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2011 National Assessment of Oil and Gas Resources: Assessment of the Pacific Outer Continental Shelf Region

BOEM
Bureau of Ocean Energy Management

U.S. Department of the Interior
Bureau of Ocean Energy Management
Pacific Outer Continental Shelf Region

2011 National Assessment of Oil and Gas Resources Assessment of the Pacific Outer Continental Shelf Region

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Front Cover. Map of the Pacific OCS Region showing provinces defined for the 2011 National Assessment. Provinces are indicated by color as follows:

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

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

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EXECUTIVE SUMMARY

This report documents the 2011 National Assessment of the undiscovered technically recoverable 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 purpose of this report is two-fold. The assessment was performed in order to develop an updated appraisal of the location and volume of undiscovered resources. It also serves as a public documentation of the results of the assessment.

The 2011 assessment of the Pacific OCS Region was performed by team of geoscientists in Camarillo, California, using a large volume and variety of proprietary and nonproprietary data (including geologic, geochemical, geophjysical, petroleum engineering, and economic data) available as of January 1, 2009.

The commodities of hydrocarbon resources that have been assessed include *oil* (including crude oil and condensate) and *natural gas* (including associated and nonassociated gas). Two categories of undiscovered resources have been assessed: *undiscovered technically recoverable resources* are those that can be removed from the subsurface with conventional extraction techniques; *undiscovered economically recoverable resources* are those undiscovered technically 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 2011 assessment of the Pacific OCS Region is an update based upon geological work that was performed for the 1995 National Assessment of United States Oil and Gas Resources by a team of MMS (Minerals Management Service) geoscientists in Camarillo, California. For the current assessment, the Region is subdivided into five assessment provinces: Pacific Northwest, Central California, Santa Barbara-Ventura Basin, Inner Borderland, and Outer Borderland. The provinces encompass 20 geologic basins and areas in which sediments accumulated and hydrocarbons may have formed. Forty-five *petroleum geological plays* (groups of geologically related hydrocarbon accumulations) have been defined and described in 12 basins and areas, and 41 of these plays have been formally assessed.

For planning purposes, the Pacific OCS Region is divided into four planning areas: Washington-Oregon, Northern California, Central California, and Southern California. Planning area boundaries are based on political boundaries such as state or county lines, rather than on geological boundaries, and cut across the geologic assessment basins and areas. Resources have also been estimated for the planning areas; because the original assessment is based on geologic basins and areas, these estimates are more uncertain.

The total volume of undiscovered technically recoverable oil resources (including crude oil and condensate) of the Region as of January 1, 2009, is estimated to range from 6.7 to 14.3 Bbbl, with a mean estimate of 10.2 Bbbl. Relatively large volumes of these oil resources (greater than 1 Bbbl) are estimated to exist in the Point Arena, Bodega, and Santa Maria-Partington basins of the Central California Province, Santa Barbara-Ventura Basin Province, and Oceanside basin of the Inner Borderland Province. The total volume of undiscovered technically recoverable gas resources (including associated and nonassociated gas) in the Region is estimated to range from 10.1 to 23.8 Tcf, with a mean estimate of 16.1 Tcf. Relatively large volumes of these gas resources (greater than 1 Tcf) are estimated to exist in the Washington-Oregon area and Eel River basin of the Pacific Northwest Province, the Point Arena and Bodega basins of the Central California Province, the Santa Barbara-Ventura Basin Province, the Los Angeles-Santa Monica-San Pedro area and Oceanside basin of the Inner Borderland Province, and the Cortes-Velero-Long area of the Outer Borderland Province. The most prolific plays are those having fractured siliceous reservoir rocks. These rocks are found throughout the Central California Province and Santa Barbara-Ventura Basin; similar rocks are presumed to occur in most of the other southern California basins.

The total volume of undiscovered technically recoverable resources of the Region that is estimated to be economically recoverable at economic and technological conditions as of January 1, 2009, (i.e., at prices of $90 per bbl of oil and $6.41 per Mcf of gas) is 7.4 Bbbl of oil and 9.9 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 Point Arena and Bodega basins of the Central California Province and in Santa Barbara-Ventura Basin Province. Increases in the volumes of resources at more favorable economic conditions are estimated to be minor.

The total resource endowment of the Region is estimated to be 13.1 Bbbl of oil and 19.0 Tcf of gas (mean estimates). This estimated endowment is composed of discovered resources (originally recoverable reserves and contingent resources totaling 2.8 Bbbl oil and 2.9 Tcf gas) and undiscovered technically recoverable resources. Undiscovered resources are estimated to compose a major portion (approximately 80 percent on the basis of mean estimates) of the total oil and gas resource endowment of the Region.

Estimates of the volume of undiscovered technically recoverable oil and gas resources in the Region from this assessment are similar to estimates from Mineral Management Service (MMS) assessments since 1995. Differences are due primarily to the increase in oil and gas prices and the corresponding increase in costs of exploration and development.

The Central California Planning Area contains 25 percent of the estimated undiscovered technically recoverable resources of the Pacific OCS Region. However, because of restrictions imposed by a series of marine sanctuaries and protected areas, it is largely unavailable to oil and gas development.

In the Southern California Planning Area, the most prospective areas have already been explored. In the Santa Barbara-Ventura basin, discovered resources compose half of the estimated total resource endowment. In Santa Maria-Partington basin, the discovered resources compose about 54 percent of the estimated total resource endowment. The most prospective unexplored basin in southern California is Oceanside basin. It is on a similar trend with the most productive trends in the onshore Los Angeles basin, which together have over 3 Bbbl of originally recoverable oil.

1 INTRODUCTION

The Outer Continental Shelf (OCS) of the United States includes submerged Federal lands offshore of the continental U.S. beyond the Federal-State boundaries. It is divided into four regions: the Atlantic, Gulf of Mexico, Pacific, and Alaska OCS Regions. The Bureau of Ocean Energy Management (BOEM, formerly the Minerals Management Service) has the responsibility to conduct periodic assessments of the undiscovered oil and gas resources of these OCS areas. The BOEM fact sheet *Assessment of Undiscovered Technically Recoverable Oil and Gas Resources of the Nation's Outer Continental Shelf, 2011* (BOEM, 2011); hereafter referred to as "the Fact Sheet") summarizes the results of the 2011 assessment (NA2011) for all four Regions. This companion 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.

BACKGROUND

This assessment is built upon major work done for the 1995 assessment. In particular, the descriptions of the petroleum geology of the Pacific OCS (Chapter 3) are derived from those in the earlier report *1995 National Assessment of United States Oil and Gas Resources: Assessment of the Pacific Outer Continental Shelf Region* (Dunkel and Piper, 1997). The petroleum geology sections have been condensed and updated, and the format standardized to make this report smaller and more readable. For more detailed descriptions of the petroleum geology and the plays, refer to the earlier document, which is available on the BOEM website. The original assessment geoscientists for the 1995 study are, by basin:

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*

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 include crude oil and/or condensate. *Crude oil* exists in a liquid state in the subsurface and at the surface. *Condensate (natural gas liquids)* is a very high-gravity (generally greater than 50 °API) liquid; it may exist in a dissolved gaseous state in the subsurface but liquefy at the surface. Moderate- to high-gravity crude oil (generally greater than 10 °API) and condensate that can be removed from the subsurface with conventional extraction techniques have been assessed for this project; other oil resources (for example, low-gravity "heavy" oil 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 include 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 (for example, 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 (that is, 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 commerciality or economic viability (fig. 1-1). For this assessment, we have adopted the classification and definitions base on the Petroleum Resources Management System and Definitions (PRMS) developed jointly by the Society of Petroleum Engineers, American Association of Petroleum Geologists, World Petroleum Council and the Society of Petroleum Evaluation Engineers. 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 are resources that have been discovered and whose location and volume have been estimated using specific geologic knowledge. They include cumulative production, remaining reserves, contingent resources, and unrecoverable resources.

Original recoverable reserves are the total amount of discovered resources that are estimated to be economically recoverable; they include cumulative production, remaining reserves and contingent resources. *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 cannot be estimated with reasonable certainty to be economically recoverable under current economic conditions. *Contingent resources* are discovered resources estimated to be potentially recoverable from known accumulations, but are not available for commercial development due to one or more contingencies. Examples of contingencies include resources on relinquished leases, lack of viable markets, commercial recovery dependent on technology under development, and where evaluation of the accumulation is insufficient to clearly assess commerciality.

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.

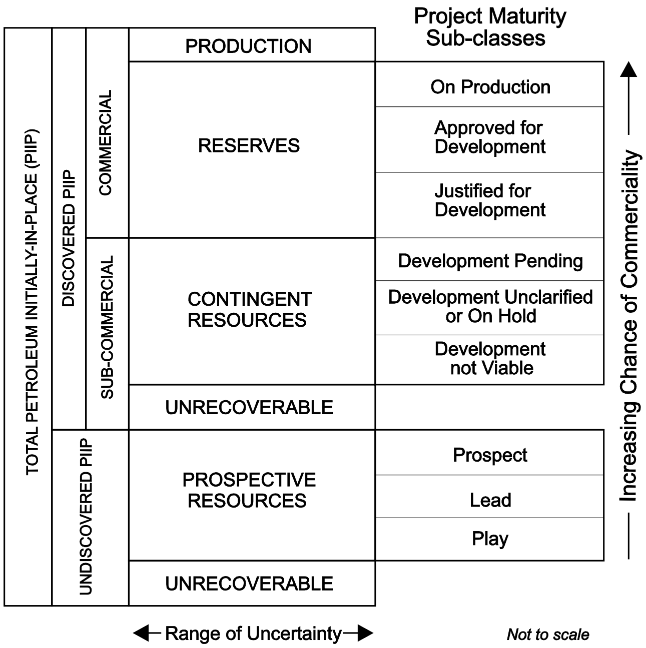


Figure 1-1. *Hydrocarbon classification based on Project Maturity. From* Petroleum Resources Management System (SPE-PRMS) *sponsored by the Society of Petroleum Engineers (SPE), the American Association of Petroleum Geologists (AAPG), the World Petroleum Council (WPC), and the Society of Petroleum Evaluation Engineers (SPEE). The SPE-PRMS was published in 2007 and is designed to provide a common reference for the petroleum industry and regulatory disclosure agencies (SPE and others, 2007).*

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—technically recoverable resources and economically recoverable resources—have been assessed.

Technically recoverable resources are resources that can be removed from the subsurface with conventional extraction techniques (that is, technology the usage of which is considered common practice as of this assessment); they include moderate- to high-gravity (generally greater than 10 °API) crude oil, condensate, and gas, but do not include low-gravity "heavy" oil, oil shale, gas shale, and gas hydrates.

Economically recoverable resources are technically 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 technically recoverable resources comprises 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 geologic framework of the coastal margin forms the basis for the delineation of assessment areas and the assessment of oil and gas resources. However, BOEM needs estimates of undiscovered resources for planning purposes (for example, five-year plans, lease sales). These plans are based on *OCS planning areas,* which are not based on geology or geography, but are delineated based on political boundaries such as state or county lines. In the Fact Sheet, results are reported for Regions and planning areas. In this report, results of the assessment are reported as they were calculated based on the geologic units. For completeness, estimates are also reported for the Pacific OCS *planning areas*. The following definitions are provided to ensure 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 and 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* includes two or more geologic basins and/or geologic areas that have been combined for the explicit purpose of this assessment.

PLAYS

The assessment of undiscovered technically 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. For example, plays having Neogene clastic reservoir rocks may include reservoir rocks that consist of Miocene and/or Pliocene sandstone, siltstone, or shale.

Summary descriptions of the plays are given by province in this report. Detailed descriptions of the location, definition, classification, petroleum geologic characteristics, and resource assessment of each play are provided in the individual regional reports.

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 are 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.

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 (for example, “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 (for example, “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 (for example, 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 technically 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 (that is, the probability of existence of the estimated volume or more is 95 in 100), a *mean (or expected) 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 (that is, the probability of existence of the estimated volume or more is 5 in 100).

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.

2 METHODOLOGY

The estimation of hydrocarbon resources was performed by a statistical analysis of geologic data. The principal procedural components of the process included 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 of a set of computer programming tools developed for the statistical analysis of play data. The results of that statistical analysis are estimates of the undiscovered technically 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 technically recoverable resources to obtain a measure of total resource endowment.

BOEM uses a play-based approach for identification and estimation of resource parameters. A statistical methodology was developed to estimate resources based on these parameters. The following sections describe the process used 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.

PETROLEUM GEOLOGICAL ANALYSIS

The first component 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.

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 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 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 proprietary interpretation and subsurface mapping of seismic-reflection data. Where feasible and appropriate, the interpretations were modified to include 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.

PLAY DEFINITION AND ANALYSIS

Starting with the 1995 assessment, 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. 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. 2-1).

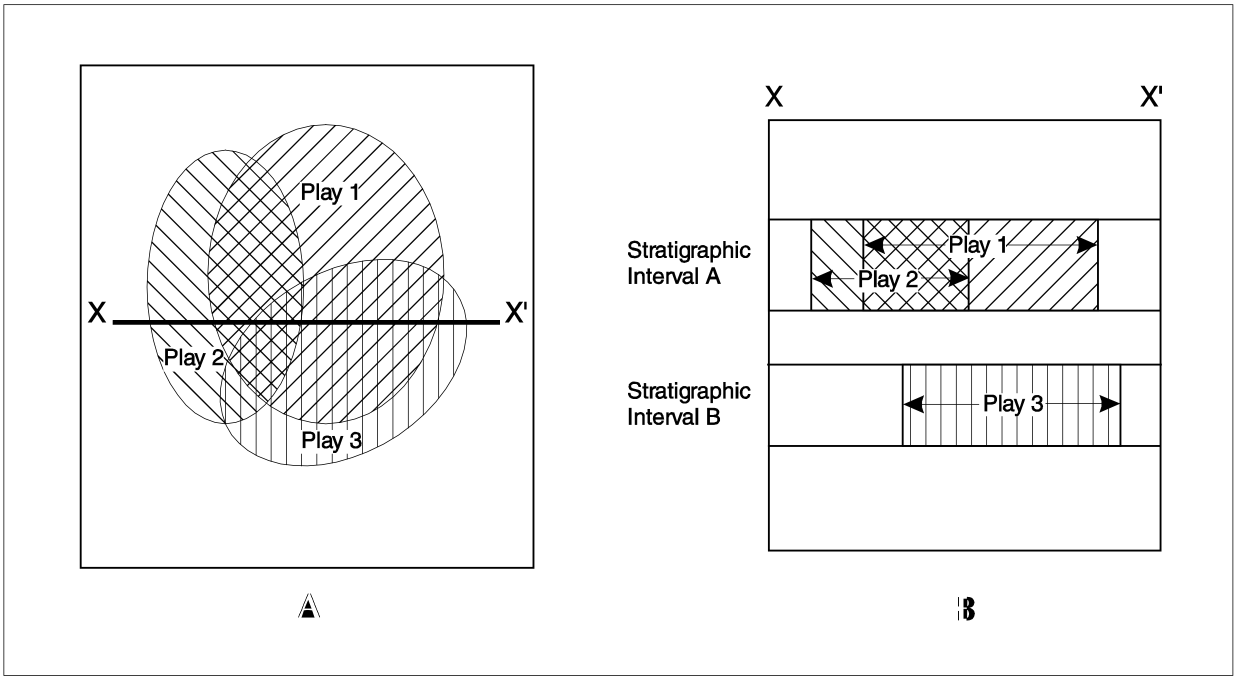


Figure 2-1. *Map-view (A) and cross-sectional (B) representations of three overlapping hypothetical plays. Plays 1 and 2 are within the same stratigraphic interval and overlap areally; play 3 is within a deeper stratigraphic interval.*

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. Comparisons among the plays ensured that parameters relating to the likelihood of hydrocarbon occurrence and prospective volumes of hydrocarbon resources were comparable among assessment areas.

Some of these values (for example, areas of mapped prospects and thicknesses of expected reservoir-rock units) were based on geophysical mapping. Others (for example, rock and hydrocarbon properties) were based on exploratory well information. Certain rock and hydrocarbon properties (for example, 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.

In addition, plays were assigned success probabilities based on discovery status and on subjective evaluation. Play and prospect probabilities for success were assigned based on a methodology modified from that presented by White (1993). 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 technically recoverable resources exists in a play. Conditional prospect chance is the probability that technically 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.

RESOURCE ESTIMATION

Volumetric estimates of undiscovered technically 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 technically 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.

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. 2-2 and 2-3). In a lognormal distribution, a plot of the frequency of occurrence of a property against the logarithm of its value will yield a normal, or bell-shaped plot. Our assessment of the volume of technically recoverable resources is based on the assumption that, within a properly defined play, the size distribution of the entire population of accumulations (which includes discovered and undiscovered accumulations) will also be lognormal.

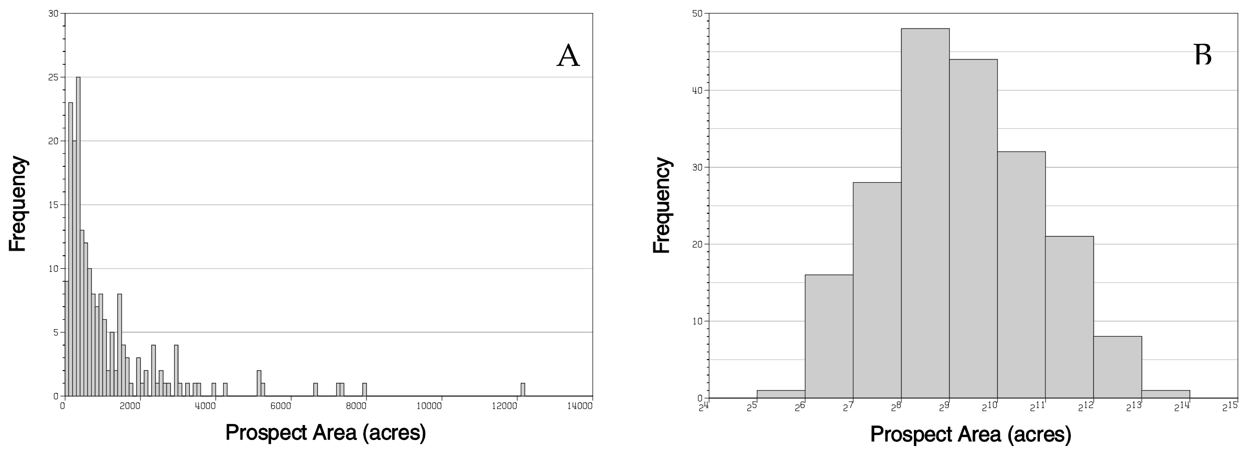


Figure 2-2. *Frequency-versus-size plots of a lognormal distribution. The example shows the areal sizes of mapped prospects in an area where data were sufficient for detailed mapping. The data plot as a skewed distribution when plotted on a linear scale (A). When the data are plotted on a logarithmic scale (B), the approximately normal (bell shape) appearance demonstrates the lognormal nature of the distribution. The example is for 199 mapped prospects in the Fractured Monterey play of the Point Arena Basin assessment area.*

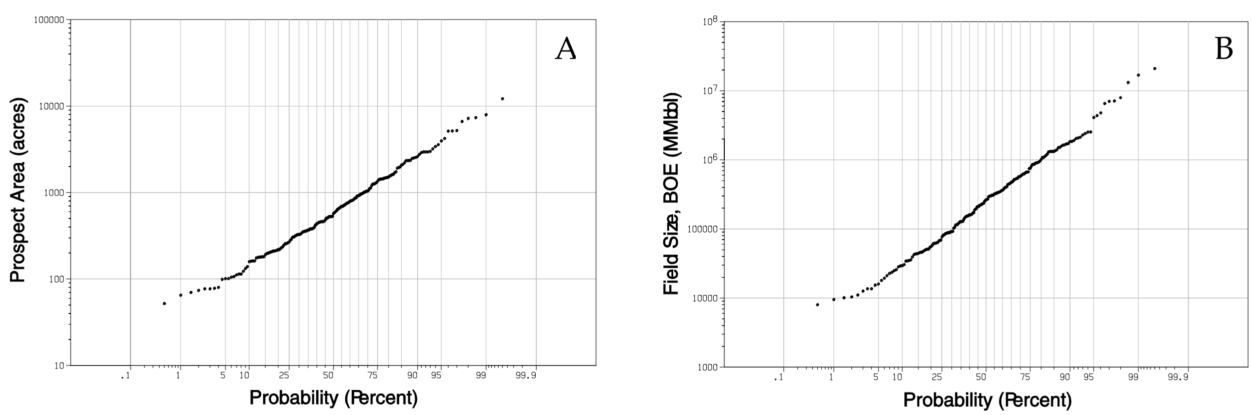


Figure 2-3. *Log-probability plots of lognormal distributions. A logarithmic plot of size versus probability is approximately linear for lognormal size distributions. Figure 2-3A is a plot of the data shown in figure 2-2. Figure 2-3B is a plot of the sizes of 155 fields in the Santa Barbara–Ventura basin (onshore and offshore).*

The concept of lognormal distributions of play parameters was used in a set of computer programs developed by the Geological Survey of Canada, the *Petroleum Resource Information Management and Evaluation System* (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 better estimation of undiscovered resources. For the 1995 assessment, MMS modified the methodology 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 was 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)*.

To estimate the portion of undiscovered technically 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). PRESTO uses Monte Carlo methodology to simulate the exploration, development, production, and delivery of the estimated resources in each assessment area. (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.)

The ranked distributions are sampled along with probability distributions for costs, production properties (for example, gas-to-oil proportion, production rates, and decline rates), and other engineering and economic factors. 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 each field. The program develops a risk-weighted discounted cash flow and calculates a present economic value for the field. The economic resources by field 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 (for example, platform and production well costs) or assessment area level (for example, 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 (for example, due to varying quality of crude oil or cost of transportation) are accounted for at the assessment area level. For the 2003 assessment, GRASP and PRESTO were incorporated into the Geologic and Economic Resource Model (GERM).

ASSESSMENT OF UNDISCOVERED TECHNICALLY RECOVERABLE RESOURCES

For the 2011 assessment, all OCS Regions used the GRASP subjective methodology. In this method, parameter estimates are combined to yield an approximately lognormal ranked size distribution of pools. Measured prospect sizes (from geophysical prospect mapping) and other parameters (for example, net pay and recovery factors) were statistically combined to estimate pool sizes. Results of the probability analysis (described in the play definition and analysis section) were used to reduce the distribution of prospects (possible pools) to a distribution of pools (containing resources). The various parameters were statistically combined to derive probability distributions for the volume of undiscovered technically recoverable resources in the play. The probability distributions for the volume of undiscovered technically recoverable resources in individual plays were aggregated to derive resource distributions for assessment basins or areas. These in turn were aggregated to provincial or planning area levels and to Regional levels using GERM.

ASSESSMENT OF UNDISCOVERED ECONOMICALLY RECOVERABLE RESOURCES

Following the assessment of undiscovered technically recoverable resources, an economic evaluation was performed 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 of the various hydrocarbon commodities; and other economic conditions (for example, interest rates, which affect the cost of capital, and revenues that could alternatively be gained by investing capital elsewhere).

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* for each planning area and Region. The price-supply plots 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; 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 (that is, a relative increase or decrease in the market value of gas relative to that of oil is not accounted for in the model). For tabulated results, the gas price is set relative to the oil price at 40, 60, and 100 percent of the oil price for equivalent energy content (for example, an oil price of $90.00 per bbl corresponds to a gas price of $6.41 per Mcf at 40 percent of the equivalent oil energy content).

ESTIMATION OF TOTAL RESOURCE ENDOWMENT

The total resource endowment, which is the sum of the technically recoverable discovered resources (originally recoverable reserves and contingent resources) and undiscovered technically recoverable resources, was estimated for assessment areas where resources have been discovered. Elsewhere, the amount of undiscovered technically recoverable resources composes the total resource endowment.

3 PETROLEUM GEOLOGY AND RESOURCE ESTIMATES OF THE PACIFIC OUTER CONTINENTAL SHELF REGION

LOCATION

The Pacific OCS Region extends from the United States–Canada maritime boundary to the United States–Mexico maritime boundary and includes submerged Federal lands (i.e., beyond the Federal-State boundary) offshore Washington, Oregon, and California. 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. 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

Because of the nature of the tectonics, the Pacific margin is narrow, by comparison with the Atlantic and Gulf of Mexico margins. Its geologic history has been dominated by the interaction of oceanic and continental crustal plates (fig. 3-1). Offshore of Cape Mendocino, California is a triple junction where three tectonic plates come together. The Mendocino fracture zone (a transform fault margin) forms an east-west boundary between two distinct tectonic environments. North of the triple junction has been a convergent margin throughout the Cenozoic era, and oceanic crust is being subducted beneath the North American continent along the Cascadia subduction zone. To the south, the plate interactions have changed from convergent to translational, and the primary plate boundary is the San Andreas transform fault. Middle to late Cenozoic geological history has been dominated by wrench tectonics along the San Andreas and related faults. In southern California, this boundary has been complicated by the approximately 120 degrees clockwise block rotation of the western Transverse Ranges into a position that now tends to impede the relative plate motions. To the south of this, the Southern California Continental Borderland is a region of extension and northwest-trending right-lateral translation that has occurred concurrently with that rotation.

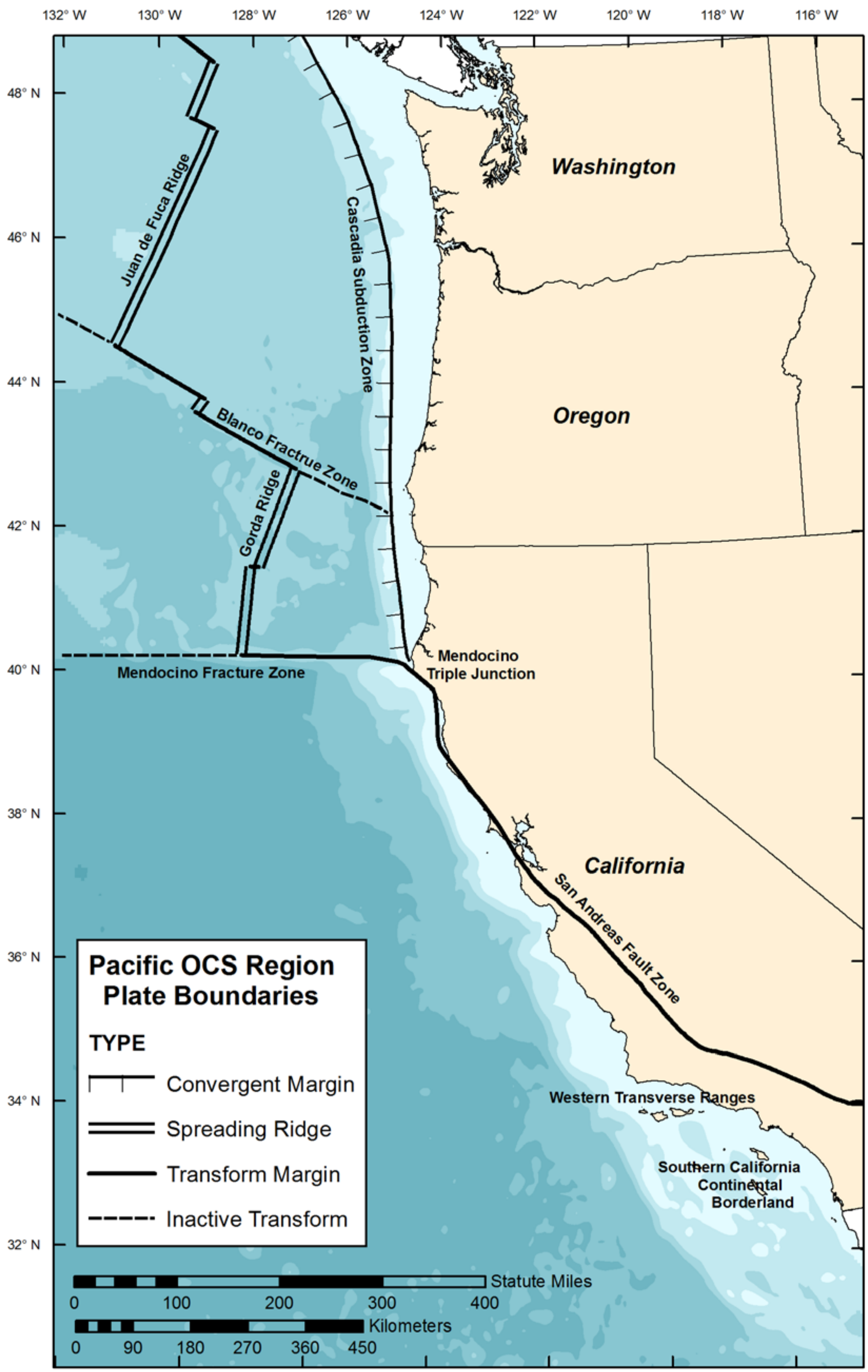


Figure 3-1. *Major plate boundaries and related tectonic elements of the Pacific OCS Region.*

GEOLOGIC PROVINCES

Beginning with the 1995 National Assessment of Undiscovered Oil and Gas Resources, the Pacific Region has been divided into geologic assessment provinces based on differences in their geologic and tectonic histories (fig. 3-2):

> The Pacific Northwest province includes the Washington–Oregon area and Eel River basin, areas that are within the accretionary complex associated with the Cascadia subduction zone.
>
> The Central California province includes five basins that lie on the continental shelf and slope: 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 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.
>
> The Santa Barbara–Ventura Basin province has been considered as a separate province because of its unique tectonic and sedimentary history. As part of the western Transverse Ranges, it has undergone as much as 120 degrees of clockwise rotation which has created an incipient east-west trending convergent margin between the Pacific and North American plates, and this has contributed to one of the world's highest rates of sedimentary accumulation.
>
> The Inner Borderland province includes coastal basins that formed as a response to the combination of the rotation of the western Transverse Ranges and the accompanying extension of the California Continental Borderland. For this assessment, the Los Angeles basin has been included as a part of the Inner Borderland Province; previously it had been considered as a separate province.
>
> The Outer Borderland province was also formed as a result of the extension of the California Continental Borderland. However, its distal location and intervening islands and ridges resulted in a more limited sedimentary section, and it is considered as a separate province for assessment purposes.

Estimates of technically and economically recoverable resources were developed for geologic plays. These plays were defined within basins (or areas) and aggregated to the basins/areas, the provinces and the Region as a whole.

