigraphic extrapolation of older strata from these wells. Possible gas-related amplitude anomalies within the upper Miocene stratigraphic section are present on seismic profiles.

RESOURCE ESTIMATES

Undiscovered Conventionally Recoverable Resources

Estimates of undiscovered conventionally recoverable resources in the play have been developed using the subjective assessment method with a combination of play-specific and analog data. Select data used to develop the resource estimates are shown in appendix C.

The area and number of prospects in the play were estimated from seismic mapping. Conservatively reduced analog data from Puente producing zones in the onshore Los Angeles basin were used to estimate the net-pay thickness, oil recovery factor, and gas-to-oil ratio for this play.

As a result of this assessment, the play is estimated to contain 73 MMbbl of oil and 38 Bcf of associated gas (mean estimates). This volume of undiscovered conventionally recoverable resources may exist in as many as 34 pools with sizes ranging from approximately 210 Mbbl to 90 MMbbl of combined oil-equivalent resources (fig. 132). The low, mean, and high estimates of resources in the play are listed in table 44.

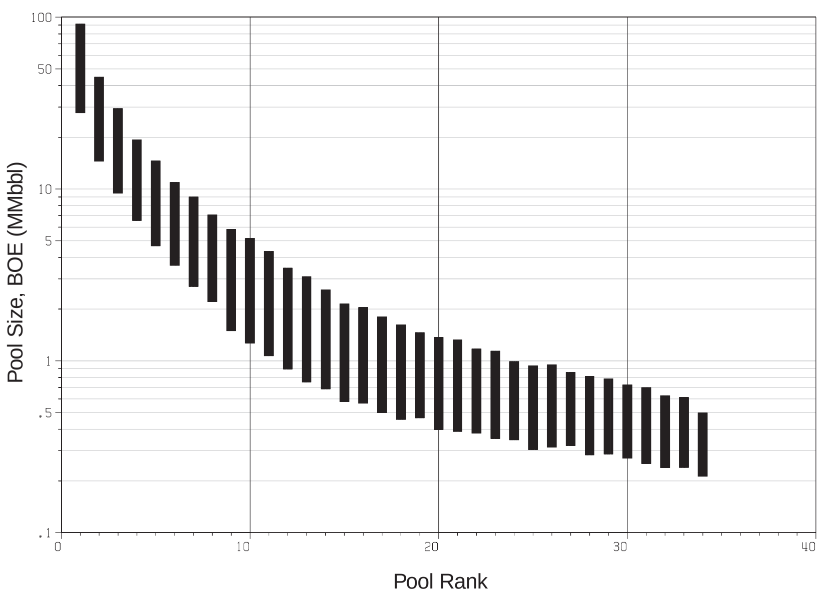


Figure 132. *Pool-size rank plot of estimated undiscovered conventionally recoverable resources of the Upper Miocene Sandstone play, San Nicolas Basin assessment area. Sizes of undiscovered pools are shown by bars; the top and bottom of a bar represent the 25th- and 75th-percentile values of a probability distribution, respectively.*

MONTEREY FRACTURED PLAY

PLAY DEFINITION

The Monterey Fractured play of the San Nicolas Basin assessment area is a conceptual play consisting of accumulations of oil and associated gas in middle Miocene fractured rocks of the Monterey Formation. The play exists over most of the basin where it encompasses an area of about 700 square miles (fig. 127). The depth to reservoir rocks in the play ranges from 3,600 to 6,500 feet below the seafloor.

PETROLEUM GEOLOGIC CHARACTERISTICS

The Monterey Formation is considered to be both petroleum source rock and reservoir rock for this play (fig. 128) by analogy with Monterey rocks in the offshore Santa Barbara-Ventura and Santa Maria basins and the onshore San Joaquin basin. The type and amount of organic matter within Monterey rocks of the San Nicolas basin are unknown; however, Monterey rocks in other California coastal basins are rich in organic matter, and similar rocks are presumed to exist in the San Nicolas basin. The geothermal gradient and the depth at which thermal maturation may have occurred in the San Nicolas basin are also unknown. The Monterey is buried no more than 6,000 feet and may not have been buried sufficiently to permit petroleum generation. However, the existence of "diagenetic reflectors" on seismic profiles suggests that temperatures conducive to silica diagenesis and possibly petroleum generation may have been attained in Monterey rocks. Due to the moderate depths of the potential reservoir rocks, the oil in this play is predicted to be of moderate (less than 30 °API) gravity.

Potential reservoir rocks in this play include middle Miocene fractured siliceous and calcareous shales and cherts and perhaps some basal clastic rocks of the Monterey Formation (fig. 128). Seismic profiles suggest that the Monterey section is thin in the basin; the thickness of these rocks is estimated to range from 500 to 1,000 feet. Diagenetic alteration, compression, and folding may have enhanced fracturing of the shales and cherts. In general, Monterey strata in the San Nicolas basin are expected to have reservoir characteristics similar to those in the offshore Santa Barbara-Ventura and Santa Maria basins.

The dominant trap type in this play is expected to be the anticline.

Exploration

None of the exploratory wells adjacent to the San Nicolas basin penetrated rocks similar to those included in this play due to erosion of middle Miocene and younger strata from the uplifted banks on which the wells were drilled. Middle Miocene strata presumably equivalent to the Monterey Formation are inferred to exist in the basin based on seismic-stratigraphic extrapolation of older strata from these wells.

Resource Estimates

Undiscovered Conventionally Recoverable Resources

Estimates of undiscovered conventionally recoverable resources in the play have been developed using the subjective assessment method with a combination of play-specific and analog data. Select data used to develop the resource estimates are shown in appendix C.

The volume and number of prospects in the play were estimated from seismic mapping. Conservatively reduced analog data from Monterey producing zones in the offshore Santa Barbara-Ventura and Santa Maria basins were used to estimate the oil recovery factor and gas-to-oil ratio for this play.

As a result of this assessment, the play is estimated to contain 202 MMbbl of oil and 226 Bcf of associated gas (mean estimates). This volume of undiscovered conventionally recoverable resources may exist in as many as 50 pools with sizes ranging from approximately 40 Mbbl to 260 MMbbl of combined oil-equivalent resources (fig. 133). The low, mean, and high estimates of resources in the play are listed in table 44.

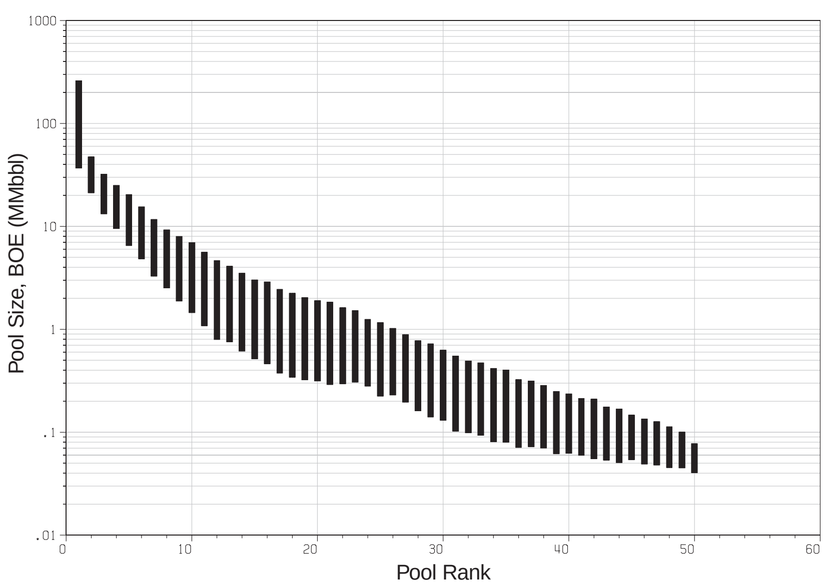


Figure 133. *Pool-size rank plot of estimated undiscovered conventionally recoverable resources of the Monterey Fractured play, San Nicolas Basin assessment area. Sizes of undiscovered pools are shown by bars; the top and bottom of a bar represent the 25th- and 75th-percentile values of a probability distribution, respectively.*

LOWER MIOCENE SANDSTONE PLAY

PLAY DEFINITION

The Lower Miocene Sandstone play of the San Nicolas Basin assessment area is a conceptual play consisting of accumulations of oil and associated gas in lower Miocene sandstones. The play exists over most of the basin where it encompasses an area of about 900 square miles (fig. 127). The depth to reservoir rocks in the play ranges from 4,000 to 8,500 feet, and averages 7,500 feet below the seafloor.

PETROLEUM GEOLOGIC CHARACTERISTICS

The primary potential petroleum source rocks for this play are Paleogene and lower Miocene mudstones and shales (fig. 128). Oligocene and Eocene rocks of adequate to excellent source quality were penetrated by the deep stratigraphic test well (OCS-CAL 75-70 No. 1) on Cortes bank. The total organic carbon content of samples from this well is 3.3 to 4.3 weight percent in Oligocene rocks and 0.4 to 2.7 weight percent in Eocene rocks (Vedder, 1987). Geochemical analysis of lower Miocene dart samples yielded an average total organic carbon content of 3.2 weight percent (Vedder, 1987). The geothermal gradient in this area is unknown; however, if a moderate (1.8 to 2.0 °F per 100 feet) geothermal gradient is assumed to have existed, petroleum generation may have occurred in these rocks under current burial conditions. However, potential source rocks are thin in the basin, and the volume of generated oil and gas may therefore be small. Rocks of the Monterey Formation may be a secondary source of petroleum for reservoir rocks in the upper part of this play.

Potential reservoir rocks in this play are lower Miocene sandstones (fig. 128). Lower Miocene strata penetrated in the wells adjacent to the basin are described as porous and fine- to medium-grained sandstones with log-derived porosities of 23 to 32 percent and with good permeability. Similar rocks of potentially good to excellent reservoir quality are presumed to exist in the San Nicolas basin. Based on seismic mapping, rocks inferred to be of early Miocene age are areally extensive throughout the San Nicolas basin; this stratigraphic unit has an average thickness of about 500 feet and a maximum thickness estimated to be 2,000 feet.

The dominant trap types in this play are small to large anticlinal folds and associated reverse-fault traps.

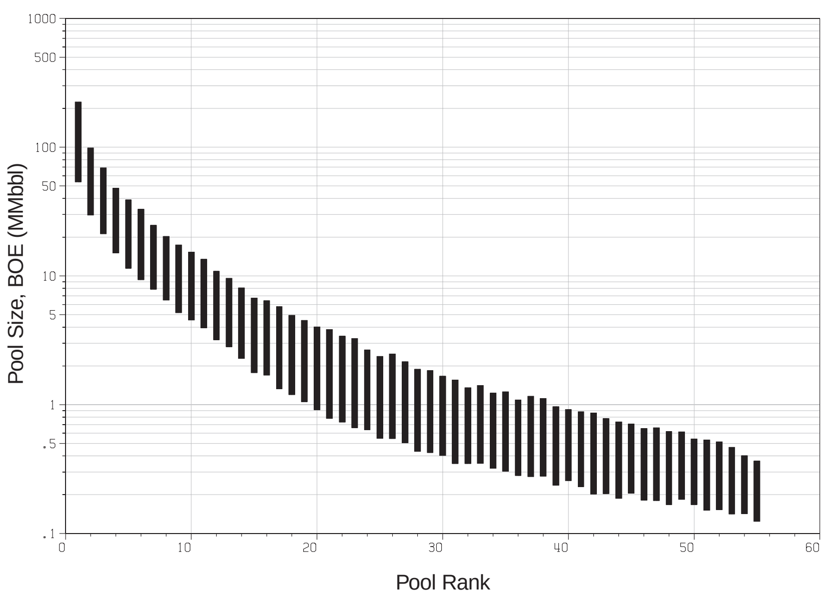


Figure 134. *Pool-size rank plot of estimated undiscovered conventionally recoverable resources of the Lower Miocene Sandstone play, San Nicolas Basin assessment area. Sizes of undiscovered pools are shown by bars; the top and bottom of a bar represent the 25th- and 75th-percentile values of a probability distribution, respectively.*

EXPLORATION

Most of the exploratory wells adjacent to the San Nicolas basin penetrated rocks similar to those included in this play. No appreciable shows of hydrocarbons were encountered in the wells; however, weak indications of hydrocarbons (oil staining, minor fluorescence, and weak gas shows) were encountered in lower Miocene and other rocks in some of the wells.

RESOURCE ESTIMATES

Undiscovered Conventionally Recoverable Resources

Estimates of undiscovered conventionally recoverable resources in the play have been developed using the subjective assessment method with a combination of play-specific and analog data. Select data used to develop the resource estimates are shown in appendix C.

The area and number of prospects in the play were estimated from seismic mapping. Conservatively reduced analog data from Vaqueros, Sespe, and Alegria producing zones in the offshore Santa Barbara-Ventura basin were used to estimate the net-pay thickness, oil recovery factor, and gas-to-oil ratio for this play.

As a result of this assessment, the play is estimated to contain 159 MMbbl of oil and 364 Bcf of associated gas (mean estimates). This volume of undiscovered conventionally recoverable resources may exist in as many as 55 pools with sizes ranging from approximately 125 Mbbl to 225 MMbbl of combined oil-equivalent resources (fig. 134). The low, mean, and high estimates of resources in the play are listed in table 44.

PALEOGENE-CRETACEOUS SANDSTONE PLAY

PLAY DEFINITION

The Paleogene-Cretaceous Sandstone play of the San Nicolas Basin assessment area is a conceptual play consisting of accumulations of oil and associated gas in Upper Cretaceous and Paleogene sandstones. The play exists over most of the basin where it encompasses an area of about 1,100 square miles (fig. 127). The depth to reservoir rocks in the play ranges from 8,000 to 11,000 feet and averages 9,000 feet below the seafloor.

PETROLEUM GEOLOGIC CHARACTERISTICS

The primary potential petroleum source rocks for this play are Paleogene mudstones and shales (fig. 128). Oligocene and Eocene rocks of adequate to excellent source quality were penetrated by the deep stratigraphic test well (OCS-CAL 75-70 No. 1) on Cortes bank. The total organic carbon content of samples from this well is 3.3 to 4.3 weight percent in Oligocene rocks and 0.4 to 2.7 weight percent in Eocene rocks; Upper Cretaceous shales containing 0.4 to 0.6 percent total organic carbon are not considered to be potential source rocks (Vedder, 1987). The geothermal gradient in this area is unknown; however, if a moderate (1.8 to 2.0 ^{o}F per 100 feet) geothermal gradient is assumed to have existed, petroleum generation may have occurred in these rocks under current burial conditions. However, potential source rocks are thin in the area, and the volume of generated oil and gas may therefore be small.

Potential reservoir rocks in this play are Paleogene and Cretaceous sandstones (fig. 128). Paleogene strata in the wells adjacent to the basin are described as porous and fine- to coarse-grained sandstones; log-derived porosities range from 23 to 30 percent in Oligocene samples, from 10 to 25 percent in Eocene samples, and from 6 to 14 percent in Upper Cretaceous samples. The proportion of sandstone within the total section is quite high; on average, sandstone composes approximately 50 percent of the total Paleogene section. Similar rocks of potentially good to excellent reservoir quality are presumed to exist in the San Nicolas basin. Based on seismic mapping and well correlations, rocks inferred to be of Paleogene and Cretaceous age are areally extensive throughout the San Nicolas basin; this stratigraphic unit has an average thickness of about 1,500 feet and a maximum thickness estimated to be 3,000 feet.

The dominant trap types in this play are small to large anticlinal folds and associated reverse-fault traps.

EXPLORATION

All of the exploratory wells adjacent to the San Nicolas basin penetrated Paleogene rocks similar to those included in this play and most of the wells penetrated Cretaceous rocks. No appreciable shows of hydrocarbons were encountered in the wells; however, weak indications of hydrocarbons (oil staining, minor fluorescence, and weak gas shows) were encountered in Paleogene, Cretaceous, and other rocks in some of the wells.

RESOURCE ESTIMATES

Undiscovered Conventionally Recoverable Resources

Estimates of undiscovered conventionally recoverable resources in the play have been developed using the subjective assessment method with a combination of play-specific and analog data. Select data used to develop the resource estimates are shown in appendix C.

The area and number of prospects in the play were estimated from seismic mapping. Analog data from Cretaceous, Eocene, and Oligocene producing zones in the Santa Barbara-Ventura, Los Angeles, and San Joaquin basins were used to estimate the net-pay thickness, oil recovery factor, and gas-to-oil ratio for this play.

As a result of this assessment, the play is estimated to contain 110 MMbbl of oil and 281 Bcf of associated gas (mean estimates). This volume of undiscovered conventionally recoverable resources may exist in as many as 45 pools with sizes ranging from approximately 175 Mbbl to 190 MMbbl of combined oil-equivalent resources (fig. 135). The low, mean, and high estimates of resources in the play are listed in table 44.

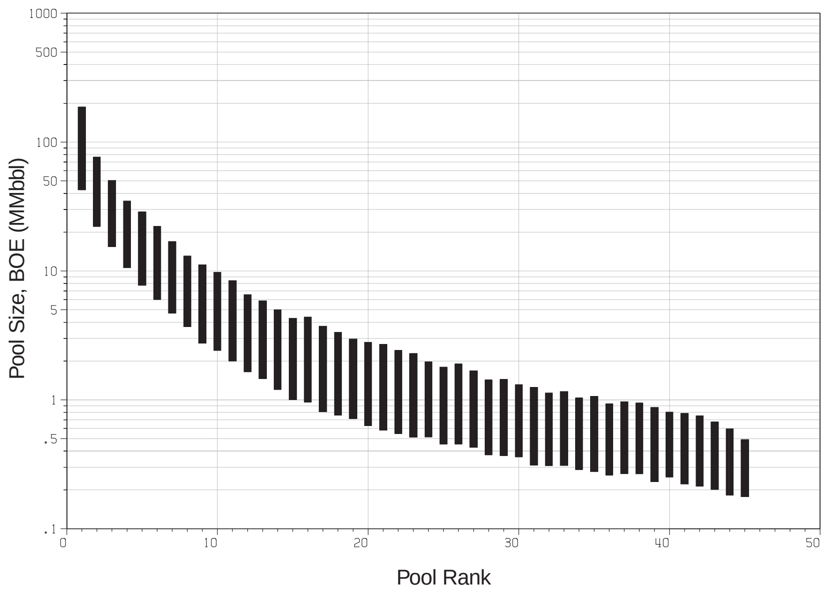


Figure 135. *Pool-size rank plot of estimated undiscovered conventionally recoverable resources of the Paleogene-Cretaceous Sandstone play, San Nicolas Basin assessment area. Sizes of undiscovered pools are shown by bars; the top and bottom of a bar represent the 25th- and 75th-percentile values of a probability distribution, respectively.*

CORTES-VELERO-LONG AREA

by Frank W. Victor

Location

The Cortes-Velero-Long assessment area is located in the southern part of the Outer Borderland province (fig. 114). This northwest-trending assessment area is approximately bounded by the Santo Tomas and Blake knolls to the east, the Patton escarpment to the west, the Northeast and Tanner banks to the north, and the U.S.-Mexico maritime boundary to the south (fig. 136). It is approximately 95 miles long, from 30 to 60 miles wide, and encompasses an area of approximately 4,800 square miles. The water depth within the area ranges from 4,500 to 6,000 feet.

This composite assessment area comprises the U.S. Federal portion of four geologic subareas: the West Cortes, East Cortes, Velero, and Long basins. These subareas have been combined as a single assessment area due to the nearly continuous extent of Paleogene strata and lack of definitive basin boundaries. The southern part of the Velero basin extends beyond the U.S.-Mexico maritime boundary; it is not included in the assessment area and has not been assessed.

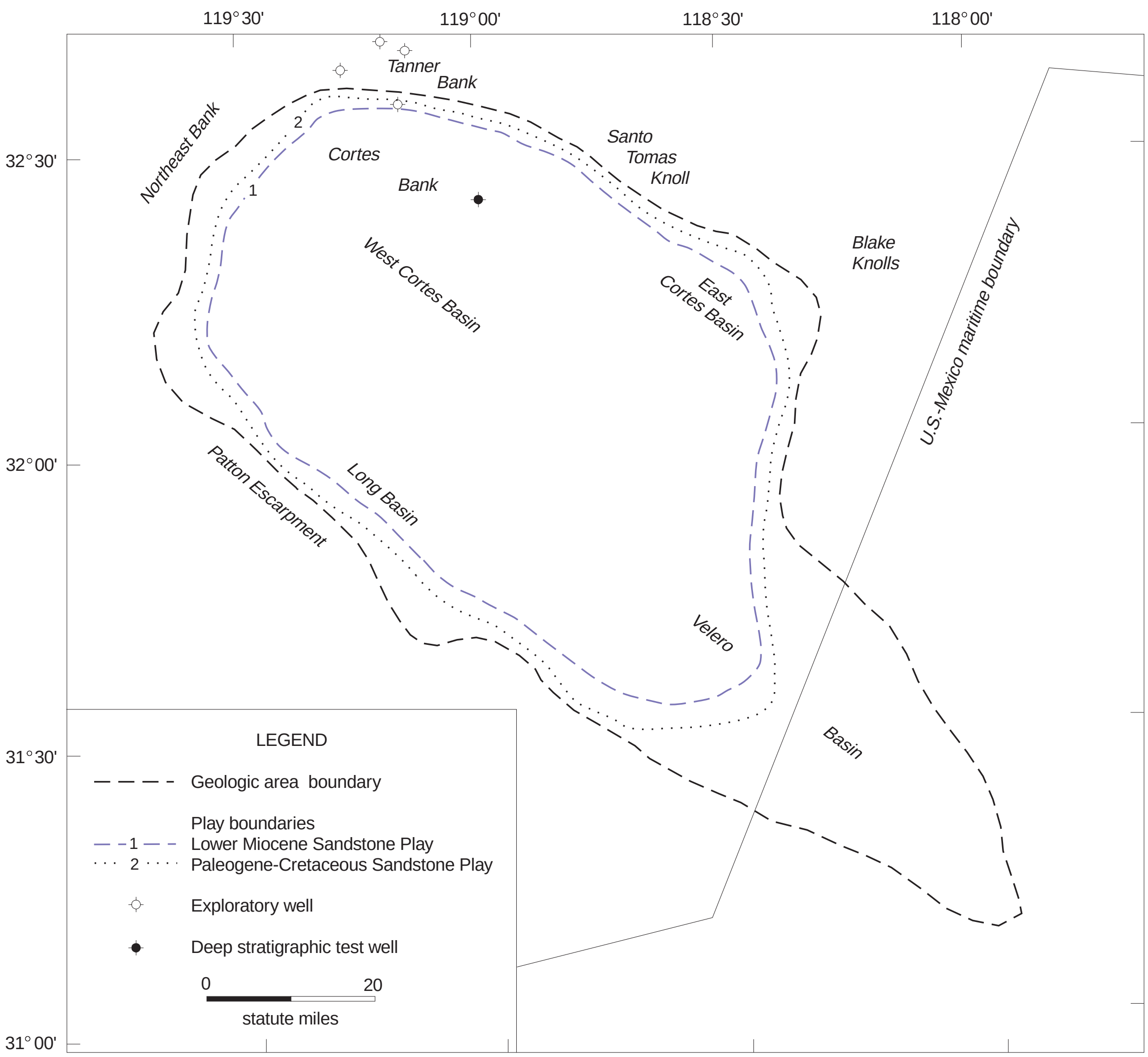
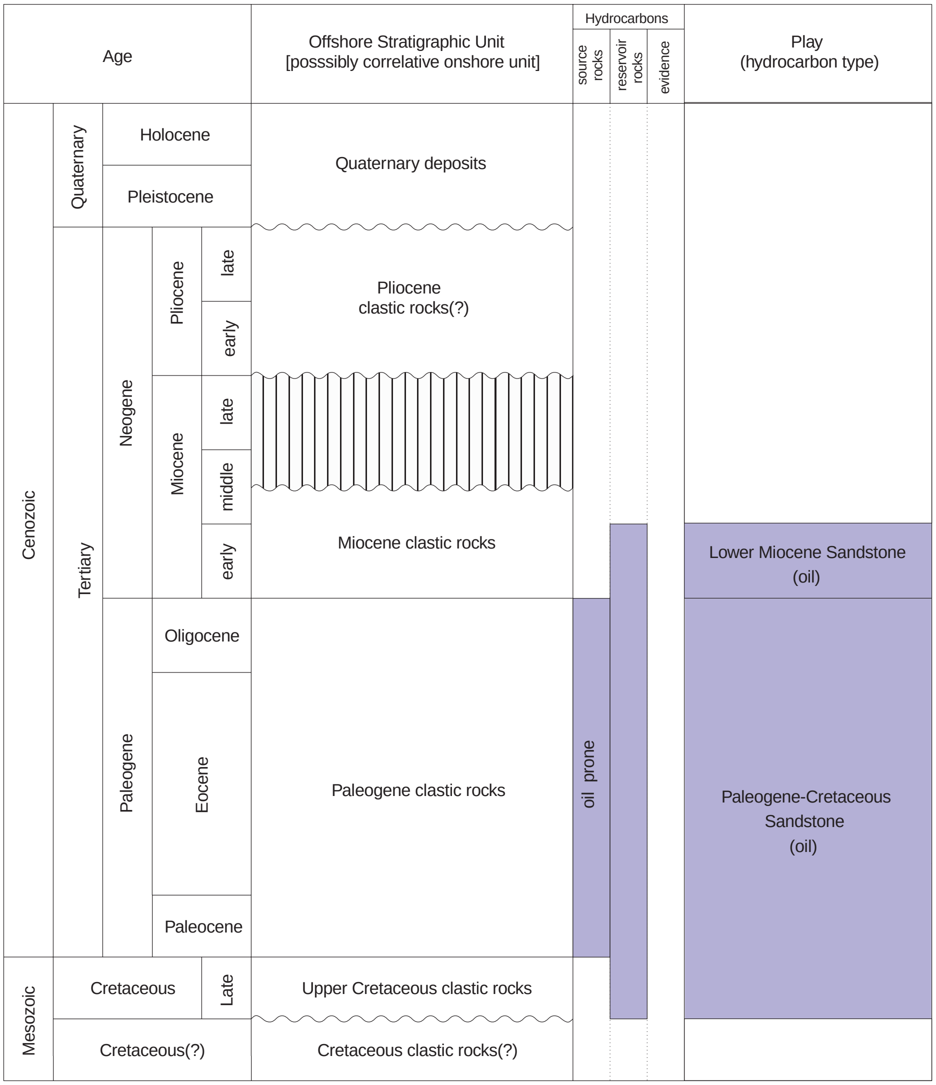


Figure 136. *Map of the Cortes-Velero-Long assessment area showing petroleum geologic plays and wells.*



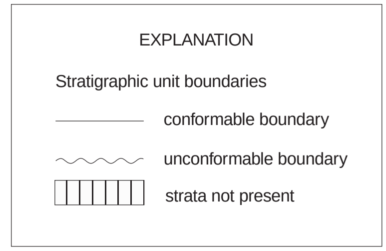


Figure 137. *Stratigraphic column of the Cortes-Velero-Long assessment area showing stratigraphic units, hydrocarbon attributes, and petroleum geologic plays.*

GEOLOGIC SETTING

The basins within the Cortes-Velero-Long assessment area are northwest-trending basins, which contain up to 7,000 feet of Upper Cretaceous through Miocene marine clastic rocks[18] (fig. 137). This remote area of the continental borderland has lacked a source of a significant volume of clastic sediment since the middle Miocene resulting in the deposition of thin sequences of predominantly biogenic (rather than terrestrial) sediment and basins that contain little or no middle Miocene and younger strata.

This part of the continental borderland has been tectonically dominated by extension and strike-slip faulting, which created a number of very broad, low-relief, normal-fault-bounded traps throughout the area. These structures are evident on seismic profiles and are numerous and large enough to trap significant quantities of oil and gas.

EXPLORATION

No exploratory wells have been drilled within the basinal areas of the Cortes-Velero-Long assessment area; however, a number of high-quality seismic-reflection surveys have been recorded. Eight wells were drilled on the southern end of the Santa Rosa-Cortes ridge. These include a deep stratigraphic test well (OCS-CAL 75-70 No. 1) on Cortes bank (in the northern part of the assessment area) and seven exploratory oil and gas wells on Dall and Tanner

[18] Descriptions of the age and lithology of stratigraphic units in the Cortes-Velero-Long assessment area are based on inference (rather than direct evidence) because no wells have been drilled within the area. Individual stratigraphic units are inferred to exist based on seismic-stratigraphic extrapolation of units that have been penetrated in wells on the Santa Rosa-Cortes ridge; analog data from these wells have been used in the assessment of plays in the Cortes-Velero-Long assessment area.

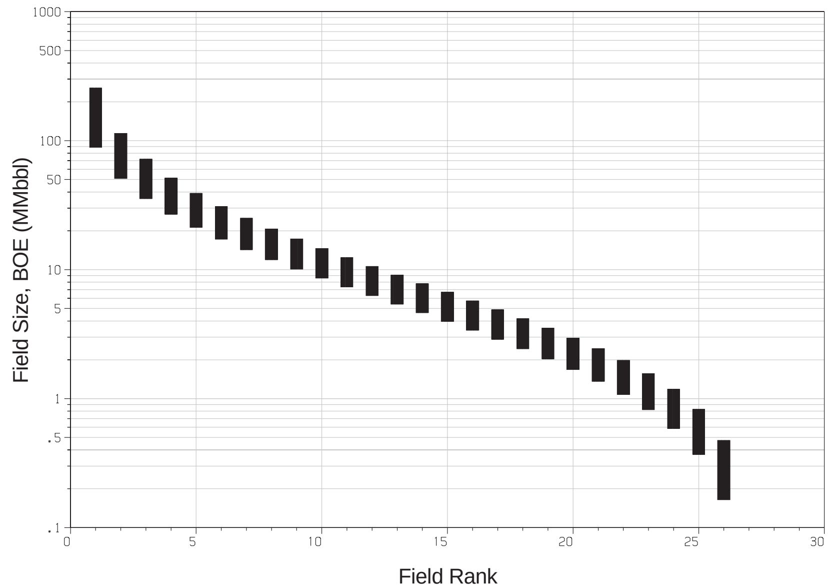


Figure 138. *Field-size rank plot of estimated undiscovered conventionally recoverable resources of the Cortes-Velero-Long assessment area. Sizes of undiscovered fields are shown by bars; the top and bottom of a bar represent the 25th- and 75th-percentile value of a probability distribution, respectively.*

banks (one of which lies on the extreme northern flank of the assessment area).

These wells penetrated lower Miocene, Paleogene, and Cretaceous strata. Most middle Miocene and younger strata have been eroded from the uplifted banks on which the wells were drilled.

No appreciable shows of oil or gas were encountered in the wells; however, weak indications of hydrocarbons (oil staining, minor fluorescence, and weak gas shows) were encountered in some of the wells.

Plays

Two petroleum geologic plays have been defined in the Cortes-Velero-Long assessment area. The plays were defined on the basis of reservoir rock stratigraphy. The plays (and corresponding reservoir rocks) consist of the Lower Miocene Sandstone play (clastic rocks) and the Paleogene-Cretaceous Sandstone play (clastic rocks).

Both of the plays in the area are considered to be conceptual plays based on the absence of directly detected hydrocarbons within the play areas. This is presumed to be a consequence of the location and limited number of the wells rather than a lack of geological conditions conducive to hydrocarbon accumulation.

Resource Estimates

Undiscovered Conventionally Recoverable Resources

Play-specific estimates of undiscovered conventionally recoverable resources have been developed using the subjective assessment method, and these estimates have been statistically aggregated to estimate the total volume of resources in the assessment area. Select data used to develop the resource estimates are shown in appendix C.

As a result of this assessment, the total volume of undiscovered conventionally recoverable resources in the Cortes-Velero-Long assessment area is estimated to be 412 MMbbl of oil and 1.10 Tcf of associated gas (mean estimates). This volume may exist in 26 fields with sizes ranging from approximately 165 Mbbl to 255 MMbbl of combined oil-equivalent resources (fig. 138). The low, mean, and high estimates of resources in the assessment area are listed in table 46 and illustrated in figure 139.