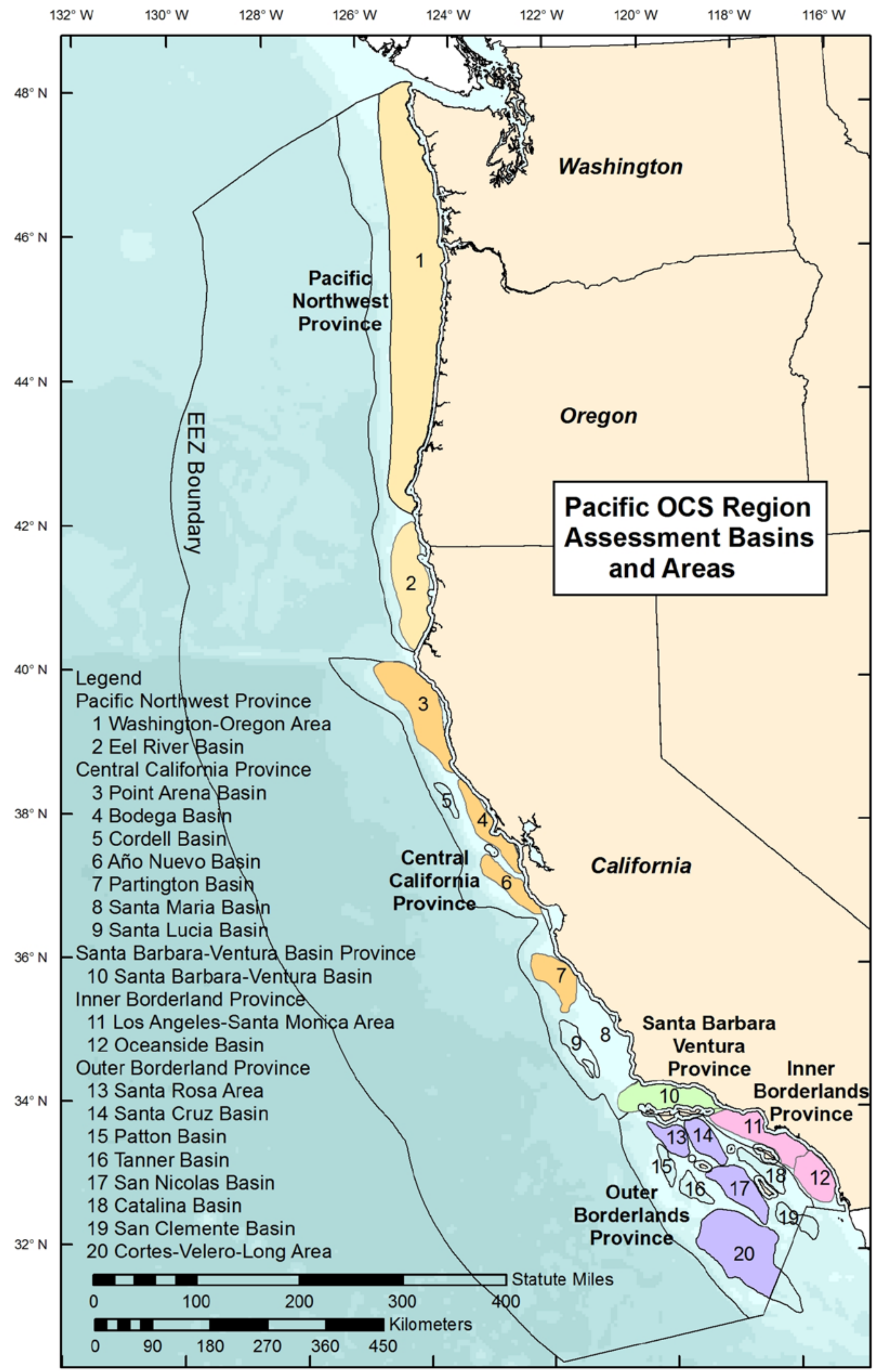


Figure 3-2. *Map of the Pacific OCS Region showing assessment provinces, geologic basins and areas, and assessed areas.*

Planning Areas

For lease planning purposes and reporting in the Fact Sheet the Pacific Region is divided into four planning areas, which are based on jurisdictional, rather than on natural geologic or geographic boundaries (fig. 3-3):

> The Washington–Oregon OCS Planning Area includes the Washington–Oregon area, and the northern part of the Eel River basin. As such, it is entirely within the Pacific Northwest Province.
>
> The Northern California OCS Planning Area includes most of the Eel River basin and the Point Arena basin. It includes the southern part of the Pacific Northwest Province and the northern part of the Central California Province.
>
> The Central California OCS Planning Area includes the Bodega, Año Nuevo and Partington basins.
>
> The Southern California OCS Planning Area includes the Santa Maria and Santa Barbara basins, and all of the assessment areas of the Inner and Outer Borderland provinces.

Estimates of technically and economically recoverable resources were developed for the planning areas because they are used for 5-year plans and lease sales. Because the planning area boundaries divide basins and plays that form the basis for the technical evaluation, these estimates have an additional subjective element, that being the apportionment of basin resources to the planning areas.

Resource Estimates

Undiscovered Technically Recoverable Resources

Estimates of the total volume of undiscovered technically recoverable resources in the Region have been developed by statistically aggregating the constituent play estimates. Results are also tabulated for the planning areasThe assessment methodology involves statistical distributions that are valid for individual plays and their aggregation to basins, but not for arbitrary subdivisions of those plays or basins. For those basins that are cut by planning area boundaries, the estimated resources assigned to each planning area are based primarily on the fraction of the area of the basin that is in each planning area, with some subjective adjustment based on knowledge of play distributions within the basin. As a result of this assessment, the total volume of undiscovered technically recoverable resources oil and gas resources in the Pacific OCS Region is estimated to be 10.20 Bbbl of oil and 16.10 Tcf of gas (mean estimates). The low, mean and high estimates in the Region are listed in table 3-1 (by province) and table 3-2 (by planning area).

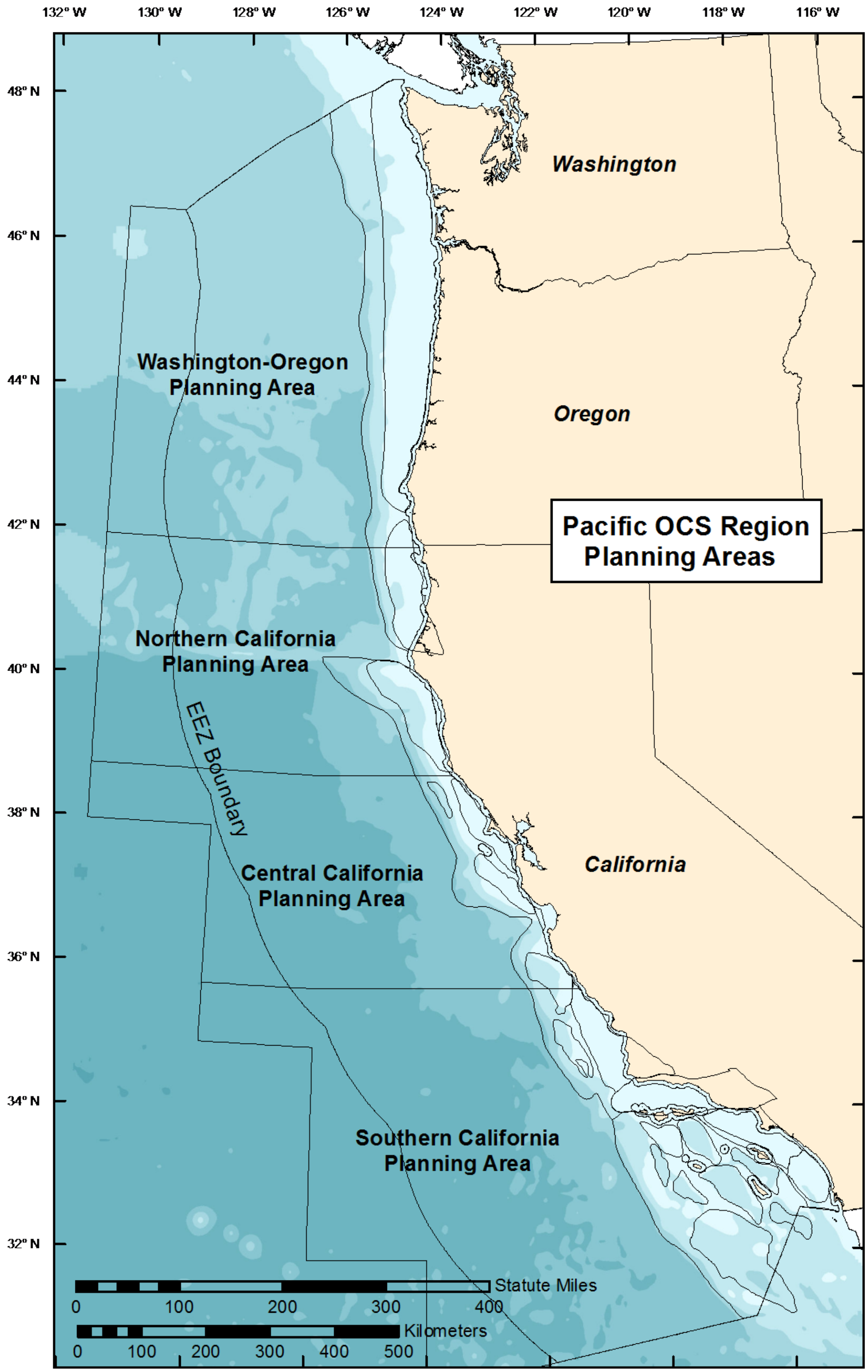


Figure 3-3. *Administrative planning areas of the Pacific OCS Region.*

Table 3-1. *Undiscovered Technically Recoverable Oil and Gas Resources of the Pacific OCS Region by province. Resource values are in billion barrels of oil (Bbbl) and trillion cubic feet of gas (Tcf). 95% indicates a 95 percent chance of at least the amount listed; 5% indicates a 5 percent chance of at least the amount listed. Only mean values are additive. Some total mean values may not equal the sum of the component values due to independent rounding of the tabulated values.*

Geologic Province	Oil (Bbbl)			Gas (Tcf)			BOE (Bbbl)		
	95%	Mean	5%	95%	Mean	5%	95%	Mean	5%
Pacific Northwest	0.03	0.47	1.23	0.88	3.76	7.50	0.19	1.14	2.56
Central California	3.34	5.23	7.53	3.18	5.21	7.67	3.90	6.16	8.89
Santa Barbara	0.34	1.34	3.50	0.53	2.74	7.01	0.44	1.83	4.75
Inner Borderland	0.21	1.96	4.23	0.21	2.15	4.83	0.24	2.34	5.09
Outer Borderland	0.00	1.20	3.09	0.00	2.24	5.91	0.00	1.60	4.14
Pacific OCS	**6.73**	**10.20**	**14.30**	**10.11**	**16.10**	**23.75**	**8.53**	**13.07**	**18.52**

Table 3-2. *Undiscovered Technically Recoverable Oil and Gas Resources of the Pacific OCS Region by planning area. Resource values are in billion barrels of oil (Bbbl) and trillion cubic feet of gas (Tcf). 95% indicates a 95 percent chance of at least the amount listed; 5% indicates a 5 percent chance of at least the amount listed. Only mean values are additive. Some total mean values may not equal the sum of the component values due to independent rounding of the tabulated values.*

Planning Area	Oil (Bbbl)			Gas (Tcf)			BOE (Bbbl)		
	95%	Mean	5%	95%	Mean	5%	95%	Mean	5%
Washington/Oregon	<0.01	0.40	1.15	0.03	2.28	5.79	0.01	0.81	2.18
Northern California	1.08	2.08	3.54	2.13	3.58	5.38	1.46	2.71	4.50
Central California	1.23	2.40	3.87	1.18	2.49	4.15	1.44	2.84	4.61
Southern California	2.52	5.32	8.83	3.27	7.76	14.42	3.10	6.70	11.40
Pacific OCS	**6.73**	**10.20**	**14.30**	**10.11**	**16.10**	**23.75**	**8.53**	**13.07**	**18.52**

Undiscovered Economically Recoverable Resources

Estimates of the total volume of undiscovered technically recoverable resources in the Region 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, 7.43 Bbbl of oil and 9.90 Tcf of gas are estimated to be economically recoverable under economic conditions existing as of this assessment (that is, the $90-per-barrel of oil scenario). Larger volumes of resources are expected to be economic under increasingly favorable economic conditions. Estimates of economically recoverable resources at several pricing scenarios are given in table 3-3 (by province) and table 3-4 (by planning area). Estimates of economically recoverable resource are illustrated in the form of price-supply curves in figure 3-4. The estimates shown in tables 3-3 and 3-4 and figure 3-4 assume a 40 percent economic value for gas relative to oil, on the basis of energy equivalence.

Table 3-3. *Mean estimates of undiscovered economically recoverable oil and gas resources in the Pacific OCS Region as of January, 1, 2009 for three economic scenarios, by province. Oil prices are coupled with a specific gas price assuming a 40 percent economic value for gas relative to oil.*

Geologic Province	$60/bbl, $4.27/Mcf		$90/bbl, $6.41/Mcf		$120/bbl, $8.54/Mcf	
	Oil (Bbbl)	Gas (Tcf)	Oil (Bbbl)	Gas (Tcf)	Oil (Bbbl)	Gas (Tcf)
Pacific Northwest	0.24	0.91	0.28	1.18	0.30	1.34
Central California	3.61	3.62	4.04	4.03	4.24	4.22
Santa Barbara	1.19	2.23	1.25	2.37	1.27	2.44
Inner Borderlands	1.40	1.59	1.56	1.75	1.63	1.83
Outer Borderlands	0.23	0.44	0.31	0.57	0.35	0.65
Pacific OCS	**6.67**	**8.80**	**7.43**	**9.90**	**7.79**	**10.49**

Table 3-4. *Mean estimates of undiscovered economically recoverable oil and gas resources in the Pacific OCS Region as of January, 1, 2009 for three economic scenarios, by planning area. Oil prices are coupled with a specific gas price assuming a 40 percent economic value for gas relative to oil.*

Planning Area	$60/bbl, $4.27/Mcf		$90/bbl, $6.41/Mcf		$120/bbl, $8.54/Mcf	
	Oil (Bbbl)	Gas (Tcf)	Oil (Bbbl)	Gas (Tcf)	Oil (Bbbl)	Gas (Tcf)
Wash./Oregon	0.21	0.74	0.24	0.89	0.26	0.99
Northern California	1.18	1.37	1.37	1.66	1.47	1.83
Central California	1.95	2.05	2.10	2.20	2.17	2.26
Southern California	3.33	4.65	3.71	5.15	3.90	5.40
Pacific OCS	**6.67**	**8.80**	**7.43**	**9.90**	**7.79**	**10.49**

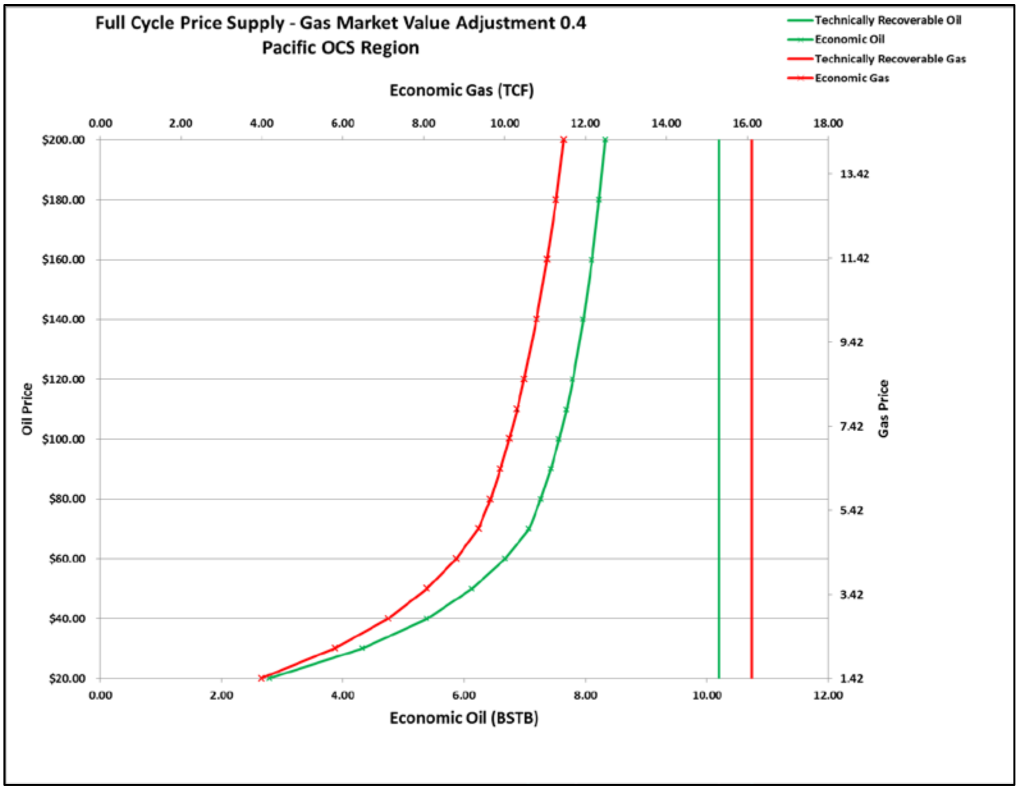


Figure 3-4. *Price-supply curves for the Pacific OCS Region. Oil prices are coupled with a specific gas price assuming a 40 percent economic value for gas relative to oil.*

Total Resource Endowment

As of this assessment, originally recoverable reserves (cumulative production plus remaining reserves) for the Region were 1.56 Bbbl of oil and 1.95 Tcf of gas. Contingent resources were estimated to be 6.67 Bbbl of oil and 7.43 Tcf of gas (BOEMRE, 2010; unpublished BOEM data). These discovered resources and the undiscovered technically recoverable resources collectively compose the Region's estimated total resource endowment of 13.03 Bbbl of oil and 18.88 Tcf of gas, which are given by province and for the total Pacific OCS Region in table 3-5. Estimates by planning area are given in table 3-6. All discovered resources are in the Southern California Planning Area.

Detailed descriptions of the provinces and basins and results of the assessment are in the sections that follow. Much of the geologic information is derived from the earlier publication *1995 National Assessment of United States Oil and Gas Resources – Assessment of the Pacific Outer Continental Shelf Region* (Dunkel and Piper, 1997).

Table 3-5. *Estimates of the total endowment of oil and gas resources in the Pacific OCS Region by province. Estimates of discovered resources, including originally recoverable reserves and contingent resources, are as of January 1, 2009. Originally recoverable reserves include cumulative production and remaining reserves. Estimates of undiscovered technically recoverable resources are risked mean values. Some total values may not equal the sum of the component values due to independent rounding.*

Geologic Province	Discovered Resources						Undiscovered Technically Recoverable Resources			Total Resource Endowment		
	Originally Recoverable Reserves			Contingent Resources								
	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	0.47	3.76	1.14	0.47	3.76	1.14
Central California	0.33	0.18	0.36	1.06	0.42	1.13	5.23	5.21	6.16	6.61	5.81	7.65
Santa Barbara	1.13	1.73	1.43	0.21	0.40	0.29	1.34	2.74	1.83	2.68	4.88	3.55
Inner Borderland	0.11	0.03	0.11	0.005	0.001	0.005	1.96	2.15	2.34	2.07	2.19	2.46
Outer Borderland	0	0	0	0	0	0	1.20	2.24	1.60	1.20	2.24	1.60
Pacific OCS	**1.56**	**1.95**	**1.91**	**1.27**	**0.83**	**1.42**	**10.20**	**16.10**	**13.07**	**13.06**	**18.98**	**16.44**

Table 3-6. *Estimates of the total endowment of oil and gas resources in the Pacific OCS Region by planning area. Estimates of discovered resources, including originally recoverable reserves and contingent resources, are as of January 1, 2009. Originally recoverable reserves include cumulative production and remaining reserves. Estimates of undiscovered technically recoverable resources are risked mean values. Some total values may not equal the sum of the component values due to independent rounding.*

Planning Area	Discovered Resources						Undiscovered Technically Recoverable Resources			Total Resource Endowment		
	Originally Recoverable Reserves			Contingent Resources								
	Oil (Bbbl)	Gas (Tcf)	BOE (Bbbl)	Oil (Bbbl)	Gas (Tcf)	BOE (Bbbl)	Oil (Bbbl)	Gas (Tcf)	BOE (Bbbl)	Oil (Bbbl)	Gas (Tcf)	BOE (Bbbl)
Wash./Oregon	0	0	0	0	0	0	0.40	2.28	0.81	0.40	2.28	0.81
Northern California	0	0	0	0	0	0	2.08	3.58	2.71	2.08	3.58	2.71
Central California	0	0	0	0	0	0	2.40	2.49	2.84	2.40	2.49	2.84
Southern California	1.56	1.95	1.91	1.27	0.83	1.42	5.32	7.76	6.70	8.19	10.64	10.08
Pacific OCS	**1.56**	**1.95**	**1.91**	**1.27**	**0.83**	**1.42**	**10.20**	**16.10**	**13.07**	**13.06**	**18.98**	**16.44**

PACIFIC NORTHWEST PROVINCE

Location

The Pacific Northwest Province includes the Washington–Oregon area and the Federal offshore portion of the Eel River basin (fig. 3-5). These areas are within the accretionary complex that is associated with the Cascadia subduction zone, and together encompass about 21,000 square miles. Water depth ranges from about 100 feet on Nehalem Bank, offshore northern Oregon to about 4,000 feet along the shelf-slope boundary in Eel River basin.

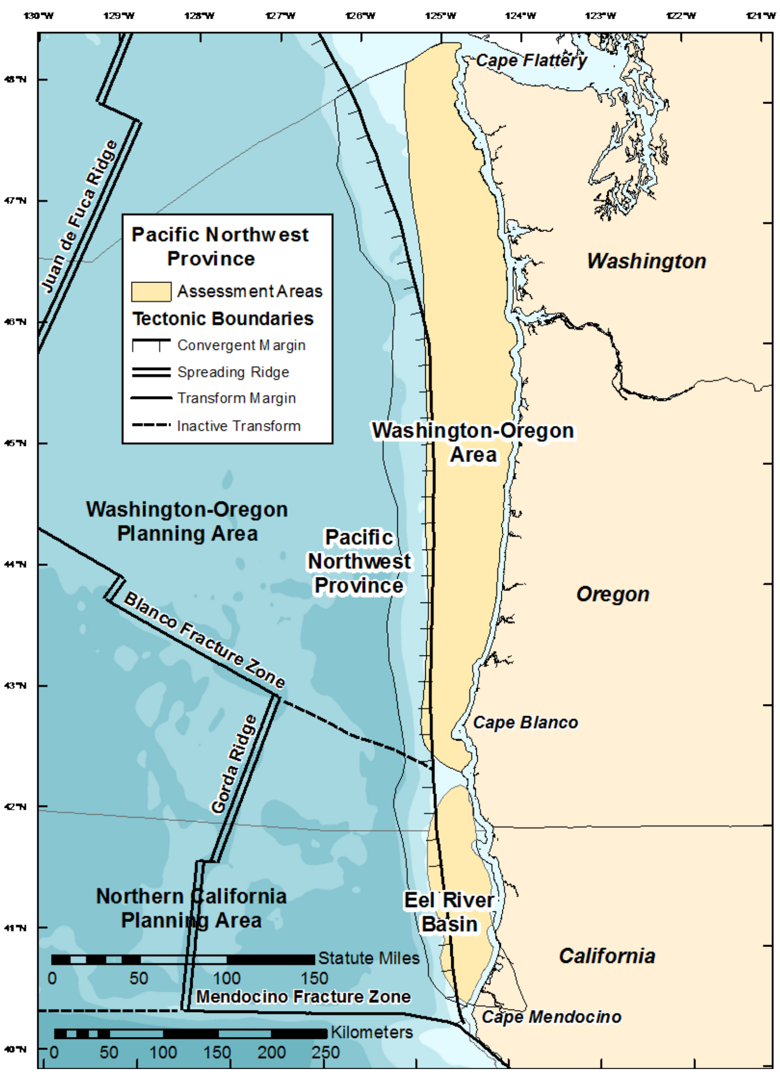


Figure 3-5. *Map of the Pacific Northwest province showing assessment areas and planning area boundaries.*

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 (up to more than 20,000 feet) on the shelf and a poorly defined bathymetric trench. 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. The Washington–Oregon area is situated above the subducting Juan de Fuca tectonic plate. Interpretation of a coarse grid of seismic-reflection profiles identified six Neogene depocenters or subbasins in the area. The Eel River basin to the south is a separate basin above the subducting Gorda plate.

EXPLORATION

Sixteen exploratory wells were drilled within the province at 14 sites in the 1960's. Eight of the wells encountered hydrocarbon shows. One well off central Washington and one off southern Oregon were tested and yielded gas at about 10 to 70 Mcf per day. Abundant gas seeps have been mapped in offshore Eel River basin.

Onshore, a small oil field produced 12,000 bbl of high gravity oil from 1957 to 1962 in coastal central Washington, and a gas field near Portland, Oregon has produced over 65 Bcf of gas since 1979. Several other wells in coastal Washington have encountered subcommercial quantities of high gravity oil. Several gas fields exist in the onshore part of the Eel River basin, the largest of which has produced over 120 Bcf of gas.

Stratigraphic and paleontologic data from the offshore wells and a relatively sparse grid of 2-D seismic data obtained in the 1970's and 1980's are the bases for interpretation of the offshore geology. No newer data exists than that used for the 1995 assessment.

PACIFIC NORTHWEST PROVINCE PLAYS

Plays in the Pacific Northwest Province are based on expected reservoir rock characteristics. Three Neogene plays, one Paleogene play, and a mélange play were defined.

In each basin there is a Neogene Fan Sandstone play and a Neogene Sandstone play. The difference is in the expected abundance of sand, dependent upon location relative to major river outfalls. In southern Washington and northern Oregon there is also defined a Growth Fault play. There are large active growth faults and associated shale diapirs. These are in an area of particularly high sediment deposition and the expectation is that there will be an even greater abundance of reservoir sand and stacked reservoirs.

Each basin also has a Paleogene Sandstone play. The older sandstones are expected to have lower porosity and a greater likelihood of chemical cementation within the pore spaces. Therefore oil yields are expected to be lower.

Finally, each basin has a mélange play. This represents primarily oil and associated gas in Paleogene and Neogene sand bodies that have been subducted below the mappable sedimentary section. Oil and gas shows were encountered in wells that were drilled into the play. This play was not quantitatively assessed, but is considered to be an important source of oil for the overlying Paleogene and Neogene plays.

ECONOMIC FACTORS

There is little oil and gas infrastructure on the coastline within this province, and no large coastal cities. Should there be any future development, pipelines could be shared among multiple platforms or subsea completions and tied to shore at one or more of several coastal harbor towns. This would minimize both cost and environmental impacts. However, the expected resources (mostly gas) are relatively small compared to the large areal extent of the province.

Resource Estimates

Undiscovered Technically Recoverable Resources

Estimates of the total volume of undiscovered technically recoverable resources within the Washington–Oregon area and Eel River basin were developed by statistically aggregating the constituent play estimates within each basin. Estimates of the total volume of undiscovered technically recoverable resources in the province were developed by statistically aggregating all constituent play estimates within the province. The low, mean, and high estimates of resources are listed in table 3-7 for each of the assessment areas and the province total. As a result of this assessment, the total volume of undiscovered technically recoverable resources in the Pacific Northwest Province assessment area is expected to be 0.47 Bbbl of oil and 3.76 Tcf of associated and non-associated gas (mean values).

Table 3-7. *Estimates of Undiscovered Technically Recoverable Oil and Gas Resources of the Pacific Northwest Province Region by assessment area. Resource values are in billion barrels of oil (Bbbl) and trillion cubic feet of gas (Tcf). 95% indicates a 95 percent chance of at least the amount listed; 5% indicates a 5 percent chance of at least the amount listed. Only mean values are additive. Some total mean values may not equal the sum of the component values due to independent rounding of the tabulated values.*

Geologic	Oil (Bbbl)			Gas (Tcf)			BOE (Bbbl)		
Basin/Area	95%	Mean	5%	95%	Mean	5%	95%	Mean	5%
Wash. –Oregon	0.00	0.40	1.14	0.00	2.23	5.76	0.00	0.80	2.17
Eel River	0.01	0.07	0.17	0.28	1.52	2.59	0.06	0.34	0.63
PNW Province	0.03	0.47	1.23	0.88	3.76	7.50	0.19	1.14	2.56

Undiscovered Economically Recoverable Resources

Estimates of the portion of the technically recoverable resources that can be economically recovered under various economic scenarios were developed by including the effects of current and expected future economic factors. Estimates of economically recoverable resources at several pricing scenarios are given in table 3-8 (for each assessment area and province total) and illustrated in the form of price-supply curves in fig. 3-6. As a result of this assessment, 0.28 Bbbl of oil and 1.18 Tcf of associated gas are estimated to be economically recoverable from the Pacific Northwest Province under economic conditions existing as of this assessment (i.e., the $90-per-barrel economic scenario). The estimates shown in table 3-8 and figure 3-6 assume a 40 percent economic value for gas relative to oil.

Table 3-8. *Estimates of undiscovered economically recoverable oil and gas resources in the Pacific Northwest Province as of January 1, 2009 for three economic scenarios, by assessment area. Oil prices are coupled with a specific gas price assuming a 40 percent economic value for gas relative to oil.*

Geologic	$60/bbl, $4.27/Mcf		$90/bbl, $6.41/Mcf		$120/bbl, $8.54/Mcf	
Basin/Area	Oil (Bbbl)	Gas (Tcf)	Oil (Bbbl)	Gas (Tcf)	Oil (Bbbl)	Gas (Tcf)
Wash. –Oregon	0.21	0.73	0.24	0.88	0.26	0.98
Eel River	0.03	0.18	0.04	0.29	0.04	0.37
PNW Province	**0.24**	**0.91**	**0.28**	**1.18**	**0.30**	**1.34**

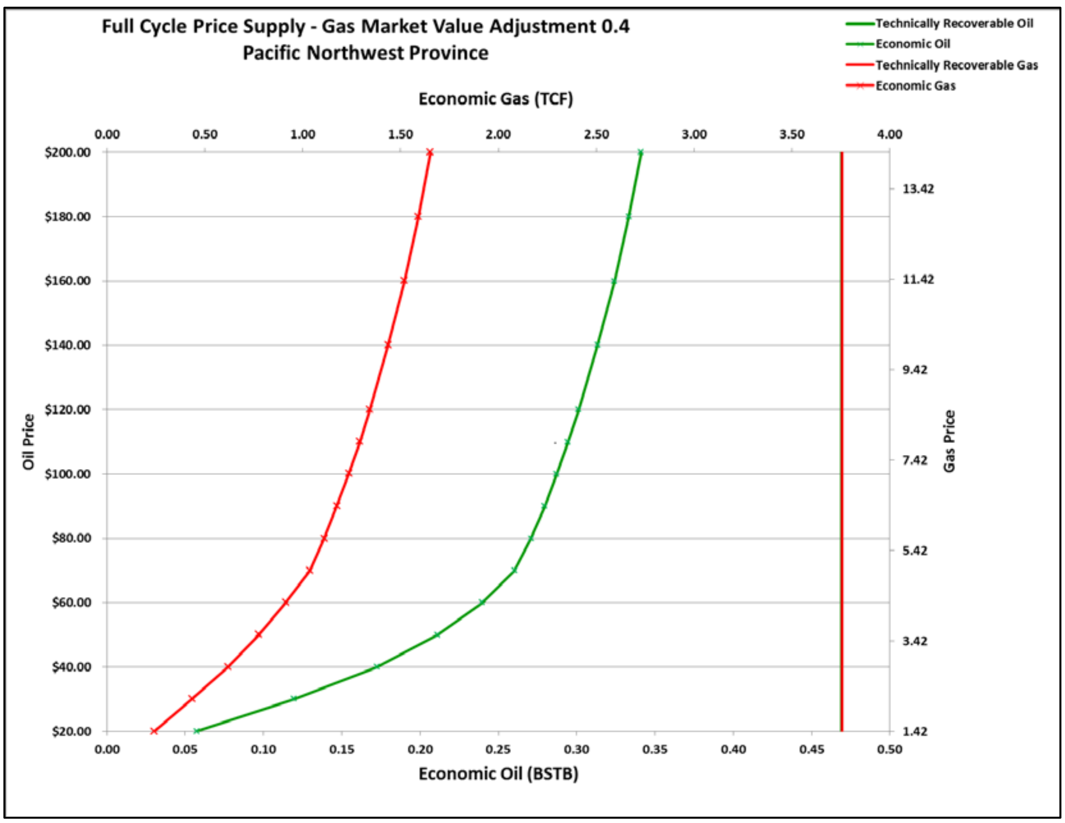


Figure 3-6. *Price-supply curves for the Pacific Northwest Province. Oil prices are coupled with a specific gas price assuming a 40 percent economic value for gas relative to oil.*

Washington–Oregon Area

Location

The Washington–Oregon assessment area is the northern subarea of the Pacific Northwest province (fig. 3-5). It extends from Cape Flattery, Washington, to south of Cape Blanco, Oregon, a distance of about 400 miles (fig. 3-7). 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.

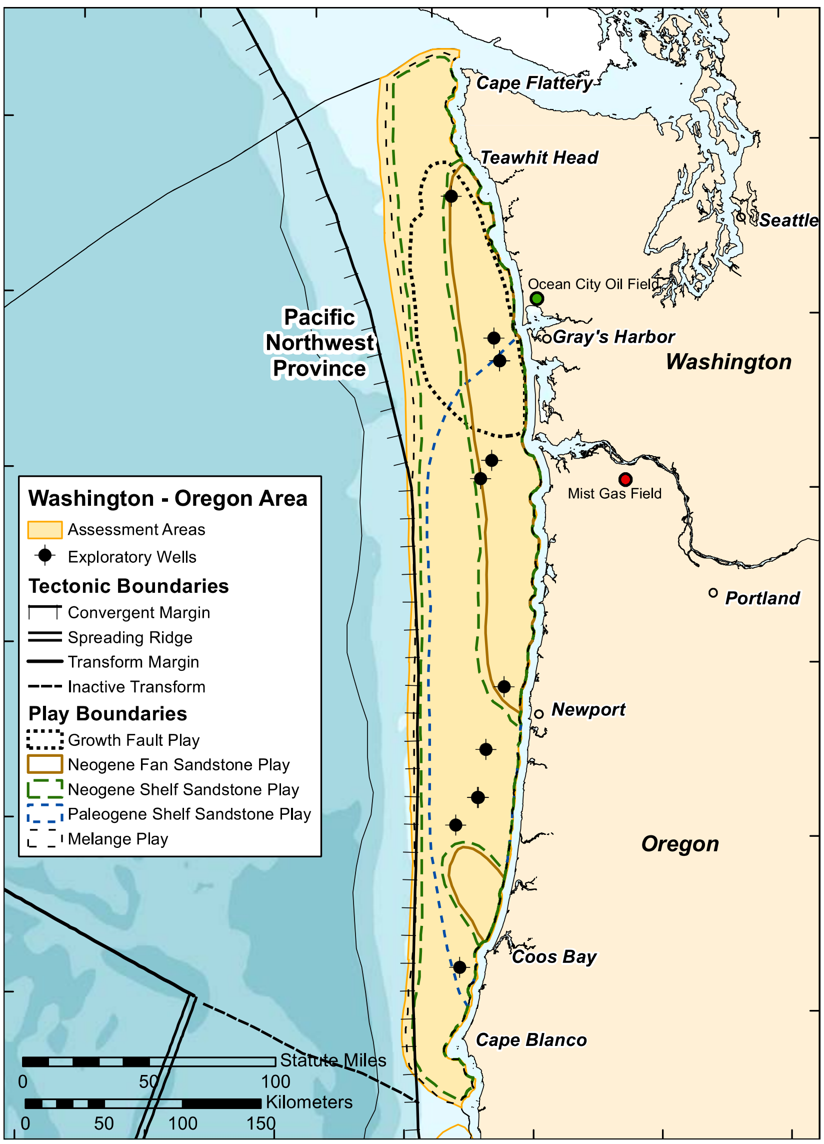


Figure 3-7. *Map of the Washington – Oregon assessment area showing petroleum geologic plays, wells, and fields*

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. 3-8). The 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,

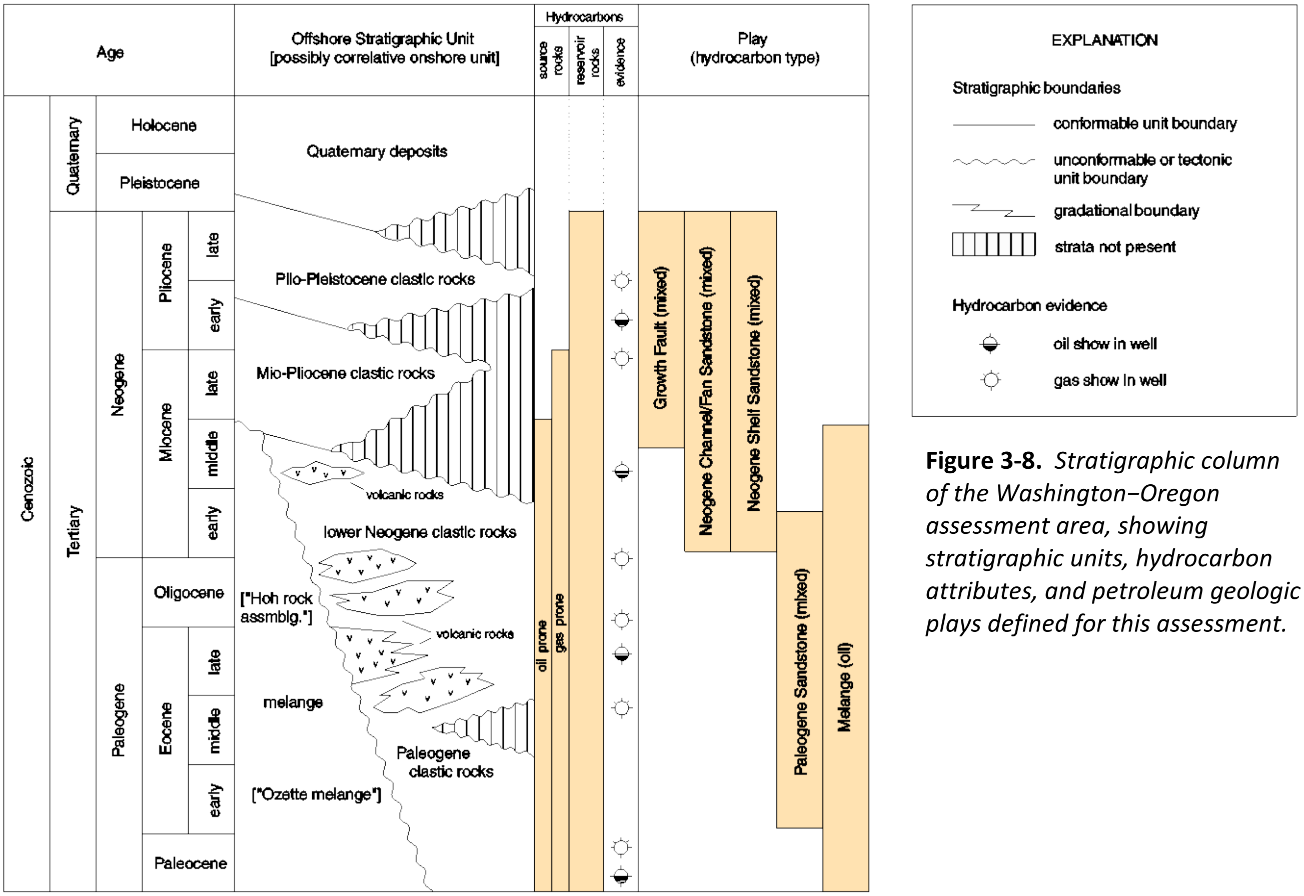


Figure 3-8. *Stratigraphic column of the Washington–Oregon assessment area, showing stratigraphic units, hydrocarbon attributes, and petroleum geologic plays defined for this assessment.*

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 within the province at 10 sites in the 1960's. Eight of the wells encountered hydrocarbon shows. One well off central Washington and one off southern Oregon were tested and yielded gas at about 10 to 70 Mcf per day; two other wells offshore southern Washington had oil shows indicating the presence of high-gravity oil (Zieglar and Cassell, 1978). Onshore, a small oil field produced 12,000 bbl of high gravity oil from 1957 to 1962 in coastal central Washington, and a gas field near Portland, Oregon has produced over 65 Bcf of gas since 1979. Several other wells in coastal Washington have encountered subcommercial quantities of high gravity oil (Braislin and others, 1971; McFarland, 1983; Palmer and Lingley, 1989). Stratigraphic and paleontologic data from the offshore wells and a relatively sparse grid of 2-D seismic data obtained in the 1970's and 1980's are the bases for interpretation of the offshore geology. No newer data exists than that used for the 1995 assessment.

PLAYS

Plays in the Washington–Oregon Area are based on expected reservoir rock characteristics. Three Neogene plays, one Paleogene play, and a mélange play were defined. Rocks that are equivalent to rocks of these plays exist onshore and in the State offshore. Some of these rock units are included in plays that were assessed within the onshore Western Oregon-Washington Province by the USGS (Johnson and Tennyson, 1995).

Growth Fault Play

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. 3-7). 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.

The primary hydrocarbon source is Miocene and older melange, which, over most of the play area, directly underlies the Neogene sedimentary section (fig. 3-8). 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 excellent to good 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 the more important trap type; they are generally larger and the associated faults may be conduits for escape of hydrocarbons rather than trapping them.

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 sources for this play. In petroleum provinces elsewhere in the world, growth faults are considered important targets.

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 10 to 30 percent of the expected pools. Previous seismic mapping of the area–based on a relatively sparse seismic data grid–was revised for the 1995 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.

Neogene Fan Sandstone Play

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. 3-7). 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).

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 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 from the Neogene Shelf Sandstone play is that this play includes a greater likelihood of channel and thick fan deposits, so potential reservoir sandstones are likely to be much 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.

Exploratory wells at six sites have penetrated rocks of this play. 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.

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 25 to 45 percent of the expected pools; nonassociated gas was modeled as a component of 55 to 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.

Neogene Shelf Sandstone Play

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. 3-7). 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.

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. 3-8). 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 fair to excellent 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.

Exploratory wells at four sites have penetrated rocks of this play. 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.

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 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 about 60 to 80 percent of the expected pools; nonassociated gas was modeled for 20 to 40 percent of the pools. Eel River basin prospect sizes 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.

Paleogene Sandstone Play

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. 3-7). 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).

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, and volcanic flows and sills, which are abundant within this section.

Exploratory wells at eight sites have penetrated rocks presumed to be within this play; 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.

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 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.

Melange Play

The Melange play of the Washington–Oregon assessment area is a frontier play, 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 area-wide, from Cape Flattery, Washington, to south of Cape Blanco, Oregon; it encompasses about 18,000 square miles (fig. 3-7). 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 cannot 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 onshore by the USGS (Johnson and Tennyson, 1995).

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.

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.

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.

ECONOMIC FACTORS

There is little oil and gas infrastructure on the coastline in the Washington–Oregon Area, and no large coastal cities. Should there be any future development, pipelines could be shared among multiple platforms or subsea completions and tied to shore at one or more of several coastal harbor towns. This would minimize both cost and environmental impacts.

RESOURCE ESTIMATES

Undiscovered Technically Recoverable Resources

Play-specific estimates of undiscovered technically 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 (table 3-9). Select data used to develop the resource estimates are shown in appendix C. As a result of this of this assessment, the total volume of undiscovered technically recoverable resources in the Washington–Oregon assessment area is expected to be 0.40 Bbbl of oil and 2.23 Tcf of associated and nonassociated gas (mean values).

Table 3-9. *Estimates of Undiscovered Technically Recoverable Oil and Gas Resources of the Washington–Oregon geologic plays and the area total. Resource values are in billion barrels of oil (Bbbl) and trillion cubic feet of gas (Tcf). 95% indicates a 95 percent chance of at least the amount listed; 5% indicates a 5 percent chance of at least the amount listed. Only mean values are additive. Some total mean values may not equal the sum of the component values due to independent rounding of the tabulated values.*

Geologic Play	**Oil (Bbbl)**			**Gas (Tcf)**			**BOE (Bbbl)**		
	95%	Mean	5%	95%	Mean	5%	95%	Mean	5%
Growth Fault	0.00	0.13	0.42	0.00	0.45	1.42	0.00	0.21	0.67
Neog. Fan Sandstone	0.00	0.11	0.29	0.00	0.85	2.15	0.00	0.26	0.67
Neog. Shelf Sandstone	0.00	0.15	0.39	0.00	0.58	1.34	0.00	0.25	0.63
Paleogene Sandstone	0.00	0.01	0.03	0.00	0.36	0.94	0.00	0.07	0.19
Wash. −Oregon Area	**0.00**	**0.40**	**1.14**	**0.00**	**2.23**	**5.76**	**0.00**	**0.80**	**2.17**

Undiscovered Economically Recoverable Resources

Estimates of the portion of the technically recoverable resources that can be economically recovered under various economic scenarios were developed by including the effects of current and expected future economic factors. Select data used to develop the resource estimates are shown in appendix D. These estimates are shown in fig. 3-9 as price-supply curves for a range of price scenarios, and for a gas market value of 40 percent of the energy equivalent value of oil. As a result of this assessment, 0.24 Bbbl of oil and 0.88 Tcf of associated gas are estimated to be economically recoverable from the Washington–Oregon area assessment area under economic conditions existing as of this assessment (i.e., the $90-per-barrel economic scenario). Larger volumes of resources are expected to be economically recoverable under increasingly favorable economic conditions. Because field development often includes multiple plays, and may not be viable for an individual play, play-specific estimates have not been tabulated.

ADDITIONAL REFERENCE FOR WASHINGTON−OREGON AREA

McLean and Wiley, 1987

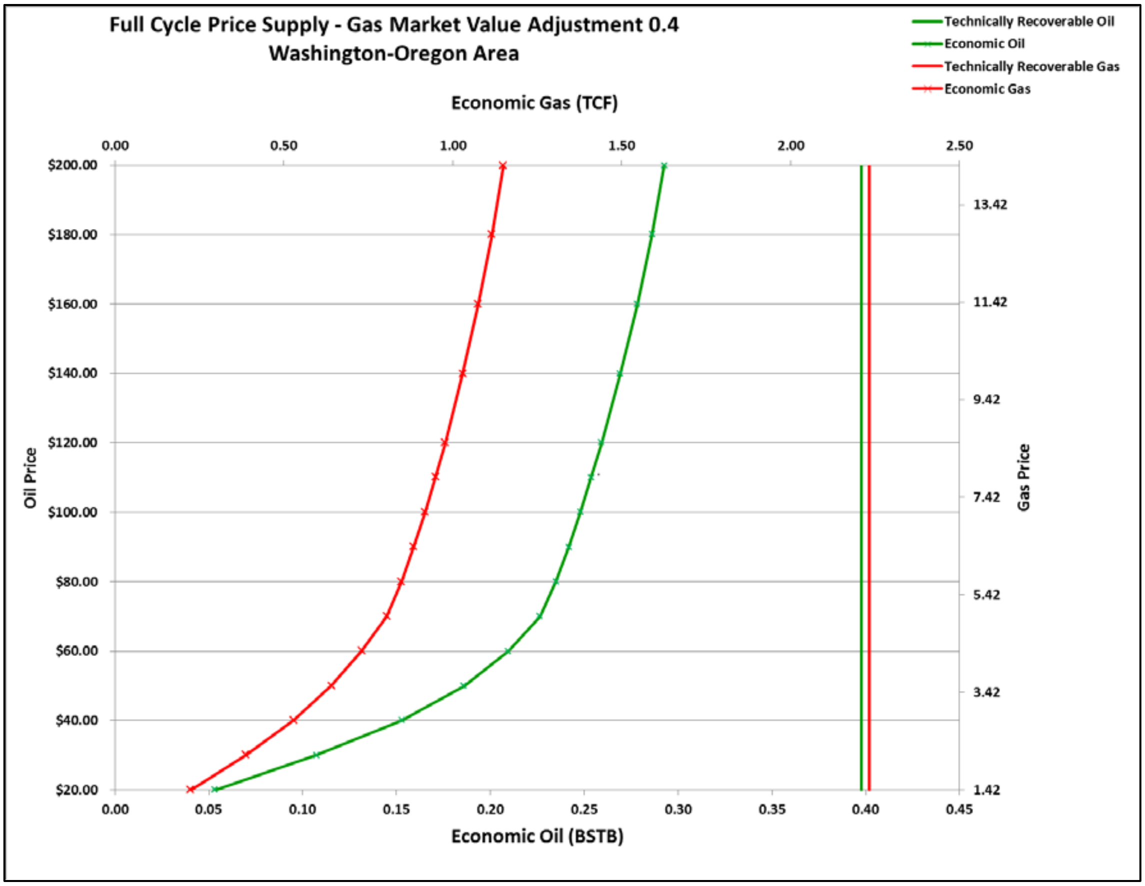


Figure 3-9. *Price-supply curves for the Washington–Oregon area. Oil prices are coupled with a specific gas price assuming a 40 percent economic value for gas relative to oil.*

EEL RIVER BASIN

LOCATION

The Eel River Basin is the southern subarea of the Pacific Northwest province (fig. 3-5). It extends from 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. 3-10).

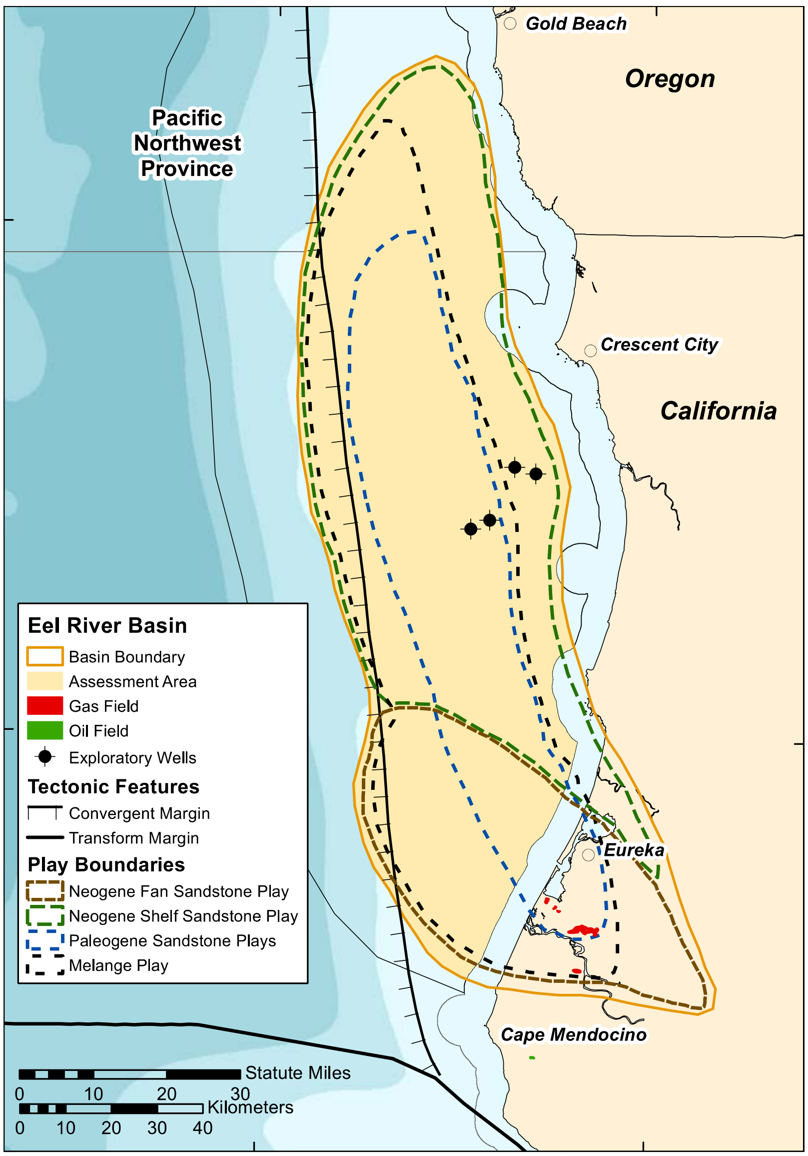


Figure 3-10. *Map of the Eel River Basin assessment area showing petroleum geologic plays, wells, and fields.*

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 3,500 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. 3-11). In the eastern offshore part of the basin, these rocks are apparently continuous 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 (Ogle, 1953); it has also been termed the "Coastal Belt thrust" by Jones and others (1978) and Aalto and others (1995), and the "Eel River fault" by Bachman and others (1984), which is exposed onshore. 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.

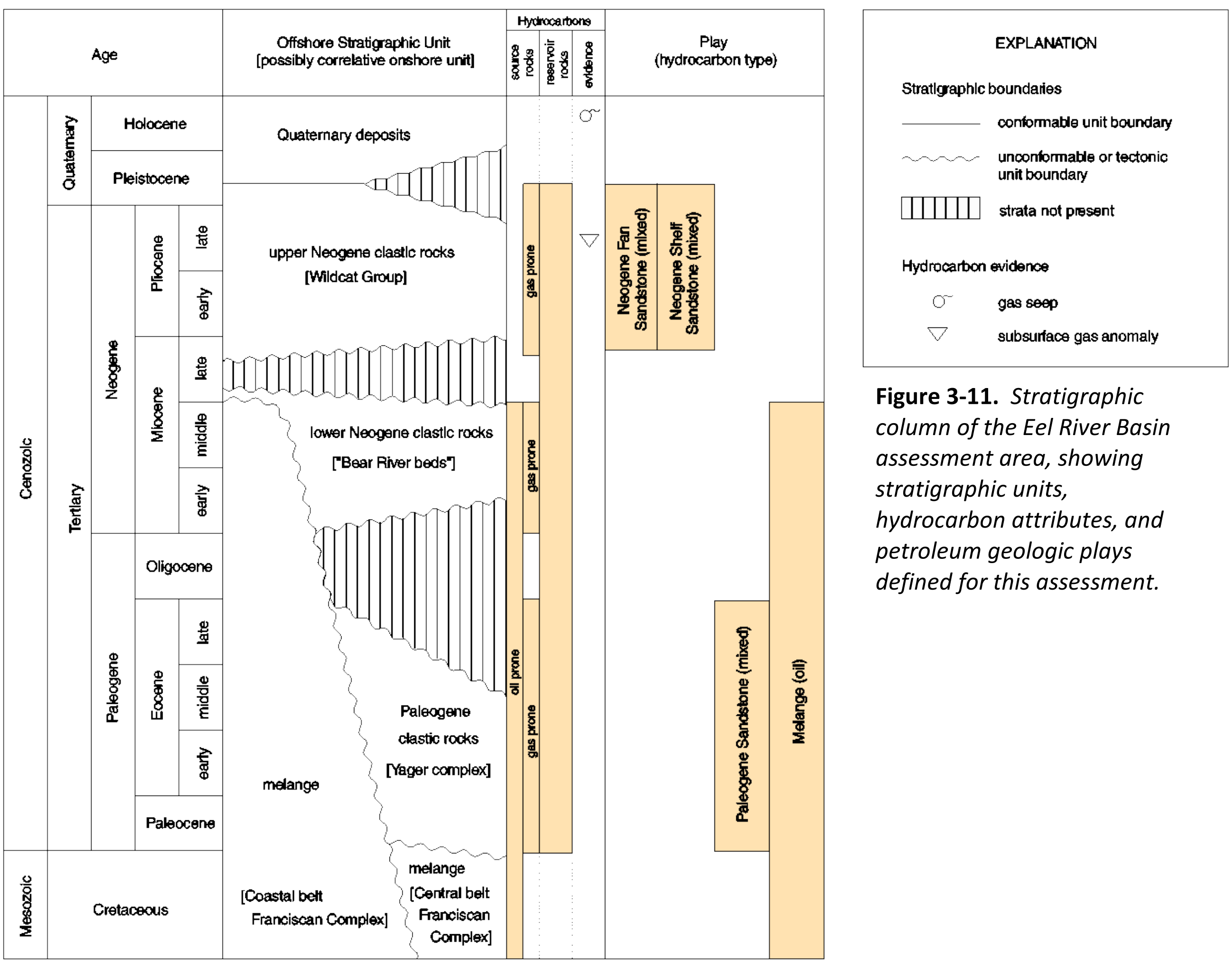


Figure 3-11. *Stratigraphic column of the Eel River Basin assessment area, showing stratigraphic units, hydrocarbon attributes, and petroleum geologic plays defined for this assessment.*

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

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, 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, 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 Mcf 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. 3-10 and 3-11). 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).

Neogene Fan Sandstone Play

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. 3-10). The Federal offshore part of the play covers an area of about 600 square miles and 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).

Potential source rocks include the Cretaceous (?) to Miocene Coastal belt of the Franciscan Complex and Tertiary deltaic and forearc basin strata (fig. 3-11). Kerogen type of onshore samples suggests the Coastal belt is primarily gas prone (Crouch, Bachman, and Associates, 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, 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, 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).

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.

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.

Neogene Shelf Sandstone Play

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. 3-10). 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).

Potential source rocks include the Cretaceous (?) to Miocene Coastal belt Franciscan and Tertiary deltaic and forearc basin strata (fig. 3-11). Kerogen type of onshore samples suggests the Coastal belt is primarily gas prone (Crouch, Bachman, and Associates, 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, 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 excellent to good 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.

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.

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.

Paleogene Sandstone Play

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. 3-10). 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).

Source rocks include the Cretaceous (?) to Miocene Coastal belt Franciscan Complex, including shales of the Paleogene Yager member of the Coastal belt (fig. 3-11). Kerogen type of onshore samples suggests the Coastal belt is primarily gas prone (Underwood, 1987; Crouch, Bachman, and Associates, 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, 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 of the Yager are well cemented with laumontite filling pore spaces (Crouch, Bachman, and Associates, 1988a).

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

In the 1960's, two exploratory wells (OCS-P 0014 #1ET; OCS-P 0019 #1ET) 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 #1ET (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.

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.

Melange Play

The Melange play of the Eel River Basin assessment area is a conceptual play, 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 3,500 square miles (fig. 3-10). 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).

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, 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.

Two of the four offshore exploratory wells (OCS-P 0014 #1ET; OCS-P 0019 #1ET) 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 #1ET (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).

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.

ECONOMIC FACTORS

There is little oil and gas infrastructure on the coastline in the Eel River Area, and no large coastal cities. Should there be any development of natural gas for local consumption, pipelines could be tied into the existing onshore infrastructure of the onshore gas fields. This would minimize both cost and environmental impacts.

Resource Estimates

Undiscovered Technically Recoverable Resources

Play-specific estimates of undiscovered technically 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 (table 3-10). Select data used to develop the resource estimates are shown in appendix C. As a result of this assessment, the total volume of undiscovered technically recoverable resources in the Eel River Basin assessment area is expected to be 0.07 Bbbl of oil and 1.52 Tcf of associated and nonassociated gas (mean values).

Table 3-10. *Estimates of Undiscovered Technically Recoverable Oil and Gas Resources of the Eel River geologic plays and the basin total. Resource values are in billion barrels of oil (Bbbl) and trillion cubic feet of gas (Tcf). 95% indicates a 95 percent chance of at least the amount listed; 5% indicates a 5 percent chance of at least the amount listed. Only mean values are additive. Some total mean values may not equal the sum of the component values due to independent rounding of the tabulated values.*

Geologic Play	Oil (Bbbl)			Gas (Tcf)			BOE (Bbbl)		
	95%	Mean	5%	95%	Mean	5%	95%	Mean	5%
Neog. Fan Sandstone	0.01	0.03	0.08	0.28	0.60	0.96	0.06	0.13	0.25
Neog. Shelf Sandstone	0.00	0.04	0.06	0.00	0.90	1.58	0.00	0.20	0.34
Paleogene Sandstone	0.00	0.01	0.03	0.00	0.03	0.09	0.00	0.01	0.04
Eel River Basin	**0.01**	**0.07**	**0.17**	**0.28**	**1.52**	**2.59**	**0.06**	**0.34**	**0.63**

Undiscovered Economically Recoverable Resources

Estimates of the portion of the technically recoverable resources that can be economically recovered under various economic scenarios were developed by including the effects of current and expected future economic factors. Select data used to develop the resource estimates are shown in appendix D. These estimates are shown in fig. 3-12 as price-supply curves for a range of price scenarios, and for a gas market value of 40 percent of the energy equivalent value of oil. As a result of this assessment, 0.38 Bbbl of oil and 0.29 Tcf of associated 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 $90-per-barrel economic scenario). Larger volumes of resources are expected to be economically recoverable under increasingly favorable economic conditions. Because field development often includes multiple plays, and may not be viable for an individual play, play-specific estimates have not been tabulated.

Additional References for Eel River Basin

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

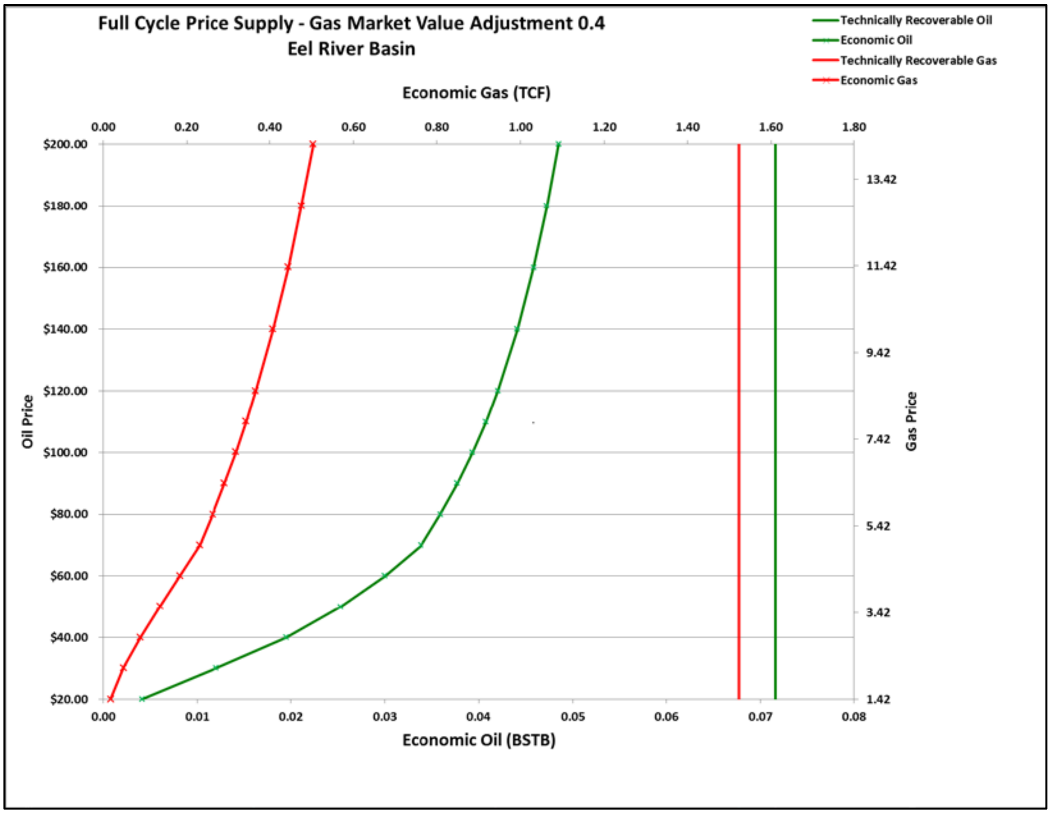


Figure 3-12. *Price-supply curves for the Eel River basin. Oil prices are coupled with a specific gas price assuming a 40 percent economic value for gas relative to oil.*

CENTRAL CALIFORNIA PROVINCE

LOCATION

The Central California Province includes the Federal offshore portion of five Tertiary basins that lie on the continental shelf and slope: Point Arena, Bodega, Año Nuevo, Partington, and Santa Maria (fig. 3-13). The Partington and Santa Maria basins have been combined as a single assessment area, due to the 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.