Undiscovered Economically Recoverable Resources

Estimates of undiscovered conventionally recoverable resources in the assessment area that may be economically recoverable under various economic scenarios have been developed using the economic assessment method. Select data used to develop the resource estimates are shown in appendix D.

As a result of this assessment, no oil and gas resources are estimated to be economically recoverable from the Cortes-Velero-Long assessment area under economic conditions existing as of this assessment (i.e., the $18-per-barrel economic scenario) (table 47). However, small to moderate volumes of resources are expected to be economically recoverable under increasingly favorable economic conditions (fig. 140).

Total Resource Endowment

No accumulations of resources have been discovered in the assessment area. Therefore, the aforementioned estimates of undiscovered conventionally recoverable resources compose the estimated total resource endowment of the area.

Table 46. *Estimates of undiscovered conventionally recoverable oil and gas resources in the Cortes-Velero-Long assessment area as of January 1, 1995, by play. All estimates are risked values. The low, mean, and high estimates correspond to the 95th-percentile, mean, and 5th-percentile values of a probability distribution, respectively. Percentile values are not additive; some total mean values may not equal the sum of the component values due to independent rounding.*

Play	Oil (MMbbl)			Gas (Bcf)			BOE (MMbbl)		
	Low	Mean	High	Low	Mean	High	Low	Mean	High
Lower Miocene Sandstone	0	242	792	0	659	2,583	0	360	1,265
Paleogene-Cretaceous Sandstone	0	169	693	0	442	2,168	0	248	1,111
Total Assessment Area	*0*	*412*	*1,202*	*0*	*1,101*	*3,493*	*0*	*607*	*1,797*

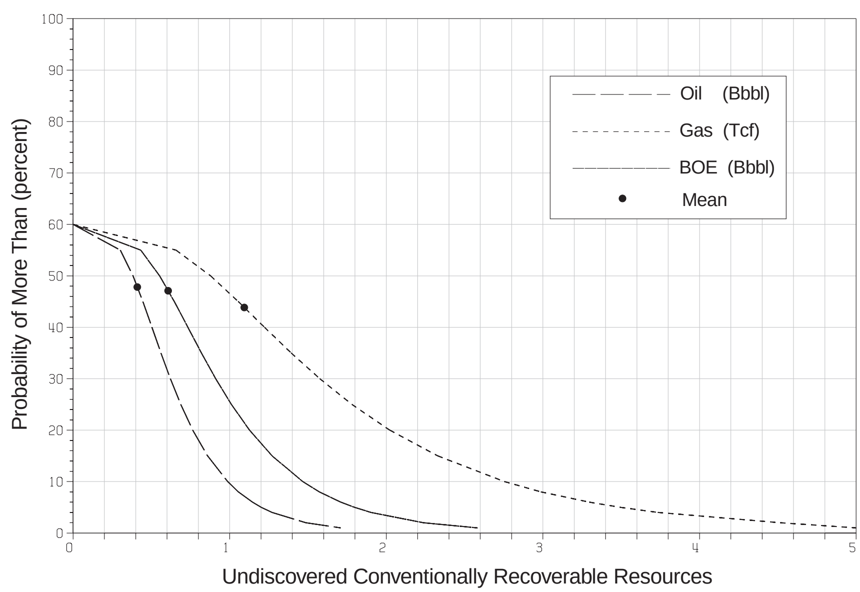


Figure 139. *Cumulative probability plot of estimated undiscovered conventionally recoverable resources of the Cortes-Velero-Long assessment area.*

Table 47. *Estimates of undiscovered economically recoverable oil and gas resources in the Cortes-Velero-Long assessment area as of January 1, 1995, by economic scenario. All estimates are risked mean values. The $18-per-barrel scenario is based on prices of $18 per bbl of oil and $2.11 per Mcf of gas; the $25-per-barrel scenario is based on prices of $25 per bbl of oil and $2.94 per Mcf of gas; the $50-per-barrel scenario is based on prices of $50 per barrel of oil and $5.87 per Mcf of gas.*

Economic Scenario	Oil (MMbbl)	Gas (Bcf)	BOE (MMbbl)
$18 per barrel	0	0	0
$25 per barrel	2	6	3
$50 per barrel	213	568	314

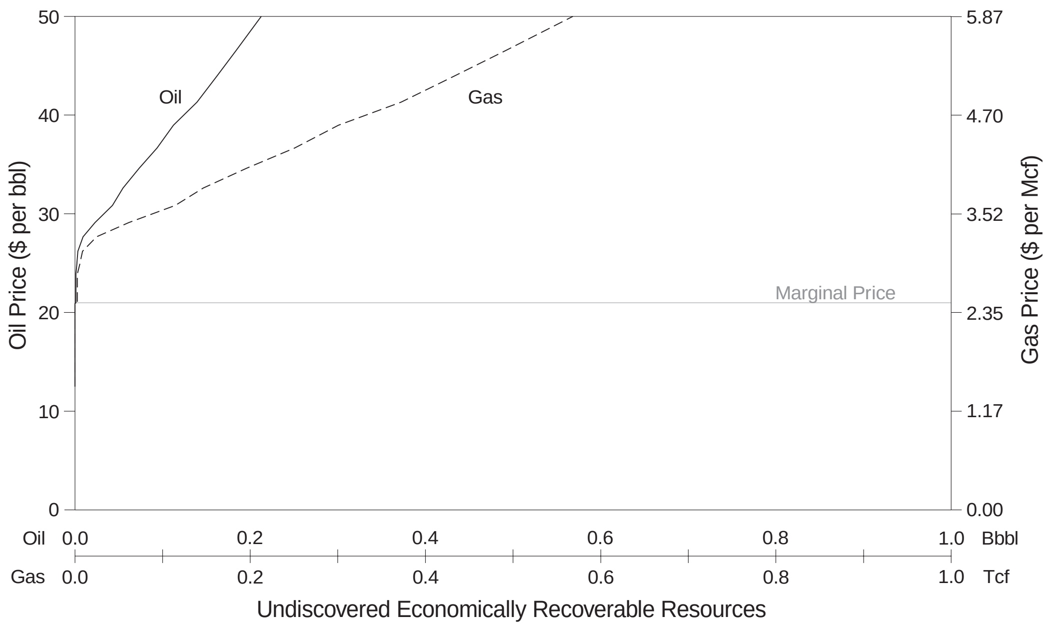


Figure 140. *Price-supply plot of estimated undiscovered economically recoverable resources of the Cortes-Velero-Long assessment area.*

LOWER MIOCENE SANDSTONE PLAY

PLAY DEFINITION

The Lower Miocene Sandstone play of the Cortes-Velero-Long assessment area is a conceptual play consisting of oil and associated gas accumulations in lower Miocene sandstones. The play exists over most of the assessment area where it encompasses an area of about 3,400 square miles (fig. 136). The depth to reservoir rocks in the play ranges from 1,000 to 4,500 feet and averages 3,000 feet below the seafloor.

PETROLEUM GEOLOGIC CHARACTERISTICS

The primary potential petroleum source rocks for this play are Paleogene mudstones and shales (fig. 137). Oligocene and Eocene rocks of adequate to excellent source quality were penetrated by the deep stratigraphic test well (OCS-CAL 75-70 No. 1) on Cortes bank. The total organic carbon content of samples from this well is 3.3 to 4.3 weight percent in Oligocene rocks and 0.4 to 2.7 weight percent in Eocene rocks (Vedder, 1987). The geothermal gradient in the Cortes-Velero-Long assessment area is unknown; however, if a moderate (1.8 to 2.0 °F per 100 feet) geothermal gradient is assumed to have existed, petroleum generation may have occurred in these rocks under current burial conditions. However, potential source rocks are thin in the area, and the volume of generated oil and gas may therefore be small.

Potential reservoir rocks in this play are lower Miocene sandstones (fig. 137). Lower Miocene strata penetrated in the wells on Dall, Tanner, and Cortes banks are described as porous and fine- to medium-grained sandstones with log-derived porosities of 23 to 32 percent and with good permeability. Similar rocks of potentially good to excellent reservoir quality are presumed to exist in the Cortes-Velero-Long assessment area. Based on seismic mapping, rocks inferred to be of early Miocene age are areally extensive throughout the assessment area; this stratigraphic unit has an average thickness of about 1,500 feet and a maximum thickness estimated to be 2,500 feet.

The dominant trap types in this play are small to large, low-relief anticlinal folds and normal-fault traps.

EXPLORATION

Most of the exploratory wells on Dall, Tanner, and Cortes banks penetrated rocks similar to those included in this play; analog data from these wells have been used in the assessment of this play. No appreciable shows of hydrocarbons were encountered in the wells; however, weak indications of hydrocarbons (oil staining, minor fluorescence, and

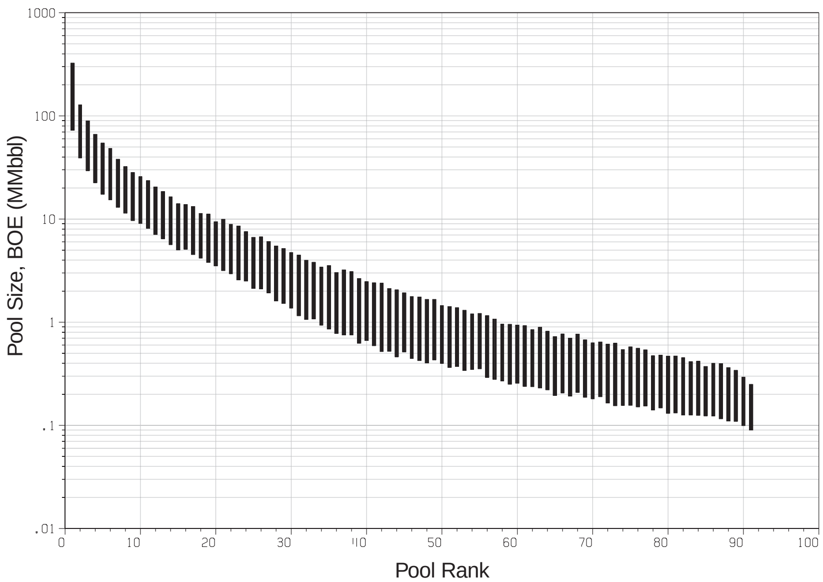


Figure 141. *Pool-size rank plot of estimated undiscovered conventionally recoverable resources of the Lower Miocene Sandstone play, Cortes-Velero-Long assessment area. Sizes of undiscovered pools are shown by bars; the top and bottom of a bar represent the 25th- and 75th-percentile values of a probability distribution, respectively.*

weak gas shows) were encountered in lower Miocene and other rocks in some of the wells.

RESOURCE ESTIMATES

Undiscovered Conventionally Recoverable Resources

Estimates of undiscovered conventionally recoverable resources in the play have been developed using the subjective assessment method with a combination of play-specific and analog data. Select data used to develop the resource estimates are shown in appendix C.

The area and number of prospects in the play were estimated from seismic mapping. Conservatively reduced analog data from Vaqueros, Sespe, and Alegria producing zones in the offshore Santa Barbara-Ventura basin were used to estimate the net-pay thickness, oil recovery factor, and gas-to-oil ratio for this play.

As a result of this assessment, the play is estimated to contain 242 MMbbl of oil and 659 Bcf of associated gas (mean estimates). This volume of undiscovered conventionally recoverable resources may exist in as many as 91 pools with sizes ranging from approximately 90 Mbbl to 325 MMbbl of combined oil-equivalent resources (fig. 141). The low, mean, and high estimates of resources in the play are listed in table 46.

PALEOGENE-CRETACEOUS SANDSTONE PLAY

PLAY DEFINITION

The Paleogene-Cretaceous Sandstone play of the Cortes-Velero-Long assessment area is a conceptual play consisting of oil and associated gas accumulations in Upper Cretaceous and Paleogene sandstones. The play exists over most of the assessment area where it encompasses an area of about 4,100 square miles (fig. 136). The depth to reservoir rocks in the play ranges from 4,000 to 8,000 feet and averages 5,500 feet below the seafloor.

PETROLEUM GEOLOGIC CHARACTERISTICS

The primary potential petroleum source rocks for this play are Paleogene mudstones and shales (fig. 137). Oligocene and Eocene rocks of adequate to excellent source quality were penetrated by the deep stratigraphic test well (OCS-CAL 75-70 No. 1) on Cortes bank. The total organic carbon content of samples from this well is 3.3 to 4.3 weight percent in Oligocene rocks and 0.4 to 2.7 weight percent in Eocene rocks; Upper Cretaceous shales containing 0.4 to 0.6 percent total organic carbon are not considered to be potential source rocks (Vedder, 1987). The geothermal gradient in this area is unknown; however, if a moderate (1.8 to 2.0 °F per 100 feet) geothermal gradient is assumed to have existed, petroleum generation may have occurred in these rocks under current burial conditions. However, potential source rocks are thin in the area, and the volume of generated oil and gas may therefore be small.

Potential reservoir rocks in this play are Paleogene and Cretaceous sandstones (fig. 137). Paleogene strata penetrated in the wells on Dall, Tanner, and Cortes banks are described as porous and fine- to coarse-grained sandstones. Log-derived porosities range from 23 to 30 percent in Oligocene samples, from 10 to 25 percent in Eocene samples, and from 6 to 14 percent in Upper Cretaceous samples. The proportion of sandstone within the total section is quite high; on average, sandstone composes approximately 50 percent of the total Paleogene section. Similar rocks of potentially good to excellent reservoir quality are presumed to exist in the Cortes-Velero-Long assessment area. Based on seismic mapping and well correlations, rocks inferred to be of Paleogene and Cretaceous age are areally extensive throughout the Cortes-Velero-Long assessment area; this stratigraphic unit has an average thickness of about 2,000 feet and a maximum thickness estimated to be 3,500 feet.

The dominant trap types in this play are small to large, low-relief anticlinal folds and normal-fault traps.

EXPLORATION

All of the exploratory wells on Dall, Tanner, and Cortes banks penetrated Paleogene rocks similar to those included in this play, and most of the wells penetrated Cretaceous rocks; analog data from these wells have been used in the assessment of this play. No appreciable shows of hydrocarbons were encountered in the wells; however, weak indications of hydrocarbons (oil staining, minor fluorescence, and weak gas shows) were encountered in Paleogene, Cretaceous, and other rocks in some of the wells.

RESOURCE ESTIMATES

Undiscovered Conventionally Recoverable Resources

Estimates of undiscovered conventionally recoverable resources in the play have been developed using the subjective assessment method with a combination of play-specific and analog data. Select data used to develop the resource estimates are shown in appendix C.

The area and number of prospects in the play were estimated from seismic mapping. Analog data from Cretaceous, Eocene, and Oligocene producing zones in the Santa Barbara-Ventura, Los Angeles, and San Joaquin basins were used to estimate the net-pay thickness, oil recovery factor, and gas-to-oil ratio for this play.

As a result of this assessment, the play is estimated to contain 169 MMbbl of oil and 442 Bcf of associated gas (mean estimates). This volume of undiscovered conventionally recoverable resources may exist in as many as 64 pools with sizes ranging from approximately 105 Mbbl to 340 MMbbl of combined oil-equivalent resources (fig. 142). The low, mean, and high estimates of resources in the play are listed in table 46.

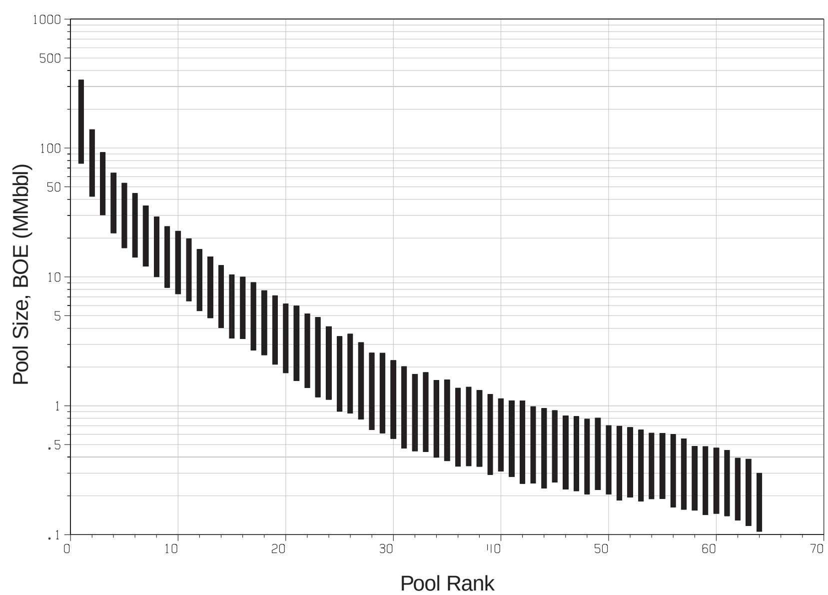


Figure 142. *Pool-size rank plot of estimated undiscovered conventionally recoverable resources of the Paleogene-Cretaceous Sandstone play, Cortes-Velero-Long assessment area. Sizes of undiscovered pools are shown by bars; the top and bottom of a bar represent the 25th- and 75th-percentile values of a probability distribution, respectively.*

SUMMARY AND DISCUSSION OF RESOURCE ESTIMATES

This section presents a summary of the estimates of oil and gas resources in the Pacific OCS Region that have been developed for this assessment and a discussion of the geographic and geologic distribution of undiscovered resources in the Region. Estimates of undiscovered resources in administrative planning areas of the Region are presented in appendix E. A discussion of the contribution of undiscovered resources in the Region to the undiscovered resources in the United States OCS is presented in appendix F.

REGIONAL RESULTS

Based on this assessment, the total volume of undiscovered conventionally recoverable oil resources (including crude oil and condensate) in the Pacific OCS Region as of this assessment (i.e., January 1, 1995) is estimated to range from 8.99 to 12.62 Bbbl (low to high estimates) with a mean estimate of 10.71 Bbbl. The total volume of undiscovered conventionally recoverable gas resources (including associated and nonassociated gas) in the Region is estimated to range from 15.21 to 23.19 Tcf with a mean estimate of 18.94 Tcf.

The total volume of undiscovered conventionally recoverable resources in the Region that is estimated to be economically recoverable at economic and technological conditions existing as of this assessment (i.e., the $18-per-barrel economic scenario) is 5.31 Bbbl of oil and 8.30 Tcf of gas (mean estimates). Larger volumes of resources are estimated to be economically recoverable at more favorable economic conditions.

Based on previous assessments of discovered resources and this assessment of undiscovered resources, the total resource endowment of the Region is estimated to be 12.77 Bbbl of oil and 22.07 Tcf of gas. This estimated endowment is composed of 2.05 Bbbl and 3.13 Tcf of discovered resources (including 678 MMbbl and 738 Bcf of cumulative production and 1.38 Bbbl and 2.39 Tcf of remaining reserves) and 10.71 Bbbl and 18.94 Tcf of undiscovered conventionally recoverable resources. Undiscovered resources are estimated to compose a major portion (approximately 85 percent on the basis of mean estimates) of the total oil and gas resource endowment of the Region.

GEOGRAPHIC DISTRIBUTION OF RESOURCES

UNDISCOVERED CONVENTIONALLY RECOVERABLE RESOURCES

The undiscovered conventionally recoverable oil and gas resources of the Region are estimated to exist within 46 assessed plays in 13 assessment areas (fig. 10). The low, mean, and high estimates of the resources in each assessment area of the Region are listed in table 48. The distribution of the resources among the assessment areas is illustrated, on the basis of mean estimates, in figures 143 and 144.

Approximately three quarters of the undiscovered conventionally recoverable combined oil-equivalent resources of the Region (76 percent on the basis of mean estimates) are estimated to be oil. Relatively large volumes of oil resources (greater than 1 Bbbl) are estimated to exist in the Point Arena basin (2.03 Bbbl), Santa Barbara-Ventura basin (1.85 Bbbl), Bodega basin (1.42 Bbbl), and Oceanside-Capistrano basin (1.11 Bbbl).

Approximately one quarter of the undiscovered conventionally recoverable combined oil-equivalent resources of the Region (24 percent on the basis of mean estimates) is estimated to be gas. Relatively large volumes of gas resources (greater than 1 Tcf) are estimated to exist in the Santa Barbara-Ventura basin (4.61 Tcf), Washington-Oregon area (2.30 Tcf), Point Arena basin (2.14 Tcf), Eel River basin (1.61 Tcf), Bodega basin (1.57 Tcf), Oceanside-Capistrano basin (1.30 Tcf), and Cortes-Velero-Long area (1.10 Tcf).

Table 48. *Estimates of undiscovered conventionally recoverable oil and gas resources in the Pacific OCS Region as of January 1, 1995, by assessment area. All estimates are risked values. The low, mean, and high estimates correspond to the 95th-percentile, mean, and 5th-percentile values of a probability distribution, respectively. Percentile values are not additive; some total mean values may not equal the sum of the component values due to independent rounding.*

Assessment Area	Oil (Bbbl)			Gas (Tcf)			BOE (Bbbl)		
	Low	Mean	High	Low	Mean	High	Low	Mean	High
Pacific Northwest Province									
Washington-Oregon Area	0.14	0.36	0.69	0.95	2.30	4.28	0.32	0.76	1.42
Eel River Basin	0.03	0.05	0.08	1.06	1.61	2.32	0.23	0.34	0.49
Total Province	*0.19*	*0.41*	*0.75*	*2.34*	*3.91*	*6.03*	*0.61*	*1.11*	*1.79*
Central California Province									
Point Arena Basin	1.50	2.03	2.66	1.45	2.14	3.01	1.77	2.41	3.18
Bodega Basin	0.97	1.42	1.98	1.00	1.57	2.30	1.16	1.70	2.37
Año Nuevo Basin	0.49	0.72	1.01	0.49	0.78	1.16	0.58	0.86	1.21
Santa Maria-Partington Basin	0.68	0.78	0.89	0.60	0.74	0.90	0.79	0.91	1.05
Total Province	*4.17*	*4.95*	*5.82*	*4.21*	*5.23*	*6.39*	*4.94*	*5.88*	*6.93*
Santa Barbara-Ventura Basin Province									
Santa Barbara-Ventura Basin	1.74	1.85	1.95	3.84	4.61	5.48	2.43	2.67	2.92
Total Province	*1.74*	*1.85*	*1.95*	*3.84*	*4.61*	*5.48*	*2.43*	*2.67*	*2.92*
Los Angeles Basin Province									
Los Angeles Basin	0.19	0.31	0.49	0.17	0.32	0.53	0.22	0.37	0.58
Total Province	*0.19*	*0.31*	*0.49*	*0.17*	*0.32*	*0.53*	*0.22*	*0.37*	*0.58*
Inner Borderland Province									
Santa Monica-San Pedro Area[1]	0.23	0.68	1.47	0.25	0.77	1.68	0.28	0.82	1.76
Oceanside-Capistrano Basin[1]	0	1.11	2.21	0	1.30	3.17	0	1.34	2.70
Total Province[1]	*0.87*	*1.79*	*3.18*	*0.79*	*2.07*	*4.19*	*1.04*	*2.16*	*3.85*
Outer Borderland Province									
Santa Cruz-Santa Rosa Area	0	0.44	0.93	0	0.78	1.85	0	0.58	1.24
San Nicolas Basin	0	0.55	1.18	0	0.91	2.42	0	0.71	1.58
Cortes-Velero-Long Area	0	0.41	1.20	0	1.10	3.49	0	0.61	1.80
Total Province	*0.63*	*1.40*	*2.56*	*0.98*	*2.79*	*5.89*	*0.82*	*1.89*	*3.56*
Total Pacific OCS Region[1]	*8.99*	*10.71*	*12.62*	*15.21*	*18.94*	*23.19*	*11.82*	*14.08*	*16.60*

[1] Includes a small area and volume of resources in the State offshore and onshore area adjacent to the Federal offshore area.

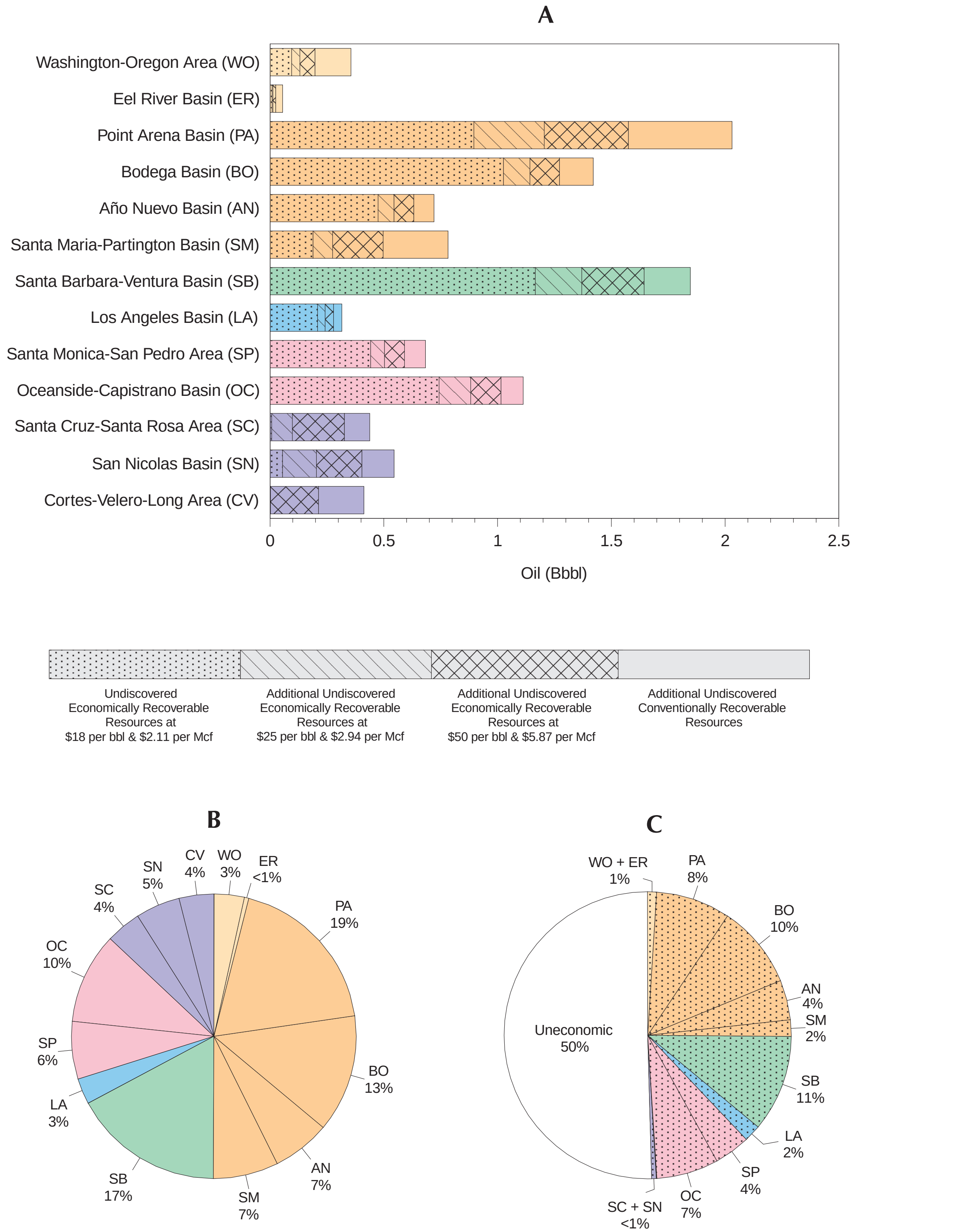


Figure 143. *Distribution of undiscovered conventionally recoverable and economically recoverable oil resources in the Pacific OCS Region, by assessment area based on risked mean estimates listed in tables 48 and 49. Bar chart (A) shows incremental volumes of undiscovered economically recoverable oil resources for three economic scenarios and additional undiscovered conventionally recoverable oil resources; the entire bar represents the estimated total volume of undiscovered conventionally recoverable oil resources. Pie charts show proportionate volumes of undiscovered conventionally recoverable oil resources (B) and undiscovered conventionally recoverable oil resources that are economically recoverable versus uneconomic at the $18-per-bbl scenario (C). The sum of the percentage values in some pie charts may not equal 100 percent due to independent rounding.*

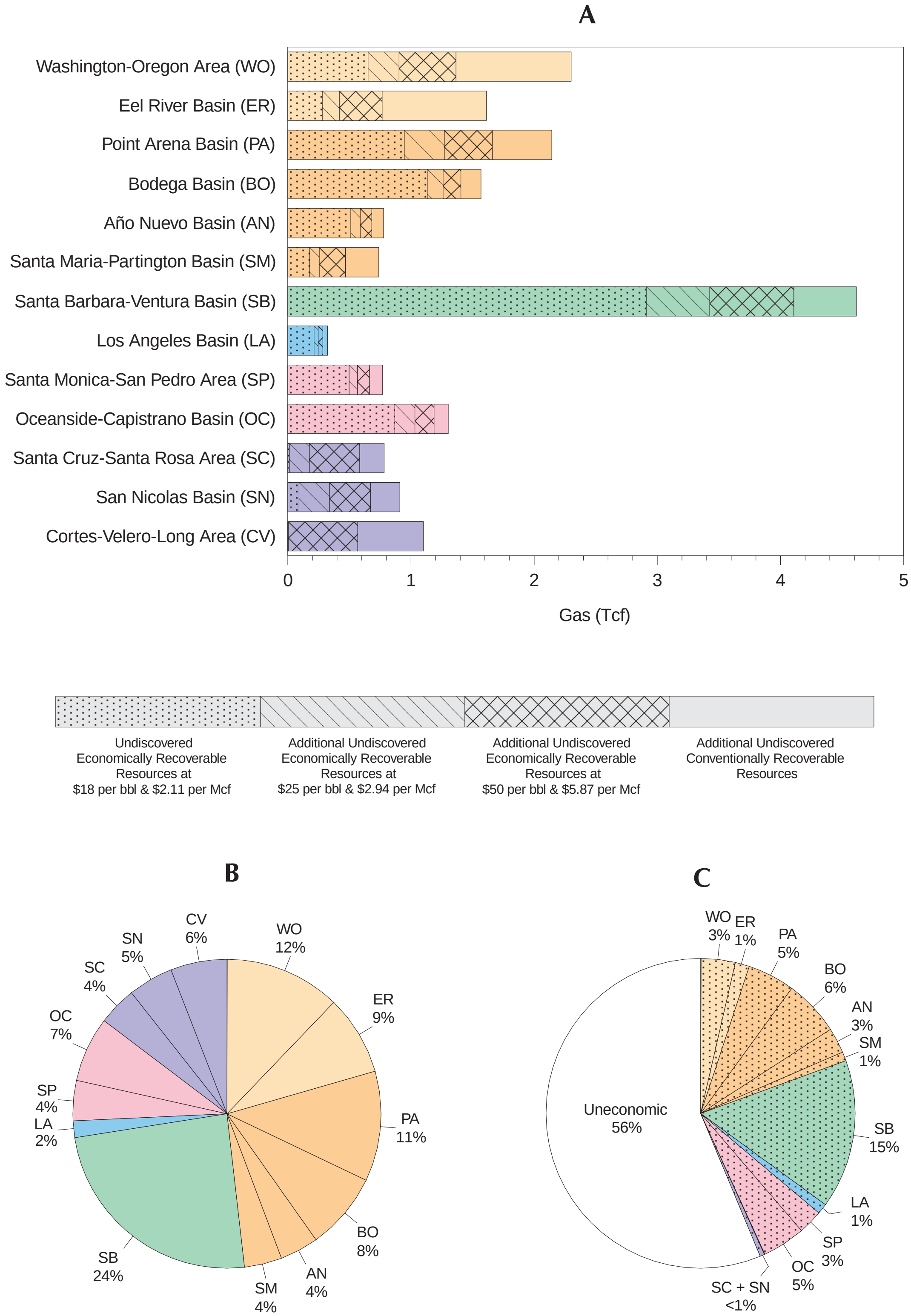


Figure 144. *Distribution of undiscovered conventionally recoverable and economically recoverable gas resources in the Pacific OCS Region, by assessment area based on risked mean estimates listed in tables 48 and 49. Bar chart (A) shows incremental volumes of undiscovered economically recoverable gas resources for three economic scenarios and additional undiscovered conventionally recoverable gas resources; the entire bar represents the estimated total volume of undiscovered conventionally recoverable gas resources. Pie charts show proportionate volumes of undiscovered conventionally recoverable gas resources (B) and undiscovered conventionally recoverable gas resources that are economically recoverable versus uneconomic at the $18-per-bbl scenario (C). The sum of the percentage values in some pie charts may not equal 100 percent due to independent rounding.*

Table 49. *Estimates of undiscovered economically recoverable oil and gas resources in the Pacific OCS Region as of January 1, 1995 for three economic scenarios, by assessment area. All estimates are risked mean values. The $18-per-barrel scenario is based on prices of $18 per bbl of oil and $2.11 per Mcf of gas; the $25-per-barrel scenario is based on prices of $25 per bbl of oil and $2.94 per Mcf of gas; the $50-per-barrel scenario is based on prices of $50 per barrel of oil and $5.87 per Mcf of gas. Some total values may not equal the sum of the component values due to independent rounding.*

Assessment Area	$18-per-barrel Scenario			$25-per-barrel Scenario			$50-per-barrel Scenario		
	Oil (Bbbl)	Gas (Tcf)	BOE (Bbbl)	Oil (Bbbl)	Gas (Tcf)	BOE (Bbbl)	Oil (Bbbl)	Gas (Tcf)	BOE (Bbbl)
Pacific Northwest Province									
Washington-Oregon Area	0.09	0.65	0.21	0.13	0.90	0.29	0.20	1.37	0.44
Eel River Basin	<0.01	0.28	0.06	0.01	0.42	0.09	0.03	0.77	0.16
Total Province	*0.10*	*0.93*	*0.27*	*0.14*	*1.32*	*0.38*	*0.22*	*2.13*	*0.60*
Central California Province									
Point Arena Basin	0.90	0.95	1.06	1.21	1.27	1.43	1.58	1.66	1.87
Bodega Basin	1.03	1.13	1.23	1.14	1.26	1.37	1.27	1.41	1.52
Año Nuevo Basin	0.48	0.51	0.57	0.55	0.59	0.65	0.63	0.68	0.75
Santa Maria-Partington Basin	0.19	0.18	0.22	0.28	0.26	0.32	0.50	0.47	0.58
Total Province	*2.59*	*2.77*	*3.08*	*3.17*	*3.38*	*3.77*	*3.98*	*4.22*	*4.73*
Santa Barbara-Ventura Basin Province									
Santa Barbara-Ventura Basin	1.17	2.91	1.68	1.37	3.43	1.98	1.64	4.11	2.38
Total Province	*1.17*	*2.91*	*1.68*	*1.37*	*3.43*	*.98*	*1.64*	*4.11*	*2.38*
Los Angeles Basin Province									
Los Angeles Basin	0.21	0.21	0.25	0.24	0.25	0.29	0.28	0.29	0.33
Total Province	*0.21*	*0.21*	*0.25*	*0.24*	*0.25*	*0.29*	*0.28*	*0.29*	*0.33*
Inner Borderland Province									
Santa Monica-San Pedro Area[1]	0.44	0.50	0.53	0.50	0.57	0.60	0.59	0.66	0.71
Oceanside-Capistrano Basin[1]	0.74	0.87	0.90	0.88	1.03	1.07	1.02	1.19	1.23
Total Province[1]	*1.19*	*1.37*	*1.43*	*1.39*	*1.60*	*1.67*	*1.61*	*1.85*	*1.94*
Outer Borderland Province									
Santa Cruz-Santa Rosa Area	<0.01	0.01	0.01	0.10	0.18	0.13	0.33	0.58	0.43
San Nicolas Basin	0.06	0.09	0.07	0.20	0.34	0.26	0.40	0.67	0.52
Cortes-Velero-Long Area	0	0	0	<0.01	<0.01	<0.01	0.21	0.57	0.31
Total Province	*0.06*	*0.10*	*0.08*	*0.30*	*0.52*	*0.40*	*0.94*	*1.83*	*1.27*
Total Pacific OCS Region[1]	*5.31*	*8.30*	*6.79*	*6.61*	*10.49*	*8.48*	*8.67*	*14.42*	*11.24*

[1] Includes a small area and volume of resources in the State offshore and onshore area adjacent to the Federal offshore area.