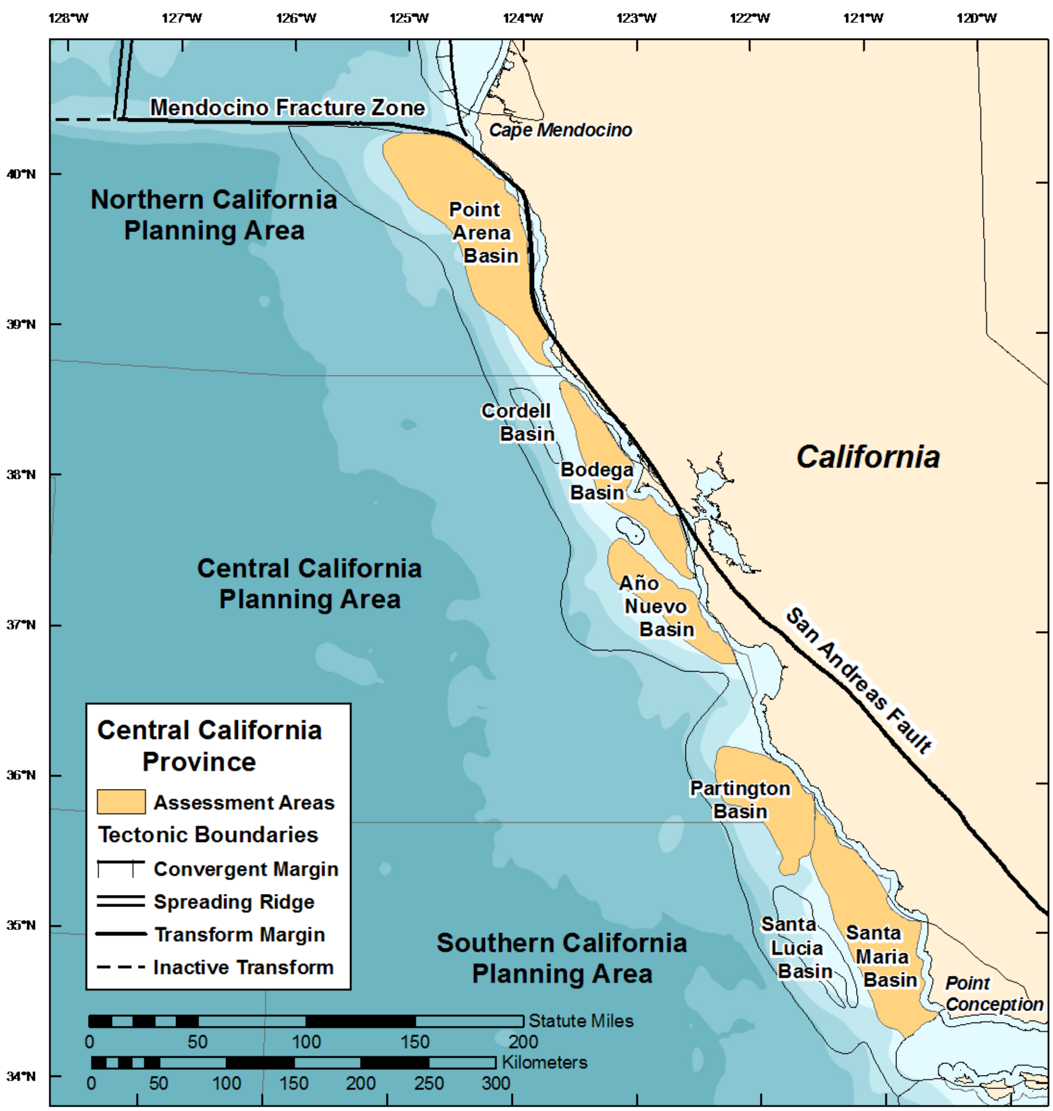


Figure 3-13. *Map of the Central California province showing assessment areas and planning area boundaries.*

GEOLOGIC SETTING

The central California margin has a complex tectonic history. In the early Cenozoic, oceanic crust of the Farallon Plate and related plates was being subducted along the entire Pacific margin of North America. By the Oligocene epoch, parts of the east Pacific spreading center were approaching the North American continental margin. Once the East Pacific spreading center was sufficiently close to the subduction boundary, the young lithosphere was sufficiently hot, light, and thin that it broke off as microplates from the downgoing lithosphere and became sutured to the Pacific Plate at the former spreading center. This effectively shut off both spreading and subduction and facilitated the formation of the modern transform boundary and the development of the Mendocino and Riviera triple junctions (the latter is southeast of the southern tip of Baja California, Mexico). Because of the relative global plate motions, the Mendocino triple junction has migrated northward relative to the North American continent, and basins formed through the combined translational and convergent tectonic movements. (For a more detailed account of the tectonic interactions, see Nicholson and others 1994, and Atwater, 1998.)

Although they have stratigraphic similarities, the complexity of the plate interactions has resulted in differences in the geologic history of the several central California basins. Most of the basins are bounded on the east by faults associated with the right-lateral San Andreas transform 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.

EXPLORATION AND DISCOVERY STATUS

The central California basins all have significant deposition of the siliceous Miocene Monterey Formation and equivalents. From the standpoint of oil exploration, this is the most important rock unit in offshore California, because it is the most prolific source and reservoir rock for hydrocarbons.

Sixteen offshore exploratory wells were drilled in the province in the 1960's, including 3 in southern-most Point Arena basin, 10 in Bodega basin, 2 in Año Nuevo basin, and 1 in Santa Maria basin. Although most of these wells penetrated the Monterey section, oil shows were ignored because the Monterey Formation was not considered a target at that time. Had those wells been drilled twenty years later, many of them would likely be considered as discoveries.

As a result of 4 lease sales that occurred from 1979 to 1983, an additional 55 exploratory wells were drilled in the southern Santa Maria basin, including 35 discoveries. No newer data exists than that used for the 1995 assessment. However, some of the seismic data was reinterpreted, and that is the basis for an increase in the contingent resources and a revision in the assessment of undiscovered resources.

The only production in the province is in the southern part of the Santa Maria basin, where three fields are producing originally recoverable reserves estimated to be about 0.33 Bbbl of oil and 0.18 Tcf of gas. Production through 2009 is about 0.27 Bbbl of oil and 0.18 Tcf of gas (gas production includes reinjected gas). To the north in the Santa Maria basin, contingent resources of over 1.00 Bbbl of oil and over 0.42 Tcf of gas have been discovered, but the leases have been terminated without any production. Essentially all of these resources are Monterey oil and gas.

Central California Province Plays

In each of the basins the primary hydrocarbon play is the Fractured Monterey Play. The Monterey is an organic-rich siliceous shale that is both source and reservoir for primarily low-gravity oil and associated gas. Under sufficient pressure and temperature silica in the rock undergoes a mineralogic diagenesis, which results in pervasive fractures in the rock, and these fractures provide the pore space for the hydrocarbons generated by the organic shales. The Monterey Formation is considered to be the primary source-rock for the other Central California plays.

In each basin we defined a post-Monterey sandstone play that may provide a reservoir rock for hydrocarbons that are sourced from the Monterey. In the northern basins, this is called the Neogene Sandstone Play. In the Santa Maria−Partington basin the equivalent play is the Basal Sisquoc Sandstone Play. Petroleum characteristics for these plays are expected to be similar to Monterey oil and gas.

Each basin also has a Pre-Monterey sandstone play that may also be sourced stratigraphically downward from the Monterey. In the northern basins this is the Pre-Monterey Sandstone Play. In the Santa Maria−Partington basin it is termed the Paleogene Sandstone Play, which is an established play in the onshore Santa Maria basin. The Santa Maria basin also has a conceptual breccia play defined to include rocks that are presumed to exist as erosional debris from large areas of uplifted basement in the western part of the basin and also sourced from the Monterey.

Economic Factors

There is little oil and gas infrastructure on the coastline north of the San Francisco Bay, and no large coastal cities. Pipelines could be shared among multiple platforms or subsea completions and tied to shore at either Eureka to the north or San Francisco Bay. South of San Francisco, the only infrastructure is in southern Santa Maria basin, the location of the only oil and gas development in this province. Future development would likely tie in to existing pipelines. The number of platforms could be minimized by the use of extended-reach drilling. In Santa Barbara Channel, the longest extended-reach wells reach nearly 7 miles from the production platform. .

RESOURCE ESTIMATES

Undiscovered Technically Recoverable Resources

Estimates of the total volume of undiscovered technically recoverable resources in the province were developed by statistically aggregating the constituent play estimates included within all basins in the province. The low, mean and high estimates of resources are listed in table 3-11 for each of the basins and the province total. As a result of this assessment, the total volume of undiscovered technically recoverable resources in the Central California Province is expected to be 5.23 Bbbl of oil and 5.21 Tcf of associated and nonassociated gas (mean values).

Table 3-11. *Estimates of Undiscovered Technically Recoverable Oil and Gas Resources of the Central California province by assessment area. Resource values are in billion barrels of oil (Bbbl) and trillion cubic feet of gas (Tcf). 95% indicates a 95 percent chance of at least the amount listed; 5% indicates a 5 percent chance of at least the amount listed. Only mean values are additive. Some total mean values may not equal the sum of the component values due to independent rounding of the tabulated values.*

Geologic Basin/Area	Oil (Bbbl)			Gas (Tcf)			BOE (Bbbl)		
	95%	Mean	5%	95%	Mean	5%	95%	Mean	5%
Point Arena	1.00	2.01	3.46	0.99	2.10	3.85	1.18	2.38	4.14
Bodega	0.50	1.40	2.67	0.50	1.52	3.06	0.59	1.68	3.21
Año Nuevo	0.22	0.71	1.46	0.22	0.75	1.54	0.26	0.84	1.73
S. Maria-Partington	0.41	1.11	2.34	0.31	0.84	1.83	0.47	1.26	2.66
Cent. Cal. Prov.	**3.34**	**5.23**	**7.53**	**3.18**	**5.21**	**7.67**	**3.90**	**6.16**	**8.89**

Undiscovered Economically Recoverable Resources

Estimates of the portion of the technically recoverable resources that can be economically recovered under various economic scenarios were developed by including the effects of current and expected future economic factors. Estimates of economically recoverable resources at several pricing scenarios are given in table 3-12 (for each assessment area and province total) and illustrated in the form of price-supply curves in fig. 3-14. These estimates assume a 40 percent economic value for gas relative to oil. As a result of this assessment, 4.04 Bbbl of oil and 4.03 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 $90-per-barrel economic scenario).

Table 3-12. *Estimates of undiscovered economically recoverable oil and gas resources in the Central California province as of January 1, 2009 for three economic scenarios, by assessment area. Oil prices are coupled with a specific gas price assuming a 40 percent economic value for gas relative to oil.*

Geologic	$60/bbl, $4.27/Mcf		$90/bbl, $6.41/Mcf		$120/bbl, $8.54/Mcf	
Basin/Area	Oil (Bbbl)	Gas (Tcf)	Oil (Bbbl)	Gas (Tcf)	Oil (Bbbl)	Gas (Tcf)
Point Arena	1.15	1.19	1.33	1.38	1.43	1.48
Bodega	1.18	1.28	1.26	1.37	1.29	1.40
Año Nuevo	0.60	0.63	0.63	0.67	0.65	0.69
S. Maria-Partington	0.68	0.51	0.81	0.61	0.87	0.65
Central California	**3.61**	**3.62**	**4.04**	**4.03**	**4.24**	**4.22**

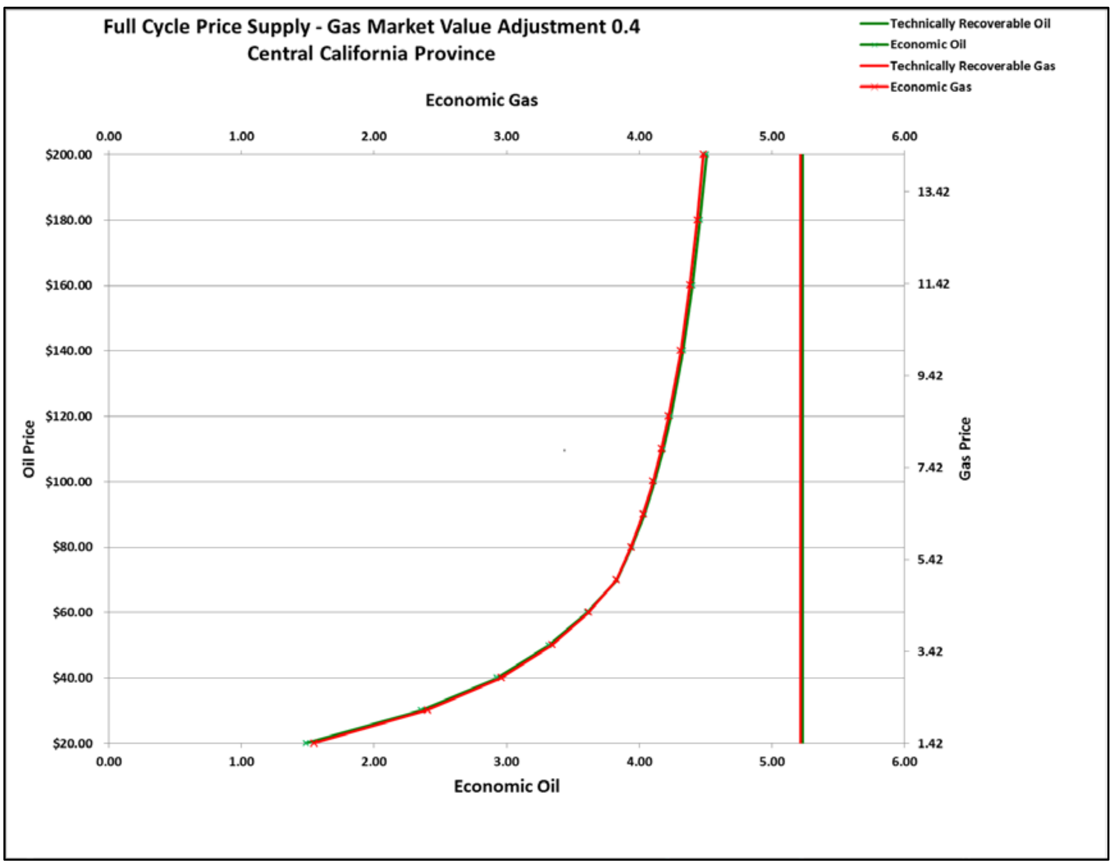


Figure 3-14. *Price-supply curves for the Central California province. Oil prices are coupled with a specific gas price assuming a 40 percent economic value for gas relative to oil.*

Total Resource Endowment

All discovered resources for the Central California Province are within the Santa Maria basin, and entirely from the Fractured Monterey Play. As of this assessment, originally recoverable reserves (cumulative production plus remaining reserves) for the basin were 0.33 Bbbl of oil and 0.18 Tcf of gas. Contingent resources were estimated to be 1.06 Bbbl of oil and 0.42 Tcf of gas (BOEMRE, 2010; unpublished BOEM data). These discovered resources and the undiscovered technically recoverable resources collectively compose the province's estimated total resource endowment of 6.61 Bbbl of oil and 5.82 Tcf of gas (table 3-13).

Table 3-13. *Estimates of the total endowment of oil and gas resources in the Central California Province. Estimates of discovered resources, including originally recoverable reserves and contingent resources, are as of January 1, 2009. Originally recoverable reserves include cumulative production and remaining reserves. Estimates of undiscovered technically 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)
Originally Recoverable Reserves	0.33	0.18	0.36
Contingent Resources	1.06	0.42	1.13
Undiscovered Technically Recoverable Resources	5.23	5.21	6.16
Total Resource Endowment	*6.61*	*5.82*	*7.65*

POINT ARENA BASIN

LOCATION

The Point Arena basin is the northernmost basin in the Central California province (fig. 3-13). 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. 3-15). 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. 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.

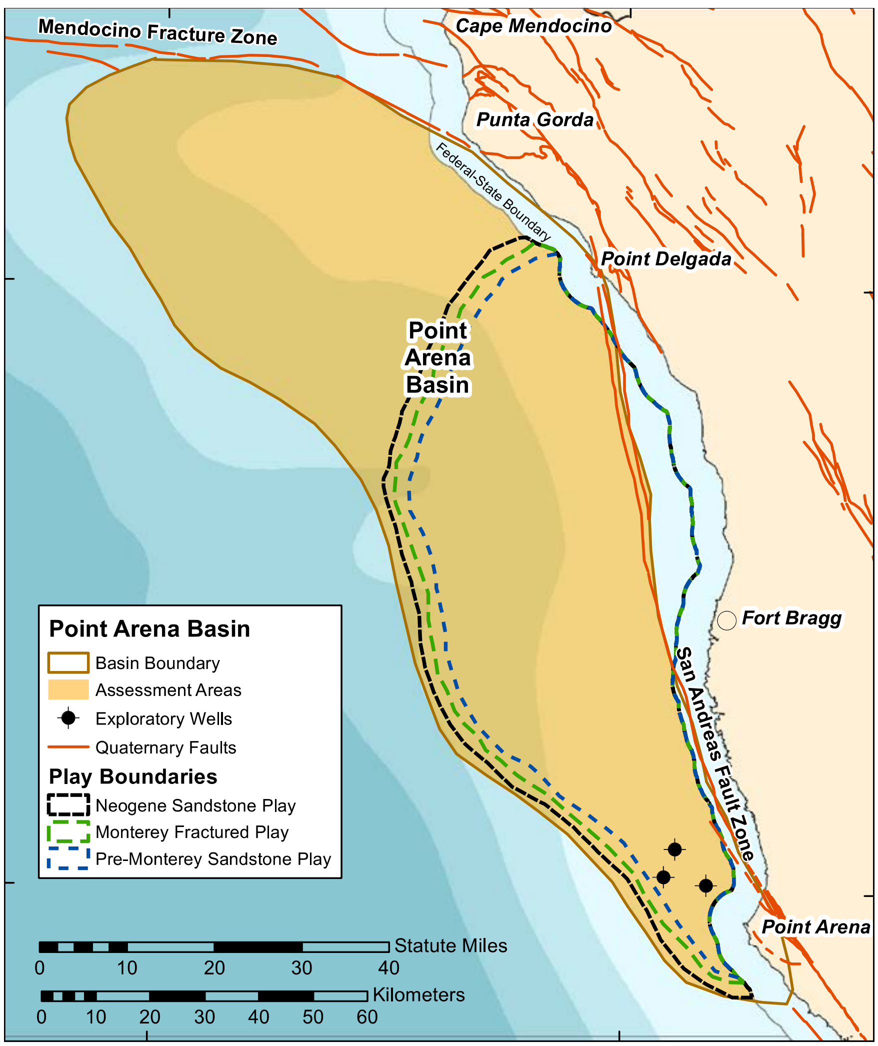
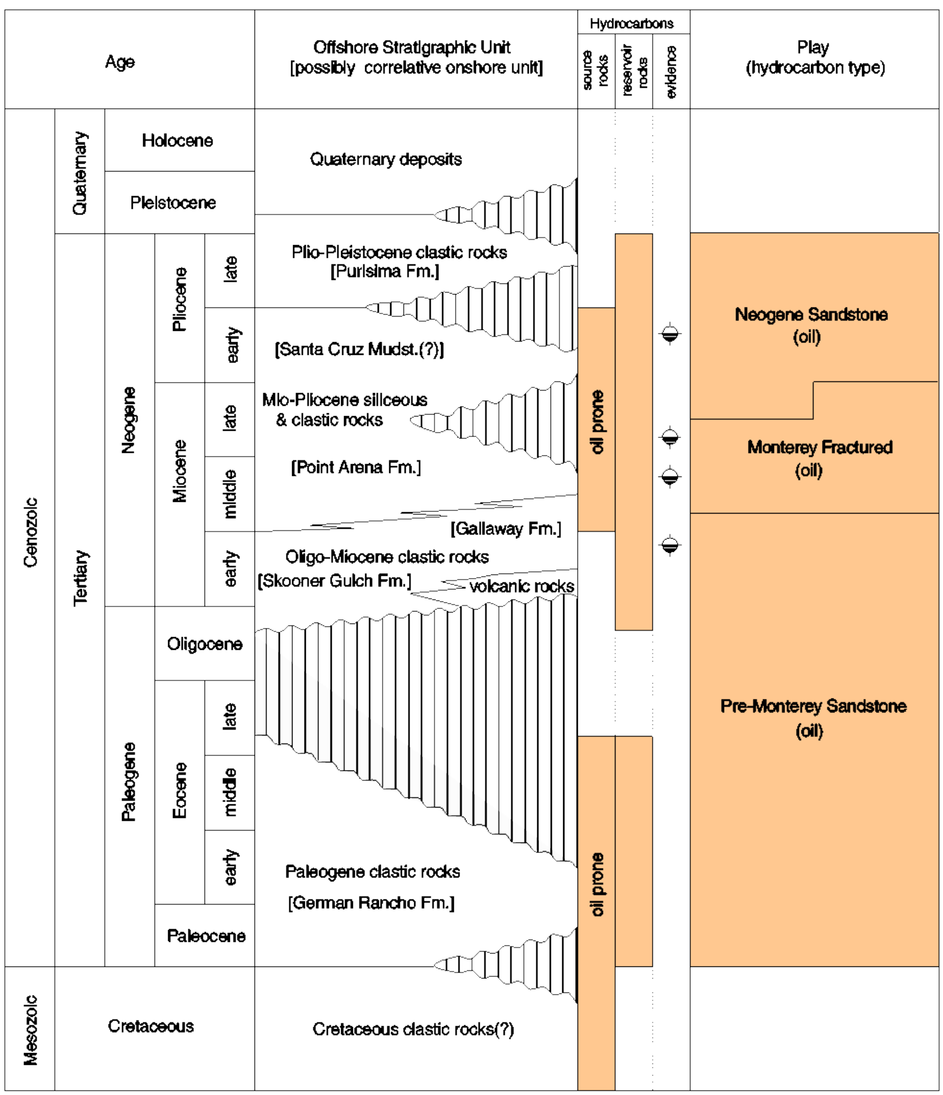


Figure 3-15. *Map of the Point Arena Basin assessment area showing petroleum geologic plays and wells*

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 (Kulm, von Huene, and others, 1973; McCulloch, 1989). Well cuttings from an offshore exploration well at the south end of the basin (OCS-P 0033 #1ET) 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).



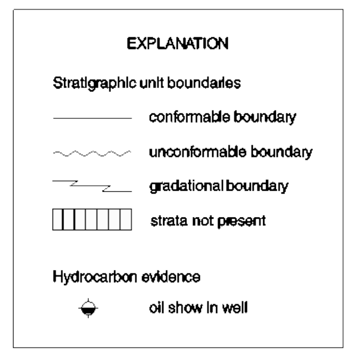


Figure 3-16. *Stratigraphic column of the Point Arena Basin assessment area, showing stratigraphic units, hydrocarbon attributes, and petroleum geologic plays defined for this assessment.*

The lowest known sedimentary unit in the assessment area is a probable equivalent to the onshore Paleocene to Eocene German Rancho Formation (fig. 3-16). 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 Point Arena Formation is 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; 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. 3-15). 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. 3-15 and 3-16). The major play (Fractured Monterey) 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, non-siliceous 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 Point Arena Formation is considered to be the petroleum source for the Neogene Sandstone play and a secondary source for the Pre-Monterey Sandstone play.

Neogene Sandstone Play

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. The play exists in the central and southern part of the basin from Point Delgada to south of Point Arena. The play is defined on the basis of reservoir rock stratigraphy.

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 in discrete sandstone units within the dominantly siltstone and mudstone section at burial depths to about 5,000 feet. 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.

Two of the offshore exploratory wells (OCS-P 0032 #1, 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.

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.

Fractured Monterey Play

The Fractured Monterey 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 play is defined on the basis of reservoir rock stratigraphy.

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. Strata immediately overlying the Point Arena Formation, possibly correlative with the Santa Cruz Mudstone, 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.

Reservoirs are expected to be fractured zones within siliceous shales of the 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 in fractured shale in anticlinal, fault, and stratigraphic traps at burial depths from about 1,000 to 10,000 feet. 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.

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

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.

Pre-Monterey Sandstone Play

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 play is defined on the basis of reservoir rock stratigraphy.

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, 1987). The German Rancho Formation has potential for nonassociated gas as well as oil generation (Crouch, Bachman, and Associates, 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 paleotemperature.

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 in discrete sandstone units within the mostly siltstone and mudstone section at burial depths from about 1,000 to 15,000 feet. 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.

All three of the offshore exploratory wells (OCS-P 0030 #1, OCS-P 0032 #1, 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, 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).

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.

ECONOMIC FACTORS

There is little oil and gas infrastructure on the coastline north of the San Francisco Bay, and no large coastal cities. Pipelines could be shared among multiple platforms or subsea completions and tied to shore at either Eureka to the north or San Francisco Bay.

RESOURCE ESTIMATES

Undiscovered Technically Recoverable Resources

Play-specific estimates of undiscovered technically 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 estimates are shown in appendix C. As a result of this assessment, the total volume of undiscovered technically recoverable resources in the Point Arena Basin assessment area is expected to be 2.01 Bbbl of oil and 2.10 Tcf of associated gas (mean estimates). The majority of these resources (approximately 87 percent on a combined oil-equivalence basis) are estimated to exist in the Fractured Monterey play. The low, mean, and high estimates of resources in the area are listed in table 3-14.

Table 3-14. *Estimates of Undiscovered Technically Recoverable Oil and Gas Resources of the Point Arena Basin geologic plays and the Basin total. Resource values are in billion barrels of oil (Bbbl) and trillion cubic feet of gas (Tcf). 95% indicates a 95 percent chance of at least the amount listed; 5% indicates a 5 percent chance of at least the amount listed. Only mean values are additive. Some total mean values may not equal the sum of the component values due to independent rounding of the tabulated values.*

Geologic Play	Oil (Bbbl)			Gas (Tcf)			BOE (Bbbl)		
	95%	Mean	5%	95%	Mean	5%	95%	Mean	5%
Neogene Sandstone	0.00	0.08	0.22	0.00	0.09	0.40	0.00	0.10	0.29
Fractured Monterey	1.03	1.77	2.82	0.84	1.78	3.38	1.18	2.08	3.42
Pre-Monterey Sandstone	0.00	0.16	0.32	0.00	0.22	0.66	0.00	0.20	0.43
Point Arena Basin	**1.00**	**2.01**	**3.46**	**0.99**	**2.10**	**3.85**	**1.18**	**2.38**	**4.14**

Undiscovered Economically Recoverable Resources

Estimates of the portion of the technically recoverable resources that can be economically recovered under various economic scenarios were developed by including the effects of current and expected future economic factors. Select data used to develop the resource estimates are shown in appendix D. These estimates are shown in fig. 3-17 as price-supply curves for a range of price scenarios, and for a gas market value of 40 percent of the energy equivalent value of oil. As a result of this assessment, 1.33 Bbbl of oil and 1.38 Tcf of associated gas are estimated to be economically recoverable from the Point Arena Basin assessment area under economic conditions existing as of this assessment (i.e., the $90-per-barrel economic scenario). Larger volumes of resources are expected to be economically recoverable under increasingly favorable economic conditions. Because field development often includes multiple plays, and may not be viable for an individual play, play-specific estimates have not been tabulated.