Undiscovered Economically Recoverable Resources

The undiscovered economically recoverable oil and gas resources of the Region are estimated to exist within 13 assessment areas (fig. 10). Mean estimates of the resources in each assessment area of the Region are listed, for three economic scenarios, in table 49. The distribution of undiscovered economically recoverable oil and gas resources among the assessment areas is illustrated in figures 143 and 144. Resource estimates for the $18-per-barrel economic scenario (which assumes prices of $18.00 per bbl of oil and $2.11 per Mcf of gas) are used for illustrative and comparative purposes in this discussion because the oil price of this scenario closely approximates the market price of oil as of this assessment.

One half of the undiscovered conventionally recoverable oil resources of the Region (50 percent on the basis of mean estimates and the $18-per-barrel economic scenario) is estimated to be economically recoverable at economic and technological conditions existing as of this assessment. These resources include relatively large volumes of oil (greater than 1 Bbbl) in the Santa Barbara-Ventura basin (1.17 Bbbl) and Bodega basin (1.03 Bbbl). At more favorable economic conditions, larger volumes of undiscovered economically recoverable oil resources are estimated to exist in these and other areas, particularly in the Point Arena and Oceanside-Capistrano basins.

Less than one half of the undiscovered conventionally recoverable gas resources of the Region (44 percent on the basis of mean estimates and the $18-per-barrel economic scenario) is estimated to be economically recoverable at economic and technological conditions existing as of this assessment. These resources include relatively large volumes of gas (greater than 1 Tcf) in the Santa Barbara-Ventura basin (2.91 Tcf) and Bodega basin (1.13 Tcf). At more favorable economic conditions, larger volumes of undiscovered economically recoverable gas resources are estimated to exist in these and other areas, particularly in the Point Arena basin, Washington-Oregon area, and Oceanside-Capistrano basin.

Total Resource Endowment

The total resource endowment of the Region is estimated to exist in 13 assessment areas (fig. 10). Estimates of the total resource endowment in each assessment area of the Region are listed in table 50. The distribution of the total endowment of oil and gas resources among the assessment areas is illustrated in figures 145A and 146A.

Approximately three quarters (77 percent) of the total endowment of combined oil-equivalent resources of the Region are estimated to be oil. Relatively large endowments of oil resources (greater than 1 Bbbl) are estimated in the Santa Barbara-Ventura basin (2.99 Bbbl), Point Arena basin (2.03 Bbbl), Santa Maria-Partington basin (1.57 Bbbl), Bodega basin (1.42 Bbbl), and Oceanside-Capistrano basin (1.11 Bbbl).

Approximately one quarter (24 percent) of the total endowment of combined oil-equivalent resources of the Region is estimated to be gas. Relatively large endowments of gas resources (greater than 1 Tcf) are estimated to exist in the Santa Barbara-Ventura basin (7.01 Tcf), Washington-Oregon area (2.30 Tcf), Point Arena basin (2.14 Tcf), Eel River basin (1.61 Tcf), Bodega basin (1.57 Tcf), Oceanside-Capistrano basin (1.30 Tcf), and Cortes-Velero-Long area (1.10 Tcf).

The estimated volume of undiscovered oil and gas resources in the Region is more than five times that of discovered resources (figs. 145B and 146B); however, the relative significance of discovered and undiscovered resources in areas where resources have been discovered varies. Nearly identical volumes of discovered and undiscovered resources are estimated to exist in the Santa Maria-Partington Basin assessment area (figs. 145C and 146C). In the Santa Barbara-Ventura Basin assessment area, the estimated volume of undiscovered resources is nearly twice that of discovered resources (figs. 145D and 146D). The estimated volume of undiscovered resources in the Los Angeles Basin assessment area is nearly three times that of discovered oil resources (fig. 145E) and ten times that of discovered gas resources (fig. 146E).

Table 50. *Estimates of the total endowment of oil and gas resources in the Pacific OCS Region, by assessment area. Estimates of discovered resources (including cumulative production and remaining reserves) and undiscovered resources are as of January 1, 1995. Estimates of undiscovered conventionally recoverable resources are risked mean values. Some total values may not equal the sum of the component values due to independent rounding.*

Assessment Area	Discovered Resources (Reserves): Cumulative Production			Discovered Resources (Reserves): Remaining Reserves			Undiscovered Conventionally Recoverable Resources			Total Resource Endowment		
	Oil (Bbbl)	Gas (Tcf)	BOE (Bbbl)	Oil (Bbbl)	Gas (Tcf)	BOE (Bbbl)	Oil (Bbbl)	Gas (Tcf)	BOE (Bbbl)	Oil (Bbbl)	Gas (Tcf)	BOE (Bbbl)
Pacific Northwest Province												
Washington-Oregon Area	0	0	0	0	0	0	0.36	2.30	0.76	0.36	2.30	0.77
Eel River Basin	0	0	0	0	0	0	0.05	1.61	0.34	0.06	1.61	0.34
Total Province	*0*	*0*	*0*	*0*	*0*	*0*	*0.41*	*3.91*	*1.11*	*0.41*	*3.91*	*1.11*
Central California Province												
Point Arena Basin	0	0	0	0	0	0	2.03	2.14	2.41	2.03	2.14	2.41
Bodega Basin	0	0	0	0	0	0	1.42	1.57	1.70	1.42	1.57	1.70
Año Nuevo Basin	0	0	0	0	0	0	0.72	0.78	0.86	0.72	0.78	0.86
Santa Maria-Partington Basin	0.12	0.04	0.13	0.67	0.66	0.78	0.78	0.74	0.91	1.57	1.44	1.82
Total Province	*0.12*	*0.04*	*0.13*	*0.67*	*0.66*	*0.78*	*4.95*	*5.23*	*5.88*	*5.74*	*5.93*	*6.79*
Santa Barbara-Ventura Basin Province												
Santa Barbara-Ventura Basin	0.49	0.67	0.61	0.65	1.72	0.96	1.85	4.61	2.67	2.99	7.01	4.24
Total Province	*0.49*	*0.67*	*0.61*	*0.65*	*1.72*	*0.96*	*1.85*	*4.61*	*2.67*	*2.99*	*7.01*	*4.24*
Los Angeles Basin Province												
Los Angeles Basin	0.07	0.02	0.07	0.06	0.01	0.06	0.31	0.32	0.37	0.44	0.36	0.50
Total Province	*0.07*	*0.02*	*0.07*	*0.06*	*0.01*	*0.06*	*0.31*	*0.32*	*0.37*	*0.44*	*0.36*	*0.50*
Inner Borderland Province												
Santa Monica-San Pedro Area[1]	0	0	0	0	0	0	0.68	0.77	0.82	0.68	0.77	0.82
Oceanside-Capistrano Basin[1]	<0.01	<0.01	<0.01	negligible			1.11	1.30	1.34	1.11	1.30	1.34
Total Province[1]	*<0.01*	*<0.01*	*<0.01*	*negligible*			*1.79*	*2.07*	*2.16*	*1.79*	*2.07*	*2.16*
Outer Borderland Province												
Santa Cruz-Santa Rosa Area	0	0	0	0	0	0	0.44	0.78	0.58	0.44	0.78	0.58
San Nicolas Basin	0	0	0	0	0	0	0.55	0.91	0.71	0.55	0.91	0.71
Cortes-Velero-Long Area	0	0	0	0	0	0	0.41	1.10	0.61	0.41	1.10	0.61
Total Province	*0*	*0*	*0*	*0*	*0*	*0*	*1.40*	*2.79*	*1.89*	*1.40*	*2.79*	*1.89*
Total Pacific OCS Region[1]	*0.68*	*0.74*	*0.81*	*1.38*	*2.39*	*1.80*	*10.71*	*18.94*	*14.08*	*12.77*	*22.07*	*16.69*

[1] Includes a small area and volume of resources in the State offshore and onshore area adjacent to the Federal offshore area.

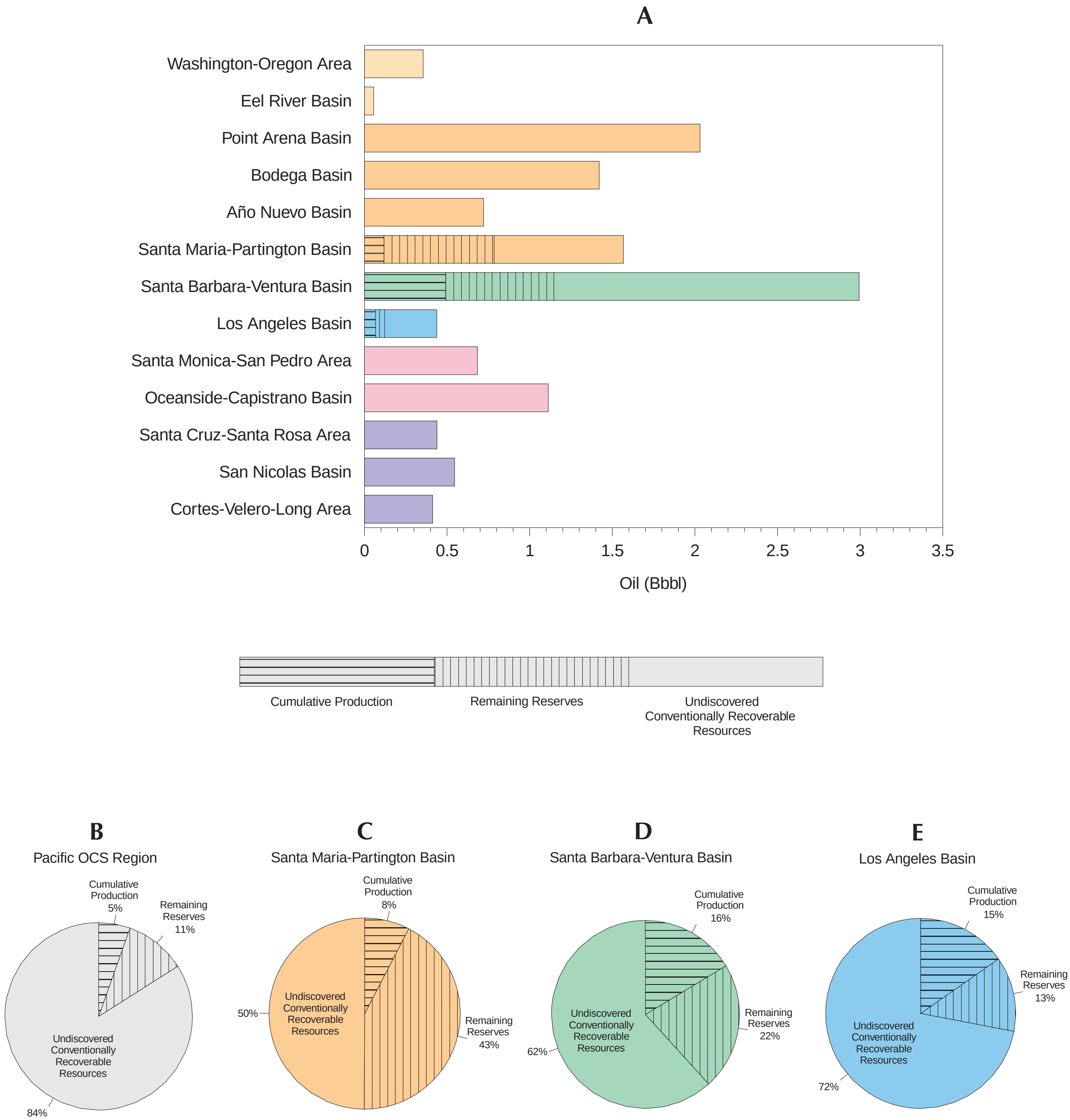


Figure 145. *Distribution of the total endowment of oil resources in the Pacific OCS Region, by assessment area based on estimates listed in table 50. Bar chart (A) shows incremental volumes of discovered oil resources (including cumulative production and remaining reserves) and undiscovered conventionally recoverable oil resources; the entire bar represents the estimated total endowment of oil resources. Pie charts show proportionate volumes of discovered oil resources and undiscovered oil resources in the Pacific OCS Region (B), Santa Maria-Partington Basin assessment area (C), Santa Barbara-Ventura Basin assessment area (D), and Los Angeles Basin assessment area (E). The sum of the percentage values in some pie charts may not equal 100 percent due to independent rounding.*

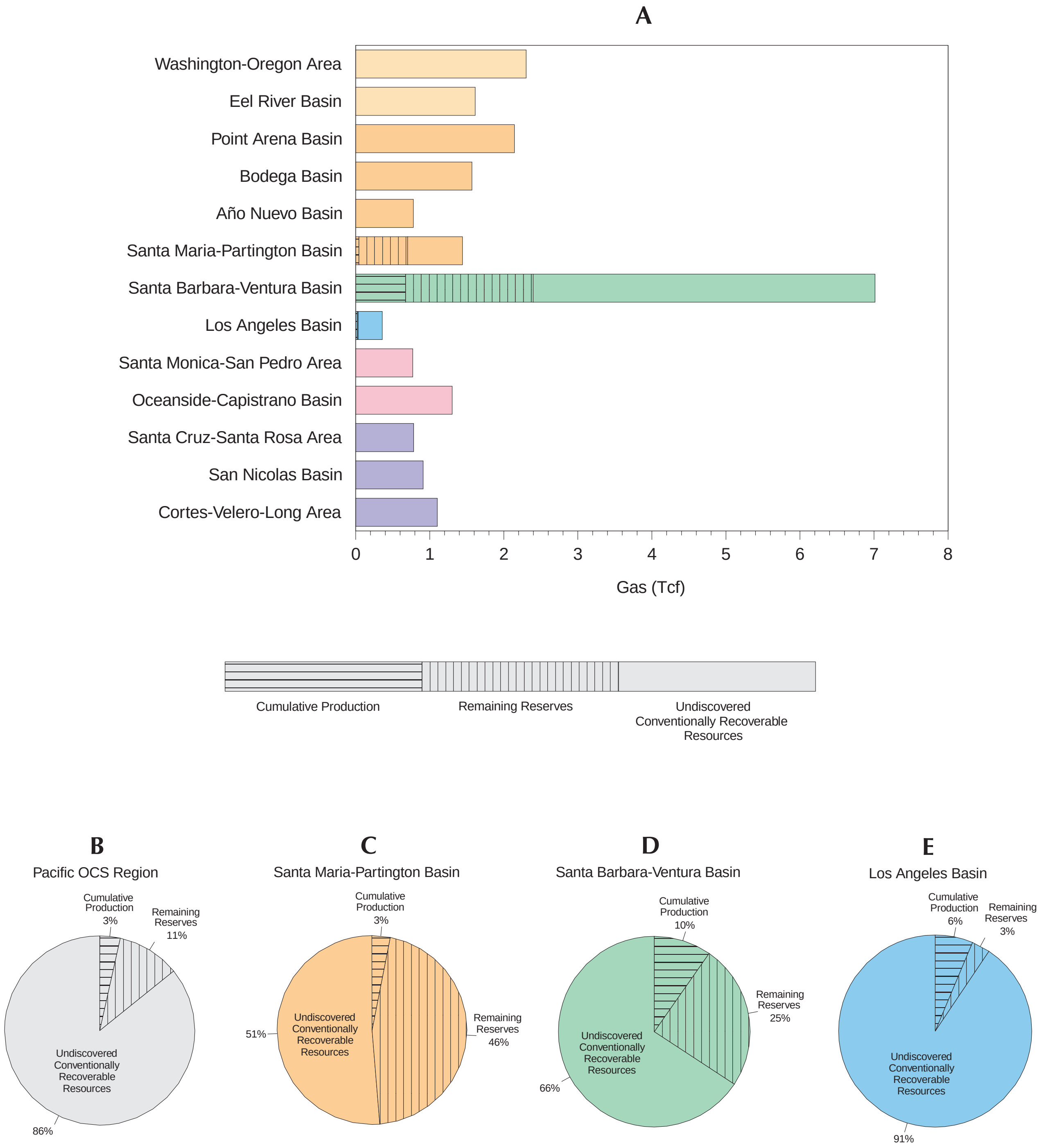


Figure 146. *Distribution of the total endowment of gas resources in the Pacific OCS Region, by assessment area based on estimates listed in table 50. Bar chart (A) shows incremental volumes of discovered gas resources (including cumulative production and remaining reserves) and undiscovered conventionally recoverable gas resources; the entire bar represents the estimated total endowment of gas resources. Pie charts show proportionate volumes of discovered gas resources and undiscovered gas resources in the Pacific OCS Region (B), Santa Maria-Partington Basin assessment area (C), Santa Barbara-Ventura Basin assessment area (D), and Los Angeles Basin assessment area (E). The sum of the percentage values in some pie charts may not equal 100 percent due to independent rounding.*

Geologic Distribution of Resources

Distribution of Resources by Exploration and Discovery Status of Plays

The 46 assessed plays in the Pacific OCS Region consist of 9 established plays, 17 frontier plays, and 20 conceptual plays (see *Introduction* section and table 1). Mean estimates of the undiscovered conventionally recoverable oil and gas resources in each play class are listed in table 51 and illustrated in figure 147.

Approximately three quarters of the undiscovered conventionally recoverable oil and gas resources in the Region are estimated to exist in frontier and conceptual plays where hydrocarbon accumulations have not yet been discovered. More than one quarter of the undiscovered conventionally recoverable oil and gas resources in the Region is estimated to exist in established plays where hydrocarbon accumulations have been discovered.

Distribution of Resources by Hydrocarbon Type of Plays

The 46 assessed plays consist of 36 oil plays and 10 mixed plays; no gas plays were defined (see *Introduction* section and table 1). Mean estimates of the undiscovered conventionally recoverable oil and gas resources in each play class are listed in table 52 and illustrated in figure 148.

The majority of the undiscovered conventionally recoverable oil and gas resources in the Region are estimated to exist in oil plays. More than one third of the undiscovered conventionally recoverable gas resources (some of which is nonassociated gas) and a small volume of undiscovered conventionally recoverable oil resources is estimated to exist in mixed plays.

Distribution of Resources by Reservoir Rocks of Plays

The 46 assessed plays consist of 25 plays having Neogene clastic reservoir rocks, 9 plays having Neogene fractured siliceous reservoir rocks, and 12 plays having Paleogene-Cretaceous reservoir rocks; no plays having melange reservoir rocks were assessed (see *Introduction* section and table 1). Mean estimates of the undiscovered conventionally recoverable oil and gas resources in each play class are listed in table 53 and illustrated in figure 149.

Although only 9 of the 46 assessed plays have Neogene fractured siliceous reservoir rocks (i.e., Monterey Formation or correlative rocks), those plays are estimated to contain more than one half of the undiscovered conventionally recoverable oil resources and one third of the undiscovered conventionally recoverable gas resources in the Region. The 25 assessed plays having Neogene clastic reservoir rocks are estimated to contain nearly one third of the undiscovered conventionally recoverable oil resources and nearly one half of the undiscovered conventionally recoverable gas resources in the Region. The 12 assessed plays having Paleogene-Cretaceous reservoir rocks are estimated to contain relatively small volumes of undiscovered conventionally recoverable oil and gas resources.

Table 51. *Estimates of undiscovered conventionally recoverable oil and gas resources in the Pacific OCS Region as of January 1, 1995, by exploration and discovery status of plays. All estimates are risked mean values. Some total values may not equal the sum of the component values due to independent rounding.*

Play Class Based on Exploration & Discovery Status	Number of Plays		Oil (Bbbl)	Gas (Tcf)	BOE (Bbbl)
	Defined	Assessed			
Established *plays in which hydrocarbon accumulations have been discovered*	10	9	2.83	6.20	3.93
Frontier *plays in which hydrocarbon accumulations have not been discovered, but in which hydrocarbons have been detected*	18	17	4.84	7.28	6.13
Conceptual *plays in which hydrocarbons have not been detected, but for which data suggest that hydrocarbon accumulations may exist*	22	20	3.04	5.47	4.02
Total	*50*	*46*	*10.71*	*18.94*	*14.08*

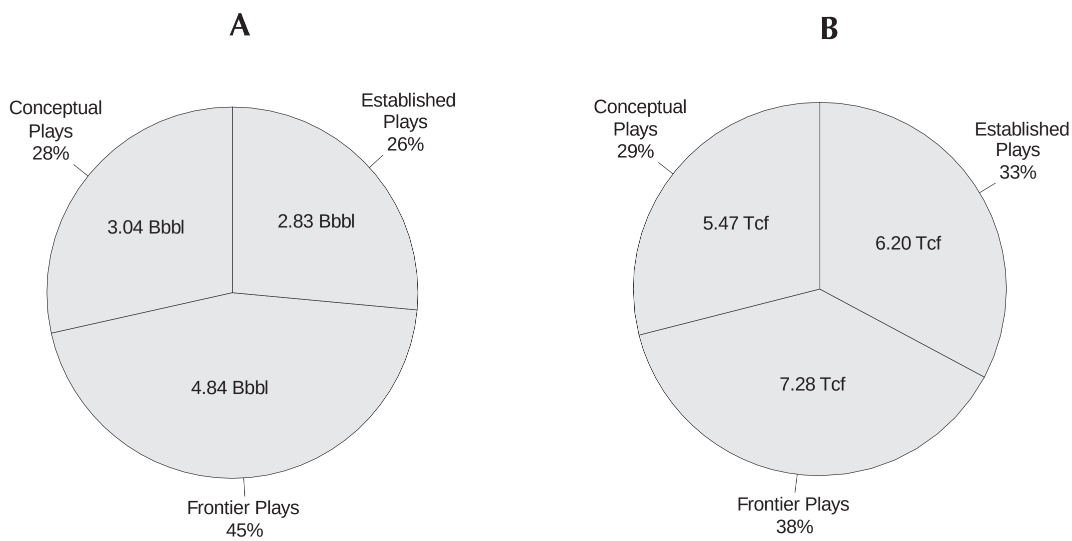


Figure 147. *Distribution of undiscovered conventionally recoverable oil (A) and gas (B) resources in the Pacific OCS Region, by exploration and discovery status of plays based on estimates listed in table 51. The sum of the percentage values in some pie charts may not equal 100 percent due to independent rounding.*

Table 52. *Estimates of undiscovered conventionally recoverable oil and gas resources in the Pacific OCS Region as of January 1, 1995, by predominant hydrocarbon type of plays. All estimates are risked mean values. Some total values may not equal the sum of the component values due to independent rounding.*

Play Class Based on Predominant Hydrocarbon Type	Number of Plays		Oil (Bbbl)	Gas (Tcf)	BOE (Bbbl)
	Defined	Assessed			
Oil *plays that contain predominantly crude oil and associated gas*	39	36	9.60	11.87	11.71
Gas *plays that contain predominantly nonassociated gas and may contain condensate*	0	0	N/A	N/A	N/A
Mixed *plays that contain crude oil, associated gas, and nonassociated gas and may contain condensate*	11	10	1.11	7.07	2.37
Total	*50*	*46*	*10.71*	*18.94*	*14.08*

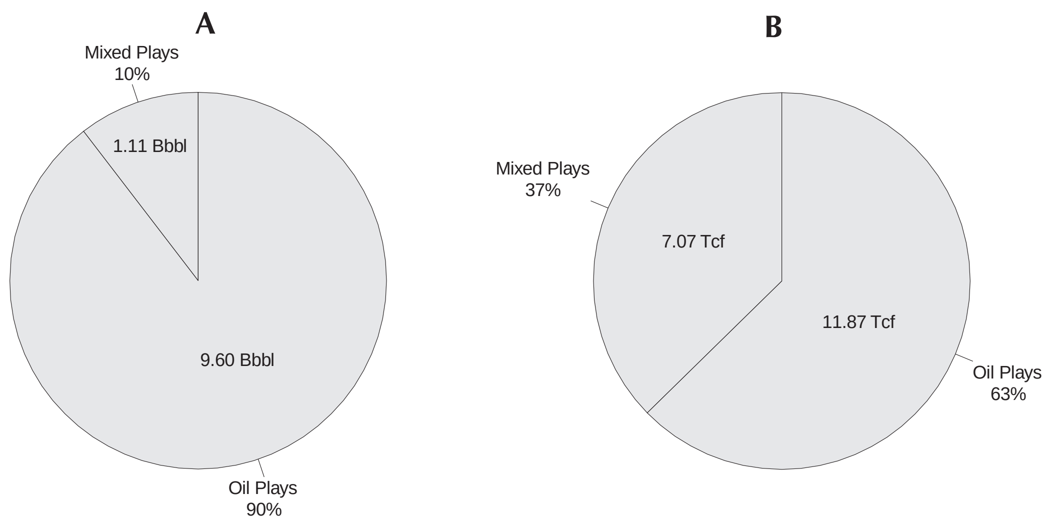


Figure 148. *Distribution of undiscovered conventionally recoverable oil (A) and gas (B) resources in the Pacific OCS Region, by predominant hydrocarbon type of plays based on estimates listed in table 52.*

Table 53. *Estimates of undiscovered conventionally recoverable oil and gas resources in the Pacific OCS Region as of January 1, 1995, by reservoir rock type of plays. All estimates are risked mean values. Some total values may not equal the sum of the component values due to independent rounding.*

Play Class Based on Reservoir Rock Type	Number of Plays		Oil (Bbbl)	Gas (Tcf)	BOE (Bbbl)
	Defined	Assessed			
Neogene Clastic *plays having reservoir rocks that consist of Miocene and/or Pliocene sandstone, siltstone, shale, and/or breccia*	26	25	3.46	8.65	5.00
Neogene Fractured Siliceous *plays having reservoir rocks that consist of Miocene fractured chert, siliceous shale, porcelanite, dolomite, and/or limestone*	9	9	5.96	6.32	7.08
Paleogene-Cretaceous Clastic *plays having reservoir rocks that consist of Cretaceous through Oligocene sandstone, siltstone, and/or shale*	13	12	1.30	3.96	2.00
Melange *plays having reservoir rocks that consist of sandstone within Cretaceous through Miocene melange*	2	0	N/A	N/A	N/A
Total	*50*	*46*	*10.71*	*18.94*	*14.08*

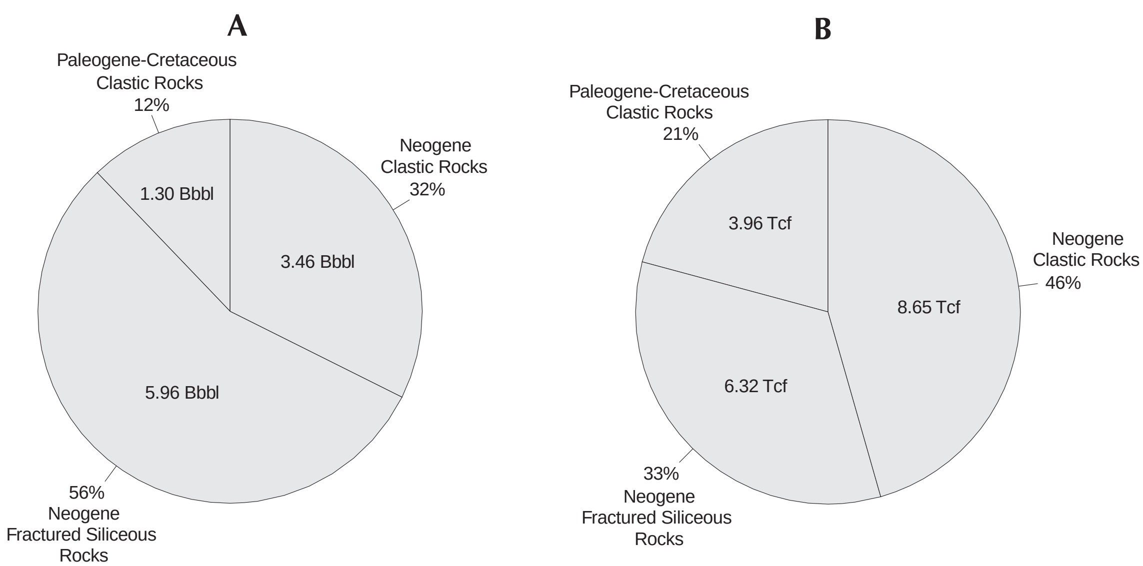


Figure 149. *Distribution of undiscovered conventionally recoverable oil (A) and gas (B) resources in the Pacific OCS Region, by reservoir rocks of plays based on estimates listed in table 53.*

COMPARISON OF RESOURCE ESTIMATES WITH PREVIOUS ASSESSMENTS

Several past assessments of the undiscovered oil and gas resources of the United States addressed resources of the Pacific OCS Region. Comparisons of resource estimates from different assessments are meaningful only if comparable areas, hydrocarbon commodities (e.g., oil vs. gas), and resource categories (e.g., conventionally recoverable vs. economically recoverable) have been assessed, and comparable types of estimates (e.g., conditional vs. risked and percentile vs. mean) are compared. Such comparisons demonstrate the degree to which resource estimates have changed and may provide insight regarding the factors that contributed to the change.