Additional References for Point Arena Basin

Bachman and Crouch, 1985
Bachman and Crouch, 1987
Bachman and others, 1984
Crouch, Bachman, and Associates, 1987
Crouch, Bachman, and Associates, 1988c
Hoskins and Griffiths, 1971
Webster and others, 1986
Webster and Yenne, 1987
Zieglar and Cassell, 1978

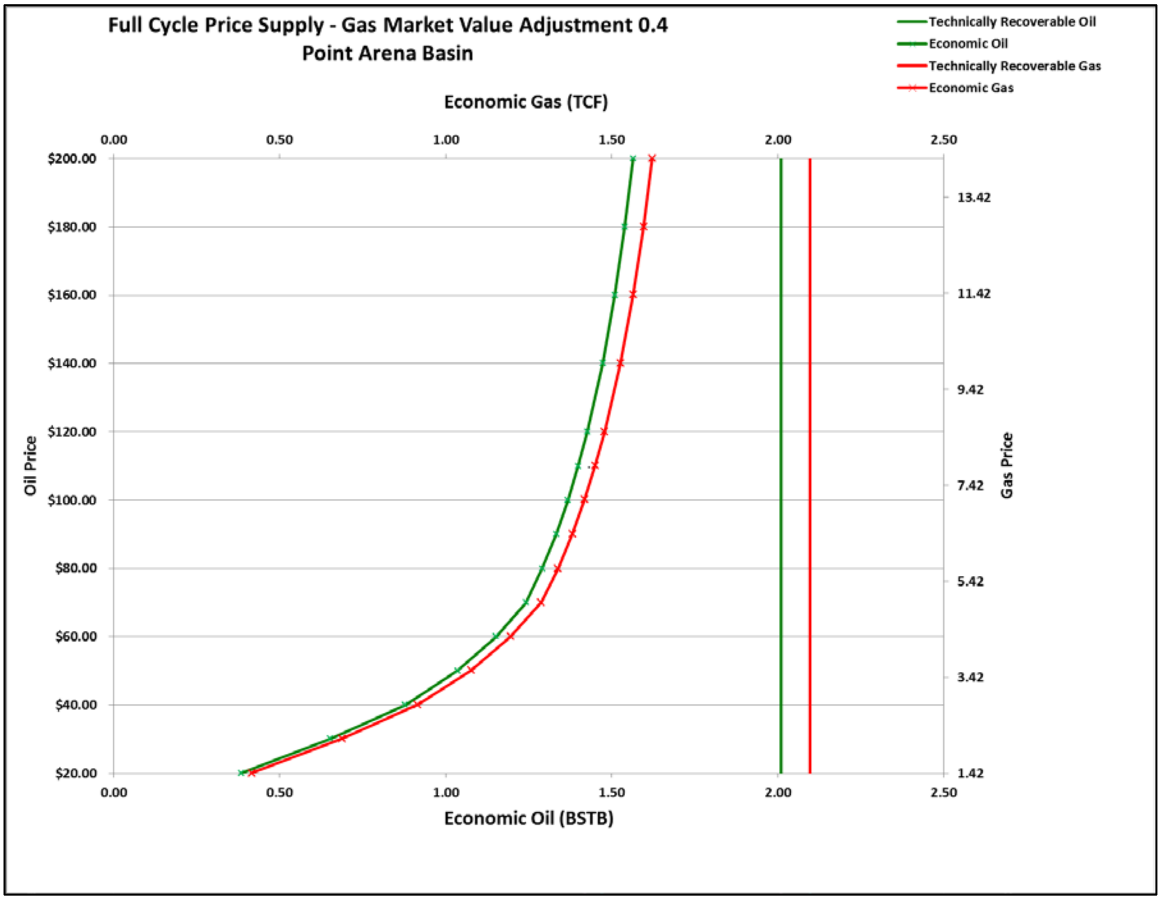


Figure 3-17. *Price-supply curves for the Point Arena basin. Oil prices are coupled with a specific gas price assuming a 40 percent economic value for gas relative to oil.*

Bodega Basin

Location

The Bodega basin is located between the Point Arena and Año Nuevo basins (fig. 3-13). It extends from just south of Point Arena to Half Moon Bay on the west side of the San Francisco Peninsula, and encompasses about 1,700 square miles (fig. 3-18). The western margin of the basin is defined by the Farallon-Pigeon Point high, and the eastern by the San Gregorio and San Andreas fault zones. A small portion of the basin lies in State waters and is

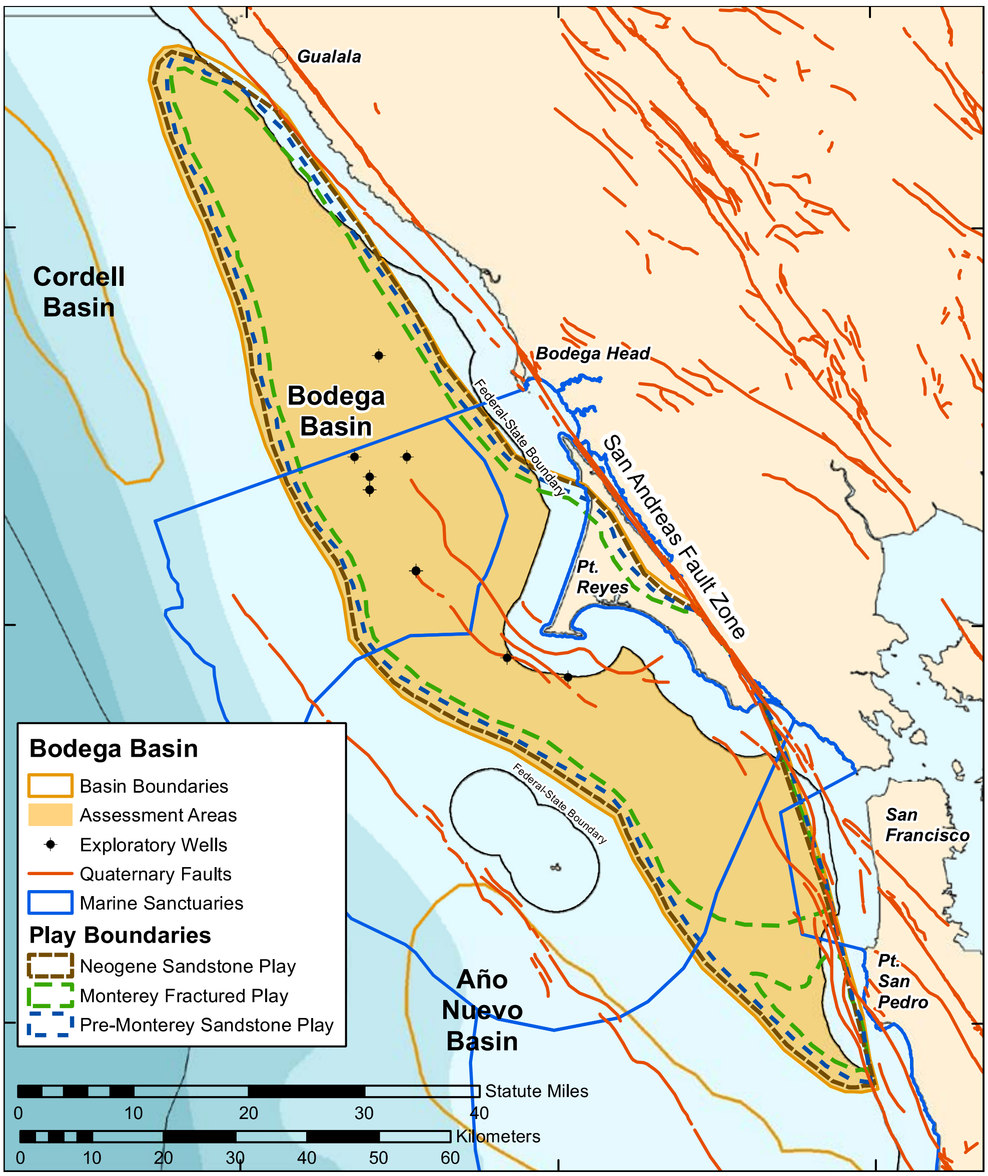


Figure 3-18. *Map of the Bodega Basin assessment area showing petroleum geologic plays and wells.*

exposed onshore at the Point Reyes Peninsula. The shelf is wider here than in Point Arena basin; water depth within the Federal offshore portion of the basin ranges from about 30 feet on the Federal-State boundary to 1,000 feet near the shelf-slope break. The relatively shallow depths could lead to lower costs of operation and therefore result in a higher percentage of resources being economic.

GEOLOGIC SETTING

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. 3-19). These rocks of the Salinia terrane are overlain offshore by Paleocene and Eocene conglomeratic rocks similar to, and possibly correlative 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 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

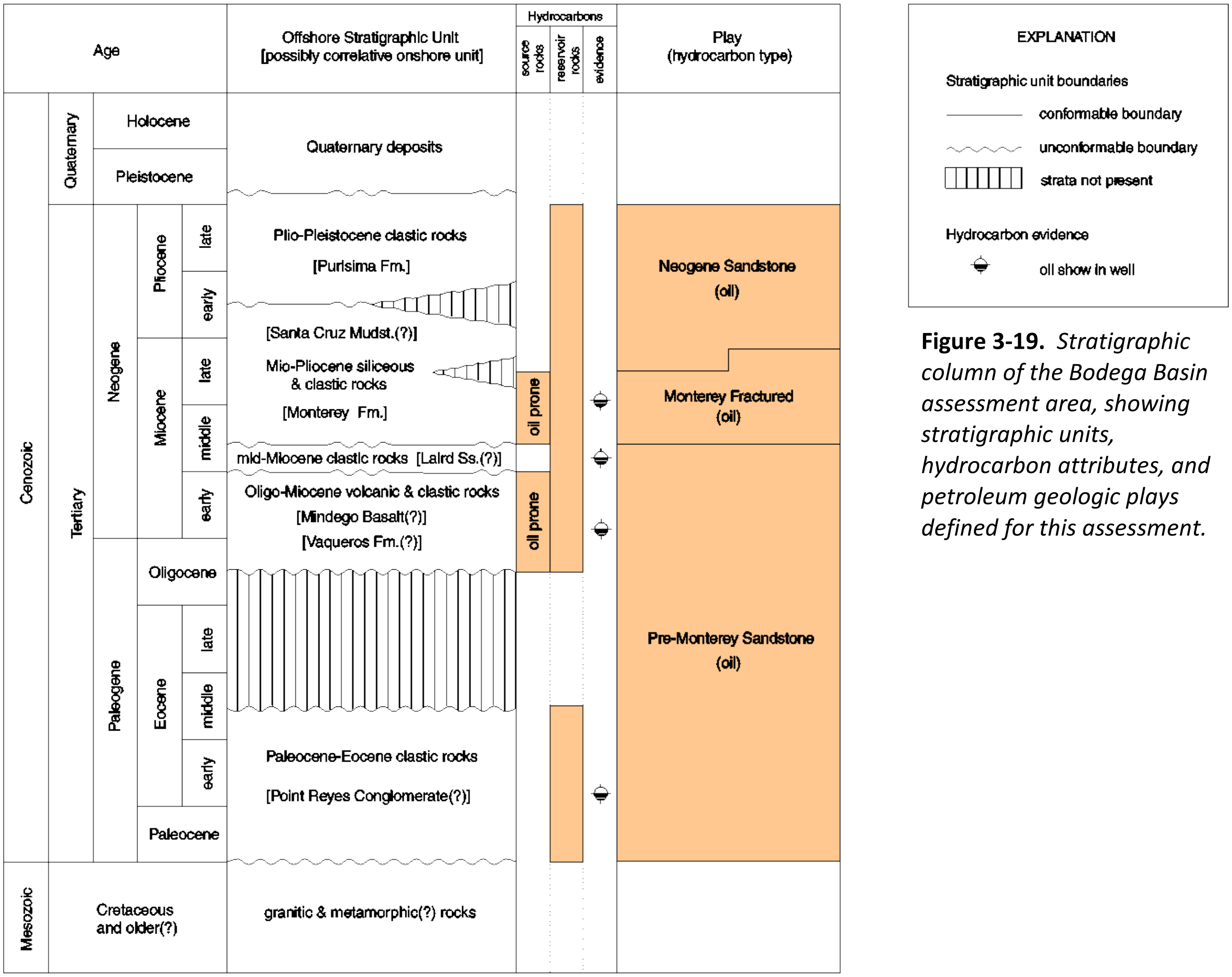


Figure 3-19. *Stratigraphic column of the Bodega Basin assessment area, showing stratigraphic units, hydrocarbon attributes, and petroleum geologic plays defined for this assessment.*

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 or all 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.

Exploration

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. 3-18) 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 (approximately 80 ^{o}C) is coincident with the onset of oil generation in Monterey rocks, as suggested by some workers, 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 to migrating hydrocarbons.

PLAYS

Three petroleum geologic plays, defined on the basis of reservoir rock stratigraphy, have been assessed in the Federal offshore portion of the basin. These are (1) the Neogene Sandstone play (upper Miocene and Pliocene clastic reservoirs), (2) the Fractured Monterey 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).

Neogene Sandstone Play

The Neogene Sandstone play of the Bodega Basin assessment area is a frontier play, 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 (fig. 3-18) exists at burial depths of up to approximately 4,300 feet.

Potential petroleum source rocks for the play are oil-prone Monterey rocks (fig. 3-19), 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. 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 to the Santa Cruz Mudstone, and lower to upper Pliocene sandstones and siltstones, possibly correlative to the Purisima Formation (fig. 3-19). 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 intraformational 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.

Eight exploratory wells have penetrated the Federal offshore portion of this 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.

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 Turbidite 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.

Fractured Monterey Play

The Fractured Monterey play of the Bodega Basin assessment area is a frontier play, 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. 3-18) and exists at burial depths of up to approximately 6,000 feet.

Potential petroleum source rocks for the play are oil-prone Monterey rocks (fig. 3-19), 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. 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 to the Santa Cruz Mudstone.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 exist below the opal-CT-quartz diagenetic boundary, where fracture density and porosity are 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. Some stratigraphic traps formed by intraformational 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.

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

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.

Pre-Monterey Sandstone Play

The Pre-Monterey Sandstone play of the Bodega Basin assessment area is a frontier play, defined to include accumulations of oil and associated gas in Paleogene and Neogene marine clastic rocks underlying the Monterey Formation. This basin-wide play (fig. 3-18) exists at burial depths of approximately 600 to more than 10,000 feet.

The primary potential petroleum source rocks for the play are oil-prone Monterey rocks (fig. 3-19), 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 to the Mindego Volcanics and Vaqueros Formation), and middle Miocene sandstones (possibly correlative to the Laird Sandstone) (fig. 3-19). 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 intraformational 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.

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

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 (Galloway, 1997) 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.

Economic Factors

There is little oil and gas infrastructure on the coastline north of the San Francisco Bay, and no large coastal cities. Should there be any future development, pipelines could be shared among multiple platforms or subsea completions and tied to shore at San Francisco Bay. The entire coastal area and about two-thirds of the basin is within the Cordell Bank, Gulf of the Farallones and Monterey Bay marine sanctuaries (fig. 3-18). The remainder is within proposed extensions of the Cordell Bank and Gulf of the Farallones marine sanctuaries.

Resource Estimates

Undiscovered Technically Recoverable Resources

Play-specific estimates of undiscovered technically recoverable resources 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 technically recoverable resources in the Bodega Basin assessment area is estimated to be 1.40 Bbbl of oil and 1.52 Tcf of associated gas (mean estimates). The majority of these resources (approximately 76 percent on a combined oil-equivalence basis) are estimated to exist in the Fractured Monterey play. The low, mean, and high estimates of resources in the assessment area are listed in table 3-15.

Table 3-15. *Estimates of Undiscovered Technically Recoverable Oil and Gas Resources of the Bodega Basin geologic plays and the Basin total. Resource values are in billion barrels of oil (Bbbl) and trillion cubic feet of gas (Tcf). 95% indicates a 95 percent chance of at least the amount listed; 5% indicates a 5 percent chance of at least the amount listed. Only mean values are additive. Some total mean values may not equal the sum of the component values due to independent rounding of the tabulated values.*

Geologic Play	Oil (Bbbl)			Gas (Tcf)			BOE (Bbbl)		
	95%	Mean	5%	95%	Mean	5%	95%	Mean	5%
Neogene Sandstone	0.00	0.05	0.17	0.00	0.06	0.18	0.00	0.06	0.20
Fractured Monterey	0.49	1.09	1.87	0.54	1.10	2.17	0.58	1.28	2.26
Pre-Monterey Sandstone	0.00	0.27	0.59	0.00	0.36	0.86	0.00	0.33	0.74
Bodega Basin	**0.50**	**1.40**	**2.67**	**0.50**	**1.52**	**3.06**	**0.59**	**1.68**	**3.21**

Undiscovered Economically Recoverable Resources

Estimates of the portion of the technically recoverable resources that can be economically recovered under various economic scenarios were developed by including the effects of current and expected future economic factors. Select data used to develop the resource estimates are shown in appendix D. These estimates are shown in fig. 3-20 as price-supply curves for a range of price scenarios, and for a gas market value of 40 percent of the energy equivalent value of oil. As a result of this assessment, 1.26 Bbbl of oil and 1.37 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 $90-per-barrel economic scenario). Larger volumes of resources are expected to be economically recoverable under increasingly favorable economic conditions. Because field development often includes multiple plays, and may not be viable for an individual play, play-specific estimates have not been tabulated.

Additional References for Bodega Basin

Bachman and Crouch, 1985
Crouch, Bachman, and Associates, 1988b
Crouch, Bachman, and Associates, 1988c
Heck and others, 1990
Isaacs, 1984
Isaacs and Petersen, 1987
Isaacs and others, 1983
McCulloch, 1989
Ogle, 1981
Webster and others, 1988

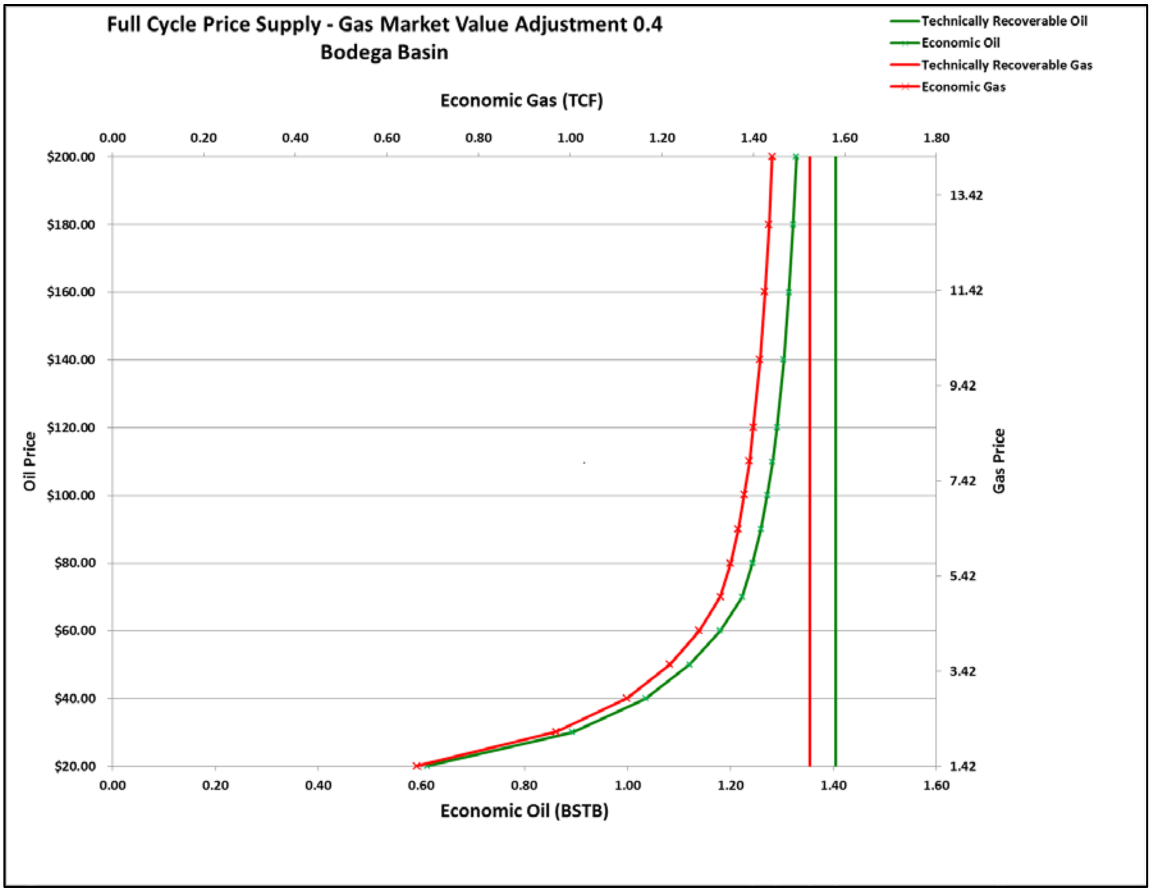


Figure 3-20. *Price-supply curves for the Bodega basin. Oil prices are coupled with a specific gas price assuming a 40 percent economic value for gas relative to oil.*

AÑO NUEVO BASIN

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. 3-13). 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. 3-21). 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.

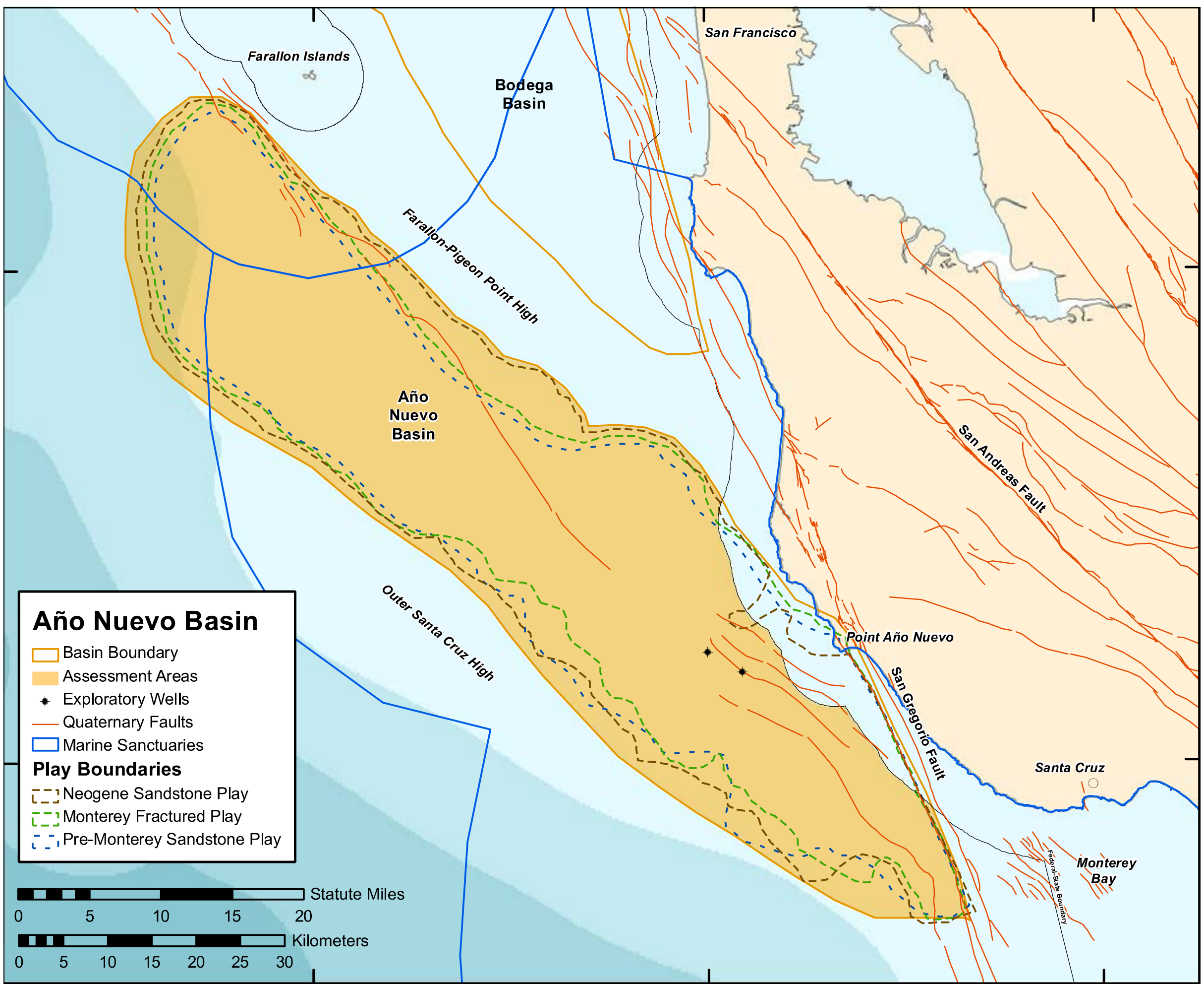
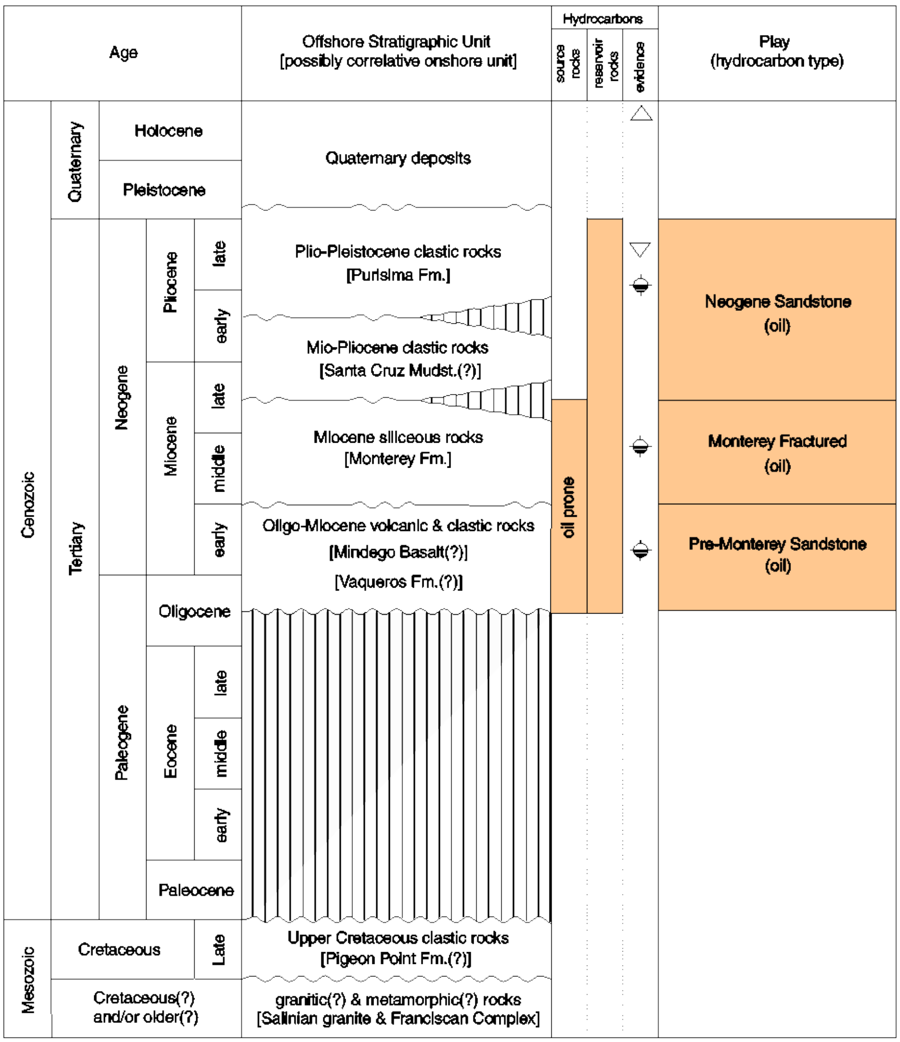


Figure 3-21. *Map of the Año Nuevo Basin assessment area showing petroleum geologic plays and wells.*

The Año Nuevo Basin assessment area comprises the Federal offshore portion of the basin. 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.



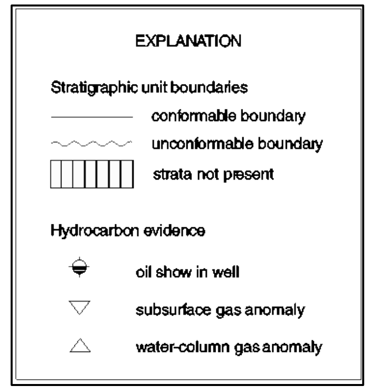


Figure 3-22. *Stratigraphic column of the Año Nuevo Basin assessment area, showing stratigraphic units, hydrocarbon attributes, and petroleum geologic plays defined for this assessment.*

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 submarine fan deposits similar to, and possibly correlative to those exposed onshore at Point Año Nuevo (fig. 3-22). 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 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 semi-consolidated 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.

EXPLORATION

Knowledge of the petroleum geology of the basin has been garnered from two offshore exploratory wells, a moderately dense grid of high-quality, seismic-reflection profiles, data from onshore wells and outcrops, and published sources. The primary petroleum source rocks for all plays in the basin are presumed to be rocks of the Miocene Monterey Formation (fig. 3-22), 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, 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 ("bright spots," interpreted to be gas) indicate that oil and gas have generated and migrated within the Año Nuevo basin (fig. 3-22). 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 plumes) 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. 3-21, 3-22). These are (1) the Neogene Sandstone play (upper Miocene and Pliocene clastic reservoirs), (2) the Fractured Monterey 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).

Neogene Sandstone Play

The Neogene Sandstone play of the Año Nuevo Basin assessment area is a frontier play, 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. 3-21) and exists at burial depths of approximately 1,000 to 3,000 feet.

Potential petroleum source rocks for the play are oil-prone Monterey rocks (fig. 3-22), 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. 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.

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. 3-22). 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 intraformational 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.

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

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 Turbidite 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.

Fractured Monterey Play

The Fractured Monterey play of the Año Nuevo Basin assessment area is a frontier play, 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. 3-21) and exists at burial depths of approximately 3,000 to 6,000 feet.

Potential petroleum source rocks for the play are oil-prone Monterey rocks (fig. 3-22), 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. 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. 3-22). 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 exist below the opal-CT-to-quartz diagenetic boundary, where fracture density and porosity are 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 intraformational 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.

Two exploratory wells have penetrated the Federal offshore portion of this 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.

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 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.

Pre-Monterey Sandstone Play

The Pre-Monterey Sandstone play of the Año Nuevo Basin assessment area is a frontier play, 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. 3-21) and exists at burial depths of approximately 5,000 to 8,000 feet.

The primary potential petroleum source rocks for the play are oil-prone Monterey rocks (fig. 3-22), 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 Volcanics and Vaqueros Formation) (fig. 3-22). 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 intraformational 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.

Two exploratory wells have penetrated the Federal offshore portion of this play. Weak oil shows and log analysis indicate the presence of hydrocarbons in one well.

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 (Galloway, 1997) 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 is estimated to be poor; 30 percent of the prospects are predicted to be pools.

Economic Factors

Should there be any future development, pipelines could be shared among multiple platforms or subsea completions and tied to shore near Santa Cruz.

Resource Estimates

Undiscovered Technically Recoverable Resources

Play-specific estimates of undiscovered technically recoverable resources have been statistically aggregated to estimate the total volume of resources in the basin. Select data used to develop the estimates are shown in appendix C. As a result of this assessment, the total volume of undiscovered technically recoverable resources in the Año Nuevo Basin assessment area is estimated to be 0.71 Bbbl of oil and 0.75 Tcf of associated gas (mean estimates). The majority of these resources (approximately 81 percent on a combined oil-equivalence basis) are estimated to exist in the Fractured Monterey play. The low, mean, and high estimates of resources in the assessment area are listed in table 3-16.

Table 3-16. *Estimates of Undiscovered Technically Recoverable Oil and Gas Resources of the Año Nuevo Basin geologic plays and the Basin total. Resource values are in billion barrels of oil (Bbbl) and trillion cubic feet of gas (Tcf). 95% indicates a 95 percent chance of at least the amount listed; 5% indicates a 5 percent chance of at least the amount listed. Only mean values are additive. Some total mean values may not equal the sum of the component values due to independent rounding of the tabulated values.*

Geologic Play	Oil (Bbbl)			Gas (Tcf)			BOE (Bbbl)		
	95%	Mean	5%	95%	Mean	5%	95%	Mean	5%
Neogene Sandstone	0.00	0.08	0.18	0.00	0.09	0.21	0.00	0.09	0.22
Fractured Monterey	0.23	0.58	1.10	0.19	0.59	1.23	0.26	0.68	1.32
Pre-Monterey Sandstone	0.00	0.05	0.15	0.00	0.07	0.25	0.00	0.07	0.19
Año Nuevo Basin	**0.22**	**0.71**	**1.46**	**0.22**	**0.75**	**1.54**	**0.26**	**0.84**	**1.73**

Undiscovered Economically Recoverable Resources

Estimates of the portion of the technically recoverable resources that can be economically recovered under various economic scenarios were developed by including the effects of current and expected future economic factors. Select data used to develop the resource estimates are shown in appendix D. These estimates are shown in fig. 3-23 as price-supply curves for a range of price scenarios, and for a gas market value of 40 percent of the energy equivalent value of oil. As a result of this assessment, 0.63 Bbbl of oil and 0.67 Tcf 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 $90-per-barrel economic scenario). Larger volumes of resources are expected to be economically recoverable under increasingly favorable economic conditions. Because field development often includes multiple plays, and may not be viable for an individual play, play-specific estimates have not been tabulated.