A comparison of select resource estimates from this and two previous MMS assessments[19] of the Pacific OCS Region is presented here. The 1987 assessment, which was conducted concurrently with the USGS and assessed resources as of January 1, 1987, is documented in Mast and others (1989) and Cooke and Dellagiarino (1990). Some of the results of the 1990 assessment, which assessed resources as of January 1990, are documented in Cooke (1991); other results have not been previously published but are presented here.

Undiscovered Conventionally Recoverable Resources

The commodities and category of hydrocarbon resources referred to as "undiscovered conventionally recoverable resources" for this assessment are comparable to those resources referred to and assessed as the "undiscovered resource base" for the 1987 and 1990 assessments. Comparable estimates of the volume of these oil and gas resources in the Region and its constituent assessment provinces are listed in tables 54 and 55 and illustrated in figures 150 and 151. Estimates of the volume of undiscovered conventionally recoverable oil and gas resources in the Region from this assessment have a significantly larger magnitude and smaller (narrower) range than estimates from the previous assessments.

The mean estimated volume of undiscovered conventionally recoverable oil resources in the Region from this assessment is approximately three times that estimated from the 1990 assessment (7.12 Bbbl more than previously estimated). Mean estimates of the volume of undiscovered conventionally recoverable oil resources have increased in all assessment provinces, particularly in the Central California province (2.87 Bbbl more than previously estimated), Santa Barbara-Ventura Basin province (1.53 Bbbl more than previously estimated), and Inner Borderland province (1.34 Bbbl more than previously estimated).

The mean estimated volume of undiscovered conventionally recoverable gas resources in the Region from this assessment is nearly twice that estimated from the 1990 assessment (8.08 Tcf more than previously estimated). Mean estimates of the volume of undiscovered conventionally recoverable gas resources have increased in most assessment provinces, particularly in the Santa Barbara-Ventura Basin province (3.71 Tcf more than previously estimated), Central California province (2.08 Tcf more than previously estimated), and Inner Borderland province (1.29 Tcf more than previously estimated). The mean estimated volume of undiscovered conventionally recoverable gas resources in the Pacific Northwest province decreased slightly.

The increased magnitude of the estimated volume of undiscovered conventionally recoverable oil and gas resources in the Region and most assessment provinces is attributed to the use of significantly different methodology and some additional data for this assessment. The more comprehensive petroleum geological analysis that was performed for this assessment led to the recognition of additional petroleum source rocks and reservoir rocks in many areas and to the definition of additional plays. Rock compositional data that were newly acquired for the analysis indicated that the volume of fractured siliceous "Monterey" reservoir rocks (which have high hydrocarbon potential) in some basins offshore California is larger than previously believed. Additionally, the recognition and applied use of the concept of lognormality in the analysis of plays (i.e., that pools within a play have sizes and volumetric properties that are lognormally distributed) are believed to have led to the consideration of additional and possibly larger pools in many plays.

[19] An assessment of undiscovered economically recoverable resources in the Pacific OCS Region as of July 1984 was conducted by MMS and is documented in Cooke (1985); however, the resource estimates from the 1984 assessment are not comparable to those from the 1987, 1990, and 1995 assessments and are not included in this discussion.

Table 54. *Comparable estimates of undiscovered conventionally recoverable oil and gas resources[1] in the Pacific OCS Region, by assessment. All estimates are risked values. The low, mean, and high estimates correspond to the 95th-percentile, mean, and 5th-percentile values of a probability distribution, respectively. N/R denotes an estimate not reported.*

Assessment	Oil (Bbbl)			Gas (Tcf)			BOE (Bbbl)		
	Low	Mean	High	Low	Mean	High	Low	Mean	High
MMS 1987	0.81	3.51	8.92	3.50	8.01	15.07	N/R	4.94	N/R
MMS 1990	1.37	3.59	7.26	6.38	10.86	16.94	N/R	5.52	N/R
MMS 1995	8.99	10.71	12.62	15.21	18.94	23.19	11.82	14.08	16.60

[1] Estimates of undiscovered conventionally recoverable resources from the 1995 assessment are comparable to estimates of the undiscovered resource base from the 1987 and 1990 assessments.

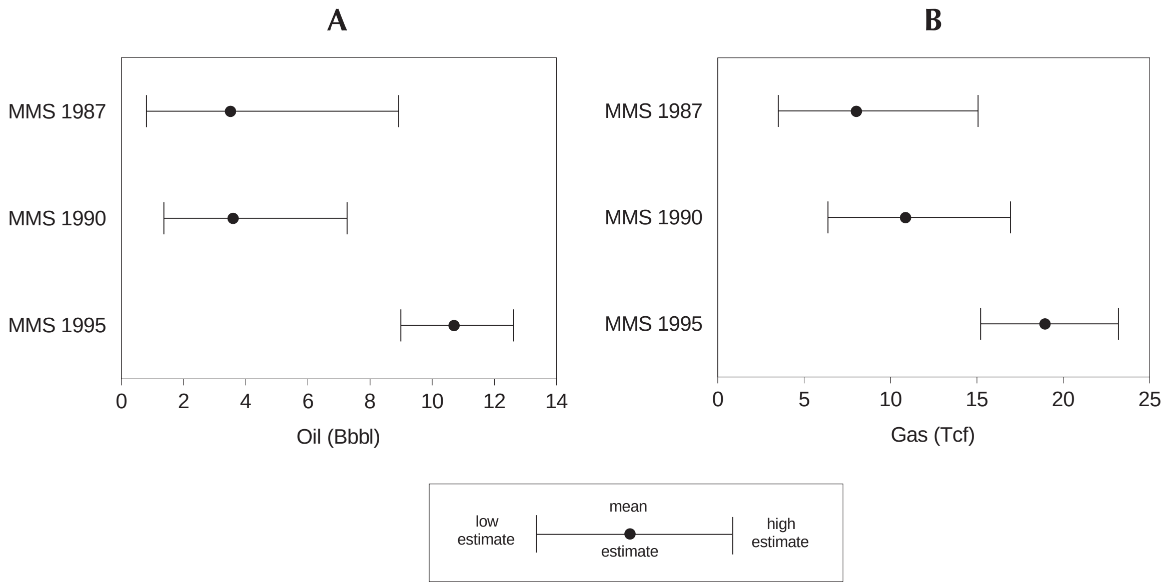


Figure 150. *Comparison of estimates of undiscovered conventionally recoverable oil (A) and gas (B) resources in the Pacific OCS Region, by assessment. The estimates correspond to those listed in table 54.*

UNDISCOVERED ECONOMICALLY RECOVERABLE RESOURCES

The commodities and category of hydrocarbon resources referred to as “undiscovered economically recoverable resources” for this and the previous assessments are conceptually comparable; however, estimates of the volume of these oil and gas resources reflect different economic assumptions (i.e., prices, costs, and timing) and are, therefore, not completely comparable. The “$18-per-barrel economic scenario” of this assessment is similar to the “primary case economic scenario” of the 1987 and 1990 assessments; therefore, the estimates of undiscovered economically recoverable resources for these scenarios are closely (but not completely) comparable. These comparable estimates of the undiscovered economically recoverable oil and gas resources in the Region and its constituent assessment provinces are listed in tables 55 and 56, and illustrated in figures 151 and 152. Mean estimates of the volume of undiscovered economically recoverable oil and gas resources in the Region and most assessment provinces have increased; however, the proportion of undiscovered conventionally recoverable resources that are estimated to be economically recoverable in the Region and most assessment provinces has decreased.

Table 55. *Comparable estimates of undiscovered conventionally recoverable and economically recoverable oil and gas resources in assessment provinces of the Pacific OCS Region, by assessment. All estimates are risked mean values.*

Assessment	Undiscovered Conventionally Recoverable Resources[1]			Undiscovered Economically Recoverable Resources[2]		
	Oil (Bbbl)	Gas (Tcf)	BOE (Bbbl)	Oil (Bbbl)	Gas (Tcf)	BOE (Bbbl)
Pacific Northwest Province[3]						
MMS 1987	0.19	2.18	0.58	0.08	1.15	0.28
MMS 1990	0.40	4.34	1.16	0.08	1.01	0.26
MMS 1995	0.41	3.91	1.11	0.10	0.93	0.27
Central California Province[4]						
MMS 1987	2.14	2.47	2.58	1.00	1.30	1.23
MMS 1990	2.08	3.15	2.64	1.28	2.17	1.67
MMS 1995	4.95	5.23	5.88	2.59	2.77	3.08
Santa Barbara-Ventura Basin Province[5]						
MMS 1987	0.32	0.90	0.48	0.29	0.79	0.43
MMS 1995	1.85	4.61	2.67	1.17	2.91	1.68
Los Angeles Basin Province[6]						
MMS 1987	0.09	0.13	0.12	0.09	0.13	0.12
MMS 1995	0.31	0.32	0.37	0.21	0.21	0.25
Inner Borderland Province[7]						
MMS 1987	0.45	0.78	0.59	0.40	0.69	0.52
MMS 1995	1.79	2.07	2.16	1.19	1.37	1.43
Outer Borderland Province[8]						
MMS 1987	0.33	1.55	0.61	0.23	1.11	0.43
MMS 1995	1.40	2.79	1.89	0.06	0.10	0.08

[1] Estimates of undiscovered conventionally recoverable resources from the 1995 assessment are comparable to estimates of the undiscovered resource base from the 1987 and 1990 assessments.

[2] Estimates of undiscovered economically recoverable resources from the 1987, 1990, and 1995 assessments are closely (but not completely) comparable, as follows:

Estimates from the 1987 and 1990 assessments are for the primary case economic scenario and are based on variable prices starting at $18.00 per bbl of oil and $1.80 per Mcf of gas.

Estimates from the 1995 assessment are for the $18-per-barrel economic scenario and are based on fixed prices of $18.00 per bbl of oil and $2.11 per Mcf of gas.

[3] Formerly referred to and assessed as the Washington-Oregon and Northern California-Southern Oregon provinces.

[4] Formerly referred to and assessed as the Central California and Santa Maria provinces.

[5] Formerly referred to and assessed as the Santa Barbara province.

[6] Formerly referred to and assessed as the Los Angeles Basin province.

[7] Formerly referred to and assessed as the Inner Banks province.

[8] Formerly referred to and assessed as the Outer Banks province.

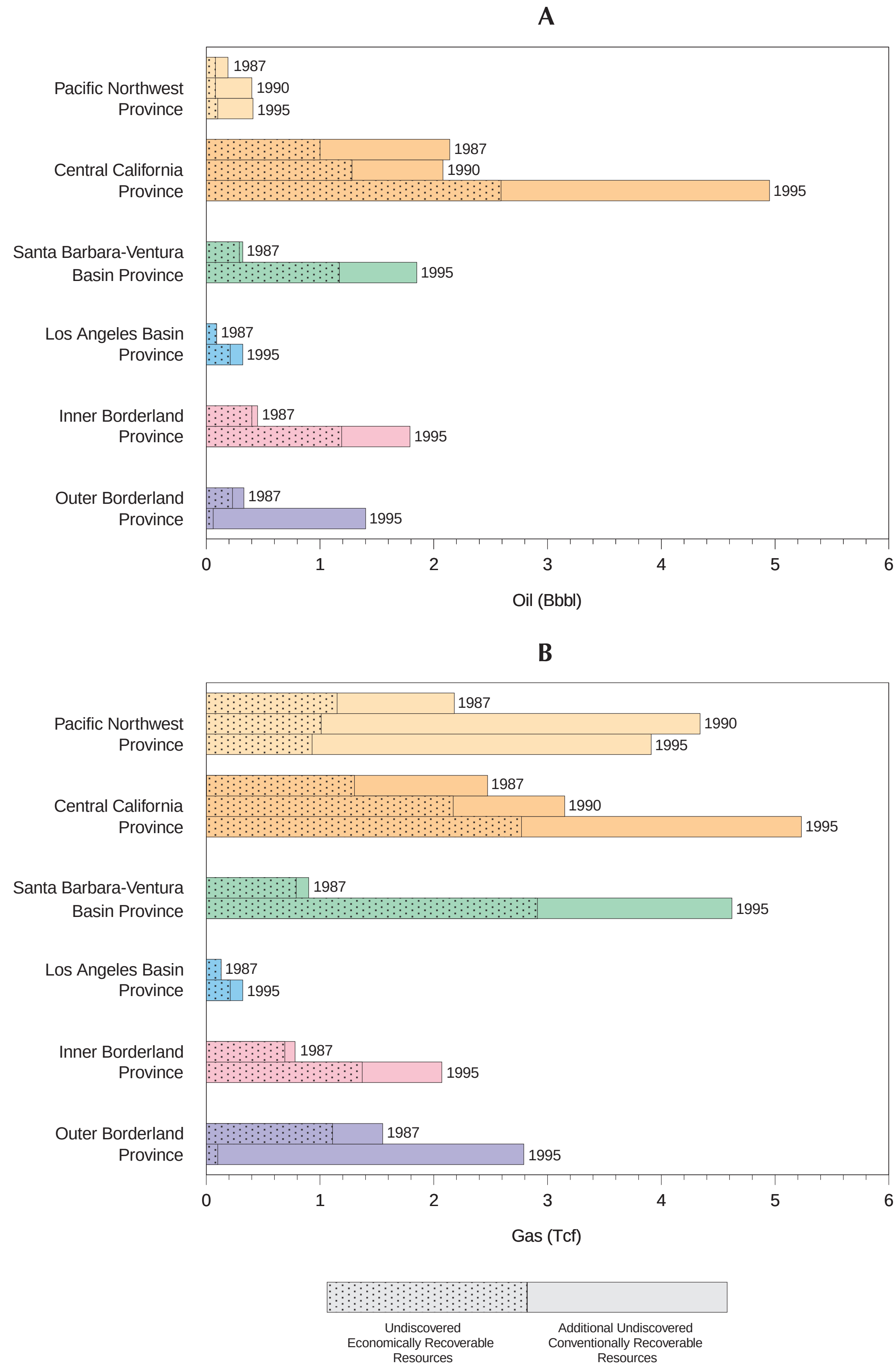


Figure 151. *Comparison of estimates of undiscovered conventionally recoverable and economically recoverable oil (A) and gas (B) resources in assessment provinces of the Pacific OCS Region, by assessment. The estimates correspond to those listed in table 55.*

Table 56. *Comparable estimates of undiscovered economically recoverable oil and gas resources*[1] *in the Pacific OCS Region, by assessment. All estimates are risked values. The low, mean, and high estimates correspond to the 95th-percentile, mean, and 5th-percentile values of a probability distribution, respectively. N/R denotes an estimate not reported.*

Assessment	Oil (Bbbl)			Gas (Tcf)			BOE (Bbbl)		
	Low	Mean	High	Low	Mean	High	Low	Mean	High
MMS 1987	0.34	2.10	6.02	1.78	5.17	11.04	N/R	3.02	N/R
MMS 1990	0.63	2.49	6.12	2.46	6.15	12.14	N/R	3.58	N/R
MMS 1995	N/R	5.31	N/R	N/R	8.30	N/R	N/R	6.79	N/R

[1] Estimates of undiscovered economically recoverable resources from the 1987, 1990, and 1995 assessments are closely (but not completely) comparable, as follows:

Estimates from the 1987 and 1990 assessments are for the primary case economic scenario and are based on variable prices starting at $18.00 per bbl of oil and $1.80 per Mcf of gas.

Estimates from the 1995 assessment are for the $18-per-barrel economic scenario and are based on fixed prices of $18.00 per bbl of oil and $2.11 per Mcf of gas.

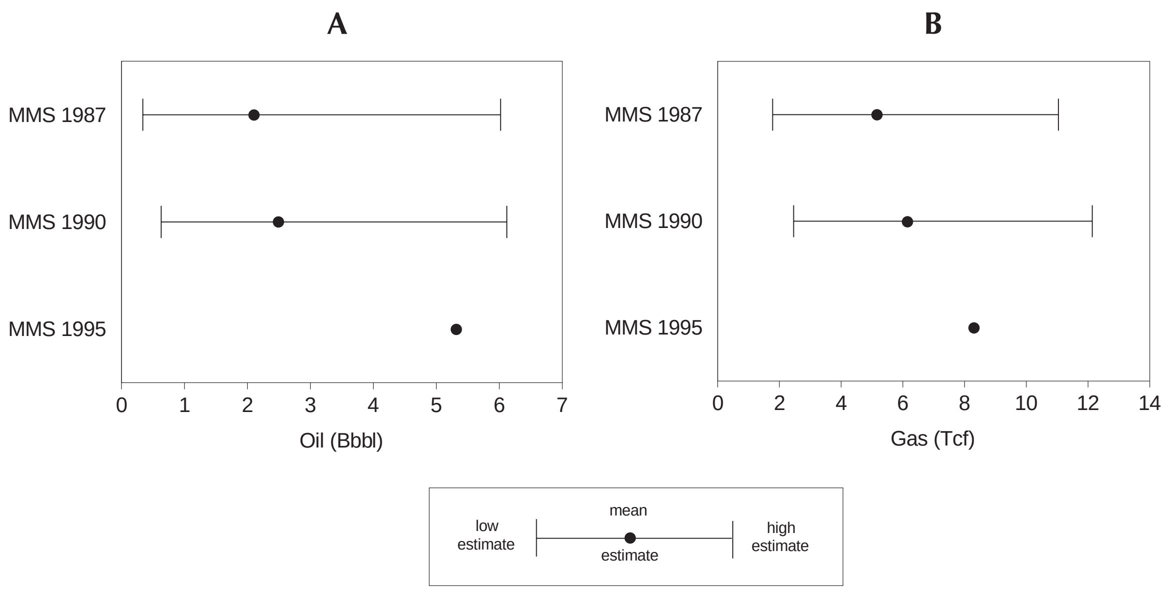


Figure 152. *Comparison of estimates of undiscovered economically recoverable oil (A) and gas (B) resources in the Pacific OCS Region, by assessment. The estimates correspond to those listed in table 56.*

The mean estimated volume of undiscovered economically recoverable oil resources in the Region from this assessment is approximately twice that estimated from the 1990 assessment (2.82 Bbbl more than previously estimated). Mean estimates of the volume of undiscovered economically recoverable oil resources have increased in most assessment provinces, particularly in the Central California province (1.31 Bbbl more than previously estimated), Santa Barbara-Ventura Basin province (0.88 Bbbl more than previously estimated), and Inner Borderland province (0.79 Bbbl more than previously estimated). The mean estimated volume of undiscovered economically recoverable oil resources in the Outer Borderland province decreased markedly.

The mean estimated volume of undiscovered economically recoverable gas resources in the Region from this assessment is nearly one and one-half times that estimated from the 1990 assessment (2.15 Tcf more than previously estimated). Mean estimates of the volume of undiscovered economically recoverable gas resources have increased in many assessment provinces, particularly in the Santa Barbara-Ventura Basin province (2.12 Tcf more than previously estimated), Inner Borderland province (0.68 Tcf more than previously estimated), and Central California province (0.60 Tcf more than previously estimated). The mean estimated volume of undiscovered economically recoverable gas resources in the Outer Borderland province decreased significantly (1.01 Tcf less than previously estimated) and in the Pacific Northwest province decreased slightly.

The increased magnitude of the estimated volume of undiscovered economically recoverable oil and gas resources in the Region and most assessment provinces is primarily attributed to the increased magnitude of the estimated volume of undiscovered conventionally recoverable oil and gas resources. The decreased magnitude of the estimated volume of undiscovered economically recoverable oil and gas resources in the Outer Borderland province is attributed to the recognition that most potential fields exist at greater water depths than previously believed.

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MMS Pacific Region National Assessment Team

Project Coordination .... *Harold E. Syms and Catherine A. Dunkel*

Assessment Geoscientists

- Washington-Oregon Area .... *Kenneth A. Piper*
- Eel River Basin .... *Kenneth A. Piper*
- Point Arena Basin .... *Kenneth A. Piper*
- Bodega Basin .... *Catherine A. Dunkel*
- Año Nuevo Basin .... *Catherine A. Dunkel*
- Santa Maria-Partington Basin .... *Drew Mayerson*
- Santa Barbara-Ventura Basin .... *James M. Galloway*
- Los Angeles Basin .... *Scott D. Drewry*
- Santa Monica-San Pedro Area .... *Scott D. Drewry*
- Oceanside-Capistrano Basin .... *Frank W. Victor*
- Santa Cruz-Santa Rosa Area .... *Frank W. Victor*
- San Nicolas Basin .... *Frank W. Victor*
- Cortes-Velero-Long Area .... *Frank W. Victor*

Economic Assessment .... *Kenneth A. Piper and Armen Voskanian*

Report Coordination .... *Catherine A. Dunkel*

Report Illustrations .... *Scott D. Drewry, Kenneth A. Piper, and Catherine A. Dunkel*

Report Layout and Digital Composition .... *Kenneth A. Piper*

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Appendix A
A DISCUSSION OF RESERVES APPRECIATION IN THE CALIFORNIA OCS

by Harold E. Syms

Reserves appreciation (reserves growth) is the amount of oil and gas resources in known accumulations that is expected to augment proved reserves as a consequence of the extension of known pools within existing fields, discovery of new pools within existing fields, or the application of improved extraction techniques. A preliminary study of reserves growth in the California Outer Continental Shelf (OCS) was performed in conjunction with this assessment in order to more thoroughly estimate the oil and gas resources of the Pacific OCS Region and to incorporate significant findings regarding reserves growth in the estimation of the Region's undiscovered conventionally recoverable oil and gas resources. A discussion of the data, methodological approaches, and conclusions of this study is presented here.

DATA

A total of 38 fields have been discovered in the California OCS; oil and gas were first produced in 1968 and were being produced from 11 fields at the time of this assessment (January 1, 1995) (Sorensen and others, 1995). The Minerals Management Service has developed estimates of proved and unproved oil and gas reserves in discovered fields of the California OCS since 1976 using decline-curve and volumetric analyses. Estimates of proved reserves from 11 producing fields comprise the database used to study reserves growth in the California OCS. A total of approximately 70 reserves estimates have been developed for the 11 fields; the number of estimates for individual fields ranges from 2 to 11.

APPROACHES

Two methodological approaches were considered for the study of reserves growth in the California OCS. An empirical approach, in which reserves estimates from the producing fields in the California OCS were studied to calculate a reserves growth factor, was followed and is described. An analog-based approach involving the use of a reserves growth factor from other areas was also considered; the rationale for rejecting this approach is also described.

Empirical approach

Volumetric estimates of proved oil and gas reserves for the 11 producing fields in the California OCS were compiled and reserves growth factors were calculated using the methodology of Root and Attanasi (1993). The results of this analysis indicate that there is not a common trend of reserves growth among the 11 fields. Several of the fields show positive growth; other fields show negative or no growth. Therefore, it was determined that a common reserves growth factor could not be calculated for the limited number of fields and that reserves growth for fields in the California OCS could not be estimated using this approach.

Analog approach

An alternative approach, in which empirically derived reserves growth factors for fields in other (analogous) areas may be applied to fields in the California OCS, was also considered. The analogous areas that were considered include onshore California and the Gulf of Mexico OCS.

Onshore California

Reserves growth factors have been calculated for onshore fields in California (Caroline Isaacs, oral commun.). Notable differences in lithology, recovery methods, and other factors in the onshore and OCS areas exist, and these factors have been considered in determining the applicability of reserves growth factors from fields onshore California to fields in the California OCS.

Most of the oil and gas produced from fields onshore California has been extracted from sandstone reservoir rocks. Although most of the oil and gas produced from fields in the California OCS (56 percent on the basis of combined oil-equivalent resources) has been extracted from Neogene sandstone reservoir rocks, the majority of original recoverable reserves in all fields of the California OCS (67 percent on the basis of combined oil-equivalent resources) is in Neogene fractured siliceous rocks of the Monterey Formation (Sorensen and others, 1995). Seven of the 11 producing fields in the California OCS have substantial reserves in the Monterey Formation, as do 21 of the 27 nonproducing fields. The reservoir and production characteristics of Monterey Formation rocks in California OCS fields are significantly different from onshore fields, and reserves growth factors are expected to differ substantially.

An important factor contributing to reserves growth of fields onshore California is enhanced recovery; a significant portion (55 percent) of the oil produced in California in 1994 was produced using secondary and tertiary recovery (including thermal stimulation and water flooding) methods (California Division of Oil, Gas, and Geothermal Resources, 1995). Of this incrementally recovered oil, 77 percent was produced using thermal stimulation, mainly in the southern San Joaquin Valley, where reservoir rocks typically consist of shallow, upper Tertiary sandstones containing heavy (less than 20 ^{o}API) oil. Thermal stimulation was tested with limited success in sandstone reservoir rocks in the California State offshore area[1]; it has not been used in the California OCS. The different lithology and greater depths at which Monterey Formation reservoirs exist in the California OCS (generally 5,000 to 8,000 feet below the seafloor) have precluded efforts at thermal stimulation of fractured siliceous reservoirs in the OCS. Although thermal stimulation is not considered to be practical for fields offshore California under current technological and economic conditions, it may be practical for certain Neogene sandstone reservoirs in the California OCS if future economic conditions are more favorable.

Water flooding accounted for 21 percent of the incrementally recovered oil produced in California in 1994 (California Division of Oil, Gas, and Geothermal Resources, 1995); approximately one half of this oil was produced from sandstone reservoir rocks in fields of the onshore and State offshore areas of the Los Angeles basin. Water-flooding methods have also been applied in sandstone reservoirs of fields in the California OCS. Five of the 11 producing fields are undergoing water injection; water injection was initiated concurrently with oil and gas production in 3 of these fields. Although water-flooding methods have increased recovery in sandstone reservoirs, their application to Monterey Formation reservoirs in the California OCS is unknown.

Reserves growth onshore California is also expected to differ from reserves growth in the California OCS due to factors other than lithology and recovery methods. For example, the limited number of drilling slots on offshore platforms may restrict infill drilling and production (i.e., some existing wells must be abandoned before additional wells can be drilled) and may, therefore, reduce calculated reserves growth. Also, premature abandonment of OCS wells due to unfavorable economic conditions may reduce reserves growth. In contrast, the application of advanced drilling techniques (e.g., horizontal and extended-reach drilling) in some fields of the OCS[2] has increased production and is expected to result in increased reserves growth.

Studies of fields in the Gulf of Mexico OCS indicate that their reserves estimates characteristically increase at a slower rate and for a shorter duration than estimates for fields in the adjacent onshore area (Lore, 1995a), and that this is a consequence of more accurate initial reserves estimates for the OCS fields. The increased accuracy of OCS reserves estimates may be attributed to a combination of factors, including the availability of high-quality marine seismic-reflection data, the drilling and analysis of additional exploratory and development wells prior to development decisions, the additional time elapsed after initial field discovery prior to the initial estimate of proved reserves, and the obligation of the assessor to more accurately estimate reserves because of the increased capital requirements of offshore projects. All of these factors apply to fields in the California OCS, suggesting that reserves growth in these fields will be less than fields onshore California.

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[1] A thermal-stimulation test was conducted in the State offshore portion of the Huntington Beach field from 1981 to 1986. The project was conducted in shallow (about 2,000 feet below the seafloor) Pliocene and Miocene sandstone reservoirs with heavy oil ranging from 11 to 14 ^{o}API. Due to economic and other constraints, the project was not expanded and the wells have been shut in since 1987.

[2] In the Dos Cuadras field of the Santa Barbara-Ventura basin, an approximate 5-percent increase in recovery was achieved by drilling horizontal and trilateral wells to produce very shallow (less than 1,000 feet below the seafloor) sandstone reservoirs that could not be reached by conventional directional drilling.

Based on these differences in lithology, recovery methods, and other factors in the onshore and OCS areas of California, it was determined that reserves growth factors from fields onshore California are not applicable to fields in the California OCS, and that reserves growth for fields in the California OCS could not be estimated using this approach.

Gulf of Mexico OCS

Reserves growth factors have also been calculated for fields in the Gulf of Mexico OCS (Drew and Lore, 1992; Lore, 1995a; Lore, 1995b). Notable differences in lithology, field size, and wells in fields of the Gulf of Mexico OCS and California OCS exist, and these differences have been considered in determining the applicability of reserves growth factors from fields in the Gulf of Mexico OCS to fields in the California OCS.

The primary oil and gas reservoir rocks in fields of the Gulf of Mexico OCS are shelf sandstones and carbonates (Bacigalupi and others, 1996); no fractured siliceous rocks similar to the Monterey Formation exist. Also, the sizes of individual fields in the Gulf of Mexico OCS are generally smaller than fields in the California OCS; many platforms in the Gulf of Mexico OCS have only one or two wells. These differences contribute to the expectation that reserves growth factors for fields in the Gulf of Mexico OCS and California OCS are much different.

Based on differences in lithology, field size, and wells in fields of the Gulf of Mexico OCS and California OCS, it was determined that reserves growth factors from fields in the Gulf of Mexico OCS are not applicable to fields in the California OCS, and that reserves growth for fields in the California OCS could not be estimated using this approach.

Conclusions

It was determined that a common reserves growth factor for fields in the California OCS could not be calculated with the existing data. Furthermore, reserves growth factors for fields onshore California and in the Gulf of Mexico OCS are not considered to be applicable to fields in the California OCS. Therefore, reserves growth for fields in the California OCS could not be estimated.

The assessment methods used to develop estimates of undiscovered conventionally recoverable oil and gas resources in petroleum geologic plays of the Pacific OCS Region allow for ample uncertainty in estimating the sizes of individual pools and fields. The amount of reserves growth that may occur in fields of the California OCS is not expected to have a statistically significant impact on the estimates of undiscovered conventionally recoverable resources of the Region.

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Appendix B

GUIDELINES AND FORM FOR PETROLEUM GEOLOGIC PROBABILITY ANALYSIS

This appendix presents definitions of terms, procedural guidelines, and the form used to perform and document the petroleum geologic probability analysis (see *Methodology* section) of 46 petroleum geologic plays of the Pacific OCS Region. The minimum accumulation size considered in the probability analysis is 1 MMbbl of combined oil-equivalent resources.

DEFINITIONS AND GUIDELINES

Play Chance is the probability that at least one accumulation of conventionally recoverable hydrocarbons exists in a play. It reflects the chance for success at the group (play) level.

<u>To estimate the Play Chance</u>:

- For each element (a_1, a_2, etc.) of a play-level component (A), assign a *qualitative* probability of success (very poor, poor, fair, good, very good, excellent, or assured), according to the guidelines in table B1.
- Circle the critical factor(s) that would significantly limit success at all prospects in the play.
- For each component (A, B, etc.), assign a *quantitative* probability of success (between zero and one, where zero indicates no chance and one indicates absolute certainty) based on consideration of the qualitative assessment of ALL elements within the component, according to table B1. This assignment should be based primarily on the critical factor(s) and secondarily on the noncritical factor(s).
- Multiply the three component success values (A, B, C) to estimate the Play Chance. Round the computed value to one of the values in table B1.

Table B1. *Guidelines for assigning petroleum geologic probabilities of success.*

Qualitative Probability	Description	Quantitative Probability
Assured	The factor is known or assumed to be adequate.	1.0
Excellent	The factor is virtually assured to be adequate.	0.95
Very Good	The factor is very probably adequate.	0.8 or 0.9
Good	The factor is probably adequate.	0.6 or 0.7
Fair	The factor may be adequate.	0.4 or 0.5
Poor	The factor is probably not adequate.	0.2 or 0.3
Very Poor	The factor is very probably not adequate.	0.1 or 0.15

Conditional Prospect Chance is the probability that conventionally recoverable resources exist within an individual prospect in the play, given the conditional assumption that at least one accumulation exists in the play (i.e., the play is successful). It reflects the chance for success at the individual (prospect) level. This probability can also be described as a conditional success ratio, i.e., the fraction of all of the prospects (or proportion of the play area) for which a particular Prospect Chance factor is successful, given the conditional assumption that the play is successful.

<u>To estimate the Conditional Prospect Chance</u>:

- For each element (d_1, d_2, etc.) of a prospect-level component (D), assign a *qualitative* probability of success assuming that at least one accumulation exists in the play, according to table B1.
- Underline the critical factor(s) that would significantly limit success at an average prospect in the play.

- For each component (D, E, etc.), assign a *quantitative* probability of success based on consideration of the qualitative assessment of ALL elements of the component, according to table B1. This assignment should be based primarily on the critical factor(s) and secondarily on the noncritical factor(s).
- Multiply the three component success values (D, E, F) to estimate the Conditional Prospect Chance. Round the computed value to one of the values in table B1.

Average Prospect Chance is the probability that conventionally recoverable resources exist within an individual prospect in the play, with consideration of the probability that at least one accumulation exists in the play. It reflects the combined chance for success at the group (play) and individual (prospect) levels.

To estimate the Average Prospect Chance:
- Multiply the Play Chance (G) and the Conditional Prospect Chance (H) values. Round the computed value to two significant digits.
- Compare the computed Average Prospect Chance to some typical success ratios in table B2. Note that many cited success ratios represent economic success and that geologic success ratios should be greater. If the computed Average Prospect Chance is not reasonable or defensible, revise the Play Chance and/or Conditional Prospect Chance.

or
- Compute and apply a success ratio from a geologically analogous area. The analog success ratio may be modified to account for less-than-complete analogy between the areas.

Table B2. *Typical success ratios for petroleum exploration.*

Source	Description	Success Ratio
White (1993)	... many wildcat success ratios range from ...	0.10 to 0.40
White (1993)	... typical plays with reasonable source-reservoir-trap conditions ...	0.25
Simmons (1990)	1969-1981 U.S. average success ratio for all exploratory wells (including step-out wells in known fields)	0.261
Simmons (1990)	1969-1981 U.S. average success ratio for "new field wildcats"	0.153
MMS (1995a)	1973-1991 U.S. average success ratio for exploratory wells	0.256
MMS (1995b)	Success ratio of Santa Maria basin OCS exploratory wells	0.70

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PETROLEUM GEOLOGIC PROBABILITY ANALYSIS FORM

1995 National Assessment of United States Oil and Gas Resources
Pacific OCS Region

Province: ____________________

Assessment Area: ____________________

Play: ____________________ Play Code: __________

Assessor: ____________________ Date: __________

For each element (a_1, a_2, etc.) of a component (A), assign a *qualitative* probability of success (very poor, poor, fair, good, very good, excellent, or assured). For each component (A, B, etc.), assign a *quantitative* probability of success (between zero and one, where zero indicates no chance and one indicates absolute certainty) based on consideration of the qualitative assessment of ALL elements of the component.

PLAY CHANCE FACTORS	PETROLEUM GEOLOGIC FACTORS FOR SUCCESS		CONDITIONAL PROSPECT CHANCE FACTORS
A.________	**HYDROCARBON FILL**		**D.**________
a_1.________	source presence	(adequate organic content, organic quality, & volume of source rock)	d_1.________
a_2.________	maturation	(enough time & temperature for maturation, & adequate volume of mature source rock)	d_2.________
a_3.________	migration	(adequate primary expulsion from source rock, secondary migration to traps, & paleodrainage area of source rock)	d_3.________
a_4.________	preservation	(freedom from flushing, biodegradation, diffusion, or thermal overmaturation)	d_4.________
a_5.________	recovery	(adequate drive, concentration (not too dispersed or diluted), & oil viscosity for effective recovery)	d_5.________
B.________	**RESERVOIR ROCK**		**E.**________
b_1.________	reservoir presence	(sufficient areal distribution & net thickness of reservoir rock)	e_1.________
b_2.________	reservoir quality	(sufficient porosity, permeability, & continuity of reservoir rock)	e_2.________
C.________	**TRAP**		**F.**________
c_1.________	trap presence	(adequate area & height of closures)	f_1.________
c_2.________	seal presence	(adequate thickness & lithology of top & lateral seals)	f_2.________
c_3.________	timing	(proper timing of trap formation relative to migration)	f_3.________

A × B × C =	**Play Chance for Success =**	**G.**________
D × E × F =	**Conditional Prospect Chance for Success =**	**H.**________
G × H =	**Average Prospect Chance for Success =**	**I.**________

Appendix C

Select Petroleum Geologic Data Used to Assess Undiscovered Conventionally Recoverable Resources

This appendix presents select petroleum geologic data and information used to develop estimates of the volume of undiscovered conventionally recoverable oil and gas resources in 46 petroleum geologic plays of the Pacific OCS Region. The data are presented in one of two tabular formats by play, depending upon the assessment method used to develop the estimates (see *Methodology* section). The following describes the categories and types of data included in each of the tabular formats. Multiple values (minimum, median, and maximum) are presented for parameters that are described by a probability distribution. A single value (most probable) is presented for parameters that are described by a constant.

Plays Assessed by the Subjective Assessment Method

Tabular data for 40 plays that have been assessed by the subjective assessment method include the following categories and parameters. Some parameters (e.g., prospect area and trap fill) have been defined using empirical data and/or subjective judgment; some parameters have been computed by combining other parameters (e.g., prospect area x trap fill = pool area). The computed values presented here correspond to specific levels of probability and have not been rounded to reflect their relative precision.

Size of Accumulations

Prospect Area:	the lateral (areal) extent of individual prospects, expressed in acres
Trap Fill:	the portion of the prospect area filled with hydrocarbons, expressed as a decimal fraction
Pool Area:	the lateral (areal) extent of individual pools, expressed in acres
Reservoir Rock Thickness:	the vertical extent (thickness) of reservoir rock, expressed in feet
Reservoir Rock Volume:	the volume of reservoir rock at individual prospects, expressed in acre-feet
Net Pay:	the vertical extent (thickness) of hydrocarbon-bearing rock, expressed in feet
Volume Fill:	the portion of the reservoir rock volume filled with hydrocarbons, expressed as a decimal fraction
Pool Volume:	the hydrocarbon-filled volume of individual pools, expressed in acre-feet

Number of Accumulations

Number of Prospects:	the number of prospects that are estimated to exist
Number of Pools:	the number of undiscovered pools that are estimated to exist

Type of Accumulations

Oil Pools:	the portion of the number of pools that contain predominantly crude oil and associated gas, expressed as a decimal fraction
Gas Pools:	the portion of the number of pools that contain predominantly nonassociated gas and may contain condensate, expressed as a decimal fraction
Mixed Pools:	the portion of the number of pools that contain crude oil, associated gas, and nonassociated gas, and may contain condensate, expressed as a decimal fraction

Oil-filled Mixed Pool Volume

Mixed Pools:	the portion of the pool volume of mixed pools that is filled with crude oil and associated gas, expressed as a decimal fraction

Petroleum Geologic Probabilities

Probability factors at the group (play chance) and individual (prospect chance) levels

Hydrocarbon Fill:	the probability that hydrocarbons have been generated, migrated, and are preserved, expressed as a decimal fraction
Reservoir Rock:	the probability that reservoir rocks exist, expressed as a decimal fraction
Trap:	the probability that traps and seals exist, and that the timing of migration and trap formation have permitted entrapment, expressed as a decimal fraction

Overall probabilities at the group (play chance) and individual (prospect chance, average chance) levels

Play Chance: the probability that conventionally recoverable hydrocarbons exist in at least one accumulation in the play, expressed as a decimal fraction

Prospect Chance: the probability that undiscovered conventionally recoverable hydrocarbons exist in an individual accumulation in the play, given the conditional assumption that at least one accumulation exists in the play, expressed as a decimal fraction

Average Chance: the probability that undiscovered conventionally recoverable hydrocarbons exist in an individual accumulation in the play, with consideration of the probability that at least one accumulation exists in the play, expressed as a decimal fraction

Hydrocarbon Recovery

Oil Yield: the proportional volume of crude oil that can be extracted from the pool volume of an oil or mixed pool, expressed in barrels per acre-foot

Gas Yield: the proportional volume of nonassociated gas that can be extracted from the pool volume of a gas pool, expressed in million cubic feet per acre-foot

Condensate Yield: the proportional volume of condensate that can be extracted with nonassociated gas from a gas or mixed pool, expressed in barrels per million cubic feet

Solution Gas-to-Oil Ratio: the proportional volume of associated gas that can be extracted with crude oil from an oil or mixed pool, expressed in cubic feet per barrel

Plays Assessed by the Discovery Assessment Method

Tabular data for six plays that have been assessed by the discovery assessment method include the following categories and parameters.

Size Distribution of Accumulations

μ (mu): the natural logarithm of the median value of a lognormal pool-size distribution, expressed as a dimensionless value

σ^2 (sigma squared): the variance of a lognormal pool-size distribution, expressed as a dimensionless value

Number of Accumulations

Discovered Pools: the number of pools that have been discovered

Undiscovered Pools: the number of undiscovered pools that are estimated to exist

Total Pools: the total number of discovered and undiscovered pools that are estimated to exist

Discovered Accumulations

Pool Rank: the rank (position) of an individual pool among the discovered pools and all (discovered and undiscovered) pools, which have been ranked in descending order of their estimated volume of undiscovered conventionally recoverable combined oil-equivalent (BOE) resources

Field: the name of the field in which the discovered pool exists

Location: the location of the pool among onshore, State offshore, and/or Federal offshore areas

Original Recoverable Reserves: the volume of discovered oil and gas resources (including cumulative production and remaining reserves) that is estimated to be economically recoverable from an individual pool

Oil: the volume of crude oil and condensate, expressed in millions of barrels

Gas: the volume of associated and nonassociated gas, expressed in billion cubic feet

BOE: the volume of combined oil-equivalent resources, expressed in millions of barrels

Washington-Oregon Area, Growth Fault Play

Size of Accumulations			
	Minimum	Median	Maximum
Prospect Area (acres)	50	900	8,500
Trap Fill (fraction)	0.07	0.25	0.95
Pool Area (acres)	12	237	6,742
Net Pay (feet)	40	200	900
Pool Volume (acre-feet)	1,590	47,316	2,266,243
Number of Accumulations			
	Minimum	Median	Maximum
Number of Prospects	37	70	140
Number of Pools	0	10	46
Type of Accumulations			
Oil Pools (fraction)	0.70		
Gas Pools (fraction)	0.10		
Mixed Pools (fraction)	0.20		
Oil-filled Mixed Pool Volume			
	Minimum	Median	Maximum
Mixed Pools (fraction)	0.1	0.3	0.6
Petroleum Geologic Probabilities			
	Play Chance	Prospect Chance	Average Chance
Hydrocarbon Fill	0.7	0.5	
Reservoir Rock	0.9	0.8	
Trap	0.9	0.5	
Overall	0.6	0.2	0.12
Hydrocarbon Recovery			
	Minimum	Median	Maximum
Oil Yield (bbl per acre-foot)	55	175	550
Gas Yield (MMcf per acre-foot)	0.2	0.425	0.9
Condensate Yield (bbl per MMcf)	0.001	0.0031	0.01
Solution Gas-to-Oil Ratio (cf per bbl)	200	2,000	20,000

Washington-Oregon Area, Neogene Fan Sandstone Play

Size of Accumulations			
	Minimum	Median	Maximum
Prospect Area (acres)	20	280	7,000
Trap Fill (fraction)	0.07	0.25	0.95
Pool Area (acres)	3	75	3,540
Net Pay (feet)	20	140	900
Pool Volume (acre-feet)	237	10,122	1,096,600
Number of Accumulations			
	Minimum	Median	Maximum
Number of Prospects	320	520	830
Number of Pools	0	81	206
Type of Accumulations			
Oil Pools (fraction)	0.25		
Gas Pools (fraction)	0.55		
Mixed Pools (fraction)	0.20		
Oil-filled Mixed Pool Volume			
	Minimum	Median	Maximum
Mixed Pools (fraction)	0.1	0.3	0.6
Petroleum Geologic Probabilities			
	Play Chance	Prospect Chance	Average Chance
Hydrocarbon Fill	0.7	0.5	
Reservoir Rock	1.0	0.9	
Trap	0.9	0.4	
Overall	0.6	0.2	0.12
Hydrocarbon Recovery			
	Minimum	Median	Maximum
Oil Yield (bbl per acre-foot)	55	175	550
Gas Yield (MMcf per acre-foot)	0.2	0.425	0.9
Condensate Yield (bbl per MMcf)	0.001	0.0031	0.01
Solution Gas-to-Oil Ratio (cf per bbl)	200	2,000	20,000

Washington-Oregon Area, Neogene Shelf Sandstone Play

Size of Accumulations			
	Minimum	Median	Maximum
Prospect Area (acres)	20	280	9,000
Trap Fill (fraction)	0.07	0.25	0.95
Pool Area (acres)	3	75	3,608
Net Pay (feet)	20	75	300
Pool Volume (acre-feet)	170	5,578	437,390
Number of Accumulations			
	Minimum	Median	Maximum
Number of Prospects	805	1,310	2,100
Number of Pools	0	102	258
Type of Accumulations			
Oil Pools (fraction)	0.60		
Gas Pools (fraction)	0.20		
Mixed Pools (fraction)	0.20		
Oil-filled Mixed Pool Volume			
	Minimum	Median	Maximum
Mixed Pools (fraction)	0.1	0.3	0.6
Petroleum Geologic Probabilities			
	Play Chance	Prospect Chance	Average Chance
Hydrocarbon Fill	0.7	0.4	
Reservoir Rock	0.9	0.4	
Trap	0.9	0.5	
Overall	0.6	0.1	0.06
Hydrocarbon Recovery			
	Minimum	Median	Maximum
Oil Yield (bbl per acre-foot)	55	175	550
Gas Yield (MMcf per acre-foot)	0.2	0.425	0.9
Condensate Yield (bbl per MMcf)	0.001	0.0031	0.01
Solution Gas-to-Oil Ratio (cf per bbl)	200	2,000	20,000

Washington-Oregon Area, Paleogene Sandstone Play

Size of Accumulations			
	Minimum	Median	Maximum
Prospect Area (acres)	20	280	7,000
Trap Fill (fraction)	0.07	0.25	0.95
Pool Area (acres)	3	75	3,540
Net Pay (feet)	20	75	300
Pool Volume (acre-feet)	170	5,583	405,770
Number of Accumulations			
	Minimum	Median	Maximum
Number of Prospects	295	480	770
Number of Pools	0	70	196
Type of Accumulations			
Oil Pools (fraction)	0.05		
Gas Pools (fraction)	0.80		
Mixed Pools (fraction)	0.15		
Oil-filled Mixed Pool Volume			
	Minimum	Median	Maximum
Mixed Pools (fraction)	0.1	0.3	0.6
Petroleum Geologic Probabilities			
	Play Chance	Prospect Chance	Average Chance
Hydrocarbon Fill	0.8	0.5	
Reservoir Rock	0.9	0.8	
Trap	0.8	0.5	
Overall	0.6	0.2	0.12
Hydrocarbon Recovery			
	Minimum	Median	Maximum
Oil Yield (bbl per acre-foot)	10	110	500
Gas Yield (MMcf per acre-foot)	0.2	0.425	0.9
Condensate Yield (bbl per MMcf)	0.001	0.0031	0.01
Solution Gas-to-Oil Ratio (cf per bbl)	200	2,000	20,000

Eel River Basin, Neogene Fan Sandstone Play

Size of Accumulations			
	Minimum	Median	Maximum
Prospect Area (acres)	20	280	4,000
Trap Fill (fraction)	0.13	0.35	1.0
Pool Area (acres)	5	103	3,292
Net Pay (feet)	20	140	900
Pool Volume (acre-feet)	364	13,861	1,205,146
Number of Accumulations			
	Minimum	Median	Maximum
Number of Prospects	46	75	120
Number of Pools	12	38	80
Type of Accumulations			
Oil Pools (fraction)	0.05		
Gas Pools (fraction)	0.80		
Mixed Pools (fraction)	0.15		
Oil-filled Mixed Pool Volume			
	Minimum	Median	Maximum
Mixed Pools (fraction)	0.1	0.3	0.6
Petroleum Geologic Probabilities			
	Play Chance	Prospect Chance	Average Chance
Hydrocarbon Fill	1.0	0.8	
Reservoir Rock	1.0	0.8	
Trap	1.0	0.8	
Overall	1.0	0.5	0.5
Hydrocarbon Recovery			
	Minimum	Median	Maximum
Oil Yield (bbl per acre-foot)	55	175	550
Gas Yield (MMcf per acre-foot)	0.2	0.425	0.9
Condensate Yield (bbl per MMcf)	0.001	0.0031	0.01
Solution Gas-to-Oil Ratio (cf per bbl)	200	2,000	20,000

Eel River Basin, Neogene Shelf Sandstone Play

Size of Accumulations			
	Minimum	Median	Maximum
Prospect Area (acres)	20	280	7,000
Trap Fill (fraction)	0.13	0.35	1.0
Pool Area (acres)	5	103	3,796
Net Pay (feet)	20	75	300
Pool Volume (acre-feet)	260	7,647	527,163
Number of Accumulations			
	Minimum	Median	Maximum
Number of Prospects	180	300	480
Number of Pools	0	117	230
Type of Accumulations			
Oil Pools (fraction)	0.05		
Gas Pools (fraction)	0.80		
Mixed Pools (fraction)	0.15		
Oil-filled Mixed Pool Volume			
	Minimum	Median	Maximum
Mixed Pools (fraction)	0.1	0.3	0.6
Petroleum Geologic Probabilities			
	Play Chance	Prospect Chance	Average Chance
Hydrocarbon Fill	0.95	0.8	
Reservoir Rock	0.95	0.6	
Trap	1.0	0.8	
Overall	0.9	0.4	0.36
Hydrocarbon Recovery			
	Minimum	Median	Maximum
Oil Yield (bbl per acre-foot)	55	175	550
Gas Yield (MMcf per acre-foot)	0.2	0.425	0.9
Condensate Yield (bbl per MMcf)	0.001	0.0031	0.01
Solution Gas-to-Oil Ratio (cf per bbl)	200	2,000	20,000

Eel River Basin, Paleogene Sandstone Play

	Minimum	Median	Maximum
Size of Accumulations			
Prospect Area (acres)	20	280	5,000
Trap Fill (fraction)	0.07	0.25	0.95
Pool Area (acres)	3	75	3,473
Net Pay (feet)	20	45	100
Pool Volume (acre-feet)	131	3,312	185,218
Number of Accumulations	Minimum	Median	Maximum
Number of Prospects	70	115	180
Number of Pools	0	0	57
Type of Accumulations			
Oil Pools (fraction)	0.50		
Gas Pools (fraction)	0.20		
Mixed Pools (fraction)	0.30		
Oil-filled Mixed Pool Volume	Minimum	Median	Maximum
Mixed Pools (fraction)	0.1	0.3	0.6
Petroleum Geologic Probabilities	Play Chance	Prospect Chance	Average Chance
Hydrocarbon Fill	0.8	0.5	
Reservoir Rock	0.6	0.6	
Trap	0.8	0.6	
Overall	0.4	0.2	0.08
Hydrocarbon Recovery	Minimum	Median	Maximum
Oil Yield (bbl per acre-foot)	10	110	500
Gas Yield (MMcf per acre-foot)	0.2	0.425	0.9
Condensate Yield (bbl per MMcf)	0.001	0.0031	0.01
Solution Gas-to-Oil Ratio (cf per bbl)	200	2,000	20,000

Point Arena Basin, Neogene Sandstone Play

	Minimum	Median	Maximum
Size of Accumulations			
Prospect Area (acres)	100	1,000	10,000
Trap Fill (fraction)	0.07	0.25	0.95
Pool Area (acres)	16	261	7,888
Net Pay (feet)	10	63	375
Pool Volume (acre-feet)	460	16,063	1,087,510
Number of Accumulations	Minimum	Median	Maximum
Number of Prospects	45	55	70
Number of Pools	0	13	37
Type of Accumulations			
Oil Pools (fraction)	1.0		
Gas Pools (fraction)	0.0		
Mixed Pools (fraction)	0.0		
Oil-filled Mixed Pool Volume	Minimum	Median	Maximum
Mixed Pools (fraction)	N/A	N/A	N/A
Petroleum Geologic Probabilities	Play Chance	Prospect Chance	Average Chance
Hydrocarbon Fill	0.9	0.6	
Reservoir Rock	1.0	0.9	
Trap	0.7	0.6	
Overall	0.6	0.3	0.18
Hydrocarbon Recovery	Minimum	Median	Maximum
Oil Yield (bbl per acre-foot)	55	175	550
Gas Yield (MMcf per acre-foot)	N/A	N/A	N/A
Condensate Yield (bbl per MMcf)	N/A	N/A	N/A
Solution Gas-to-Oil Ratio (cf per bbl)	300	1,000	3,500

Point Arena Basin, Monterey Fractured Play

Size of Accumulations			
	Minimum	Median	Maximum
Prospect Area (acres)	30	620	13,000
Reservoir Rock Thickness (feet)	500	2,000	7,000
Reservoir Rock Volume (acre-feet)	3,000	270,000	23,000,000
Volume Fill (fraction)	0.09	0.3	1.0
Pool Volume (acre-feet)	733	96,724	15,679,770
Number of Accumulations			
	Minimum	Median	Maximum
Number of Prospects	210	240	270
Number of Pools	51	96	139
Type of Accumulations			
Oil Pools (fraction)	1.0		
Gas Pools (fraction)	0.0		
Mixed Pools (fraction)	0.0		
Oil-filled Mixed Pool Volume			
	Minimum	Median	Maximum
Mixed Pools (fraction)	N/A	N/A	N/A
Petroleum Geologic Probabilities			
	Play Chance	Prospect Chance	Average Chance
Hydrocarbon Fill	1.0	0.8	
Reservoir Rock	1.0	0.8	
Trap	1.0	0.7	
Overall	1.0	0.4	0.4
Hydrocarbon Recovery			
	Minimum	Median	Maximum
Oil Yield (bbl per acre-foot)	30	49	80
Gas Yield (MMcf per acre-foot)	N/A	N/A	N/A
Condensate Yield (bbl per MMcf)	N/A	N/A	N/A
Solution Gas-to-Oil Ratio (cf per bbl)	250	880	3,000

Point Arena Basin, Pre-Monterey Sandstone Play

Size of Accumulations			
	Minimum	Median	Maximum
Prospect Area (acres)	30	520	9,000
Trap Fill (fraction)	0.1	0.35	1.0
Pool Area (acres)	10	189	5,806
Net Pay (feet)	8	45	375
Pool Volume (acre-feet)	248	8,453	837,677
Number of Accumulations			
	Minimum	Median	Maximum
Number of Prospects	240	275	330
Number of Pools	0	77	128
Type of Accumulations			
Oil Pools (fraction)	1.0		
Gas Pools (fraction)	0.0		
Mixed Pools (fraction)	0.0		
Oil-filled Mixed Pool Volume			
	Minimum	Median	Maximum
Mixed Pools (fraction)	N/A	N/A	N/A
Petroleum Geologic Probabilities			
	Play Chance	Prospect Chance	Average Chance
Hydrocarbon Fill	0.7	0.7	
Reservoir Rock	1.0	0.6	
Trap	1.0	0.7	
Overall	0.7	0.3	0.21
Hydrocarbon Recovery			
	Minimum	Median	Maximum
Oil Yield (bbl per acre-foot)	20	110	600
Gas Yield (MMcf per acre-foot)	N/A	N/A	N/A
Condensate Yield (bbl per MMcf)	N/A	N/A	N/A
Solution Gas-to-Oil Ratio (cf per bbl)	250	1,100	5,000

Bodega Basin, Neogene Sandstone Play

Size of Accumulations			
	Minimum	Median	Maximum
Prospect Area (acres)	100	1,000	10,000
Trap Fill (fraction)	0.07	0.25	0.95
Pool Area (acres)	16	261	7,888
Net Pay (feet)	10	63	375
Pool Volume (acre-feet)	460	16,063	1,087,500
Number of Accumulations			
	Minimum	Median	Maximum
Number of Prospects	30	37	45
Number of Pools	0	8	27
Type of Accumulations			
Oil Pools (fraction)	1.0		
Gas Pools (fraction)	0.0		
Mixed Pools (fraction)	0.0		
Oil-filled Mixed Pool Volume			
	Minimum	Median	Maximum
Mixed Pools (fraction)	N/A	N/A	N/A
Petroleum Geologic Probabilities			
	Play Chance	Prospect Chance	Average Chance
Hydrocarbon Fill	0.9	0.6	
Reservoir Rock	1.0	0.8	
Trap	0.7	0.6	
Overall	0.6	0.3	0.18
Hydrocarbon Recovery			
	Minimum	Median	Maximum
Oil Yield (bbl per acre-foot)	55	175	550
Gas Yield (MMcf per acre-foot)	N/A	N/A	N/A
Condensate Yield (bbl per MMcf)	N/A	N/A	N/A
Solution Gas-to-Oil Ratio (cf per bbl)	300	1,000	3,500

Bodega Basin, Monterey Fractured Play

Size of Accumulations			
	Minimum	Median	Maximum
Prospect Area (acres)	40	520	7,000
Reservoir Rock Thickness (feet)	550	2,000	7,000
Reservoir Rock Volume (acre-feet)	5,000	300,000	17,000,000
Volume Fill (fraction)	0.09	0.3	1.0
Pool Volume (acre-feet)	1,103	103,379	11,726,050
Number of Accumulations			
	Minimum	Median	Maximum
Number of Prospects	75	120	200
Number of Pools	5	62	126
Type of Accumulations			
Oil Pools (fraction)	1.0		
Gas Pools (fraction)	0.0		
Mixed Pools (fraction)	0.0		
Oil-filled Mixed Pool Volume			
	Minimum	Median	Maximum
Mixed Pools (fraction)	N/A	N/A	N/A
Petroleum Geologic Probabilities			
	Play Chance	Prospect Chance	Average Chance
Hydrocarbon Fill	1.0	0.8	
Reservoir Rock	1.0	0.8	
Trap	1.0	0.8	
Overall	1.0	0.5	0.5
Hydrocarbon Recovery			
	Minimum	Median	Maximum
Oil Yield (bbl per acre-foot)	30	49	80
Gas Yield (MMcf per acre-foot)	N/A	N/A	N/A
Condensate Yield (bbl per MMcf)	N/A	N/A	N/A
Solution Gas-to-Oil Ratio (cf per bbl)	250	880	3,000

Bodega Basin, Pre-Monterey Sandstone Play

Size of Accumulations			
	Minimum	Median	Maximum
Prospect Area (acres)	40	550	8,000
Trap Fill (fraction)	0.13	0.35	1.0
Pool Area (acres)	11	207	5,595
Net Pay (feet)	33	125	470
Pool Volume (acre-feet)	883	25,797	1,178,800
Number of Accumulations			
	Minimum	Median	Maximum
Number of Prospects	125	165	220
Number of Pools	0	45	92
Type of Accumulations			
Oil Pools (fraction)	1.0		
Gas Pools (fraction)	0.0		
Mixed Pools (fraction)	0.0		
Oil-filled Mixed Pool Volume			
	Minimum	Median	Maximum
Mixed Pools (fraction)	N/A	N/A	N/A
Petroleum Geologic Probabilities			
	Play Chance	Prospect Chance	Average Chance
Hydrocarbon Fill	0.7	0.6	
Reservoir Rock	1.0	0.7	
Trap	1.0	0.7	
Overall	0.7	0.3	0.21
Hydrocarbon Recovery			
	Minimum	Median	Maximum
Oil Yield (bbl per acre-foot)	20	110	600
Gas Yield (MMcf per acre-foot)	N/A	N/A	N/A
Condensate Yield (bbl per MMcf)	N/A	N/A	N/A
Solution Gas-to-Oil Ratio (cf per bbl)	250	1,100	5,000

Año Nuevo Basin, Neogene Sandstone Play

Size of Accumulations			
	Minimum	Median	Maximum
Prospect Area (acres)	50	540	6,000
Trap Fill (fraction)	0.13	0.35	1.0
Pool Area (acres)	12	200	5,065
Net Pay (feet)	10	63	375
Pool Volume (acre-feet)	334	12,335	845,940
Number of Accumulations			
	Minimum	Median	Maximum
Number of Prospects	25	43	73
Number of Pools	0	13	37
Type of Accumulations			
Oil Pools (fraction)	1.0		
Gas Pools (fraction)	0.0		
Mixed Pools (fraction)	0.0		
Oil-filled Mixed Pool Volume			
	Minimum	Median	Maximum
Mixed Pools (fraction)	N/A	N/A	N/A
Petroleum Geologic Probabilities			
	Play Chance	Prospect Chance	Average Chance
Hydrocarbon Fill	1.0	0.7	
Reservoir Rock	1.0	0.8	
Trap	0.95	0.6	
Overall	0.95	0.3	0.29
Hydrocarbon Recovery			
	Minimum	Median	Maximum
Oil Yield (bbl per acre-foot)	55	175	550
Gas Yield (MMcf per acre-foot)	N/A	N/A	N/A
Condensate Yield (bbl per MMcf)	N/A	N/A	N/A
Solution Gas-to-Oil Ratio (cf per bbl)	300	1,000	3,500

Año Nuevo Basin, Monterey Fractured Play

Size of Accumulations			
	Minimum	Median	Maximum
Prospect Area (acres)	70	800	10,000
Reservoir Rock Thickness (feet)	840	2,200	6,000
Reservoir Rock Volume (acre-feet)	7,000	300,000	12,000,000
Volume Fill (fraction)	0.09	0.3	1.0
Pool Volume (acre-feet)	1,505	103,380	8,534,100
Number of Accumulations			
	Minimum	Median	Maximum
Number of Prospects	31	59	112
Number of Pools	0	36	86
Type of Accumulations			
Oil Pools (fraction)	1.0		
Gas Pools (fraction)	0.0		
Mixed Pools (fraction)	0.0		
Oil-filled Mixed Pool Volume			
	Minimum	Median	Maximum
Mixed Pools (fraction)	N/A	N/A	N/A
Petroleum Geologic Probabilities			
	Play Chance	Prospect Chance	Average Chance
Hydrocarbon Fill	1.0	0.9	
Reservoir Rock	1.0	0.9	
Trap	1.0	0.7	
Overall	1.0	0.6	0.6
Hydrocarbon Recovery			
	Minimum	Median	Maximum
Oil Yield (bbl per acre-foot)	30	49	80
Gas Yield (MMcf per acre-foot)	N/A	N/A	N/A
Condensate Yield (bbl per MMcf)	N/A	N/A	N/A
Solution Gas-to-Oil Ratio (cf per bbl)	250	880	3,000

Año Nuevo Basin, Pre-Monterey Sandstone Play

Size of Accumulations			
	Minimum	Median	Maximum
Prospect Area (acres)	40	520	7,000
Trap Fill (fraction)	0.13	0.35	1.0
Pool Area (acres)	10	191	5,770
Net Pay (feet)	10	50	235
Pool Volume (acre-feet)	248	9,114	579,910
Number of Accumulations			
	Minimum	Median	Maximum
Number of Prospects	57	82	115
Number of Pools	0	20	54
Type of Accumulations			
Oil Pools (fraction)	1.0		
Gas Pools (fraction)	0.0		
Mixed Pools (fraction)	0.0		
Oil-filled Mixed Pool Volume			
	Minimum	Median	Maximum
Mixed Pools (fraction)	N/A	N/A	N/A
Petroleum Geologic Probabilities			
	Play Chance	Prospect Chance	Average Chance
Hydrocarbon Fill	1.0	0.7	
Reservoir Rock	0.6	0.6	
Trap	1.0	0.7	
Overall	0.6	0.3	0.18
Hydrocarbon Recovery			
	Minimum	Median	Maximum
Oil Yield (bbl per acre-foot)	30	130	600
Gas Yield (MMcf per acre-foot)	N/A	N/A	N/A
Condensate Yield (bbl per MMcf)	N/A	N/A	N/A
Solution Gas-to-Oil Ratio (cf per bbl)	250	1,100	5,000