ADDITIONAL REFERENCES FOR AÑO NUEVO BASIN

Bachman and Crouch, 1985
Crouch and Associates, 1987
Crouch, Bachman, and Associates, 1988b
Crouch, Bachman, and Associates, 1988c
Galloway, 1997
Heck and others, 1990
Ogle, 1981
Webster and others, 1988

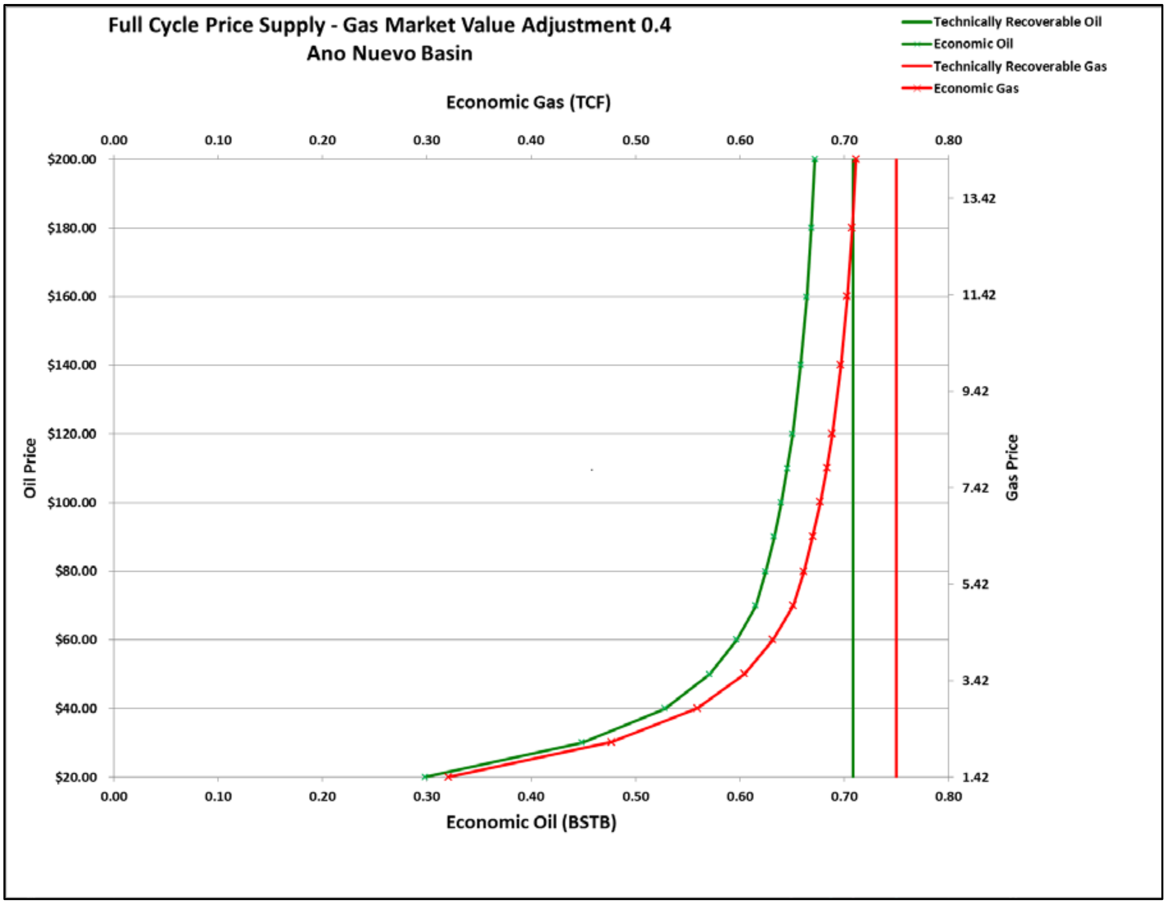


Figure 3-23. *Price-supply curves for the Año Nuevo basin. Oil prices are coupled with a specific gas price assuming a 40 percent economic value for gas relative to oil.*

Santa Maria – Partington Basin

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. 3-13). Both are northwest-trending basins with fault-bound eastern limits and structural highs on the north and south.

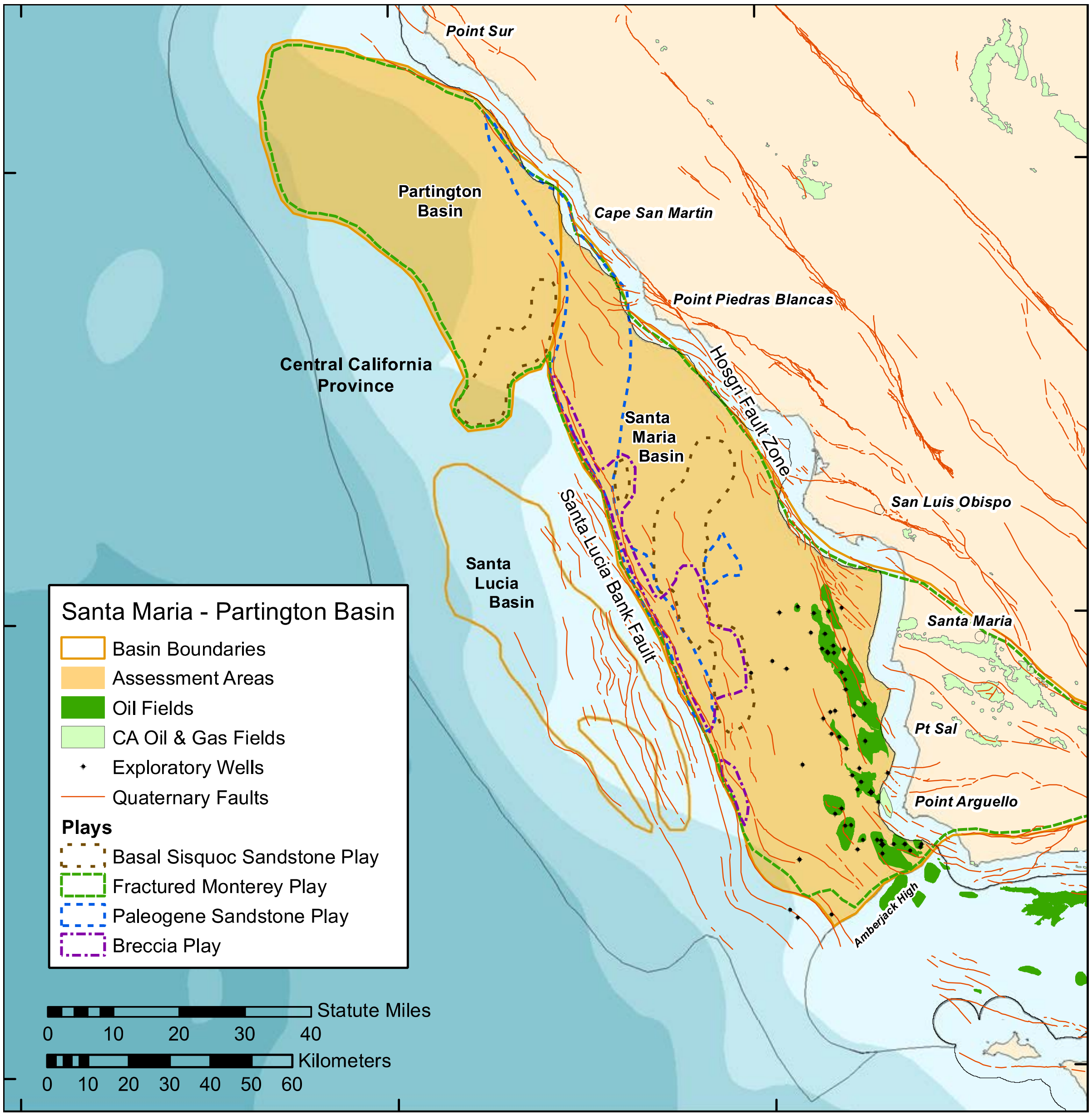


Figure 3-24. *Map of the Santa Maria–Partington Basin assessment area showing petroleum geologic plays and wells.*

The Santa Maria basin proper is informally subdivided along the Hosgri fault zone into onshore and offshore subareas (fig. 3-24). 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 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 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.

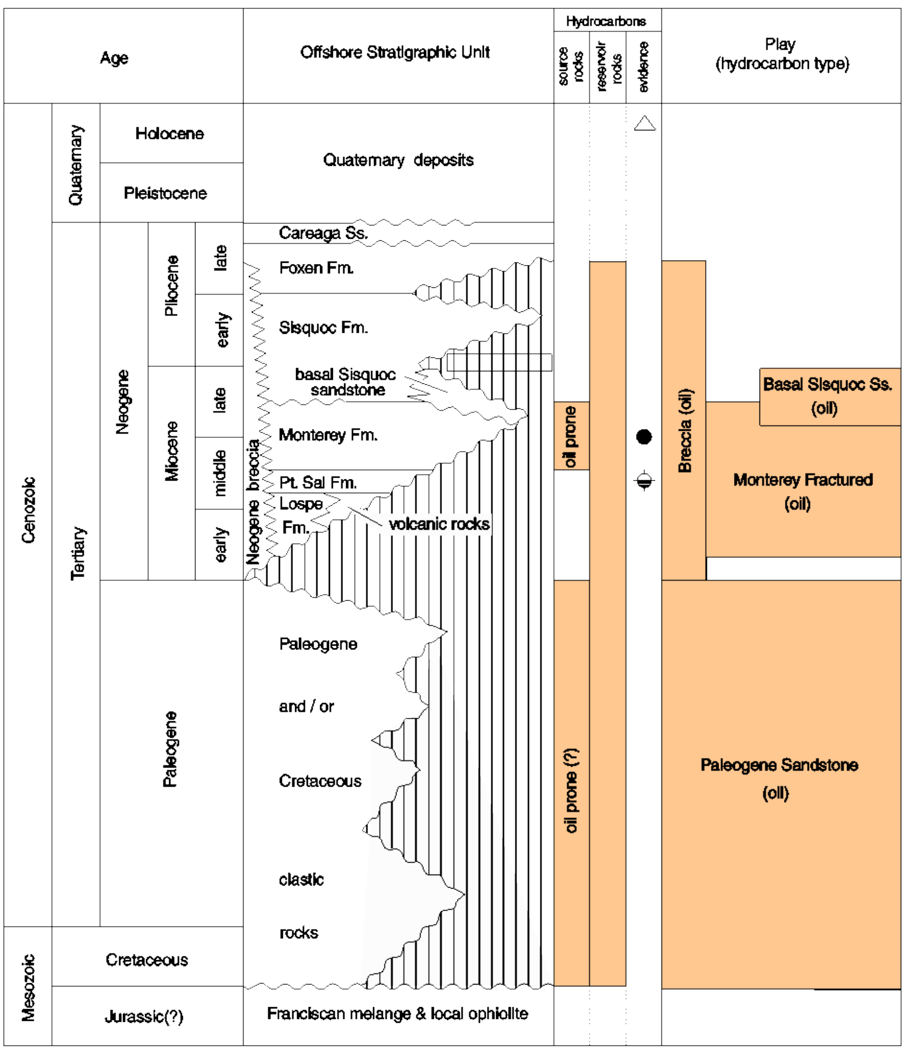
The Partington basin appears to have undergone a somewhat different tectonic history. In contrast to the complex folding in the offshore Santa Maria basin, Partington basin strata have been only minimally deformed. Basement topography dips uniformly east-northeast and terminates against or is thrust 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 the entire 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. 3-25). 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



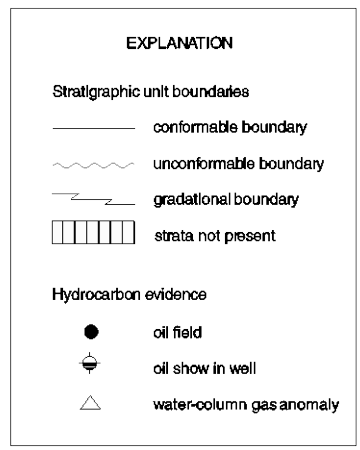


Figure 3-25. *Stratigraphic column of the Santa Maria–Partington Basin assessment area, showing stratigraphic units, hydrocarbon attributes, and petroleum geologic plays defined for this assessment.*

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 13 additional fields have been discovered. Three fields in the offshore Santa Maria basin (Point Arguello, Point Pedernales, and Rocky Point 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. 3-25). 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 Fractured Monterey play, which is established onshore and offshore. 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. 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).

Basal Sisquoc Sandstone Play

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, and is considered a frontier play. 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. 3-24).

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 larger of the two is located atop a large uplift that extends 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.

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.

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.

Fractured Monterey Play

The Fractured Monterey 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. 3-24).

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 °API (the median value is 14 °API). The Monterey Formation is also the source for petroleum in the Point Sal 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. 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 crosscutting 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 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.

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, 13 additional fields have been discovered, ranging in size from 0.01 to 0.75 Bbbl of combined oil-equivalent resources. The Monterey Formation is the primary reservoir in all of the fields. 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.

To model the number and size of potential pools, a seismic data set of multiple surveys with a grid density of approximately 1-mile spacing was interpreted. Petroleum and rock properties were based on the producing Point Arguello and Point Pedernales fields. Select petroleum geologic data is presented in appendix C.

Paleogene Sandstone Play

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. 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. 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. 3-24).

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 Oligocene 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 information 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.

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.

To model the number and size of potential pools, a seismic data set of multiple surveys with a grid density of approximately 1-mile spacing was interpreted. Petroleum and rock properties were based on expected correlative fields in the onshore Santa Maria basin and offshore Santa Barbara basin. Select petroleum geologic data is presented in appendix C.

Breccia Play

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. 3-24). 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).

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. Seismic data indicate that fault traps are the predominant trap type in this play; stratigraphic traps may exist against basement highs east of the Santa Lucia Bank fault. 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 uncertain because the fault may have been active since its inception in the early to middle Miocene.

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

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. The solution gas-to-oil ratio was estimated to be identical to the ratio for the Fractured Monterey 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. 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.

Economic Factors

The existing development is in the southern part of the basin. Should there be future development while that infrastructure is still in place, there may be opportunities for sharing some of the pipelines or onshore facilities. If development is later or further north, pipelines could still be shared among multiple platforms or subsea completions and tied to existing infrastructure onshore near Santa Maria.

Resource Estimates

Undiscovered Technically Recoverable Resources

Play-specific estimates of undiscovered technically recoverable resources have been developed and 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 technically recoverable resources in the Santa Maria–Partington Basin assessment area is estimated to be 1.11 Bbbl of oil and 0.84 Tcf of associated gas (mean estimates). The majority of these resources (approximately 88 percent on a combined oil-equivalence basis) are estimated to exist in the Fractured Monterey play. The low, mean, and high estimates of resources in the assessment area are listed in table 3-17.

Table 3-17. *Estimates of Undiscovered Technically Recoverable Oil and Gas Resources of the Santa Maria–Partington Basin geologic plays and the Basin total. Resource values are in billion barrels of oil (Bbbl) and trillion cubic feet of gas (Tcf). 95% indicates a 95 percent chance of at least the amount listed; 5% indicates a 5 percent chance of at least the amount listed. Only mean values are additive. Some total mean values may not equal the sum of the component values due to independent rounding of the tabulated values.*

Geologic Play	Oil (Bbbl)			Gas (Tcf)			BOE (Bbbl)		
	95%	Mean	5%	95%	Mean	5%	95%	Mean	5%
Basal Sisquoc Sandstone	0.03	0.08	0.15	0.03	0.08	0.12	0.04	0.09	0.17
Fractured Monterey	0.37	1.02	2.11	0.30	0.74	1.45	0.43	1.15	2.37
Paleogene Sandstone	0.00	0.01	0.04	0.00	0.02	0.12	0.00	0.01	0.06
Breccia	0.00	0.01	0.06	0.00	0.01	0.05	0.00	0.01	0.07
S. Maria–Partington Basin	**0.41**	**1.11**	**2.34**	**0.31**	**0.84**	**1.83**	**0.47**	**1.26**	**2.66**

Undiscovered Economically Recoverable Resources

Estimates of the portion of the technically recoverable resources that can be economically recovered under various economic scenarios were developed by including the effects of current and expected future economic factors. Select data used to develop the resource estimates are shown in appendix D. These estimates are shown in fig. 3-26 as price-supply curves for a range of price scenarios, and for a gas market value of 40 percent of the energy equivalent value of oil. As a result of this assessment, 0.81 Bbbl of oil and 0.61 Tcf 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 $90-per-barrel economic scenario). Larger volumes of resources are expected to be economically recoverable under increasingly favorable economic conditions. Because field development often includes multiple plays, and may not be viable for an individual play, play-specific estimates have not been tabulated.

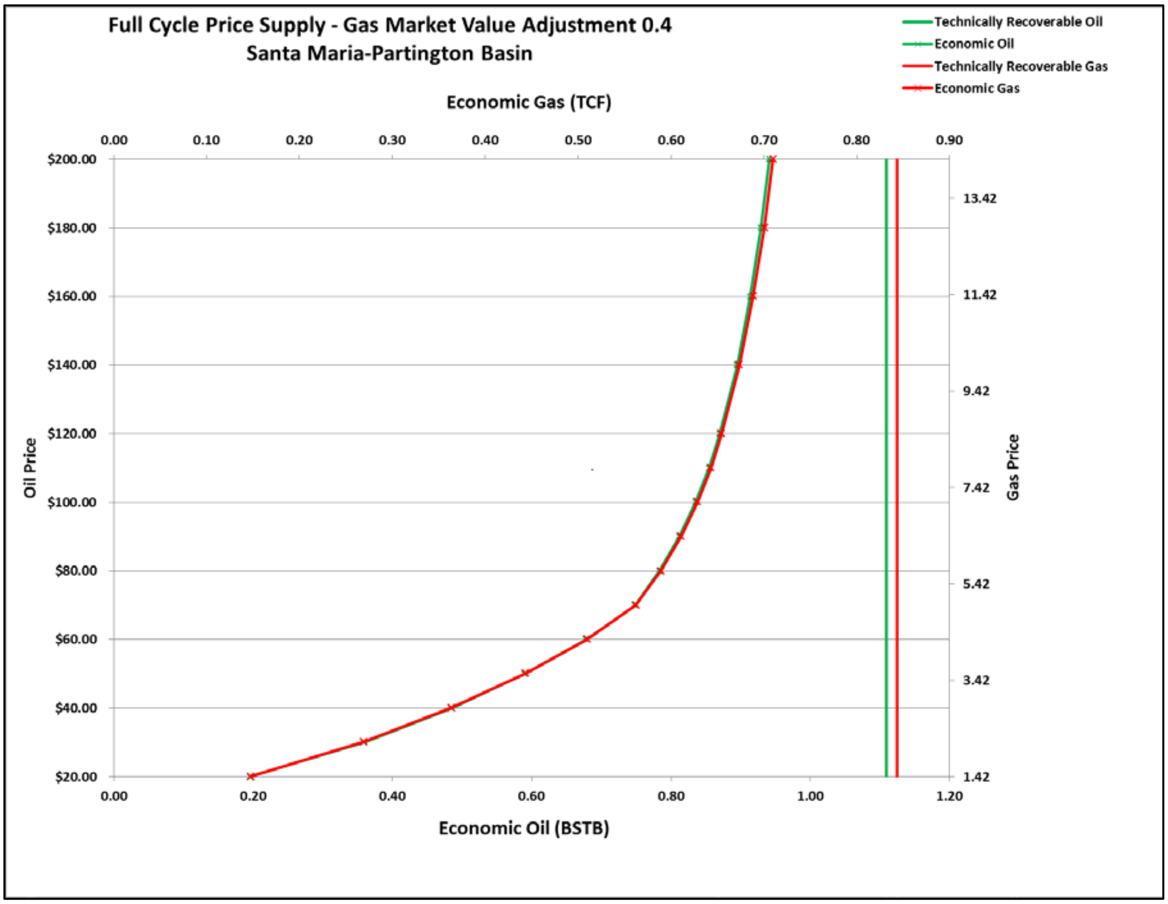


Figure 3-26. *Price-supply curves for the Santa Maria–Partington basin. Oil prices are coupled with a specific gas price assuming a 40 percent economic value for gas relative to oil.*

Total Resource Endowment

As of this assessment, originally recoverable reserves (cumulative production plus remaining reserves) for the Santa Maria–Partington basin were 0.33 Bbbl of oil and 0.18 Tcf of gas. In addition, contingent resources are estimated to be 1.06 Bbbl of oil and 0.42 Tcf of gas (BOEMRE, 2010; unpublished BOEM data). Because of litigation brought about by local opposition to development, leases comprising over a billion barrels of discovered resources remained undeveloped and were ultimately bought back by the Federal government. These discovered resources and the undiscovered technically recoverable resources collectively compose the basin's estimated total resource endowment of 2.49 Bbbl of oil and 1.44 Tcf of gas. As shown in table 3-18, contingent resources are about three times the originally recoverable reserves (cumulative production plus remaining reserves), and nearly as much as the estimated undiscovered technically recoverable resources.

Table 3-18. *Estimates of the total endowment of oil and gas resources in the Santa Maria–Partington basin. Estimates of discovered resources, including originally recoverable reserves and contingent resources, are as of January 1, 2009. Originally recoverable reserves include cumulative production and remaining reserves. Estimates of undiscovered technically 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)
Originally Recoverable Reserves	0.33	0.18	0.36
Contingent Resources	1.06	0.42	1.13
Undiscovered Technically Recoverable Resources	1.11	0.84	1.26
Total Resource Endowment	*2.49*	*1.44*	*2.75*

ADDITIONAL REFERENCES FOR SANTA MARIA–PARTINGTON BASIN

Crouch, Bachman, and Associates, 1988d
Hoskins and Griffiths, 1971
Isaacs, 1984
McCulloch, 1989
Webster and others, 1988
Webster and Yenne, 1987

SOUTHERN CALIFORNIA PROVINCES

The southern California Borderlands has undergone a unique and complex geologic history, and the province definitions reflect that history (fig. 3-27). As a result of plate interactions, the western Transverse Range geologic province, which is essentially the Santa Barbara–Ventura Basin (onshore and offshore), was rotated about 120 degrees clockwise. At the same time, the area that opened up to the south experienced extension and lateral translation that created multiple basins and ridges. This extensional area is divided into inner and outer borderlands. The Inner Borderlands Province is defined as those basins that were near-shore and received an abundance of clastic sedimentation. The Outer Borderlands Province includes the more distal basins that were isolated from much of that sedimentation by intervening ridges.

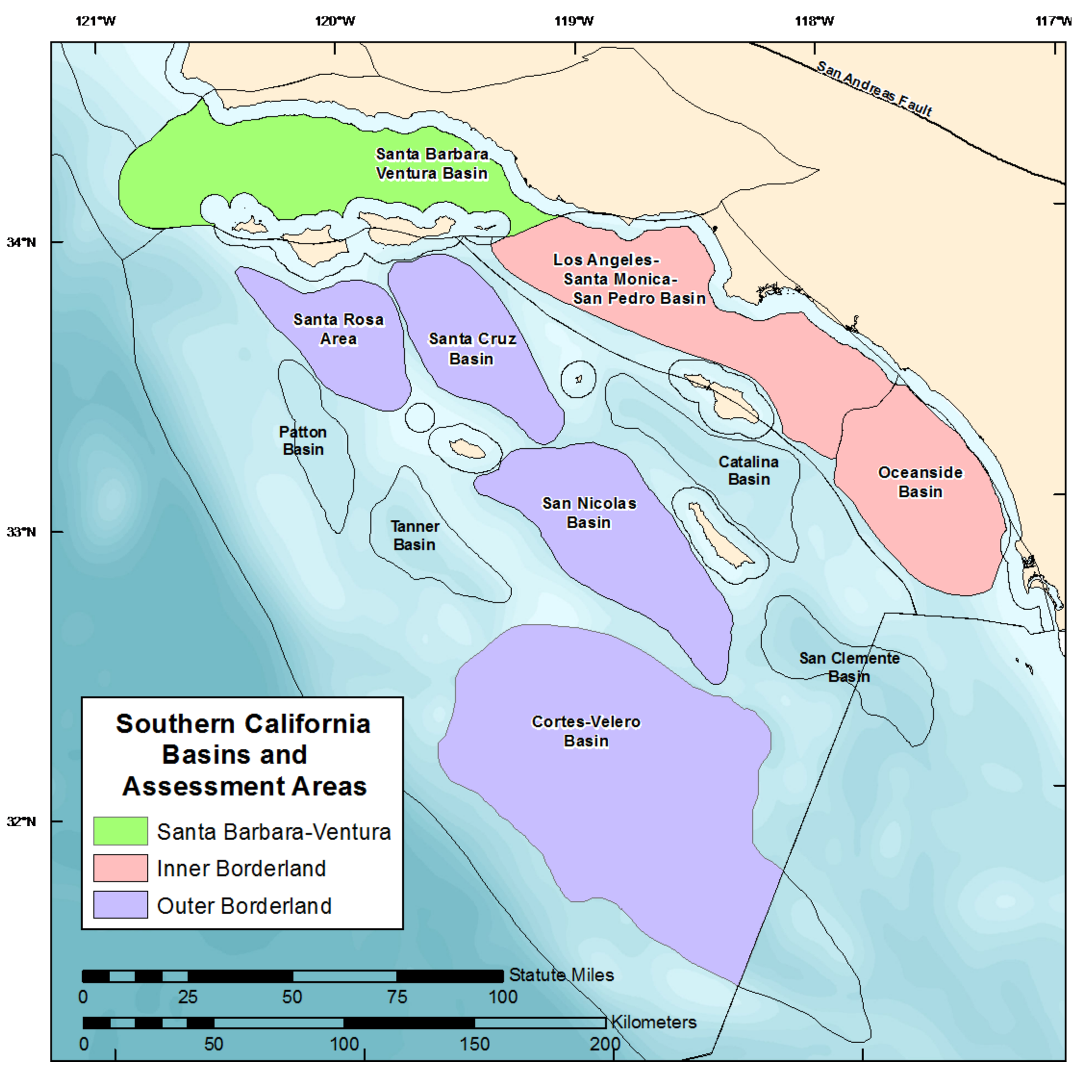


Figure 3-27. *Southern California Provinces and Assessment basins.*

SANTA BARBARA–VENTURA BASIN PROVINCE

LOCATION

The Santa Barbara–Ventura Basin Province comprises the western portion of the Transverse Ranges geomorphic province, which is so named because its east-west orientation is counter to the predominant north-northwest trend of the major structural elements of California. It is bounded on the north by the Santa Ynez fault, on the east by the San Gabriel fault, and on the south by the combined Santa Rosa Island–Santa Cruz Island–Malibu Coast–Santa Monica–Raymond fault zone. It is considered as a separate province because of its unique tectonic and sedimentary history. The Santa Barbara–Ventura basin includes an onshore area that is about equal in size to the offshore portion. Only the Federal offshore portion of the basin (generally called the Santa Barbara Channel) is included in the assessment province (figs. 3-28). The province as defined is about 1,800 square miles in area and water depths range from about 100 to 1,800 feet.

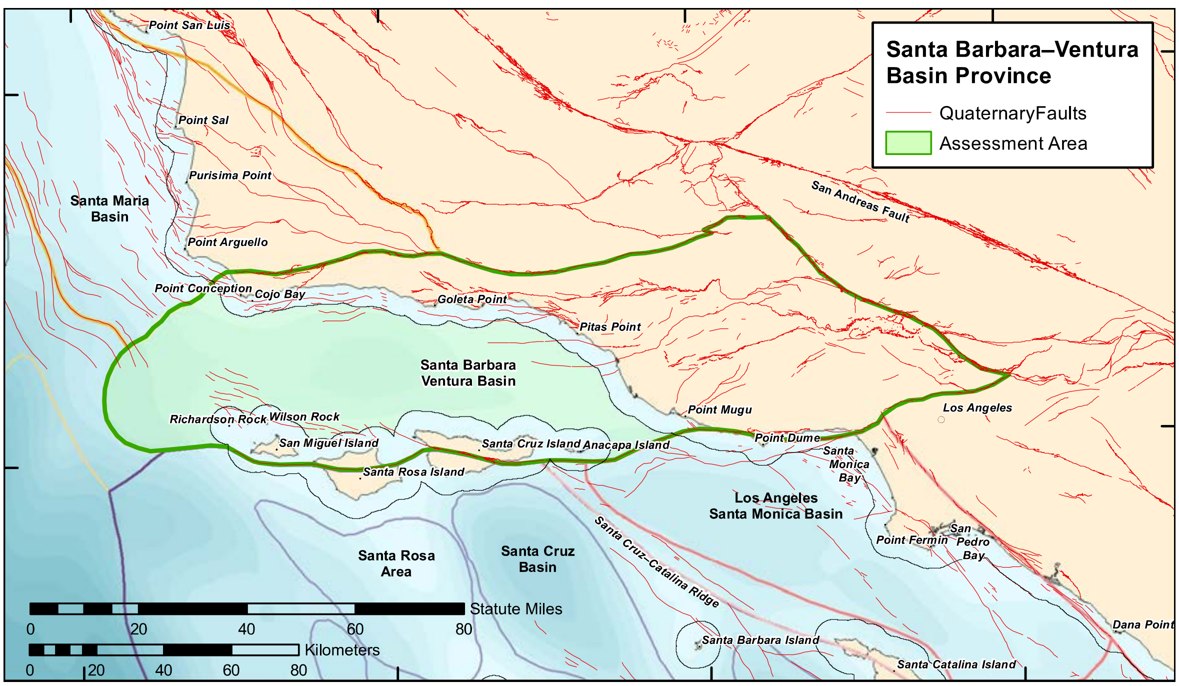


Figure 3-28. *Location of the Santa Barbara–Ventura basin, showing offshore and onshore extent.*

GEOLOGIC SETTING

The oldest rocks in the Santa Barbara–Ventura basin are early Cretaceous, and were deposited in a north-northwest-trending forearc basin. Basin sediments were primarily from highland sources to the east. The composite section is remarkably complete (fig. 3-29), although local unconformities exist in many areas. Paleomagnetic data indicate that since the Eocene, the western Transverse Ranges have undergone as much as 120 degrees of clockwise rotation (Kamerling and Luyendyk, 1979), which is related to the interactions between the North American and Pacific lithospheric plates. Structural analyses (Yeats and others, 1994) and Global Positioning System telemetry suggest that rotation and basin compression continue today. This has created an incipient east-west trending convergent margin between the Pacific and North American plates, and this in turn has contributed to one of the world's highest rates of subsidence and associated sedimentary accumulation, and uplift. In the eastern part of the Santa Barbara Channel, thickness exceeds 40,000 feet of mostly Miocene and younger sedimentary rocks.

The current north-south compressional regime has uplifted and tilted rocks on the north and south sides of the basin. This and associated faulting has created numerous geologic traps for hydrocarbons (fig. 3-30). On the west end of the Santa Barbara Channel the most important oil-producing formation is the organic-rich Monterey. The Monterey is less productive to the east; Eocene through Pliocene sandstones are the major petroleum producers in the eastern half of the offshore basin.