Santa Maria-Partington Basin, Basal Sisquoc Sandstone Play

Size of Accumulations			
	Minimum	Median	Maximum
Prospect Area (acres)			
Trap Fill (fraction)			
Pool Area (acres)	40	300	2,300
Net Pay (feet)	9	45	245
Pool Volume (acre-feet)	754	13,962	491,350
Number of Accumulations			
	Minimum	Median	Maximum
Number of Prospects			
Number of Pools		15	
Type of Accumulations			
Oil Pools (fraction)	1.0		
Gas Pools (fraction)	0.0		
Mixed Pools (fraction)	0.0		
Oil-filled Mixed Pool Volume			
	Minimum	Median	Maximum
Mixed Pools (fraction)	N/A	N/A	N/A
Petroleum Geologic Probabilities			
	Play Chance	Prospect Chance	Average Chance
Hydrocarbon Fill	1.0	0.9	
Reservoir Rock	1.0	0.95	
Trap	1.0	0.7	
Overall	1.0	0.6	0.6
Hydrocarbon Recovery			
	Minimum	Median	Maximum
Oil Yield (bbl per acre-foot)	55	175	550
Gas Yield (MMcf per acre-foot)	N/A	N/A	N/A
Condensate Yield (bbl per MMcf)	N/A	N/A	N/A
Solution Gas-to-Oil Ratio (cf per bbl)	250	880	3,000

Santa Maria-Partington Basin, Monterey Fractured Play

Size Distribution of Accumulations	
μ (mu)	1.70
σ^2 (sigma squared)	2.75
Number of Accumulations	
Discovered Pools	13
Undiscovered Pools	77
Total Pools	90

Discovered Accumulations

Pool Rank Of Disc.	Of All	Field	Location	Original Recoverable Reserves Oil (MMbbl)	Gas (Bcf)	BOE (MMbbl)
1	1	Point Arguello	Federal Offshore	266.65	320.37	323.66
2	3	Rocky Point	Federal Offshore	84.26	84.26	99.25
3	4	Point Pedernales	Federal Offshore	77.30	17.00	80.33
4	5	San Miguel	Federal Offshore	72.40	30.80	77.88
5	6	Point Sal	Federal Offshore	63.30	63.50	74.60
6	7	Purisima Point	Federal Offshore	54.70	37.00	61.29
7	8	Unnamed OCS-P 0435	Federal Offshore	46.65	23.32	50.80
8	9	Bonito	Federal Offshore	40.80	51.00	49.88
9	23	Unnamed OCS-P 0443	Federal Offshore	14.00	14.00	16.49
10	25	Unnamed OCS-P 0395	Federal Offshore	12.39	12.39	14.60
11	27	Electra	Federal Offshore	10.90	13.30	13.27
12	29	Jalama	Federal Offshore	10.51	7.20	11.79
13	68	Santa Maria	Federal Offshore	1.54	1.54	1.81

Santa Maria-Partington Basin, Paleogene Sandstone Play

	Size of Accumulations		
	Minimum	Median	Maximum
Prospect Area (acres)	40	520	7,000
Trap Fill (fraction)	0.13	0.35	1.0
Pool Area (acres)	10	191	5,770
Net Pay (feet)	14	72	375
Pool Volume (acre-feet)	359	13,692	924,110
	Number of Accumulations		
	Minimum	Median	Maximum
Number of Prospects	23	33	46
Number of Pools	0	0	20
	Type of Accumulations		
Oil Pools (fraction)	1.0		
Gas Pools (fraction)	0.0		
Mixed Pools (fraction)	0.0		
	Oil-filled Mixed Pool Volume		
	Minimum	Median	Maximum
Mixed Pools (fraction)	N/A	N/A	N/A
	Petroleum Geologic Probabilities		
	Play Chance	Prospect Chance	Average Chance
Hydrocarbon Fill	0.7	0.7	
Reservoir Rock	0.7	0.7	
Trap	0.5	0.5	
Overall	0.2	0.2	0.04
	Hydrocarbon Recovery		
	Minimum	Median	Maximum
Oil Yield (bbl per acre-foot)	20	110	600
Gas Yield (MMcf per acre-foot)	N/A	N/A	N/A
Condensate Yield (bbl per MMcf)	N/A	N/A	N/A
Solution Gas-to-Oil Ratio (cf per bbl)	250	2,000	15,000

Santa Maria-Partington Basin, Breccia Play

	Size of Accumulations		
	Minimum	Median	Maximum
Prospect Area (acres)			
Trap Fill (fraction)			
Pool Area (acres)	20	200	2,000
Net Pay (feet)	20	100	500
Pool Volume (acre-feet)	802	21,154	854,530
	Number of Accumulations		
	Minimum	Median	Maximum
Number of Prospects	31	38	45
Number of Pools	0	0	17
	Type of Accumulations		
Oil Pools (fraction)	1.0		
Gas Pools (fraction)	0.0		
Mixed Pools (fraction)	0.0		
	Oil-filled Mixed Pool Volume		
	Minimum	Median	Maximum
Mixed Pools (fraction)	N/A	N/A	N/A
	Petroleum Geologic Probabilities		
	Play Chance	Prospect Chance	Average Chance
Hydrocarbon Fill	0.9	0.9	
Reservoir Rock	0.5	0.5	
Trap	0.3	0.3	
Overall	0.15	0.15	0.02
	Hydrocarbon Recovery		
	Minimum	Median	Maximum
Oil Yield (bbl per acre-foot)	70	180	450
Gas Yield (MMcf per acre-foot)	N/A	N/A	N/A
Condensate Yield (bbl per MMcf)	N/A	N/A	N/A
Solution Gas-to-Oil Ratio (cf per bbl)	250	880	3,000

Santa Barbara-Ventura Basin, Pico-Repetto Sandstone Play

Size Distribution of Accumulations	
μ (mu)	1.05
σ^2 (sigma squared)	6.20

Number of Accumulations	
Discovered Pools	26
Undiscovered Pools	54
Total Pools	80

Discovered Accumulations

Pool Rank				Original Recoverable Reserves		
Of Disc.	Of All	Field (Area)	Location	Oil (MMbbl)	Gas (Bcf)	BOE (MMbbl)
1	1	Ventura-San Miguelito-Rincon	Onshore & State Offshore	1,324.40	2,501.80	1,769.50
2	3	Dos Cuadras	Federal Offshore	256.20	137.00	280.58
3	5	Carpinteria	State & Federal Offshore	108.80	110.97	128.55
4	7	Saticoy-South Mountain (Bridge pool)	Onshore	69.26	95.24	86.21
5	9	Placerita	Onshore	60.66	6.89	61.89
6	10	Santa Clara	Federal Offshore	44.27	60.19	54.98
7	11	Pitas Point	Federal Offshore	0.26	239.21	42.83
8	12	Aliso Canyon	Onshore	33.15	31.95	38.83
9	19	Fillmore	Onshore	13.42	20.25	17.02
10	23	West Montalvo	Onshore	4.37	36.67	10.90
11	24	Timber Canyon	Onshore	8.04	16.07	10.89
12	29	Oxnard	Onshore	7.13	<0.01	7.13
13	33	Del Valle	Onshore	1.26	21.15	5.03
14	37	Bardsdale	Onshore	3.33	1.86	3.66
15	47	Shiells Canyon	Onshore	1.31	2.12	1.69
16	51	Anacapa	Federal Offshore	1.11	0.88	1.26
17	52	Ojai (Weldon Canyon)	Onshore	0.96	1.13	1.16
18	53	Newhall (Elsmere)	Onshore	1.07	<0.01	1.07
19	55	Santa Paula (Adams Canyon)	Onshore	0.87	0.27	0.91
20	57	Santa Paula (Wheeler Canyon)	Onshore	0.45	1.51	0.72
21	61	Santa Paula (Santa Paula Canyon)	Onshore	0.47	0.10	0.49
22	62	Mission (Fernando pool)	Onshore	0.42	0.18	0.45
23	63	Santa Paula (Aliso Canyon)	Onshore	0.40	<0.01	0.40
24	64	Santa Paula (Salt Marsh Canyon)	Onshore	0.36	0.05	0.37
25	72	Cañada Larga	Onshore	0.11	0.08	0.13
26	78	Long Canyon	Onshore	0.02	0.04	0.02

Santa Barbara-Ventura Basin, Monterey Fractured Play

Size Distribution of Accumulations						
μ (mu)			2.00			
σ^2 (sigma squared)			2.50			
Number of Accumulations						
Discovered Pools			26			
Undiscovered Pools			104			
Total Pools			130			
Discovered Accumulations						
Pool Rank				Original Recoverable Reserves		
Of	Of			Oil	Gas	BOE
Disc.	All	Field (Area)	Location	(MMbbl)	(Bcf)	(MMbbl)
1	1	Hondo	Federal Offshore	261.90	737.52	393.13
2	2	Smuggler's Cove	Federal Offshore	200.00	331.93	259.06
3	5	Pescado	Federal Offshore	100.20	150.60	127.00
4	6	Coal Oil Point Offshore (Devereaux)	State Offshore	100.00	50.00	108.90
5	10	Sacate	Federal Offshore	55.06	82.60	69.76
6	12	South Ellwood Offshore	State Offshore	56.00	34.00	62.05
7	13	Gato Canyon	Federal Offshore	46.95	63.38	58.22
8	16	Sockeye	Federal Offshore	36.00	52.50	45.34
9	17	Molino Offshore	State Offshore	40.00	20.00	43.56
10	21	Santa Clara	Federal Offshore	25.75	54.15	35.38
11	22	Sword	Federal Offshore	29.50	30.10	34.86
12	23	"Embarcadero Offshore"	State Offshore	30.00	15.00	32.67
13	25	Ojai (Silverthread)	Onshore	22.06	44.93	30.05
14	33	Unnamed OCS-P 0335	Federal Offshore	18.92	15.14	21.61
15	34	Castle Rock OCS-P 0321	Federal Offshore	17.20	19.78	20.72
16	35	Cojo Offshore (PRC 2879)	State Offshore	19.00	5.65	20.01
17	44	Ojai (North Sulphur Mountain)	Onshore	9.40	29.35	14.62
18	50	Oxnard	Onshore	11.61	2.33	12.03
19	76	Unnamed OCS-P 0358	Federal Offshore	5.11	1.02	5.29
20	82	Unnamed OCS-P 0479	Federal Offshore	4.26	0.85	4.41
21	87	Castle Rock OCS-P 0324	Federal Offshore	3.10	3.57	3.73
22	95	Unnamed OCS-P 0512	Federal Offshore	2.53	1.84	2.86
23	125	Ojai (Sulphur Mountain)	Onshore	0.45	0.11	0.47
24	127	Ojai (Sisar Creek)	Onshore	0.28	0.32	0.33
25	128	Sacate OCS-P 0195	Federal Offshore	0.24	0.36	0.30
26	130	Unnamed OCS-P 0318	Federal Offshore	0.16	0.03	0.17

Santa Barbara-Ventura Basin, Rincon-Monterey-Topanga Sandstone Play

Size Distribution of Accumulations						
μ (mu)			1.75			
σ^2 (sigma squared)			1.01			
Number of Accumulations						
Discovered Pools			8			
Undiscovered Pools			45			
Total Pools			53			
Discovered Accumulations						
Pool Rank				Original Recoverable Reserves		
Of	Of			Oil	Gas	BOE
Disc.	All	Field (Area)	Location	(MMbbl)	(Bcf)	(MMbbl)
1	1	"Embarcadero Offshore"	State Offshore	45.00	45.00	53.01
2	2	Coal Oil Point Offshore (Devereaux)	State Offshore	35.00	35.00	41.23
3	3	South Ellwood Offshore	State Offshore	25.50	25.50	30.04
4	8	Hueneme	Federal Offshore	15.80	4.81	16.66
5	10	Sockeye	Federal Offshore	11.73	14.53	14.32
6	21	Hondo	Federal Offshore	6.00	9.00	7.60
7	41	Ojai (Sulphur Crest)	Onshore	1.74	5.64	2.74
8	51	Ellwood	Onshore & State Offshore	0.60	2.47	1.04

Santa Barbara-Ventura Basin, Sespe-Alegria-Vaqueros Sandstone Play

Size Distribution of Accumulations						
μ (mu)			1.30			
σ^2 (sigma squared)			2.40			
Number of Accumulations						
Discovered Pools			44			
Undiscovered Pools			106			
Total Pools			150			
Discovered Accumulations						
Pool Rank				Original Recoverable Reserves		
Of	Of			Oil	Gas	BOE
Disc.	All	Field (Area)	Location	(MMbbl)	(Bcf)	(MMbbl)
1	1	South Mountain	Onshore	112.29	228.00	152.86
2	2	Ellwood	Onshore & State Offshore	107.79	97.69	125.17
3	6	Sespe (Tar Creek-Topatopa)	Onshore	43.91	69.17	56.22
4	7	Molino Offshore	State Offshore	4.42	240.00	47.13
5	8	Summerland Offshore	State Offshore	27.56	97.03	44.82
6	9	"Embarcadero Offshore"	State Offshore	25.00	100.00	42.79
7	10	Sockeye	Federal Offshore	23.00	97.75	40.39
8	11	West Montalvo	Onshore & State Offshore	34.85	29.15	40.04
9	12	Shiells Canyon	Onshore	24.88	49.11	33.62
10	14	Oxnard	Onshore	25.03	21.93	28.93
11	15	Hondo	Federal Offshore	13.00	80.50	27.32
12	16	South Ellwood Offshore	State Offshore	15.20	60.80	26.02
13	18	Capitan	Onshore & State Offshore	19.96	14.80	22.60
14	19	Conception Offshore	State Offshore	20.31	11.96	22.43
15	22	Coal Oil Point Offshore (Devereaux)	State Offshore	11.31	43.25	19.00
16	26	Sacate	Federal Offshore	8.67	40.60	15.89
17	32	Gaviota Offshore	State Offshore	<0.01	69.96	12.45
18	33	Unnamed OCS-P 0176	Federal Offshore	11.64	2.91	12.16
19	35	Bardsdale	Onshore	5.13	34.97	11.35
20	38	Santa Susana	Onshore	8.16	13.63	10.58
21	45	La Goleta	Onshore	<0.01	47.29	8.42
22	54	Santa Clara Avenue	Onshore	5.78	3.75	6.45
23	58	Caliente Offshore	State Offshore	<0.01	32.80	5.84
24	62	West Mountain	Onshore	4.47	3.76	5.14
25	63	Government Point	Federal Offshore	2.00	17.50	5.11
26	65	Sespe (Foot of the Hills)	Onshore	3.32	8.33	4.80
27	72	Naples Offshore	State Offshore	0.22	20.82	3.93
28	73	Cuarta Offshore	State Offshore	0.58	18.43	3.86
29	74	Mesa	Onshore	3.73	<0.01	3.73
30	75	Pescado	Federal Offshore	2.67	5.66	3.68
31	83	Sespe (Little Sespe Creek)	Onshore	2.19	4.69	3.03
32	85	Simi (Cañada de la Brea)	Onshore	2.63	1.37	2.88
33	91	Big Mountain	Onshore	1.88	3.15	2.44
34	98	Oak Park	Onshore	1.90	0.54	2.00
35	99	South Tapo	Onshore	1.51	2.41	1.94
36	102	Alegria Offshore	State Offshore	1.10	4.08	1.83
37	108	Simi (Old)	Onshore	1.44	0.50	1.53
38	120	Summerland	Onshore	0.71	1.70	1.01
39	137	Ojai (Lion Mountain)	Onshore	0.34	0.69	0.46
40	138	El Rio	Onshore	0.39	0.19	0.42
41	143	Moorpark West	Onshore	0.29	<0.01	0.29
42	145	Simi (Alamos Canyon)	Onshore	0.20	0.12	0.22
43	147	Refugio Cove	Onshore	<0.01	1.03	0.19
44	148	Goleta	Onshore	0.14	0.06	0.15

Santa Barbara-Ventura Basin, Gaviota-Sacate-Matilija Sandstone Play

Size Distribution of Accumulations	
μ (mu)	1.25
σ^2 (sigma squared)	2.00
Number of Accumulations	
Discovered Pools	20
Undiscovered Pools	55
Total Pools	75

Discovered Accumulations

Pool Rank Of Disc.	Of All	Field	Location	Original Recoverable Reserves Oil (MMbbl)	Gas (Bcf)	BOE (MMbbl)
1	1	Cojo Offshore (PRC 2879)	State Offshore	50.00	150.00	76.69
2	2	Government Point	Federal Offshore	21.00	211.70	58.67
3	4	Molino Offshore	State Offshore	3.02	200.00	38.61
4	7	Sacate	Federal Offshore	7.57	84.30	22.57
5	8	Wilson Rock	Federal Offshore	17.41	20.88	21.13
6	10	Pescado	Federal Offshore	6.14	62.33	17.23
7	15	Bardsdale	Onshore	6.34	30.00	11.67
8	21	Unnamed PRC 2879	State Offshore	5.00	17.50	8.11
9	24	Hondo	Federal Offshore	4.00	16.00	6.85
10	27	Shiells Canyon	Onshore	2.05	22.12	5.99
11	33	Capitan	Onshore	4.29	0.17	4.32
12	41	Oat Mountain	Onshore	2.73	1.37	2.97
13	47	Sacate OCS-P 0195	Federal Offshore	0.76	8.40	2.25
14	53	Santa Rosa	Federal Offshore	0.44	7.00	1.69
15	54	Point Conception	Onshore & State Offshore	1.41	0.87	1.56
16	55	Chaffee Canyon	Onshore	0.34	6.49	1.49
17	66	Conception Offshore	State Offshore	0.63	0.37	0.69
18	70	Sespe (Tar Creek-Topatopa)	Onshore	0.39	0.14	0.42
19	71	Ojai (Lion Mountain)	Onshore	0.35	0.20	0.39
20	75	Las Llajas	Onshore	0.09	0.06	0.10

Los Angeles Basin, Puente Fan Sandstone Play

Size of Accumulations	Minimum	Median	Maximum
Prospect Area (acres)	40	400	4,000
Trap Fill (fraction)	0.25	0.5	1.0
Pool Area (acres)	16	209	3,512
Net Pay (feet)	50	155	500
Pool Volume (acre-feet)	1,429	32,114	1,008,271
Number of Accumulations	Minimum	Median	Maximum
Number of Prospects	54	62	71
Number of Pools	0	19	39
Type of Accumulations			
Oil Pools (fraction)	1.0		
Gas Pools (fraction)	0.0		
Mixed Pools (fraction)	0.0		
Oil-filled Mixed Pool Volume	Minimum	Median	Maximum
Mixed Pools (fraction)	N/A	N/A	N/A
Petroleum Geologic Probabilities	Play Chance	Prospect Chance	Average Chance
Hydrocarbon Fill	1.0	0.7	
Reservoir Rock	1.0	0.8	
Trap	1.0	0.6	
Overall	1.0	0.3	0.3
Hydrocarbon Recovery	Minimum	Median	Maximum
Oil Yield (bbl per acre-foot)	55	180	600
Gas Yield (MMcf per acre-foot)	N/A	N/A	N/A
Condensate Yield (bbl per MMcf)	N/A	N/A	N/A
Solution Gas-to-Oil Ratio (cf per bbl)	220	900	3,600

Los Angeles Basin, San Onofre Breccia Play

	Minimum	Median	Maximum
Size of Accumulations			
	Minimum	Median	Maximum
Prospect Area (acres)			
Trap Fill (fraction)			
Pool Area (acres)	20	200	2,000
Net Pay (feet)	20	100	500
Pool Volume (acre-feet)	802	21,155	854,532
Number of Accumulations			
	Minimum	Median	Maximum
Number of Prospects	11	14	16
Number of Pools	0	4	13
Type of Accumulations			
Oil Pools (fraction)	1.0		
Gas Pools (fraction)	0.0		
Mixed Pools (fraction)	0.0		
Oil-filled Mixed Pool Volume			
	Minimum	Median	Maximum
Mixed Pools (fraction)	N/A	N/A	N/A
Petroleum Geologic Probabilities			
	Play Chance	Prospect Chance	Average Chance
Hydrocarbon Fill	1.0	0.7	
Reservoir Rock	1.0	0.8	
Trap	0.95	0.6	
Overall	0.95	0.3	0.29
Hydrocarbon Recovery			
	Minimum	Median	Maximum
Oil Yield (bbl per acre-foot)	70	180	450
Gas Yield (MMcf per acre-foot)	N/A	N/A	N/A
Condensate Yield (bbl per MMcf)	N/A	N/A	N/A
Solution Gas-to-Oil Ratio (cf per bbl)	150	400	1,000

Santa Monica-San Pedro Area, Upper Miocene Sandstone Play

	Minimum	Median	Maximum
Size of Accumulations			
	Minimum	Median	Maximum
Prospect Area (acres)	30	300	3,000
Trap Fill (fraction)	0.13	0.35	1.0
Pool Area (acres)	7	109	2,585
Net Pay (feet)	30	95	300
Pool Volume (acre-feet)	396	10,290	418,690
Number of Accumulations			
	Minimum	Median	Maximum
Number of Prospects	58	70	86
Number of Pools	0	13	34
Type of Accumulations			
Oil Pools (fraction)	1.0		
Gas Pools (fraction)	0.0		
Mixed Pools (fraction)	0.0		
Oil-filled Mixed Pool Volume			
	Minimum	Median	Maximum
Mixed Pools (fraction)	N/A	N/A	N/A
Petroleum Geologic Probabilities			
	Play Chance	Prospect Chance	Average Chance
Hydrocarbon Fill	0.8	0.3	
Reservoir Rock	1.0	0.8	
Trap	1.0	0.8	
Overall	0.8	0.2	0.16
Hydrocarbon Recovery			
	Minimum	Median	Maximum
Oil Yield (bbl per acre-foot)	40	125	420
Gas Yield (MMcf per acre-foot)	N/A	N/A	N/A
Condensate Yield (bbl per MMcf)	N/A	N/A	N/A
Solution Gas-to-Oil Ratio (cf per bbl)	200	400	800

Santa Monica-San Pedro Area, Modelo Play

	Size of Accumulations		
	Minimum	Median	Maximum
Prospect Area (acres)	15	450	14,000
Trap Fill (fraction)	0.13	0.35	1.0
Pool Area (acres)	4	172	11,828
Net Pay (feet)	20	165	1,200
Pool Volume (acre-feet)	226	29,004	6,387,195
	Number of Accumulations		
	Minimum	Median	Maximum
Number of Prospects	43	58	78
Number of Pools	0	11	31
	Type of Accumulations		
Oil Pools (fraction)	1.0		
Gas Pools (fraction)	0.0		
Mixed Pools (fraction)	0.0		
	Oil-filled Mixed Pool Volume		
	Minimum	Median	Maximum
Mixed Pools (fraction)	N/A	N/A	N/A
	Petroleum Geologic Probabilities		
	Play Chance	Prospect Chance	Average Chance
Hydrocarbon Fill	0.95	0.5	
Reservoir Rock	0.95	0.7	
Trap	1.0	0.6	
Overall	0.9	0.2	0.18
	Hydrocarbon Recovery		
	Minimum	Median	Maximum
Oil Yield (bbl per acre-foot)	20	90	480
Gas Yield (MMcf per acre-foot)	N/A	N/A	N/A
Condensate Yield (bbl per MMcf)	N/A	N/A	N/A
Solution Gas-to-Oil Ratio (cf per bbl)	200	1,100	6,850

Santa Monica-San Pedro Area, Dume Thrust Fault Play

	Size of Accumulations		
	Minimum	Median	Maximum
Prospect Area (acres)	24	420	7,400
Trap Fill (fraction)	0.13	0.35	1.0
Pool Area (acres)	6	157	6,182
Net Pay (feet)	130	370	1,000
Pool Volume (acre-feet)	1,451	57,935	3,583.980
	Number of Accumulations		
	Minimum	Median	Maximum
Number of Prospects	51	60	69
Number of Pools	0	16	37
	Type of Accumulations		
Oil Pools (fraction)	1.0		
Gas Pools (fraction)	0.0		
Mixed Pools (fraction)	0.0		
	Oil-filled Mixed Pool Volume		
	Minimum	Median	Maximum
Mixed Pools (fraction)	N/A	N/A	N/A
	Petroleum Geologic Probabilities		
	Play Chance	Prospect Chance	Average Chance
Hydrocarbon Fill	0.95	0.7	
Reservoir Rock	1.0	0.8	
Trap	0.7	0.5	
Overall	0.7	0.3	0.21
	Hydrocarbon Recovery		
	Minimum	Median	Maximum
Oil Yield (bbl per acre-foot)	50	155	485
Gas Yield (MMcf per acre-foot)	N/A	N/A	N/A
Condensate Yield (bbl per MMcf)	N/A	N/A	N/A
Solution Gas-to-Oil Ratio (cf per bbl)	185	1,050	6,000

Santa Monica-San Pedro Area, San Onofre Breccia Play

Size of Accumulations			
	Minimum	Median	Maximum
Prospect Area (acres)			
Trap Fill (fraction)			
Pool Area (acres)	20	200	2,000
Net Pay (feet)	20	100	500
Pool Volume (acre-feet)	802	21,155	854,532
Number of Accumulations			
	Minimum	Median	Maximum
Number of Prospects	12	14	17
Number of Pools	0	4	14
Type of Accumulations			
Oil Pools (fraction)	1.0		
Gas Pools (fraction)	0.0		
Mixed Pools (fraction)	0.0		
Oil-filled Mixed Pool Volume			
	Minimum	Median	Maximum
Mixed Pools (fraction)	N/A	N/A	N/A
Petroleum Geologic Probabilities			
	Play Chance	Prospect Chance	Average Chance
Hydrocarbon Fill	0.95	0.7	
Reservoir Rock	0.95	0.8	
Trap	0.9	0.6	
Overall	0.8	0.3	0.24
Hydrocarbon Recovery			
	Minimum	Median	Maximum
Oil Yield (bbl per acre-foot)	70	180	450
Gas Yield (MMcf per acre-foot)	N/A	N/A	N/A
Condensate Yield (bbl per MMcf)	N/A	N/A	N/A
Solution Gas-to-Oil Ratio (cf per bbl)	150	400	1,000

Oceanside-Capistrano Basin, Upper Miocene Sandstone Play

Size of Accumulations			
	Minimum	Median	Maximum
Prospect Area (acres)	35	600	11,000
Trap Fill (fraction)	0.13	0.35	1.0
Pool Area (acres)	9	221	8,908
Net Pay (feet)	50	155	500
Pool Volume (acre-feet)	967	33,903	2,331,045
Number of Accumulations			
	Minimum	Median	Maximum
Number of Prospects	63	88	124
Number of Pools	0	37	83
Type of Accumulations			
Oil Pools (fraction)	1.0		
Gas Pools (fraction)	0.0		
Mixed Pools (fraction)	0.0		
Oil-filled Mixed Pool Volume			
	Minimum	Median	Maximum
Mixed Pools (fraction)	N/A	N/A	N/A
Petroleum Geologic Probabilities			
	Play Chance	Prospect Chance	Average Chance
Hydrocarbon Fill	0.9	0.7	
Reservoir Rock	0.9	0.9	
Trap	0.8	0.8	
Overall	0.6	0.5	0.3
Hydrocarbon Recovery			
	Minimum	Median	Maximum
Oil Yield (bbl per acre-foot)	55	180	600
Gas Yield (MMcf per acre-foot)	N/A	N/A	N/A
Condensate Yield (bbl per MMcf)	N/A	N/A	N/A
Solution Gas-to-Oil Ratio (cf per bbl)	200	500	1,300

Oceanside-Capistrano Basin, Monterey Fractured Play

Size of Accumulations			
	Minimum	Median	Maximum
Prospect Area (acres)	25	570	11,500
Reservoir Rock Thickness (feet)			
Reservoir Rock Volume (acre-feet)	3,000	200,000	12,000,000
Volume Fill (fraction)	0.09	0.3	1.0
Pool Volume (acre-feet)	685	72,545	8,526,200
Number of Accumulations			
	Minimum	Median	Maximum
Number of Prospects	64	90	137
Number of Pools	0	32	76
Type of Accumulations			
Oil Pools (fraction)	1.0		
Gas Pools (fraction)	0.0		
Mixed Pools (fraction)	0.0		
Oil-filled Mixed Pool Volume			
	Minimum	Median	Maximum
Mixed Pools (fraction)	N/A	N/A	N/A
Petroleum Geologic Probabilities			
	Play Chance	Prospect Chance	Average Chance
Hydrocarbon Fill	0.9	0.8	
Reservoir Rock	0.8	0.7	
Trap	0.95	0.8	
Overall	0.7	0.4	0.28
Hydrocarbon Recovery			
	Minimum	Median	Maximum
Oil Yield (bbl per acre-foot)	20	33	55
Gas Yield (MMcf per acre-foot)	N/A	N/A	N/A
Condensate Yield (bbl per MMcf)	N/A	N/A	N/A
Solution Gas-to-Oil Ratio (cf per bbl)	200	940	4,600

Oceanside-Capistrano Basin, Lower Miocene Sandstone Play

Size of Accumulations			
	Minimum	Median	Maximum
Prospect Area (acres)	20	500	14,000
Trap Fill (fraction)	0.13	0.35	1.0
Pool Area (acres)	6	185	11,083
Net Pay (feet)	12	100	530
Pool Volume (acre-feet)	287	18,983	2,605,043
Number of Accumulations			
	Minimum	Median	Maximum
Number of Prospects	99	130	175
Number of Pools	0	0	74
Type of Accumulations			
Oil Pools (fraction)	1.0		
Gas Pools (fraction)	0.0		
Mixed Pools (fraction)	0.0		
Oil-filled Mixed Pool Volume			
	Minimum	Median	Maximum
Mixed Pools (fraction)	N/A	N/A	N/A
Petroleum Geologic Probabilities			
	Play Chance	Prospect Chance	Average Chance
Hydrocarbon Fill	0.8	0.7	
Reservoir Rock	0.8	0.7	
Trap	0.7	0.8	
Overall	0.4	0.3	0.12
Hydrocarbon Recovery			
	Minimum	Median	Maximum
Oil Yield (bbl per acre-foot)	30	145	550
Gas Yield (MMcf per acre-foot)	N/A	N/A	N/A
Condensate Yield (bbl per MMcf)	N/A	N/A	N/A
Solution Gas-to-Oil Ratio (cf per bbl)	200	1,500	12,000

Oceanside-Capistrano Basin, Paleogene-Cretaceous Sandstone Play

Size of Accumulations			
	Minimum	Median	Maximum
Prospect Area (acres)	20	90	400
Trap Fill (fraction)	0.13	0.35	1.0
Pool Area (acres)	4	32	361
Net Pay (feet)	10	80	670
Pool Volume (acre-feet)	126	2,744	116,937
Number of Accumulations			
	Minimum	Median	Maximum
Number of Prospects	10	23	50
Number of Pools	0	0	27
Type of Accumulations			
Oil Pools (fraction)	1.0		
Gas Pools (fraction)	0.0		
Mixed Pools (fraction)	0.0		
Oil-filled Mixed Pool Volume			
	Minimum	Median	Maximum
Mixed Pools (fraction)	N/A	N/A	N/A
Petroleum Geologic Probabilities			
	Play Chance	Prospect Chance	Average Chance
Hydrocarbon Fill	0.7	0.5	
Reservoir Rock	0.7	0.8	
Trap	0.7	0.7	
Overall	0.3	0.3	0.09
Hydrocarbon Recovery			
	Minimum	Median	Maximum
Oil Yield (bbl per acre-foot)	50	180	700
Gas Yield (MMcf per acre-foot)	N/A	N/A	N/A
Condensate Yield (bbl per MMcf)	N/A	N/A	N/A
Solution Gas-to-Oil Ratio (cf per bbl)	200	1,600	12,000