EXPLORATION AND DISCOVERY STATUS

Onshore production of seeps has been ongoing since prehistoric time, and refined oil production since the 1850's. Some of the earliest-discovered fields are still in production today. The first offshore oil wells in North America were drilled here in 1894. Federal leases were first offered in the Santa Barbara Channel in 1966 in order to avoid drainage from the State-leased Carpinteria field. Further exploration and development expanded through the early 1990's. Oil and natural gas reservoirs have been identified in nearly every formation (from Cretaceous through Pleistocene) in the Santa Barbara−Ventura basin (fig. 3-29). Fifteen platforms are currently producing from 9 fields that through 2009 had produced about 878 million barrels of oil and 1.45 trillion cubic feet of gas.

Nearly three-quarters of Pacific Regional production is from the Santa Barbara Channel. Eighty-five percent of that is from a North Channel anticlinal trend that includes the Carpinteria and Dos Cuadras fields (0.33 Bbbl of oil and 0.21 Tcf of gas; mostly Pliocene production) and the Hondo, Pescado and Sacate fields (0.45 Bbbl of oil and 0.85 Tcf of gas; mostly Miocene Monterey production). If onshore fields are included, this trend has already produced over 2 Bbbl of oil, and is likely to ultimately produce over 3 Bbbl of oil.

Stratigraphic and paleontologic data from onshore and offshore wells and a dense grid of 2-D seismic data obtained in the 1970's and 1980's are the bases for interpretation of the offshore geology. No newer data exists than that used for the 1995 assessment.

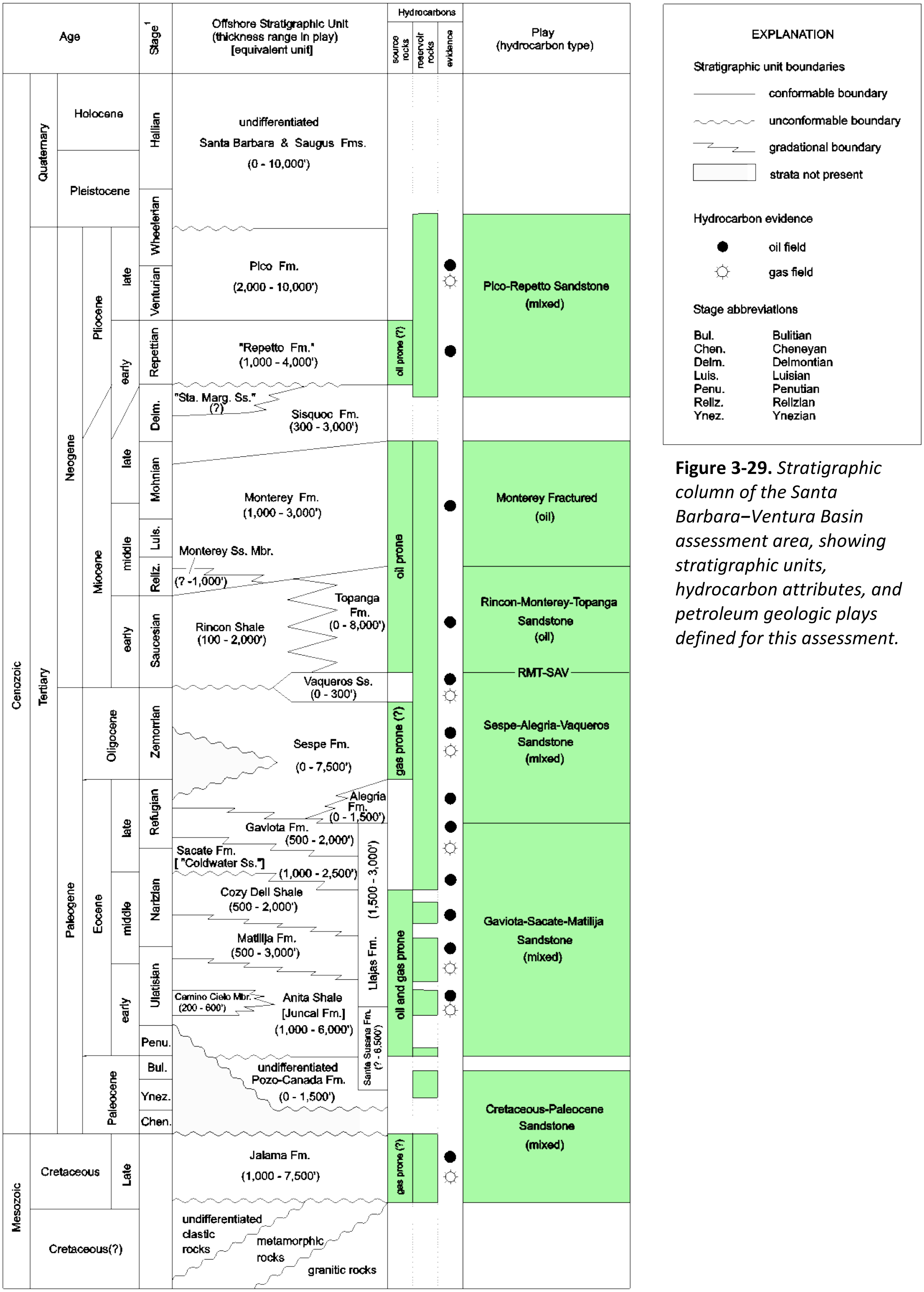


Figure 3-29. *Stratigraphic column of the Santa Barbara–Ventura Basin assessment area, showing stratigraphic units, hydrocarbon attributes, and petroleum geologic plays defined for this assessment.*

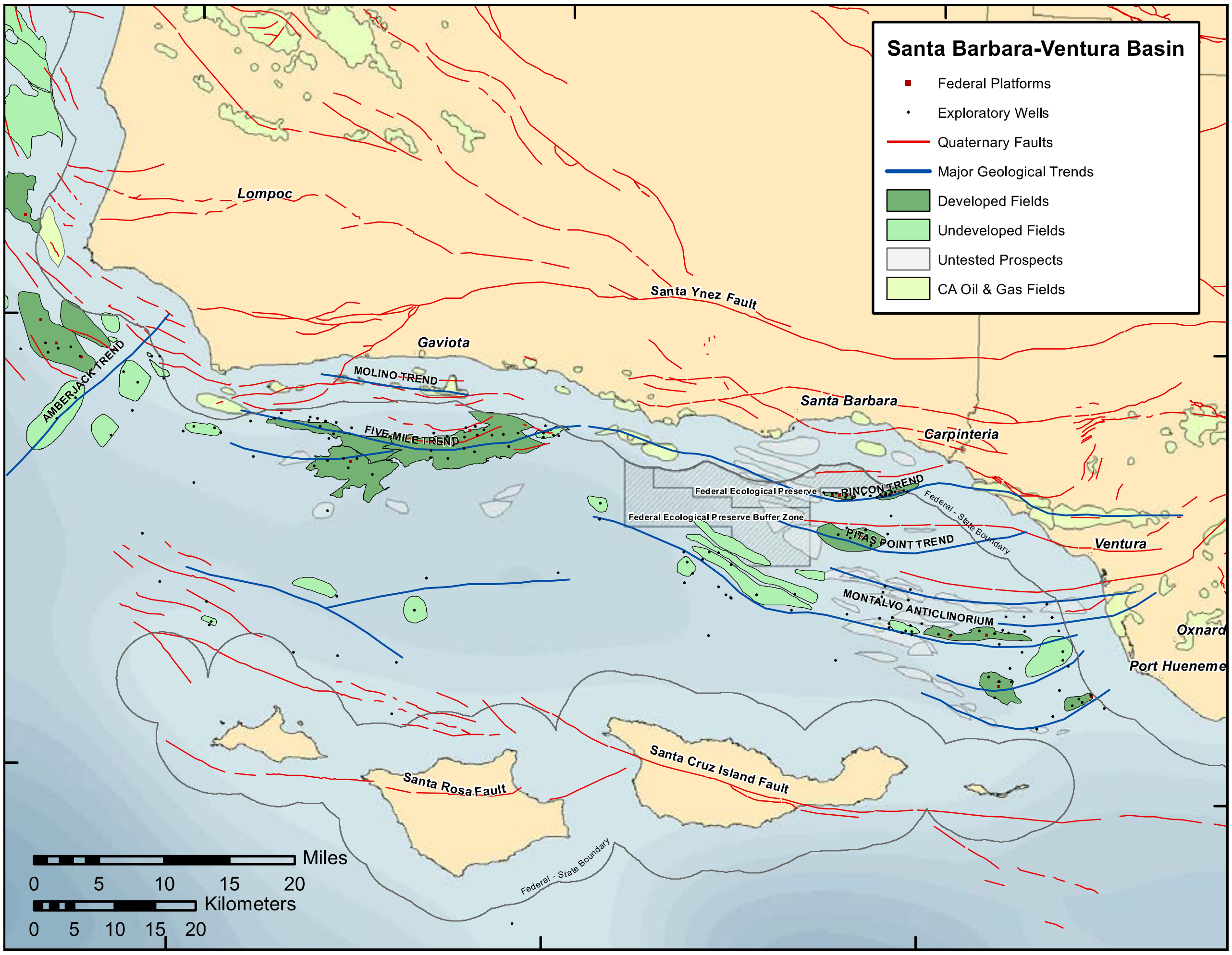


Figure 3-30. *Offshore Santa Barbara–Ventura basin showing major petroleum producing trends.*

PLAYS

The Santa Barbara–Ventura basin includes four assessed plays. The Pico-Repetto Sandstone play consists of oil and gas accumulations in Pliocene and early Pleistocene turbidite sandstones. It exists in the eastern part of the Channel where it is the most prolific producer. The Fractured Monterey play exists throughout the basin and consists of middle to late Miocene siliceous fractured shale reservoirs of the Monterey Formation. This is the most prolific play in the Federal offshore area, particularly in the western part of the Channel. The Rincon-Monterey-Topanga Sandstone play (RMT) and the Sespe-Alegria-Vaqueros Sandstone play (SAV) defined in the 1995 assessment have been combined into a single play (RMT–SAV), based primarily on the stratigraphic proximity and occurrence of hydrocarbons in the corresponding formations. The RMT is limited to two isolated areas within the basin, whereas the SAV is basin-wide. The Gaviota-Sacate-Matilija (GSM) play includes known and prospective accumulations of oil and associated gas in Eocene to early Oligocene sandstones of various depositional environments, including deep-water turbidites, slope-to shelf fans and channels, nearshore bars, and continental and deltaic deposits. These plays, described in the following sections, 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).

Pico–Repetto Sandstone Play

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 2 Bbbl of oil and 3 Tcf of gas (over 2.5 BBOE). Pliocene strata are distributed throughout the basin; however, this play is limited to the central and eastern portions of the basin (fig. 3-31) 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.

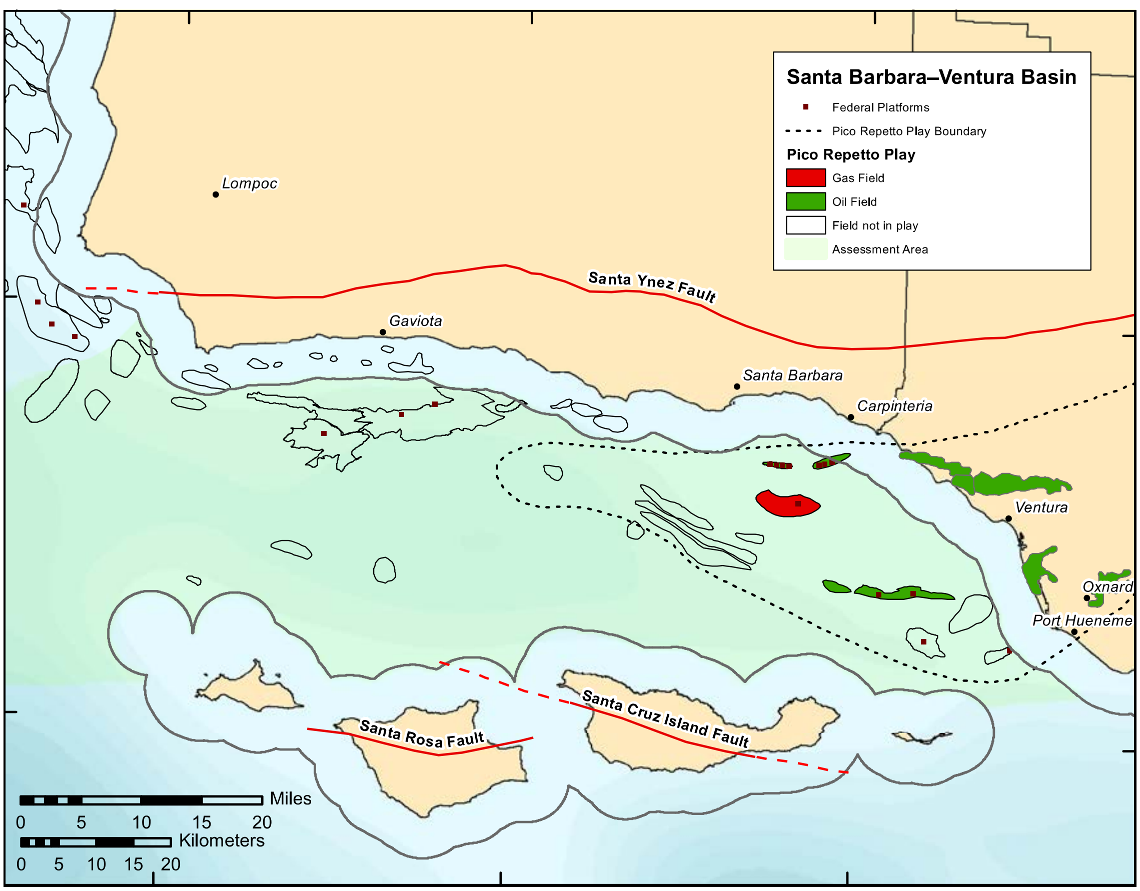


Figure 3-31. *Pico–Repetto Sandstone play, showing fields within the play.*

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

Reservoir rocks of this play are primarily sandstones of the “Repetto” and Pico Formations (fig. 3-29). 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 reaches a maximum thickness of over 10,000 feet in the basin's Pliocene depocenter.

Traps within this play are expected to 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.

The first commercial production from this play was obtained from oil tunnels at the Santa Paula field as early as 1861. The largest productive accumulations in the play (based on original recoverable reserves) include the Ventura-San Miguelito-Rincon field (discovered 1919; 1.8 BBOE), Dos Cuadras field (1968; 301 MMBOE), Carpinteria Offshore field (1966; 139 MMBOE), and the Saticoy-South Mountain (Bridge Pool) field (1955; 86 MMBOE).

Fractured Monterey Play

The Fractured Monterey 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 1.6 BBOE (combined oil and gas equivalent).

The Monterey Formation is distributed throughout the Santa Barbara−Ventura basin (fig. 3-32). 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.

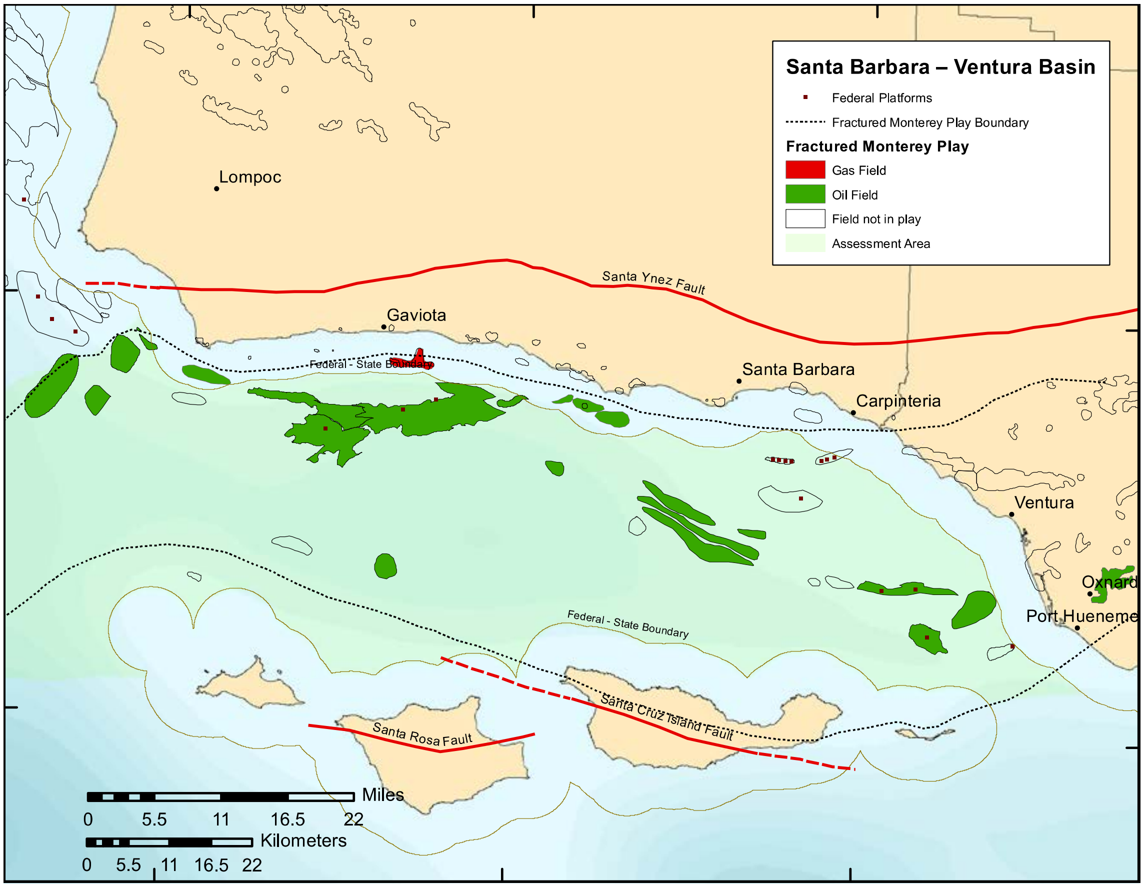


Figure 3-32. *Fractured Monterey play, showing fields within the play.*

Reservoir rocks of this play are fractured zones within the Monterey Formation (fig. 3-29). Silica diagenesis (which causes the rock mass to become increasingly brittle) coupled with late Neogene compressional tectonics has 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. 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 evolution 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, viscosity).

Traps within this play are predominantly complexly faulted anticlines. Less-common traps 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.

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 field. The largest productive accumulations in Fractured Monterey rocks of this play (based on original recoverable reserves) include the Hondo, Pescado, and Sacate fields of the Santa Ynez Unit (estimated at over 800 MMBOE for the unit, as of January 2009). Other large, undeveloped accumulations have been identified offshore.

Rincon–Monterey–Topanga–Sespe–Alegria–Vaqueros (RMT–SAV) Sandstone Play

The RMT–SAV Sandstone Play includes known and prospective oil and associated gas accumulations in late Eocene to middle Miocene reservoirs. This is an established play in both onshore and offshore fields. The play as redefined for this assessment exists throughout the federal offshore assessment basin (fig. 3-33).

Multiple source rocks are likely, as indicated by the variability in oil gravity among the known reservoirs. Sources for high gravity oil include Eocene and Miocene deep-water shales. Sources for low gravity, high sulfur oil are most likely overlying Miocene formations,

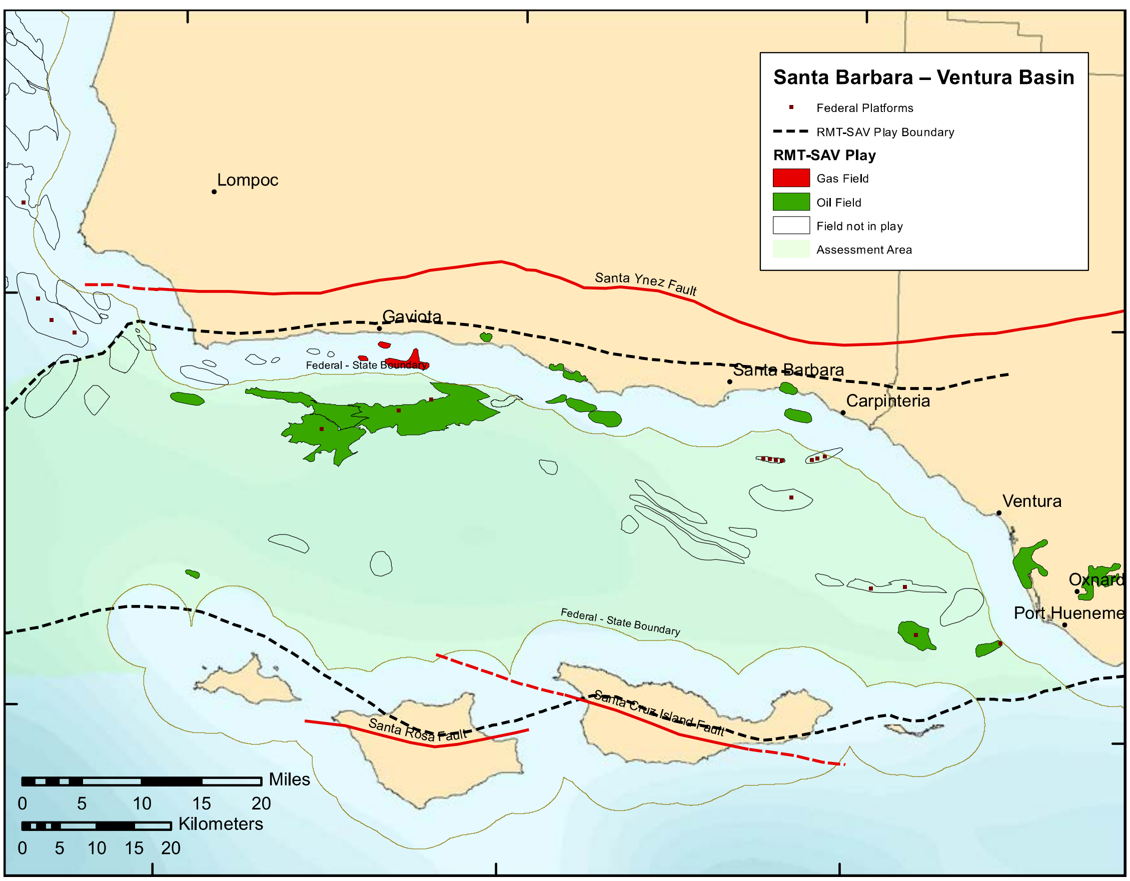


Figure 3-33. *Rincon–Monterey–Topanga–Sespe–Alegria–Vaqueros Sandstone play, showing fields within the play.*

Reservoir rocks include coarse clastics within marine and non-marine fluvial and fan-delta systems that formed in late Eocene to early Miocene, and deep-water sandstones deposited in Miocene fans and channels. Sandstone porosity is good (20 to 35 percent) and permeability is fair to excellent (200 to 1,500 millidarcies). The Miocene RMT sandstone section exceeds 1,000 feet with individual stacked sand bodies as thick as 150 feet. The Oligocene SAV section averages 3,00 to 4,000 feet in the Santa Barbara Channel, and may exceed 7,500 feet in the thicker parts of the basin.

Traps include anticlinal and faulted structures, often associated with reservoirs in the younger part of the section. Known accumulations in the Santa Barbara – Ventura Basin have been of moderate size (two onshore fields exceed 100 MMbbl). In the western part of the offshore basin, existing accumulations are not important by themselves, but are a valuable source of high gravity oil that is used as diluent to improve the extraction and transport of heavy oil from the overlying fractured Monterey section.

Gaviota–Sacate–Matilija Sandstone Play

The Gaviota-Sacate-Matilija Sandstone play of the Santa Barbara–Ventura Basin province includes known and prospective oil, associated gas, nonassociated gas, and natural gas liquid accumulations in Eocene to early Oligocene (?) reservoirs. This is an established play; original recoverable reserves in onshore and offshore fields exceed 130 MMbbl of oil and 840 Bcf of gas. Based on exploratory and production well information and seismic interpretation, it is assumed that this play exists throughout the basin (fig. 3-34).

As with the overlying RMT–SAV play, the oil, and gas found in reservoirs of this play comes from multiple sources. Likely sources of high-gravity products include Cretaceous to Eocene organic shales. Heavy oils typical of Miocene sourcing exist in some reservoirs, and it is likely that there are some mixed-source accumulations.

Reservoir rocks are primarily fine- to coarse-grained sandstones of varied depositional environments, including deep-water turbidites, slope to shelf fans and channels, nearshore bars, and continental and deltaic deposits. Section thickness is commonly 3,00 to 8.000 feet; maximum section is estimated from well and seismic data to exceed 15,000 feet.

Traps are predominantly in anticlines, faulted anticlines and fault blocks. Stratigraphic traps may also occur along permeability barriers and in angular unconformities.

Most discovered accumulations occur in conjunction with other plays. The most productive accumulation offshore is less than 40 MMbbl. It is therefore not considered to be an important play by itself, but rather to bolster production of fields in other plays, or to provide diluent to reservoirs with heavy Monterey-type oil accumulations.

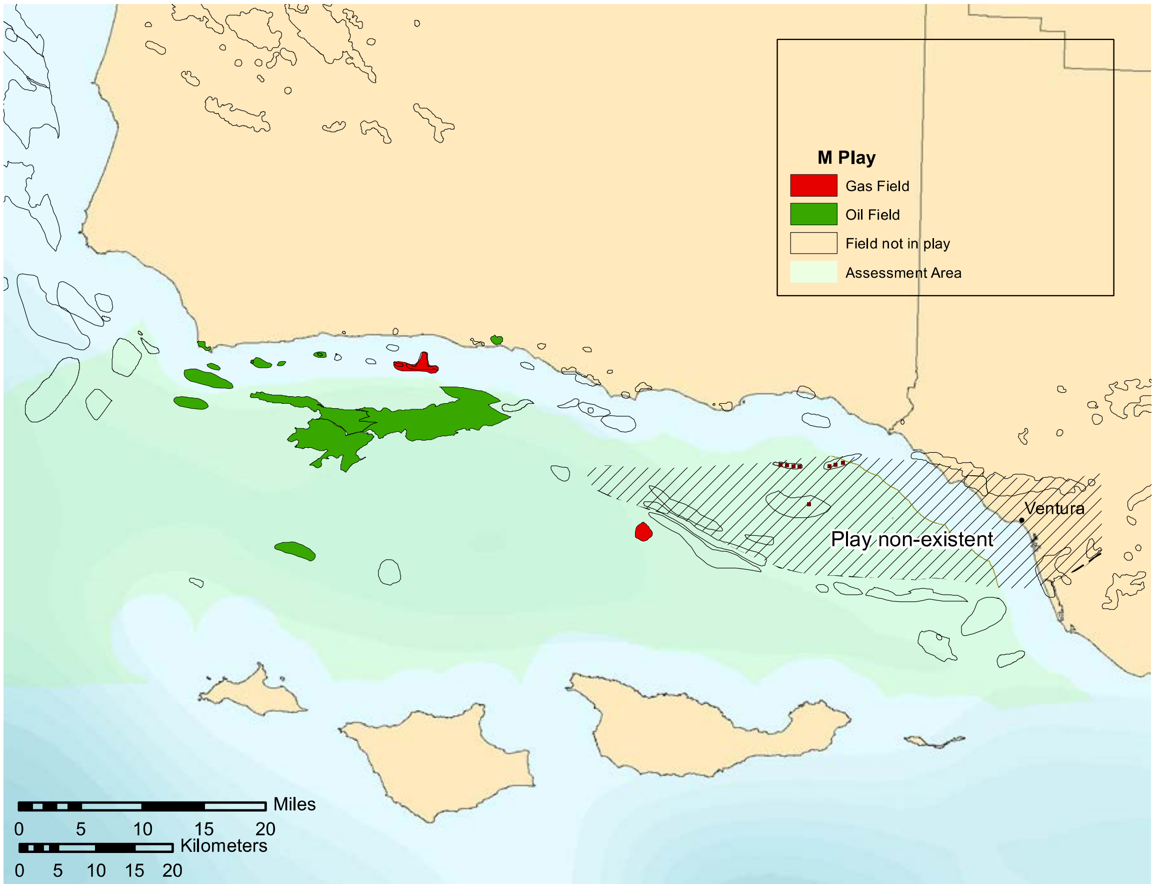


Figure 3-34. *Gaviota–Sacate–Matilija Sandstone play, showing fields within the play.*

Economic Factors

Santa Barbara Channel has the most oil and gas development and infrastructure of the Pacific OCS. Future development would likely be required to tie in to existing pipelines. The number of platforms would be minimized by the use of extended-reach drilling. In Santa Barbara Channel, the longest extended-reach wells reach nearly 7 miles from the production platform.

Resource Estimates

Undiscovered Technically Recoverable Resources

Play-specific estimates of undiscovered technically recoverable resources have been developed using the subjective assessment and discovery 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 technically recoverable resources in the Santa Barbara–Ventura Basin assessment area is estimated to be 1.34 Bbbl of oil and 2.74 Tcf of associated gas (mean estimates). About half of these resources (approximately 49 percent on a combined oil-equivalence basis) are estimated to exist in the Fractured Monterey play. The low, mean, and high estimates of resources in the assessment area are listed in table 3-19.

Table 3-19. *Estimates of Undiscovered Technically Recoverable Oil and Gas Resources of the Santa Barbara–Ventura Basin geologic plays and the Basin total. Resource values are in billion barrels of oil (Bbbl) and trillion cubic feet of gas (Tcf). 95% indicates a 95 percent chance of at least the amount listed; 5% indicates a 5 percent chance of at least the amount listed. Only mean values are additive. Some total mean values may not equal the sum of the component values due to independent rounding of the tabulated values.*

Geologic Play	Oil (Bbbl)			Gas (Tcf)			BOE (Bbbl)		
	95%	Mean	5%	95%	Mean	5%	95%	Mean	5%
Pico-Repetto Sandstone	0.00	0.19	0.85	0.02	0.39	1.62	0.01	0.26	1.13
Fractured Monterey	0.28	0.76	1.68	0.29	0.70	1.05	0.33	0.89	1.87
RMT–SAV Sandstone	0.02	0.28	0.34	0.36	1.21	4.76	0.09	0.49	1.19
GSM Sandstone	0.00	0.11	0.31	0.04	0.45	1.34	0.01	0.19	0.55
Santa Barbara Basin	**0.34**	**1.34**	**3.50**	**0.53**	**2.74**	**7.01**	**0.44**	**1.83**	**4.75**

Undiscovered Economically Recoverable Resources

Estimates of the portion of the technically recoverable resources that can be economically recovered under various economic scenarios were developed by including the effects of current and expected future economic factors. Select data used to develop the resource estimates are shown in appendix D. These estimates are tabulated in table 3-20 and shown in fig. 3-35 as price-supply curves for a range of price scenarios. Estimates are based on a gas market value of 40 percent of the energy equivalent value of oil. As a result of this assessment, 1.25 Bbbl of oil and 2.37 Bcf of associated gas are estimated to be economically recoverable from the Santa Barbara–Ventura Basin assessment area under economic conditions existing as of this assessment (i.e., the $90-per-barrel economic scenario). Larger volumes of resources are expected to be economically recoverable under increasingly favorable economic conditions. Because field development often includes multiple plays, and may not be viable for an individual play, play-specific estimates have not been tabulated.