Santa Cruz Basin, Monterey Fractured Play

Size of Accumulations			
	Minimum	Median	Maximum
Prospect Area (acres)	50	550	6,000
Reservoir Rock Thickness (feet)			
Reservoir Rock Volume (acre-feet)	20,000	350,000	7,000,000
Volume Fill (fraction)	0.09	0.3	1.0
Pool Volume (acre-feet)	4,017	115,290	4,988,500
Number of Accumulations			
	Minimum	Median	Maximum
Number of Prospects	40	55	75
Number of Pools	0	18	46
Type of Accumulations			
Oil Pools (fraction)	1.0		
Gas Pools (fraction)	0.0		
Mixed Pools (fraction)	0.0		
Oil-filled Mixed Pool Volume			
	Minimum	Median	Maximum
Mixed Pools (fraction)	N/A	N/A	N/A
Petroleum Geologic Probabilities			
	Play Chance	Prospect Chance	Average Chance
Hydrocarbon Fill	0.7	0.7	
Reservoir Rock	0.9	0.8	
Trap	0.9	0.8	
Overall	0.6	0.4	0.24
Hydrocarbon Recovery			
	Minimum	Median	Maximum
Oil Yield (bbl per acre-foot)	25	40	65
Gas Yield (MMcf per acre-foot)	N/A	N/A	N/A
Condensate Yield (bbl per MMcf)	N/A	N/A	N/A
Solution Gas-to-Oil Ratio (cf per bbl)	200	940	4,600

Santa Cruz Basin, Lower Miocene Sandstone Play

Size of Accumulations			
	Minimum	Median	Maximum
Prospect Area (acres)	30	430	5,100
Trap Fill (fraction)	0.13	0.35	1.0
Pool Area (acres)	8	157	4,300
Net Pay (feet)	12	100	530
Pool Volume (acre-feet)	389	15,821	1,038,811
Number of Accumulations			
	Minimum	Median	Maximum
Number of Prospects	40	54	74
Number of Pools	0	0	46
Type of Accumulations			
Oil Pools (fraction)	1.0		
Gas Pools (fraction)	0.0		
Mixed Pools (fraction)	0.0		
Oil-filled Mixed Pool Volume			
	Minimum	Median	Maximum
Mixed Pools (fraction)	N/A	N/A	N/A
Petroleum Geologic Probabilities			
	Play Chance	Prospect Chance	Average Chance
Hydrocarbon Fill	0.7	0.6	
Reservoir Rock	0.9	0.8	
Trap	0.8	0.8	
Overall	0.5	0.4	0.2
Hydrocarbon Recovery			
	Minimum	Median	Maximum
Oil Yield (bbl per acre-foot)	30	145	550
Gas Yield (MMcf per acre-foot)	N/A	N/A	N/A
Condensate Yield (bbl per MMcf)	N/A	N/A	N/A
Solution Gas-to-Oil Ratio (cf per bbl)	200	1,500	12,000

Santa Rosa Area, Monterey Fractured Play

Size of Accumulations			
	Minimum	Median	Maximum
Prospect Area (acres)	50	575	7,000
Reservoir Rock Thickness (feet)			
Reservoir Rock Volume (acre-feet)	8,000	150,000	2,500,000
Volume Fill (fraction)	0.09	0.3	1.0
Pool Volume (acre-feet)	1,591	49,321	4,785,500
Number of Accumulations			
	Minimum	Median	Maximum
Number of Prospects	16	31	63
Number of Pools	0	0	39
Type of Accumulations			
Oil Pools (fraction)	1.0		
Gas Pools (fraction)	0.0		
Mixed Pools (fraction)	0.0		
Oil-filled Mixed Pool Volume			
	Minimum	Median	Maximum
Mixed Pools (fraction)	N/A	N/A	N/A
Petroleum Geologic Probabilities			
	Play Chance	Prospect Chance	Average Chance
Hydrocarbon Fill	0.5	0.7	
Reservoir Rock	0.9	0.8	
Trap	0.9	0.7	
Overall	0.4	0.4	0.16
Hydrocarbon Recovery			
	Minimum	Median	Maximum
Oil Yield (bbl per acre-foot)	25	40	65
Gas Yield (MMcf per acre-foot)	N/A	N/A	N/A
Condensate Yield (bbl per MMcf)	N/A	N/A	N/A
Solution Gas-to-Oil Ratio (cf per bbl)	200	940	4,600

Santa Rosa Area, Lower Miocene Sandstone Play

Size of Accumulations			
	Minimum	Median	Maximum
Prospect Area (acres)	60	600	6,000
Trap Fill (fraction)	0.13	0.35	1.0
Pool Area (acres)	16	225	5,276
Net Pay (feet)	12	100	530
Pool Volume (acre-feet)	765	23,443	1,354,878
Number of Accumulations			
	Minimum	Median	Maximum
Number of Prospects	16	26	45
Number of Pools	0	0	25
Type of Accumulations			
Oil Pools (fraction)	1.0		
Gas Pools (fraction)	0.0		
Mixed Pools (fraction)	0.0		
Oil-filled Mixed Pool Volume			
	Minimum	Median	Maximum
Mixed Pools (fraction)	N/A	N/A	N/A
Petroleum Geologic Probabilities			
	Play Chance	Prospect Chance	Average Chance
Hydrocarbon Fill	0.5	0.7	
Reservoir Rock	0.8	0.6	
Trap	0.7	0.7	
Overall	0.3	0.3	0.09
Hydrocarbon Recovery			
	Minimum	Median	Maximum
Oil Yield (bbl per acre-foot)	30	145	550
Gas Yield (MMcf per acre-foot)	N/A	N/A	N/A
Condensate Yield (bbl per MMcf)	N/A	N/A	N/A
Solution Gas-to-Oil Ratio (cf per bbl)	200	1,500	12,000

Santa Cruz-Santa Rosa Area, Paleogene-Cretaceous Sandstone Play

Size of Accumulations			
	Minimum	Median	Maximum
Prospect Area (acres)	58	600	6,300
Trap Fill (fraction)	0.13	0.35	1.0
Pool Area (acres)	15	219	5,237
Net Pay (feet)	10	80	670
Pool Volume (acre-feet)	509	18,963	1,526,478
Number of Accumulations			
	Minimum	Median	Maximum
Number of Prospects	67	80	96
Number of Pools	0	0	46
Type of Accumulations			
Oil Pools (fraction)	1.0		
Gas Pools (fraction)	0.0		
Mixed Pools (fraction)	0.0		
Oil-filled Mixed Pool Volume			
	Minimum	Median	Maximum
Mixed Pools (fraction)	N/A	N/A	N/A
Petroleum Geologic Probabilities			
	Play Chance	Prospect Chance	Average Chance
Hydrocarbon Fill	0.6	0.6	
Reservoir Rock	0.8	0.7	
Trap	0.7	0.8	
Overall	0.3	0.3	0.09
Hydrocarbon Recovery			
	Minimum	Median	Maximum
Oil Yield (bbl per acre-foot)	50	180	700
Gas Yield (MMcf per acre-foot)	N/A	N/A	N/A
Condensate Yield (bbl per MMcf)	N/A	N/A	N/A
Solution Gas-to-Oil Ratio (cf per bbl)	200	1,600	12,000

San Nicolas Basin, Upper Miocene Sandstone Play

Size of Accumulations			
	Minimum	Median	Maximum
Prospect Area (acres)	50	700	10,000
Trap Fill (fraction)	0.13	0.35	1.0
Pool Area (acres)	12	253	8,486
Net Pay (feet)	40	115	350
Pool Volume (acre-feet)	1,118	30,255	1,667,150
Number of Accumulations			
	Minimum	Median	Maximum
Number of Prospects	21	33	53
Number of Pools	0	0	34
Type of Accumulations			
Oil Pools (fraction)	1.0		
Gas Pools (fraction)	0.0		
Mixed Pools (fraction)	0.0		
Oil-filled Mixed Pool Volume			
	Minimum	Median	Maximum
Mixed Pools (fraction)	N/A	N/A	N/A
Petroleum Geologic Probabilities			
	Play Chance	Prospect Chance	Average Chance
Hydrocarbon Fill	0.8	0.7	
Reservoir Rock	0.7	0.8	
Trap	0.7	0.7	
Overall	0.4	0.4	0.16
Hydrocarbon Recovery			
	Minimum	Median	Maximum
Oil Yield (bbl per acre-foot)	45	150	450
Gas Yield (MMcf per acre-foot)	N/A	N/A	N/A
Condensate Yield (bbl per MMcf)	N/A	N/A	N/A
Solution Gas-to-Oil Ratio (cf per bbl)	200	500	1,300

San Nicolas Basin, Monterey Fractured Play

Size of Accumulations			
	Minimum	Median	Maximum
Prospect Area (acres)	40	725	12,000
Reservoir Rock Thickness (feet)			
Reservoir Rock Volume (acre-feet)	2,800	200,000	12,000,000
Volume Fill (fraction)	0.09	0.3	1.0
Pool Volume (acre-feet)	620	75,193	8,496,800
Number of Accumulations			
	Minimum	Median	Maximum
Number of Prospects	21	42	82
Number of Pools	0	14	50
Type of Accumulations			
Oil Pools (fraction)	1.0		
Gas Pools (fraction)	0.0		
Mixed Pools (fraction)	0.0		
Oil-filled Mixed Pool Volume			
	Minimum	Median	Maximum
Mixed Pools (fraction)	N/A	N/A	N/A
Petroleum Geologic Probabilities			
	Play Chance	Prospect Chance	Average Chance
Hydrocarbon Fill	0.8	0.7	
Reservoir Rock	0.9	0.8	
Trap	0.9	0.8	
Overall	0.7	0.4	0.28
Hydrocarbon Recovery			
	Minimum	Median	Maximum
Oil Yield (bbl per acre-foot)	25	40	65
Gas Yield (MMcf per acre-foot)	N/A	N/A	N/A
Condensate Yield (bbl per MMcf)	N/A	N/A	N/A
Solution Gas-to-Oil Ratio (cf per bbl)	200	940	4,600

San Nicolas Basin, Lower Miocene Sandstone Play

Size of Accumulations			
	Minimum	Median	Maximum
Prospect Area (acres)	40	700	11,000
Trap Fill (fraction)	0.13	0.35	1.0
Pool Area (acres)	10	255	9,137
Net Pay (feet)	12	100	530
Pool Volume (acre-feet)	504	26,117	2,193,454
Number of Accumulations			
	Minimum	Median	Maximum
Number of Prospects	38	60	96
Number of Pools	0	0	55
Type of Accumulations			
Oil Pools (fraction)	1.0		
Gas Pools (fraction)	0.0		
Mixed Pools (fraction)	0.0		
Oil-filled Mixed Pool Volume			
	Minimum	Median	Maximum
Mixed Pools (fraction)	N/A	N/A	N/A
Petroleum Geologic Probabilities			
	Play Chance	Prospect Chance	Average Chance
Hydrocarbon Fill	0.6	0.6	
Reservoir Rock	0.8	0.8	
Trap	0.8	0.8	
Overall	0.4	0.4	0.16
Hydrocarbon Recovery			
	Minimum	Median	Maximum
Oil Yield (bbl per acre-foot)	30	145	550
Gas Yield (MMcf per acre-foot)	N/A	N/A	N/A
Condensate Yield (bbl per MMcf)	N/A	N/A	N/A
Solution Gas-to-Oil Ratio (cf per bbl)	200	1,500	12,000

San Nicolas Basin, Paleogene-Cretaceous Sandstone Play

Size of Accumulations			
	Minimum	Median	Maximum
Prospect Area (acres)	65	730	8,000
Trap Fill (fraction)	0.13	0.35	1.0
Pool Area (acres)	16	277	6,763
Net Pay (feet)	10	80	670
Pool Volume (acre-feet)	572	23,970	2,036,101
Number of Accumulations			
	Minimum	Median	Maximum
Number of Prospects	31	54	95
Number of Pools	0	0	45
Type of Accumulations			
Oil Pools (fraction)	1.0		
Gas Pools (fraction)	0.0		
Mixed Pools (fraction)	0.0		
Oil-filled Mixed Pool Volume			
	Minimum	Median	Maximum
Mixed Pools (fraction)	N/A	N/A	N/A
Petroleum Geologic Probabilities			
	Play Chance	Prospect Chance	Average Chance
Hydrocarbon Fill	0.5	0.6	
Reservoir Rock	0.8	0.7	
Trap	0.9	0.8	
Overall	0.4	0.3	0.12
Hydrocarbon Recovery			
	Minimum	Median	Maximum
Oil Yield (bbl per acre-foot)	50	180	700
Gas Yield (MMcf per acre-foot)	N/A	N/A	N/A
Condensate Yield (bbl per MMcf)	N/A	N/A	N/A
Solution Gas-to-Oil Ratio (cf per bbl)	200	1,600	12,000

Cortes-Velero-Long Area, Lower Miocene Sandstone Play

	Size of Accumulations		
	Minimum	Median	Maximum
Prospect Area (acres)	45	800	14,500
Trap Fill (fraction)	0.07	0.25	0.95
Pool Area (acres)	8	217	10,920
Net Pay (feet)	12	100	530
Pool Volume (acre-feet)	433	22,073	2,549,489
	Number of Accumulations		
	Minimum	Median	Maximum
Number of Prospects	76	110	172
Number of Pools	0	0	91
	Type of Accumulations		
Oil Pools (fraction)	1.0		
Gas Pools (fraction)	0.0		
Mixed Pools (fraction)	0.0		
	Oil-filled Mixed Pool Volume		
	Minimum	Median	Maximum
Mixed Pools (fraction)	N/A	N/A	N/A
	Petroleum Geologic Probabilities		
	Play Chance	Prospect Chance	Average Chance
Hydrocarbon Fill	0.5	0.6	
Reservoir Rock	0.9	0.8	
Trap	0.8	0.8	
Overall	0.4	0.4	0.16
	Hydrocarbon Recovery		
	Minimum	Median	Maximum
Oil Yield (bbl per acre-foot)	30	145	550
Gas Yield (MMcf per acre-foot)	N/A	N/A	N/A
Condensate Yield (bbl per MMcf)	N/A	N/A	N/A
Solution Gas-to-Oil Ratio (cf per bbl)	200	1,500	12,000

Cortes-Velero-Long Area, Paleogene-Cretaceous Sandstone Play

	Size of Accumulations		
	Minimum	Median	Maximum
Prospect Area (acres)	60	925	14,000
Trap Fill (fraction)	0.07	0.25	0.95
Pool Area (acres)	10	251	10,919
Net Pay (feet)	10	80	670
Pool Volume (acre-feet)	376	21,567	2,816,912
	Number of Accumulations		
	Minimum	Median	Maximum
Number of Prospects	76	105	150
Number of Pools	0	0	64
	Type of Accumulations		
Oil Pools (fraction)	1.0		
Gas Pools (fraction)	0.0		
Mixed Pools (fraction)	0.0		
	Oil-filled Mixed Pool Volume		
	Minimum	Median	Maximum
Mixed Pools (fraction)	N/A	N/A	N/A
	Petroleum Geologic Probabilities		
	Play Chance	Prospect Chance	Average Chance
Hydrocarbon Fill	0.5	0.6	
Reservoir Rock	0.9	0.7	
Trap	0.7	0.8	
Overall	0.3	0.3	0.09
	Hydrocarbon Recovery		
	Minimum	Median	Maximum
Oil Yield (bbl per acre-foot)	50	180	700
Gas Yield (MMcf per acre-foot)	N/A	N/A	N/A
Condensate Yield (bbl per MMcf)	N/A	N/A	N/A
Solution Gas-to-Oil Ratio (cf per bbl)	200	1,600	12,000

Appendix D

Select Petroleum Engineering and Economic Data Used to Assess Undiscovered Economically Recoverable Resources

This appendix presents select petroleum engineering and economic data and information used to develop estimates of the volume of undiscovered economically recoverable oil and gas resources in 13 assessment areas of the Pacific OCS Region. The data are presented in tabular format by area. The following describes the categories and types of data presented. Multiple values (minimum, most probable, and maximum) are presented for parameters that are described by a probability distribution. A single value (most probable) is presented for parameters that are described by a constant.

Exploration Parameters

These parameters are used to estimate exploration costs.

Exploratory Wells:	the number of wells drilled to discover a field in the area
Delineation Wells:	the number of wells drilled to delineate a field in the area
E & D Well Drilling Depth:	the measured depth of exploratory and delineation (E & D) wells in the area, expressed in feet
E & D Well Drilling Time:	the period of time to drill an exploratory or delineation well, expressed in months per well

Development Parameters

These parameters are used to estimate development costs.

Platform Size:	the range of platform sizes in the area, expressed as the number of well slots
Water Depth:	the water depth at platforms, expressed in feet
Production Well Depth:	the total measured depth of production wells, expressed in feet

Oil Production Parameters

These parameters are used to estimate the production profile of a well using common reservoir engineering methods.

Oil Well Recovery:	the total volume of crude oil produced from a well in the area, expressed in million barrels per well
Initial Oil Rate:	the initial rate of crude oil production from a well, expressed in barrels per day per well
Oil Produced Before Decline:	the fraction of the total volume of crude oil produced from a well that is produced before the initial production rate declines, expressed as a decimal fraction
Initial Oil Decline Rate:	the rate at which crude oil production declines at the onset of decline, expressed as a decimal fraction per year
Hyperbolic Decline Coefficient:	an exponential coefficient used to describe the shape of an oil production decline curve that is defined by a hyperbolic function (zero indicates an exponential decline and one indicates a harmonic decline)

Gas Production Parameters

These parameters are used to estimate the production profile of a well using common reservoir engineering methods.

Gas-to-Oil Proportion:	the proportional volume of gas (including associated and nonassociated gas) that can be extracted from the area relative to the volume of crude oil that can be extracted from the area, expressed in cubic feet per barrel
Initial Gas Rate:	the initial rate of gas production from a well, expressed in thousand cubic feet per day per well
Gas Produced Before Decline:	the fraction of the total volume of gas produced from a well that is produced before the initial production rate declines, expressed as a decimal fraction
Initial Gas Decline Rate:	the rate at which gas production declines at the onset of decline, expressed as a decimal fraction per year
Hyperbolic Decline Coefficient:	an exponential coefficient used to describe the shape of a gas production decline curve that is defined by a hyperbolic function (zero indicates an exponential decline and one indicates a harmonic decline)

Pipeline Network Parameters

These parameters are used to determine the size of the oil and gas pipeline network at field and area levels to estimate pipeline costs.

Trunkline Length	the estimated total length of trunk pipeline(s) to develop the area, expressed in miles
Branchline Length:	the estimated length of pipelines that branch from a trunkline to a platform, expressed in miles

Economic Parameters

These parameters are used to model the economic viability of developing the oil and gas resources of the area. Rates are expected average values during the period of development and production in the area. The oil price adjustment is used to normalize differences in price due to differences of oil gravity among areas.

Interest Rate:	the private after-tax discount rate, expressed as a percent
Inflation Rate:	the inflation rate, expressed as a percent
Royalty Rate:	the royalty rate, expressed as a percent
Tax Rate:	the Federal corporate tax rate, expressed as a percent
Oil Price Adjustment:	the adjustment of the price of crude oil produced from the area compared to an assumed price ($18 per bbl of 32 °API crude oil), based on the expected gravity of the oil, expressed as an increased (+) or decreased (-) value in dollars per barrel

Washington-Oregon Area

	Minimum	Most Probable	Maximum
Exploration Parameters			
Exploratory Wells		3	
Delineation Wells		2	
E & D Well Drilling Depth (feet)		12,000	
E & D Well Drilling Time (months per well)		2	
Development Parameters	Minimum	Most Probable	Maximum
Platform Size (slots)	18		60
Water Depth (feet)	100	300	500
Production Well Depth (feet)	3,200	7,700	20,000
Oil Production Parameters	Minimum	Most Probable	Maximum
Oil Well Recovery (MMbbl per well)		1.6 to 2.0	
Initial Oil Rate (bbl per day per well)		700	
Oil Produced Before Decline (fraction)	0.15	0.175	0.20
Initial Oil Decline Rate (fraction per year)	0.15	0.20	0.25
Oil Hyperbolic Decline Coefficient		0.30	
Gas Production Parameters	Minimum	Most Probable	Maximum
Gas-to-Oil Proportion (cf per bbl)		N/A	
Initial Gas Rate (Mcf per day per well)		100,000	
Gas Produced Before Decline (fraction)		0.22	
Initial Gas Decline Rate (fraction per year)		0.22	
Gas Hyperbolic Decline Coefficient		0.50	
Transportation and Pipeline Network Parameters	Minimum	Most Probable	Maximum
Trunkline Length (miles)		80	
Branchline Length (miles)		35	
Economic Parameters	Minimum	Most Probable	Maximum
Interest Rate (percent)		12.0	
Inflation Rate (percent)		3.0	
Royalty Rate (percent)		16.67	
Tax Rate (percent)		35.0	
Oil Price Adjustment (dollars per bbl)		+ 0.40	

Eel River Basin

	Minimum	Most Probable	Maximum
Exploration Parameters			
Exploratory Wells		2	
Delineation Wells		2	
E & D Well Drilling Depth (feet)		9,000	
E & D Well Drilling Time (months per well)		2	
Development Parameters	Minimum	Most Probable	Maximum
Platform Size (slots)	18		60
Water Depth (feet)	200	600	1,200
Production Well Depth (feet)	6,000	7,700	17,000
Oil Production Parameters	Minimum	Most Probable	Maximum
Oil Well Recovery (MMbbl per well)		1.6 to 2.0	
Initial Oil Rate (bbl per day per well)		700	
Oil Produced Before Decline (fraction)	0.15	0.175	0.20
Initial Oil Decline Rate (fraction per year)	0.15	0.20	0.25
Oil Hyperbolic Decline Coefficient		0.30	
Gas Production Parameters	Minimum	Most Probable	Maximum
Gas-to-Oil Proportion (cf per bbl)		N/A	
Initial Gas Rate (Mcf per day per well)		100,000	
Gas Produced Before Decline (fraction)		0.22	
Initial Gas Decline Rate (fraction per year)		0.22	
Gas Hyperbolic Decline Coefficient		0.50	
Transportation and Pipeline Network Parameters	Minimum	Most Probable	Maximum
Trunkline Length (miles)		15	
Branchline Length (miles)		20	
Economic Parameters	Minimum	Most Probable	Maximum
Interest Rate (percent)		12.0	
Inflation Rate (percent)		3.0	
Royalty Rate (percent)		16.67	
Tax Rate (percent)		35.0	
Oil Price Adjustment (dollars per bbl)		+ 0.40	

Point Arena Basin

	Minimum	Most Probable	Maximum
Exploration Parameters			
Exploratory Wells		2	
Delineation Wells		2	
E & D Well Drilling Depth (feet)		10,000	
E & D Well Drilling Time (months per well)		2	
Development Parameters			
Platform Size (slots)	18		60
Water Depth (feet)	350		3,250
Production Well Depth (feet)	4,000	10,000	25,000
Oil Production Parameters			
Oil Well Recovery (MMbbl per well)		3.5 to 4.0	
Initial Oil Rate (bbl per day per well)		1,250	
Oil Produced Before Decline (fraction)	0.15	0.175	0.20
Initial Oil Decline Rate (fraction per year)		0.15	
Oil Hyperbolic Decline Coefficient		0.30	
Gas Production Parameters			
Gas-to-Oil Proportion (cf per bbl)		1,060	
Initial Gas Rate (Mcf per day per well)		N/A	
Gas Produced Before Decline (fraction)		N/A	
Initial Gas Decline Rate (fraction per year)		N/A	
Gas Hyperbolic Decline Coefficient		N/A	
Transportation and Pipeline Network Parameters			
Trunkline Length (miles)		20	
Branchline Length (miles)		15	
Economic Parameters			
Interest Rate (percent)		12.0	
Inflation Rate (percent)		3.0	
Royalty Rate (percent)		12.5	
Tax Rate (percent)		35.0	
Oil Price Adjustment (dollars per bbl)		– 1.60	

Bodega Basin

	Minimum	Most Probable	Maximum
Exploration Parameters			
Exploratory Wells		2	
Delineation Wells		2	
E & D Well Drilling Depth (feet)		7,500	
E & D Well Drilling Time (months per well)		2	
Development Parameters			
Platform Size (slots)	18		60
Water Depth (feet)	100	350	750
Production Well Depth (feet)	5,000	10,000	19,000
Oil Production Parameters			
Oil Well Recovery (MMbbl per well)		3.4 to 3.8	
Initial Oil Rate (bbl per day per well)		1,250	
Oil Produced Before Decline (fraction)	0.15	0.175	0.20
Initial Oil Decline Rate (fraction per year)		0.15	
Oil Hyperbolic Decline Coefficient		0.30	
Gas Production Parameters			
Gas-to-Oil Proportion (cf per bbl)		1,100	
Initial Gas Rate (Mcf per day per well)		N/A	
Gas Produced Before Decline (fraction)		N/A	
Initial Gas Decline Rate (fraction per year)		N/A	
Gas Hyperbolic Decline Coefficient		N/A	
Transportation and Pipeline Network Parameters			
Trunkline Length (miles)		12	
Branchline Length (miles)		15	
Economic Parameters			
Interest Rate (percent)		12.0	
Inflation Rate (percent)		3.0	
Royalty Rate (percent)		16.67	
Tax Rate (percent)		35.0	
Oil Price Adjustment (dollars per bbl)		– 1.35	

Año Nuevo Basin

	Minimum	Most Probable	Maximum
Exploration Parameters			
Exploratory Wells		2	
Delineation Wells		2	
E & D Well Drilling Depth (feet)		8,300	
E & D Well Drilling Time (months per well)		2	
Development Parameters			
Platform Size (slots)	18		60
Water Depth (feet)	225	350	1,250
Production Well Depth (feet)	5,000	10,000	19,500
Oil Production Parameters			
Oil Well Recovery (MMbbl per well)		3.5 to 3.9	
Initial Oil Rate (bbl per day per well)		1,250	
Oil Produced Before Decline (fraction)	0.15	0.175	0.20
Initial Oil Decline Rate (fraction per year)		0.15	
Oil Hyperbolic Decline Coefficient		0.30	
Gas Production Parameters			
Gas-to-Oil Proportion (cf per bbl)		1,080	
Initial Gas Rate (Mcf per day per well)		N/A	
Gas Produced Before Decline (fraction)		N/A	
Initial Gas Decline Rate (fraction per year)		N/A	
Gas Hyperbolic Decline Coefficient		N/A	
Transportation and Pipeline Network Parameters			
Trunkline Length (miles)		7.5	
Branchline Length (miles)		15	
Economic Parameters			
Interest Rate (percent)		12.0	
Inflation Rate (percent)		3.0	
Royalty Rate (percent)		16.67	
Tax Rate (percent)		35.0	
Oil Price Adjustment (dollars per bbl)		– 1.65	

Santa Maria-Partington Basin

	Minimum	Most Probable	Maximum
Exploration Parameters			
Exploratory Wells		2	
Delineation Wells		2	
E & D Well Drilling Depth (feet)		12,000	
E & D Well Drilling Time (months per well)		2	
Development Parameters			
Platform Size (slots)	18		60
Water Depth (feet)	200		2,300
Production Well Depth (feet)	6,000	10,000	14,000
Oil Production Parameters			
Oil Well Recovery (MMbbl per well)		3.0 to 4.0	
Initial Oil Rate (bbl per day per well)		1,250	
Oil Produced Before Decline (fraction)	0.15	0.175	0.20
Initial Oil Decline Rate (fraction per year)		0.15	
Oil Hyperbolic Decline Coefficient		0.30	
Gas Production Parameters			
Gas-to-Oil Proportion (cf per bbl)		940	
Initial Gas Rate (Mcf per day per well)		N/A	
Gas Produced Before Decline (fraction)		N/A	
Initial Gas Decline Rate (fraction per year)		N/A	
Gas Hyperbolic Decline Coefficient		N/A	
Transportation and Pipeline Network Parameters			
Trunkline Length (miles)		30	
Branchline Length (miles)		20	
Economic Parameters			
Interest Rate (percent)		12.0	
Inflation Rate (percent)		3.0	
Royalty Rate (percent)		16.67	
Tax Rate (percent)		35.0	
Oil Price Adjustment (dollars per bbl)		– 2.10	

Santa Barbara-Ventura Basin

	Minimum	Most Probable	Maximum
Exploration Parameters			
Exploratory Wells		1	
Delineation Wells		2	
E & D Well Drilling Depth (feet)		14,000	
E & D Well Drilling Time (months per well)		2	
Development Parameters			
Platform Size (slots)	18		60
Water Depth (feet)	100	600	1,650
Production Well Depth (feet)	5,000	10,500	23,000
Oil Production Parameters			
Oil Well Recovery (MMbbl per well)		2.5 to 3.0	
Initial Oil Rate (bbl per day per well)		1,300	
Oil Produced Before Decline (fraction)	0.20	0.225	0.25
Initial Oil Decline Rate (fraction per year)		0.20	
Oil Hyperbolic Decline Coefficient		0.30	
Gas Production Parameters			
Gas-to-Oil Proportion (cf per bbl)		2,500	
Initial Gas Rate (Mcf per day per well)		N/A	
Gas Produced Before Decline (fraction)		N/A	
Initial Gas Decline Rate (fraction per year)		N/A	
Gas Hyperbolic Decline Coefficient		N/A	
Transportation and Pipeline Network Parameters			
Trunkline Length (miles)		0	
Branchline Length (miles)		7	
Economic Parameters			
Interest Rate (percent)		12.0	
Inflation Rate (percent)		3.0	
Royalty Rate (percent)		16.67	
Tax Rate (percent)		35.0	
Oil Price Adjustment (dollars per bbl)		– 1.05	

Los Angeles Basin

	Minimum	Most Probable	Maximum
Exploration Parameters			
Exploratory Wells		2	
Delineation Wells		2	
E & D Well Drilling Depth (feet)		10,000	
E & D Well Drilling Time (months per well)		2	
Development Parameters			
Platform Size (slots)	18		60
Water Depth (feet)	200	750	1,700
Production Well Depth (feet)	5,000	10,000	19,000
Oil Production Parameters			
Oil Well Recovery (MMbbl per well)		2.6	
Initial Oil Rate (bbl per day per well)		1,200	
Oil Produced Before Decline (fraction)	0.20	0.225	0.25
Initial Oil Decline Rate (fraction per year)	0.20	0.225	0.25
Oil Hyperbolic Decline Coefficient		N/A	
Gas Production Parameters			
Gas-to-Oil Proportion (cf per bbl)		1,020	
Initial Gas Rate (Mcf per day per well)		N/A	
Gas Produced Before Decline (fraction)		N/A	
Initial Gas Decline Rate (fraction per year)		N/A	
Gas Hyperbolic Decline Coefficient		N/A	
Transportation and Pipeline Network Parameters			
Trunkline Length (miles)		5	
Branchline Length (miles)		5	
Economic Parameters			
Interest Rate (percent)		12.0	
Inflation Rate (percent)		3.0	
Royalty Rate (percent)		16.67	
Tax Rate (percent)		35.0	
Oil Price Adjustment (dollars per bbl)		– 0.75	

Santa Monica-San Pedro Area

	Minimum	Most Probable	Maximum
Exploration Parameters			
Exploratory Wells		2	
Delineation Wells		2	
E & D Well Drilling Depth (feet)		7,000	
E & D Well Drilling Time (months per well)		2	
Development Parameters			
Platform Size (slots)	18		60
Water Depth (feet)	200	1,750	2,850
Production Well Depth (feet)	7,000	11,000	18,000
Oil Production Parameters			
Oil Well Recovery (MMbbl per well)		2.52 to 3.15	
Initial Oil Rate (bbl per day per well)		1,300	
Oil Produced Before Decline (fraction)	0.20	0.225	0.25
Initial Oil Decline Rate (fraction per year)		0.15	
Oil Hyperbolic Decline Coefficient		0.30	
Gas Production Parameters			
Gas-to-Oil Proportion (cf per bbl)		1,130	
Initial Gas Rate (Mcf per day per well)		N/A	
Gas Produced Before Decline (fraction)		N/A	
Initial Gas Decline Rate (fraction per year)		N/A	
Gas Hyperbolic Decline Coefficient		N/A	
Transportation and Pipeline Network Parameters			
Trunkline Length (miles)		15	
Branchline Length (miles)		6	
Economic Parameters			
Interest Rate (percent)		12.0	
Inflation Rate (percent)		3.0	
Royalty Rate (percent)		16.67	
Tax Rate (percent)		35.0	
Oil Price Adjustment (dollars per bbl)		– 0.90	

Oceanside-Capistrano Basin

	Minimum	Most Probable	Maximum
Exploration Parameters			
Exploratory Wells		3	
Delineation Wells		2	
E & D Well Drilling Depth (feet)		11,000	
E & D Well Drilling Time (months per well)		2	
Development Parameters			
Platform Size (slots)	18		60
Water Depth (feet)	300	1,000	2,000
Production Well Depth (feet)	7,500	11,000	24,000
Oil Production Parameters			
Oil Well Recovery (MMbbl per well)		2.3 to 2.5	
Initial Oil Rate (bbl per day per well)		1,100	
Oil Produced Before Decline (fraction)	0.20	0.23	0.25
Initial Oil Decline Rate (fraction per year)	0.15	0.175	0.225
Oil Hyperbolic Decline Coefficient		0.30	
Gas Production Parameters			
Gas-to-Oil Proportion (cf per bbl)		1,170	
Initial Gas Rate (Mcf per day per well)		N/A	
Gas Produced Before Decline (fraction)		N/A	
Initial Gas Decline Rate (fraction per year)		N/A	
Gas Hyperbolic Decline Coefficient		N/A	
Transportation and Pipeline Network Parameters			
Trunkline Length (miles)		21	
Branchline Length (miles)		5	
Economic Parameters			
Interest Rate (percent)		12.0	
Inflation Rate (percent)		3.0	
Royalty Rate (percent)		16.67	
Tax Rate (percent)		35.0	
Oil Price Adjustment (dollars per bbl)		– 1.20	

Santa Cruz-Santa Rosa Area

Exploration Parameters	Minimum	Most Probable	Maximum
Exploratory Wells		3	
Delineation Wells		2	
E & D Well Drilling Depth (feet)		13,000	
E & D Well Drilling Time (months per well)		2	
Development Parameters	Minimum	Most Probable	Maximum
Platform Size (slots)	18		60
Water Depth (feet)	1,500	4,000	5,000
Production Well Depth (feet)	6,200	11,000	22,000
Oil Production Parameters	Minimum	Most Probable	Maximum
Oil Well Recovery (MMbbl per well)		2.5 to 2.75	
Initial Oil Rate (bbl per day per well)		800	
Oil Produced Before Decline (fraction)		0.15	
Initial Oil Decline Rate (fraction per year)	0.15	0.20	0.25
Oil Hyperbolic Decline Coefficient		0.30	
Gas Production Parameters	Minimum	Most Probable	Maximum
Gas-to-Oil Proportion (cf per bbl)		1,790	
Initial Gas Rate (Mcf per day per well)		N/A	
Gas Produced Before Decline (fraction)		N/A	
Initial Gas Decline Rate (fraction per year)		N/A	
Gas Hyperbolic Decline Coefficient		N/A	
Transportation and Pipeline Network Parameters	Minimum	Most Probable	Maximum
Trunkline Length (miles)		40	
Branchline Length (miles)		16	
Economic Parameters	Minimum	Most Probable	Maximum
Interest Rate (percent)		12.0	
Inflation Rate (percent)		3.0	
Royalty Rate (percent)		12.5	
Tax Rate (percent)		35.0	
Oil Price Adjustment (dollars per bbl)		– 0.60	

San Nicolas Basin

Exploration Parameters	Minimum	Most Probable	Maximum
Exploratory Wells		3	
Delineation Wells		2	
E & D Well Drilling Depth (feet)		13,000	
E & D Well Drilling Time (months per well)		2	
Development Parameters	Minimum	Most Probable	Maximum
Platform Size (slots)	18		60
Water Depth (feet)	2,500	4,000	5,000
Production Well Depth (feet)	8,000	10,500	23,000
Oil Production Parameters	Minimum	Most Probable	Maximum
Oil Well Recovery (MMbbl per well)		2.2 to 2.4	
Initial Oil Rate (bbl per day per well)		1,050	
Oil Produced Before Decline (fraction)	0.20	0.23	0.25
Initial Oil Decline Rate (fraction per year)	0.15	0.20	0.25
Oil Hyperbolic Decline Coefficient		0.30	
Gas Production Parameters	Minimum	Most Probable	Maximum
Gas-to-Oil Proportion (cf per bbl)		1,670	
Initial Gas Rate (Mcf per day per well)		N/A	
Gas Produced Before Decline (fraction)		N/A	
Initial Gas Decline Rate (fraction per year)		N/A	
Gas Hyperbolic Decline Coefficient		N/A	
Transportation and Pipeline Network Parameters	Minimum	Most Probable	Maximum
Trunkline Length (miles)		75	
Branchline Length (miles)		12	
Economic Parameters	Minimum	Most Probable	Maximum
Interest Rate (percent)		12.0	
Inflation Rate (percent)		3.0	
Royalty Rate (percent)		12.5	
Tax Rate (percent)		35.0	
Oil Price Adjustment (dollars per bbl)		– 0.60	

Cortes-Velero-Long Area

	Minimum	Most Probable	Maximum
Exploration Parameters			
Exploratory Wells		3	
Delineation Wells		2	
E & D Well Drilling Depth (feet)		14,000	
E & D Well Drilling Time (months per well)		2	
Development Parameters	Minimum	Most Probable	Maximum
Platform Size (slots)	18		60
Water Depth (feet)	3,000	4,500	6,000
Production Well Depth (feet)	8,500	11,800	23,000
Oil Production Parameters	Minimum	Most Probable	Maximum
Oil Well Recovery (MMbbl per well)		0.80	
Initial Oil Rate (bbl per day per well)		550	
Oil Produced Before Decline (fraction)		0.25	
Initial Oil Decline Rate (fraction per year)	0.15	0.20	0.25
Oil Hyperbolic Decline Coefficient		0.30	
Gas Production Parameters	Minimum	Most Probable	Maximum
Gas-to-Oil Proportion (cf per bbl)		2,670	
Initial Gas Rate (Mcf per day per well)		N/A	
Gas Produced Before Decline (fraction)		N/A	
Initial Gas Decline Rate (fraction per year)		N/A	
Gas Hyperbolic Decline Coefficient		N/A	
Transportation and Pipeline Network Parameters	Minimum	Most Probable	Maximum
Trunkline Length (miles)		75	
Branchline Length (miles)		35	
Economic Parameters	Minimum	Most Probable	Maximum
Interest Rate (percent)		12.0	
Inflation Rate (percent)		3.0	
Royalty Rate (percent)		12.5	
Tax Rate (percent)		35.0	
Oil Price Adjustment (dollars per bbl)		0.00	

Appendix E

Estimates of Undiscovered Resources in Planning Areas of the Pacific OCS Region

This appendix presents estimates of the volume of undiscovered conventionally recoverable and economically recoverable oil and gas resources in four administrative planning areas of the Pacific OCS Region (fig. E1). The estimates are presented in table E1.

The volume of undiscovered conventionally recoverable resources in planning areas of the Region was estimated by allocating the estimated mean volume of undiscovered conventionally recoverable resources in plays of two assessment areas among multiple planning areas[1] , and summing the constituent play (and subplay) estimates to the assessment-area and planning-area levels. The volume of undiscovered economically recoverable resources in planning areas of the Region was estimated by allocating the estimated mean volume of undiscovered economically recoverable resources in two assessment areas among multiple planning areas[1], and summing the constituent assessment area (and subarea) estimates to the planning-area level; the estimates are presented for two economic scenarios.

Table E1. *Estimates of undiscovered conventionally recoverable and economically recoverable oil and gas resources in the Pacific OCS Region as of January 1, 1995, by planning area. All estimates are risked mean values. The $18-per-barrel scenario is based on prices of $18 per bbl of oil and $2.11 per Mcf of gas; the $30-per-barrel scenario is based on prices of $30 per bbl of oil and $3.52 per Mcf of gas. Some total values may not equal the sum of the component values due to independent rounding.*

Planning Area	Undiscovered Conventionally Recoverable Resources			Undiscovered Economically Recoverable Resources					
				$18-per-barrel Scenario			$30-per-barrel Scenario		
	Oil (Bbbl)	Gas (Tcf)	BOE (Bbbl)	Oil (Bbbl)	Gas (Tcf)	BOE (Bbbl)	Oil (Bbbl)	Gas (Tcf)	BOE (Bbbl)
Washington-Oregon OCS	0.36	2.35	0.78	0.10	0.65	0.21	0.15	1.04	0.33
Northern California OCS	2.08	3.71	2.74	0.91	1.23	1.12	1.34	1.89	1.67
Central California OCS	2.35	2.55	2.80	1.57	1.71	1.87	1.86	2.02	2.22
Southern California OCS	5.92	10.34	7.76	2.75	4.71	3.59	3.90	6.67	5.08
Total Pacific OCS Region	*10.71*	*18.94*	*14.08*	*5.31*	*8.30*	*6.79*	*7.23*	*11.62*	*9.30*

[1] The estimated volume of undiscovered resources in the Eel River Basin assessment area was allocated between the Washington-Oregon OCS and Northern California OCS planning areas. The estimated volume of undiscovered resources in the Santa Maria-Partington Basin assessment area was allocated between the Central California OCS and Southern California OCS planning areas.

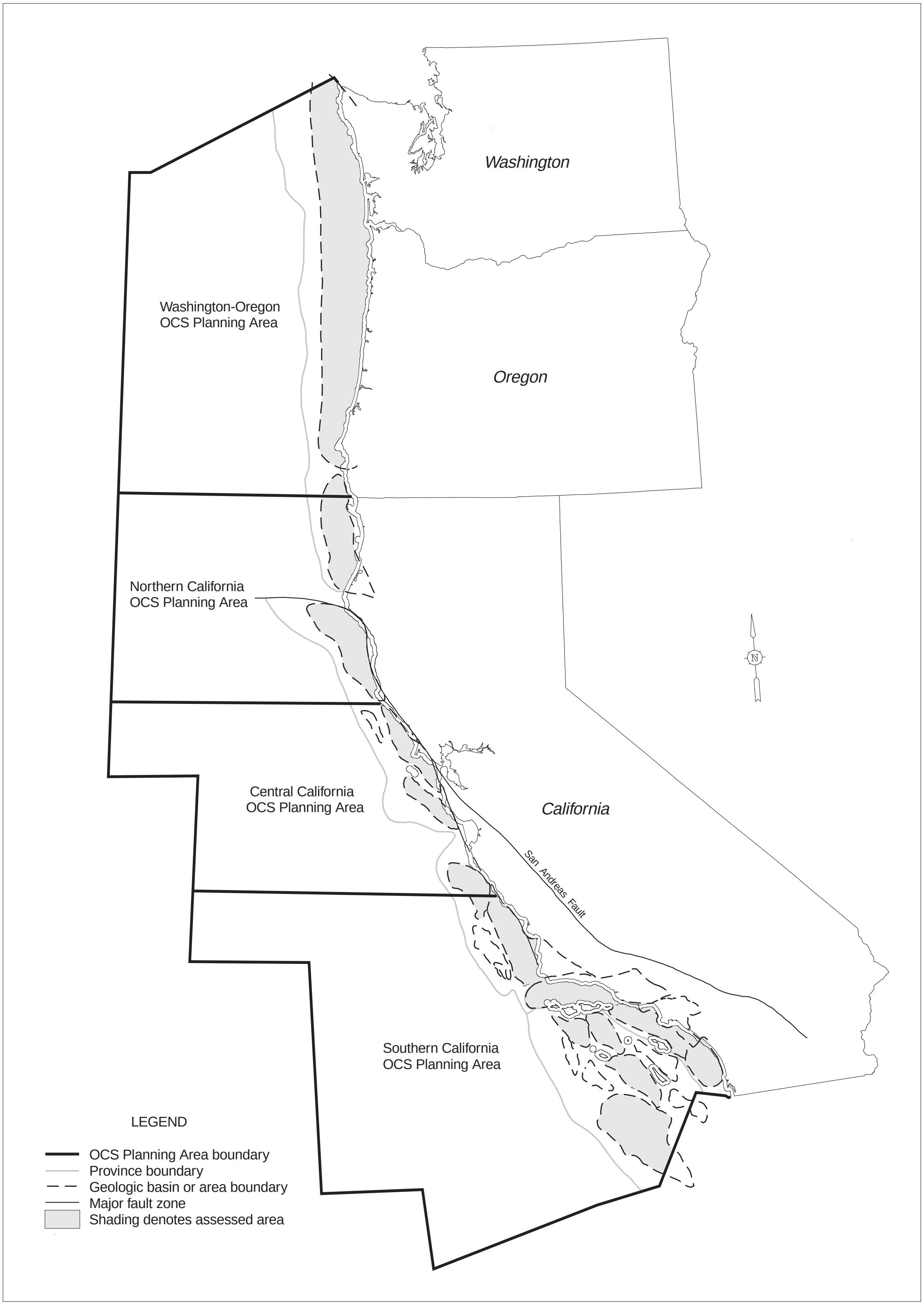


Figure E1. *Map showing administrative planning areas of the Pacific OCS Region. Names of assessment provinces and geologic basins and areas are shown on figure 10.*

Appendix F

CONTRIBUTION OF UNDISCOVERED RESOURCES IN THE PACIFIC OCS REGION TO UNDISCOVERED RESOURCES IN THE UNITED STATES OCS

This appendix presents a discussion of the contribution of undiscovered conventionally recoverable and economically recoverable oil and gas resources in the Pacific OCS Region to the undiscovered resources of the United States OCS. The undiscovered resources of the OCS are estimated to exist in four administrative regions (fig. F1).

Estimates of undiscovered resources in the Pacific OCS Region discussed here are from the *Summary and Discussion of Resource Estimates* section of this report. Estimates of undiscovered resources in other OCS regions and the United States OCS are from the following sources: Sherwood and others, 1996 (Alaska OCS Region); Lore and others, 1996 (Atlantic and Gulf of Mexico OCS Regions); and Minerals Management Service, 1996 (United States OCS).

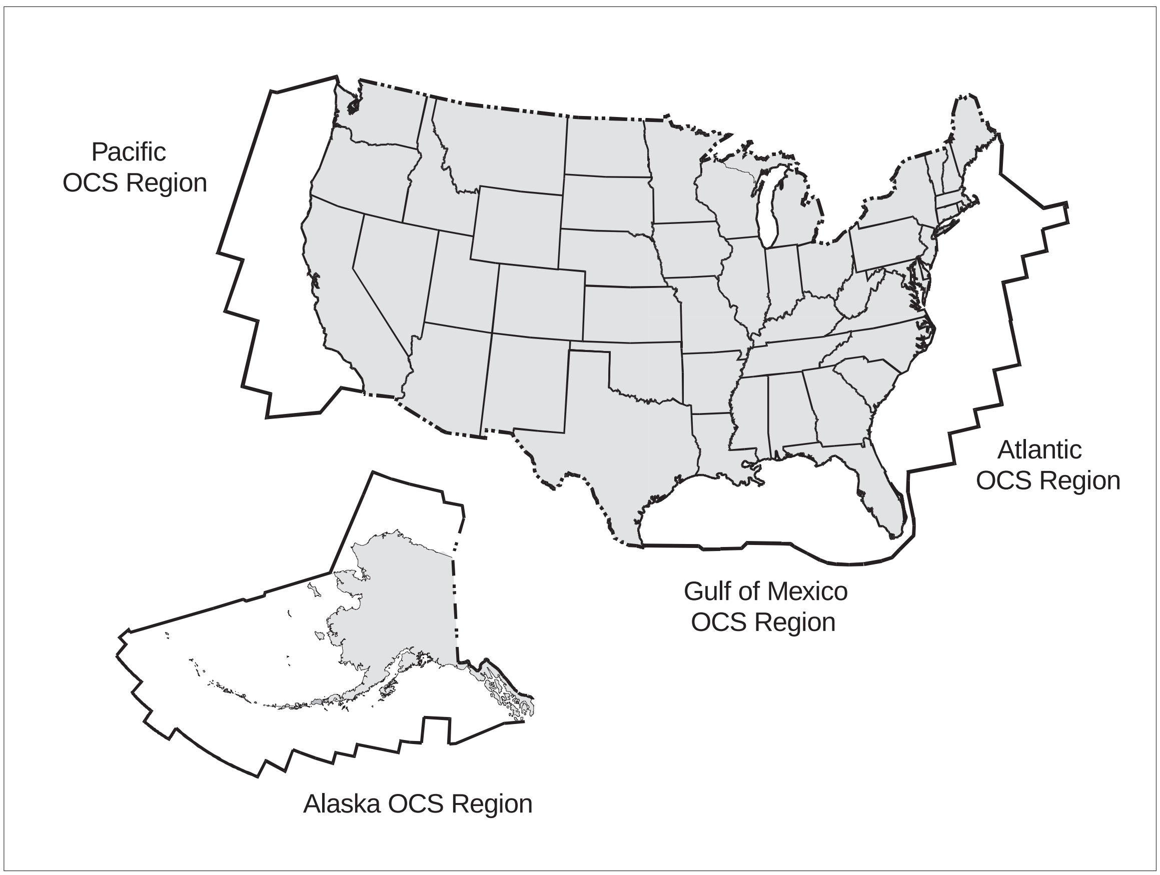


Figure F1. *Map showing administrative regions of the United States OCS.*

UNDISCOVERED CONVENTIONALLY RECOVERABLE RESOURCES

Based on this assessment, the total volume of undiscovered conventionally recoverable oil resources (including crude oil and condensate) in the United States OCS is estimated to range from 37.1 to 55.3 Bbbl (low to high estimates) with a mean estimate of 45.6 Bbbl. The total volume of undiscovered conventionally recoverable gas resources (including associated and nonassociated gas) in the OCS is estimated to range from 186.3 to 369.2 Tcf with a mean estimate of 268.0 Tcf.

The low, mean, and high estimates of the resources in each OCS region are listed in table F1. The distribution of the resources among the OCS regions is illustrated, on the basis of mean estimates, in figures F2 and F3.

The Pacific OCS Region is estimated to contribute nearly one quarter of the undiscovered conventionally recoverable oil resources (23 percent on the basis of mean estimates) and less than one tenth of the undiscovered conventionally recoverable gas resources (7 percent on the basis of mean estimates) of the OCS.

Table F1. *Estimates of undiscovered conventionally recoverable oil and gas resources in the United States OCS as of January 1, 1995, by region. All estimates are risked values. The low, mean, and high estimates correspond to the 95th-percentile, mean, and 5th-percentile values of a probability distribution, respectively. Percentile values are not additive; some total mean values may not equal the sum of the component values due to independent rounding.*

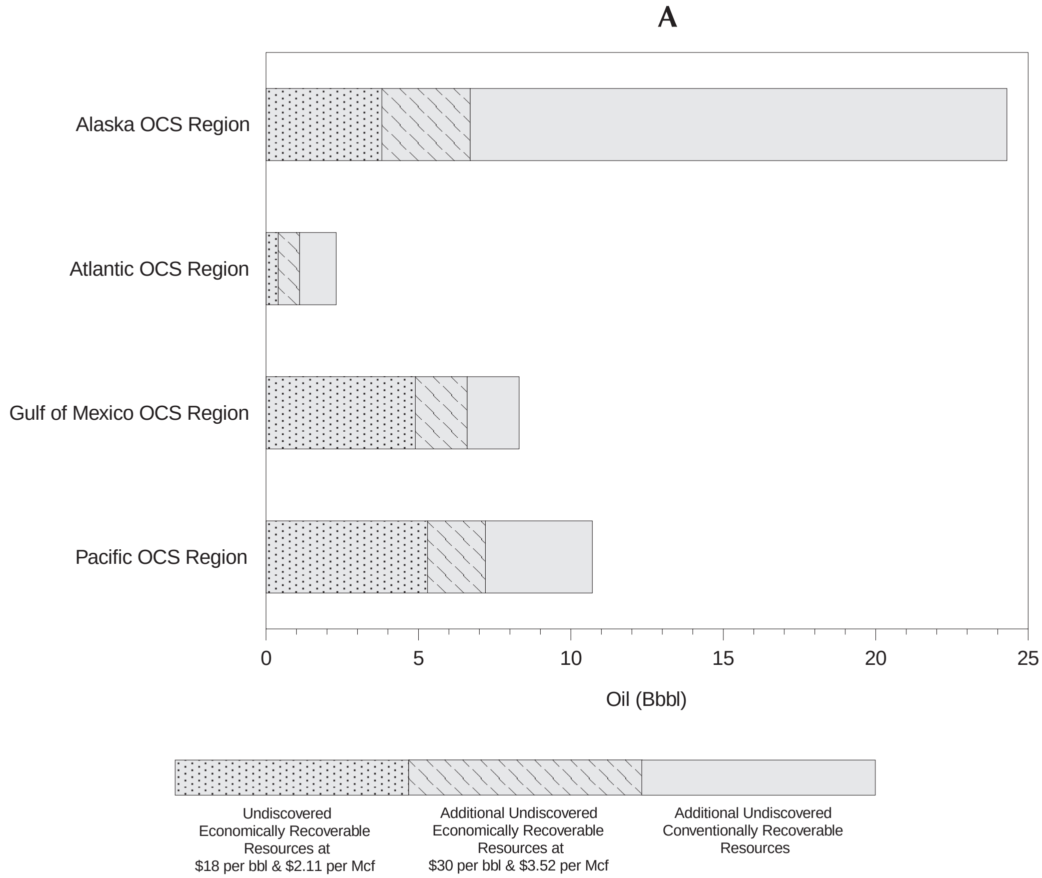
Region	Oil (Bbbl)			Gas (Tcf)			BOE (Bbbl)		
	Low	Mean	High	Low	Mean	High	Low	Mean	High
Alaska OCS	16.9	24.3	33.6	58.0	125.9	229.5	28.7	46.7	70.6
Atlantic OCS	1.3	2.3	3.7	15.9	27.5	43.4	4.5	7.2	10.7
Gulf of Mexico OCS	6.0	8.3	11.1	82.3	95.7	110.3	21.2	25.4	30.0
Pacific OCS	9.0	10.7	12.6	15.2	18.9	23.2	11.8	14.1	16.6
Total United States OCS	*37.1*	*45.6*	*55.3*	*186.3*	*268.0*	*369.2*	*72.9*	*93.4*	*117.0*

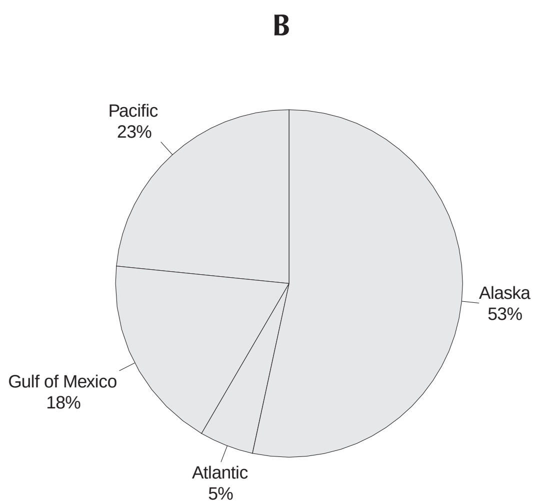
UNDISCOVERED ECONOMICALLY RECOVERABLE RESOURCES

The total volume of undiscovered conventionally recoverable resources in the United States OCS that is estimated to be economically recoverable at economic and technological conditions existing as of this assessment (i.e., the $18-per-barrel economic scenario) is 14.4 Bbbl of oil and 72.5 Tcf of gas (mean estimates). Larger volumes of resources are estimated to be economically recoverable at more favorable economic conditions.

Mean estimates of the resources in each OCS region are listed, for two economic scenarios, in table F2. The distribution of undiscovered economically recoverable oil and gas resources among the regions is illustrated in figures F2 and F3. Resource estimates for the $18-per-barrel economic scenario (which assumes prices of $18.00 per bbl of oil and $2.11 per Mcf of gas) are used for illustrative and comparative purposes in this discussion because the oil price of this scenario closely approximates the market price of oil as of this assessment.

Nearly one third of the undiscovered conventionally recoverable oil resources of the OCS (32 percent on the basis of mean estimates and the $18-per-barrel economic scenario) and approximately one quarter of the undiscovered conventionally recoverable gas resources of the OCS (27 percent on the basis of mean estimates and the $18-per-barrel economic scenario) are estimated to be economically recoverable at economic and technological conditions existing as of this assessment. The Pacific OCS Region is estimated to contribute more than one third of the undiscovered economically recoverable oil resources (37 percent on the basis of mean estimates) and more than one tenth of the undiscovered economically recoverable gas resources (11 percent on the basis of mean estimates) of the OCS.





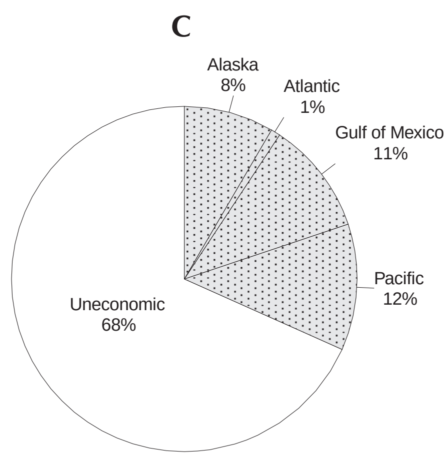


Figure F2. *Distribution of undiscovered conventionally recoverable and economically recoverable oil resources in the United States OCS, by region based on risked mean estimates listed in tables F1 and F2. Bar chart (A) shows incremental volumes of undiscovered economically recoverable oil resources for two economic scenarios and additional undiscovered conventionally recoverable oil resources; the entire bar represents the estimated total volume of undiscovered conventionally recoverable oil resources. Pie charts show proportionate volumes of undiscovered conventionally recoverable oil resources (B) and undiscovered conventionally recoverable oil resources that are economically recoverable versus uneconomic at the $18-per-bbl scenario (C). The sum of the percentage values in some pie charts may not equal 100 percent due to independent rounding.*

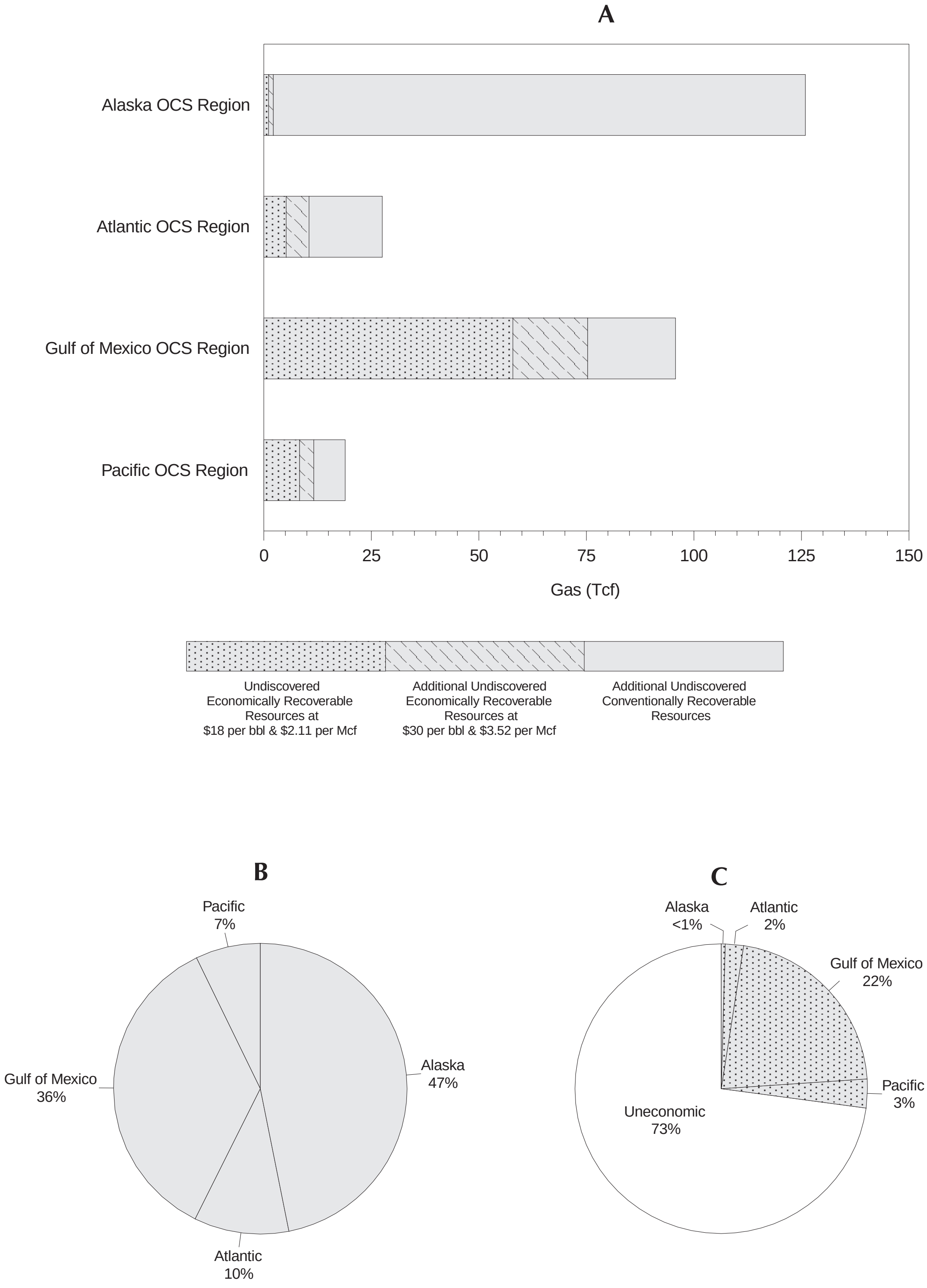


Figure F3. *Distribution of undiscovered conventionally recoverable and economically recoverable gas resources in the United States OCS, by region based on risked mean estimates listed in tables F1 and F2. Bar chart (A) shows incremental volumes of undiscovered economically recoverable gas resources for two economic scenarios and additional undiscovered conventionally recoverable gas resources; the entire bar represents the estimated total volume of undiscovered conventionally recoverable gas resources. Pie charts show proportionate volumes of undiscovered conventionally recoverable gas resources (B) and undiscovered conventionally recoverable gas resources that are economically recoverable versus uneconomic at the $18-per-bbl scenario (C). The sum of the percentage values in some pie charts may not equal 100 percent due to independent rounding.*

Table F2. *Estimates of undiscovered economically recoverable oil and gas resources in the United States OCS as of January 1, 1995, by region. All estimates are risked mean values. The $18-per-barrel economic scenario is based on prices of $18 per bbl of oil and $2.11 per Mcf of gas; the $30-per-barrel economic scenario is based on prices of $30 per bbl of oil and $3.52 per Mcf of gas. Some total values may not equal the sum of the component values due to independent rounding.*

Region	$18-per-barrel Scenario			$30-per-barrel Scenario		
	Oil (Bbbl)	Gas (Tcf)	BOE (Bbbl)	Oil (Bbbl)	Gas (Tcf)	BOE (Bbbl)
Alaska OCS	3.8	1.1	4.0	6.7	2.2	7.1
Atlantic OCS	0.4	5.2	1.3	1.1	10.5	2.9
Gulf of Mexico OCS	4.9	57.9	15.3	6.6	75.3	20.0
Pacific OCS	5.3	8.3	6.8	7.2	11.6	9.3
Total United States OCS	*14.4*	*72.5*	*27.3*	*21.6*	*99.6*	*39.3*

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