Table 3-20. *Estimates of undiscovered economically recoverable oil and gas resources in the Santa Barbara–Ventura Basin Province as of January 1, 2009 for three economic scenarios, by assessment area. Oil prices are coupled with a specific gas price assuming a 40 percent economic value for gas relative to oil.*

Geologic Basin/Area	$60/bbl, $4.27/Mcf		$90/bbl, $6.41/Mcf		$120/bbl, $8.54/Mcf	
	Oil (Bbbl)	Gas (Tcf)	Oil (Bbbl)	Gas (Tcf)	Oil (Bbbl)	Gas (Tcf)
Santa Barbara	**1.19**	**2.23**	**1.25**	**2.37**	**1.27**	**2.44**

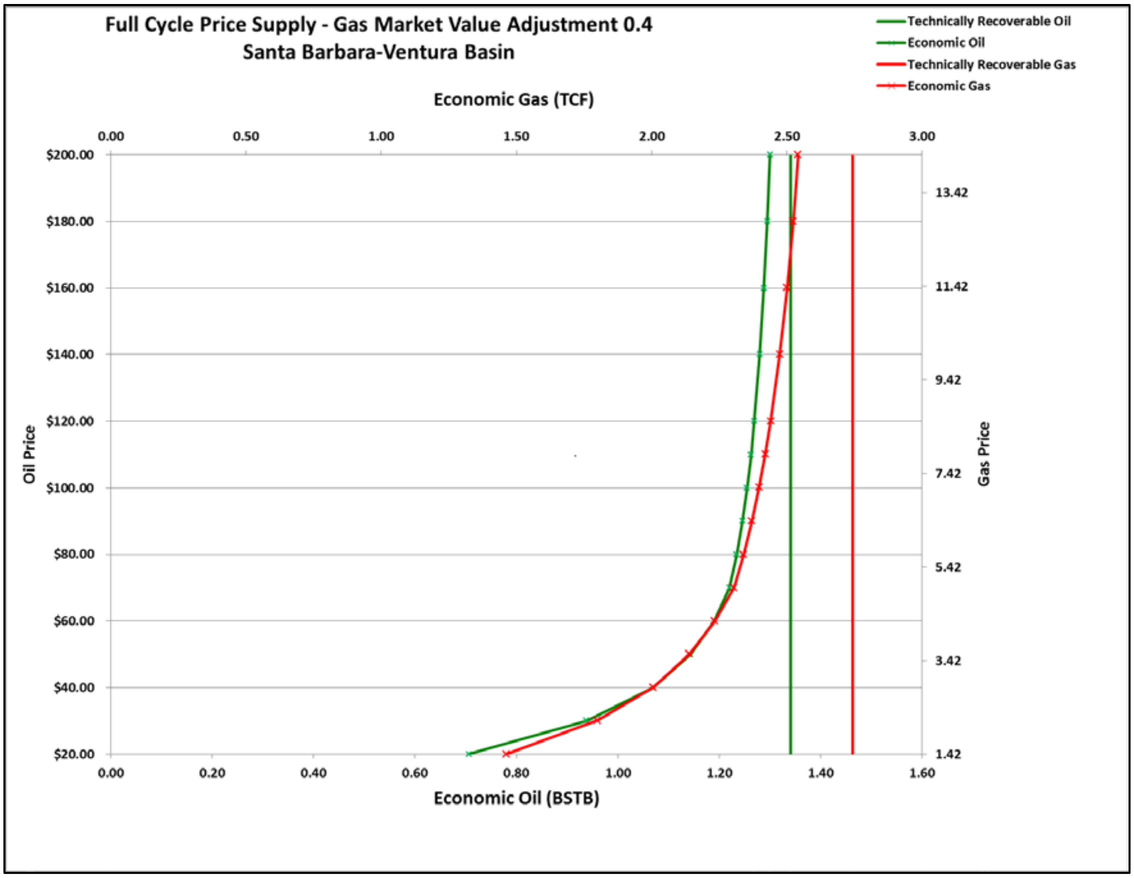


Figure 3-35. *Price-supply curves for the Santa Barbara–Ventura basin. Oil prices are coupled with a specific gas price assuming a 40 percent economic value for gas relative to oil.*

Total Resource Endowment

As of this assessment, originally recoverable reserves (including cumulative production and remaining reserves) from the assessment area was 1.13 Bbbl of oil and 1.73 Tcf of gas; contingent resources were estimated to be 0.18 Bbbl of oil and 0.20 Tcf of gas (BOEMRE, 2010; unpublished BOEM data). These discovered resources and the aforementioned undiscovered technically recoverable resources collectively compose the area's estimated total resource endowment of 2.70 Bbbl of oil and 4.97 Tcf of gas (table 3-21).

Table 3-21. *Estimates of the total endowment of oil and gas resources in the Santa Barbara-Ventura basin. Estimates of discovered resources, including originally recoverable reserves and contingent resources, are as of January 1, 2009. Originally recoverable reserves include cumulative production and remaining reserves. Estimates of undiscovered technically 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)
Originally Recoverable Reserves	1,13	1.73	1.43
Contingent Resources	0.21	0.40	0.29
Undiscovered Technically Recoverable Resources	1.34	2.74	1.83
Total Resource Endowment	*2.68*	*4.88*	*3.55*

ADDITIONAL REFERENCES

California Division of Oil, Gas, and Geothermal Resources, 1993
Conservation Committee of California Oil Producers, 1961
Conservation Committee of California Oil and Gas Producers, 1991
Conservation Committee of California Oil and Gas Producers, 1993
Campion and others, 1994
Crain and others, 1985
Garrison and Douglas, 1981
Gordon and Weigand, 1994
Hornafius and others, 1986
Ingle, 1981
Isaacs and Garrison, 1983
Keller, 1995
Sorensen and others, 1993
Sorensen and others, 1994

INNER BORDERLAND PROVINCE

Location and Geologic Setting

The Inner Borderland Province includes coastal basins that formed as a response to the combination of the rotation of the western Transverse Ranges and the accompanying translation and extension of the California Continental Borderland (fig. 3-36).

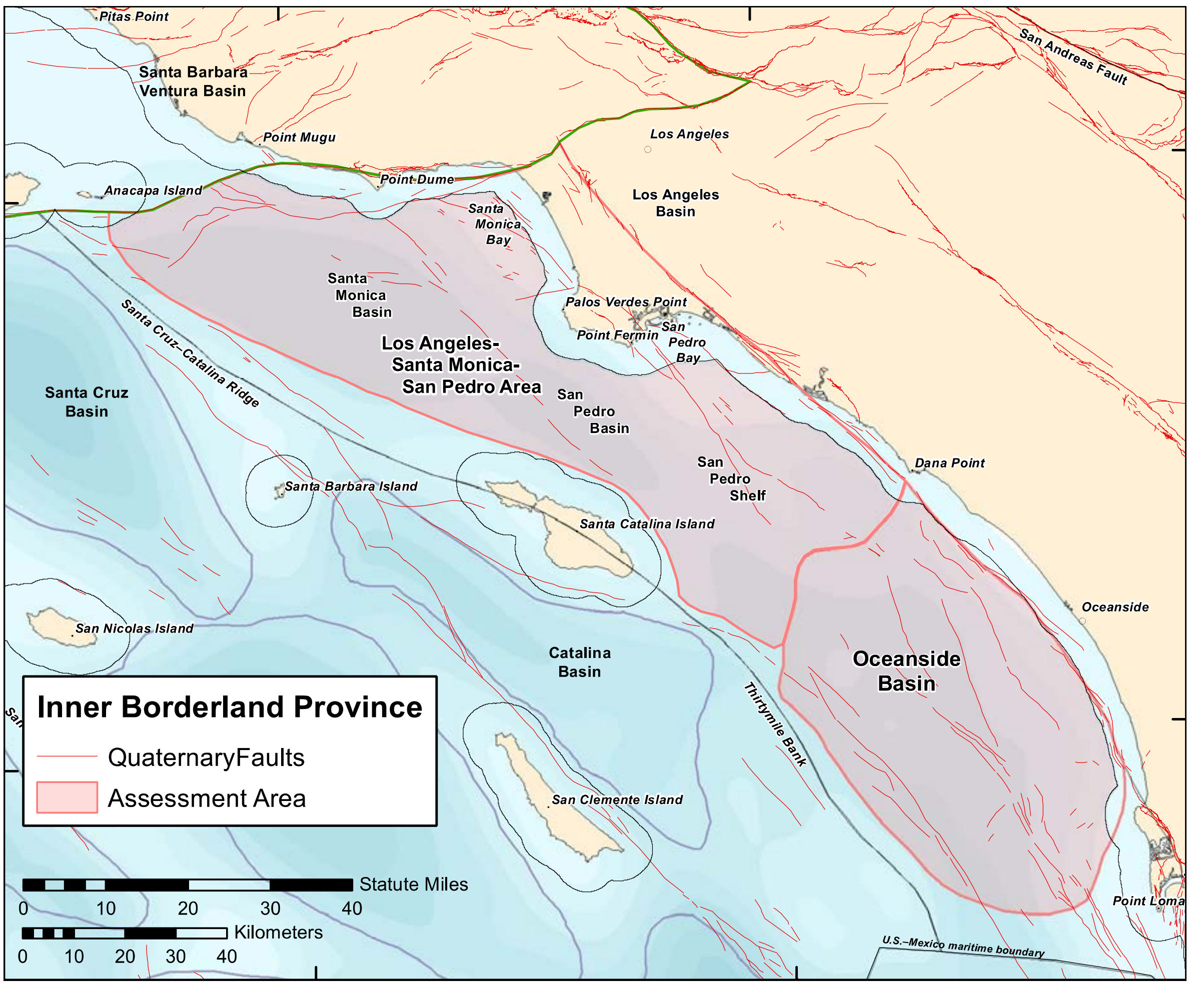


Figure 3-36. *Map of the Inner Borderland province showing assessment areas and basins.*

The Los Angeles basin has a thick accumulation of sediments (over 30,000 feet) that is related to the tectonic rotation of the western Transverse Ranges. The onshore part of the basin has been one of the most prolific petroleum provinces of the world on a per-square-mile basis. However, the Federal offshore part of the basin is small in area and sufficiently similar to the adjacent Santa Monica-San Pedro assessment area (defined in the 1995 assessment), that for this assessment the two areas have been combined and termed the Los Angeles–Santa

Monica–San Pedro (LA–SM–SP) area, a part of the Inner Borderland Province. The LA–SM–SP area is about 1,500 square miles in area, and water depth ranges from about 100 feet to over 3,000 feet in the Federal offshore area. Within the assessed area as much as 11,000 feet of Miocene and younger sediments have accumulated.

The Oceanside basin lies to the south of the Los Angeles basin. In the 1995 assessment, by request of the U.S. Geological Survey, the Minerals Management Service had included the State waters and a small onshore area of the Capistrano embayment (the USGS was responsible for assessing State waters and the onshore United States). For the current assessment, that area was dropped. Doing so eliminated one hydrocarbon play that only exists to the east of the Newport-Inglewood fault zone, which lies approximately along the Federal-State boundary in this area. The basin is about 1,500 square miles in area, and water depth ranges from about 100 to about 3,000 feet within the Federal offshore assessment area. West of the Newport-Inglewood fault zone the basin formed as a result of the clockwise rotation of the western Transverse Ranges and associated extension of the Southern California Borderlands geomorphic province, and has accumulated up to about 11,000 feet of Neogene sediments.

EXPLORATION AND DISCOVERY STATUS

Onshore Los Angeles basin is one of the most prolific oil provinces in the world on a per-square-mile basis, and so far has produced about 9 Bbbl of oil. There are two major trends (each with about 3 Bbbl of originally recoverable oil) in the southern part of the onshore basin that trend into the offshore area. Two fields (one producing) have been discovered in the southern Federal offshore area of the LA–SM–SP area. Most exploratory wells have not tapped the thickest parts of the basins.

One of the major oil-producing trends is along the Newport-Inglewood fault zone, which is the eastern boundary of the province. The producing area is along the northern part of that trend, onshore and in State water. The southern part of the trend borders Oceanside basin, and has been tested by two exploratory stratigraphic test wells.

Stratigraphic and paleontologic data from the offshore wells and a moderate to dense grid of 2-D seismic data obtained in the 1970's and 1980's are the bases for interpretation of the offshore geology. No newer data exists than that used for the 1995 assessment.

INNER BORDERLAND PROVINCE PLAYS

Assessed plays in the Inner Borderland Province include one established play (Puente Fan play), two frontier plays (Dume Thrust Fault, and San Onofre Breccia plays), and four conceptual plays (Upper Miocene Sandstone, Monterey or "Modelo," and Lower Miocene Sandstone plays). In addition a conceptual Pliocene Clastic play was defined but not assessed.

The lower to middle Miocene Puente Fan play exists in the LA−SM−SP area. Two oil fields have been discovered in the southern area of this play, and through 2009, one (Beta field) has produced about 91 MMbbl of oil and 30 Bcf of gas of originally recoverable reserves estimated at about 108 MMbbl of oil and 35 Bcf of gas.

The Dume Thrust Fault play is defined to include source and reservoir rocks that have been structurally stacked by a series of north-dipping reverse faults associated with the compression and uplift of the western Transverse Ranges at the northern end of the LA−SM−SP area. Possible reservoir rocks include Miocene to Pliocene clastics, and Paleocene to Miocene brecciated or otherwise fractured schists and shales. Evidence of oil has been observed in two of seven exploratory wells that were drilled in State and Federal waters.

The San Onofre Breccia play is defined to include fractured Catalina schist, San Onofre Breccia and fractured nodular shale that overlies the breccia. These rocks range from Cretaceous (possibly Jurassic) to early Miocene in age. The play is considered frontier based on the presence of tar and gas shows in exploratory wells and coreholes and seeps south of the Palos Verdes Peninsula.

Conceptual plays include a Monterey play (called Modelo in the LA−SM−SP area). The Modelo was not penetrated by any exploratory wells in the LA−SM−SP area. In the Oceanside basin area, one of the two coreholes drilled on the east side of the Newport-Inglewood fault zone penetrated Monterey section, but there were no reports of hydrocarbon shows.

In addition, there were lower and upper Miocene sandstone plays and a Pliocene clastic play (not assessed) postulated in the Inner Borderland Province. Five exploratory wells were drilled into the Upper Miocene Sandstone play but did not encounter any significant hydrocarbons.

Economic Factors

Although there is only one developed field in the Inner Borderland Province, the Los Angeles basin has the largest concentration of onshore facilities on the West Coast, and there are multiple coastal access points in the LA−SM−SP area. Oceanside basin has no coastal facilities, but has available access points and harbors suitable for support facilities. Future development would likely be required to tie share pipelines and other facilities. The number of platforms would be minimized by the use of extended-reach drilling.

RESOURCE ESTIMATES

Undiscovered Technically Recoverable Resources

Estimates of the total volume of undiscovered technically recoverable resources within the Los Angeles–Santa Monica and Oceanside basins were developed by statistically aggregating the constituent play estimates within each basin. Estimates of the total volume of undiscovered technically recoverable resources in the province were developed by statistically aggregating all constituent basin estimates within the province. As a result of this assessment, the total volume of undiscovered technically recoverable resources in the Inner Borderland Province is estimated to be 1.96 Bbbl of oil and 2.15 Tcf of associated gas (mean estimates). The low, mean and high estimates of resources are listed in table 3-22 for each of the basins and the province total.

Table 3-22. *Estimates of Undiscovered Technically Recoverable Oil and Gas Resources of the Inner Borderland Province by assessment area. Resource values are in billion barrels of oil (Bbbl) and trillion cubic feet of gas (Tcf). 95% indicates a 95 percent chance of at least the amount listed; 5% indicates a 5 percent chance of at least the amount listed. Only mean values are additive. Some total mean values may not equal the sum of the component values due to independent rounding of the tabulated values.*

Geologic	Oil (Bbbl)			Gas (Tcf)			BOE (Bbbl)		
Basin/Area	95%	Mean	5%	95%	Mean	5%	95%	Mean	5%
L. A.–S. Monica	0.10	0.89	2.16	0.10	1.03	2.62	0.12	1.08	2.62
Oceanside	0.00	1.06	2.94	0.00	1.12	3.51	0.00	1.26	3.56
Inner Borderland	**0.21**	**1.96**	**4.23**	**0.21**	**2.15**	**4.83**	**0.24**	**2.34**	**5.09**

Undiscovered Economically Recoverable Resources

Estimates of the portion of the technically recoverable resources that can be economically recovered under various economic scenarios were developed by including the effects of current and expected future economic factors. Select data used to develop the resource estimates are shown in appendix D. These estimates are tabulated in table 3-23 and shown in fig. 3-37 as price-supply curves for a range of price scenarios. Estimates are based on a gas market value of 40 percent of the energy equivalent value of oil. As a result of this assessment, 1.56 Bbbl of oil and 1.75 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 $90-per-barrel economic scenario). Larger volumes of resources are expected to be economically recoverable under increasingly favorable economic conditions. Because field development often includes multiple plays, and may not be viable for an individual play, play-specific estimates have not been tabulated.

Table 3-23. *Estimates of undiscovered economically recoverable oil and gas resources in the Inner Borderland Province as of January 1, 2009 for three economic scenarios, by assessment area. Oil prices are coupled with a specific gas price assuming a 40 percent economic value for gas relative to oil.*

Geologic	$60/bbl, $4.27/Mcf		$90/bbl, $6.41/Mcf		$120/bbl, $8.54/Mcf	
Basin/Area	Oil (Bbbl)	Gas (Tcf)	Oil (Bbbl)	Gas (Tcf)	Oil (Bbbl)	Gas (Tcf)
L. A.–Santa Monica	0.61	0.74	0.68	0.82	0.72	0.86
Oceanside	0.79	0.85	0.88	0.93	0.91	0.96
Inner Borderlands	**1.40**	**1.59**	**1.56**	**1.75**	**1.63**	**1.83**

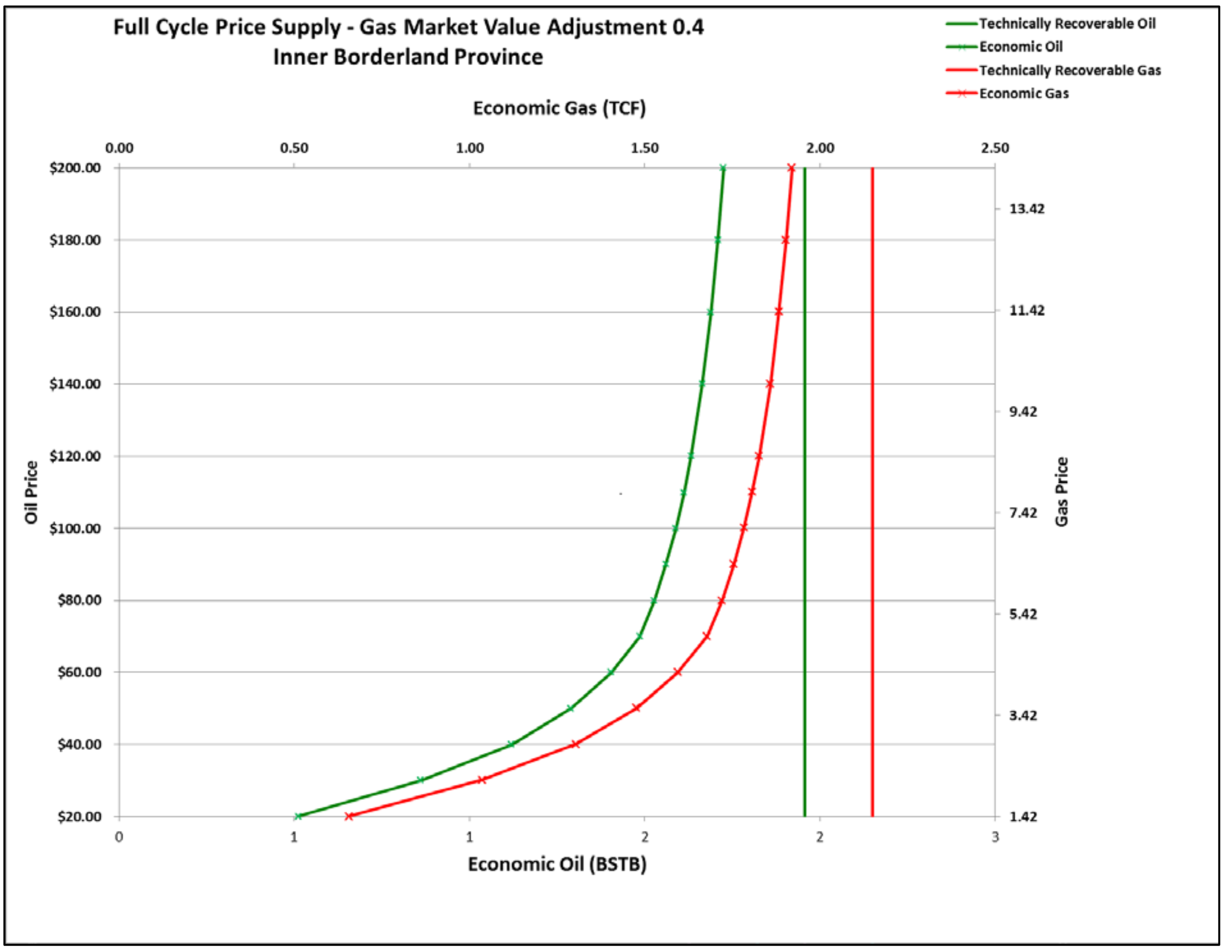


Figure 3-37. *Price-supply curves for the Inner Borderland province. Oil prices are coupled with a specific gas price assuming a 40 percent economic value for gas relative to oil.*

TOTAL RESOURCE ENDOWMENT

As of this assessment, originally recoverable reserves (including cumulative production and remaining reserves) from the assessment area was 108MMbbl of oil and 34.8 Bcf of gas; contingent resources were estimated to be 4.8 MMbbl of oil and 912 Mcf of gas. These discovered resources (all of which are from the Puente Fan play in the LA-SM-SP basin) and the aforementioned undiscovered technically recoverable resources collectively compose the area's estimated total resource endowment of 2.07 Bbbl of oil and 2.19 Tcf of gas (table 3-24).

Table 3-24. *Estimates of the total endowment of oil and gas resources in the Inner Borderland Province. Estimates of discovered resources, including originally recoverable reserves and contingent resources, are as of January 1, 2009. Originally recoverable reserves include cumulative production and remaining reserves. Estimates of undiscovered technically 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)
Originally Recoverable Reserves	0.11	0.03	0.11
Contingent Resources	0.005	0.001	0.005
Undiscovered Technically Recoverable Resources	1.96	2.15	2.34
Total Resource Endowment	*2.07*	*2.19*	*2.46*

Los Angeles–Santa Monica–San Pedro Area

Location

The Los Angeles basin is generally considered to be the structural basin that approximately coincides with the Los Angeles coastal plain. The Newport-Inglewood fault zone marks a major change in basement lithology and an important tectonic boundary. For this assessment, only the part of the basin west of that fault zone is considered, and it has been combined with the Santa Monica-San Pedro Area of the 1995 assessment. The combined area, in this report termed the Los Angeles-Santa Monica-San Pedro (LA-SM-SP) area, is bounded on the north by the Malibu Coast–Santa Monica fault zone, and extends westward to the Santa Cruz-Catalina Ridge and southeastward to Dana Point (fig. 3-38). In addition to the western part of the Los Angeles basin, the assessment area includes three other depositional subareas—the Santa Monica basin, the San Pedro basin, and the San Pedro shelf. The area is about 90 miles long from northwest to southeast, and about 40 miles wide, encompassing an area of about 1,600 square miles. Water depth ranges from about 100 feet to 3,000 feet.

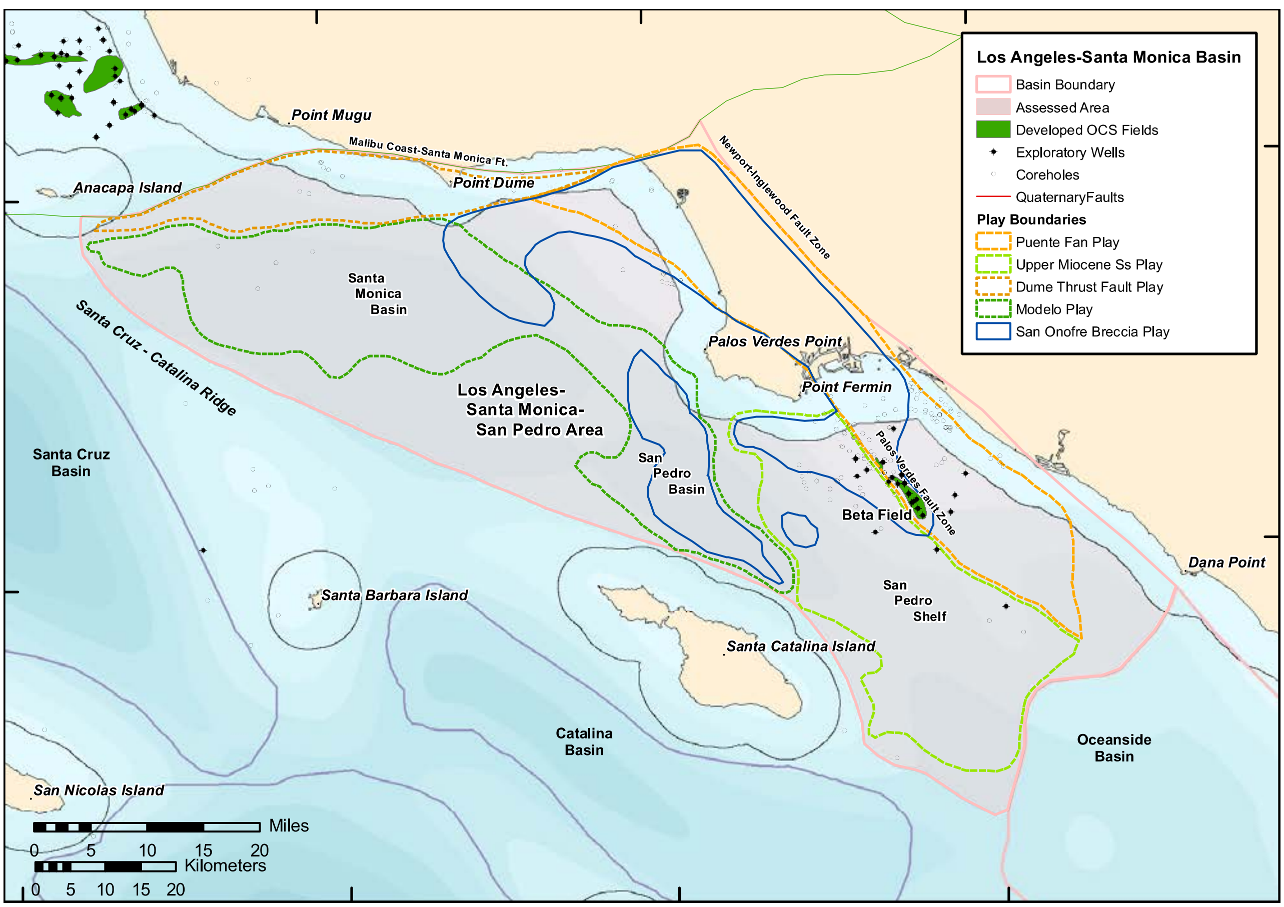
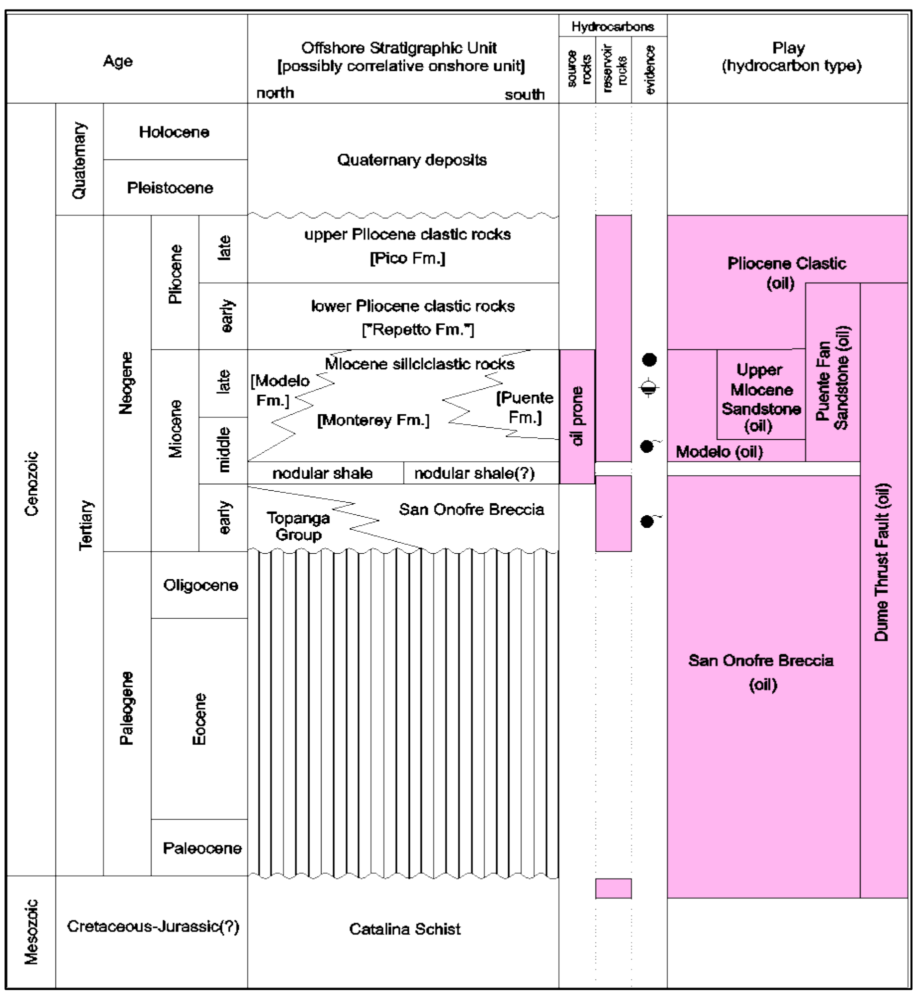


Figure 3-38. *Los Angeles–Santa Monica–San Pedro area plays, exploratory wells and coreholes.*

GEOLOGIC SETTING

The Los Angeles basin is a structurally controlled basin that formed in part as the result of the clockwise rotation of the western Transverse Ranges. Basement rocks are considered to be primarily Catalina Schist and related rocks that were formed by metamorphosis of subducted trench deposits, and later exhumed as a result of the extension associated with the rotation of the western Transverse Ranges. Rotation and rifting began in the early Miocene as a response to relative plate motions of the Pacific and North American plates. Paleogene strata are missing in the area, due to the early Miocene rifting (fig. 3-39). There are in excess of 30,000 feet of sediments that were deposited as the basin opened, starting with the early Miocene San Onofre Breccia, and continuing to the present. Early-middle Miocene warm oceanic upwelling contributed to a basin-wide organic-rich shale that is a prolific source of high-sulphur, low gravity oil in the Los Angeles basin. The relatively high heat flow associated with the rifting, combined with rapid accumulation of clastic sediments, has created one of the most prolific petroleum-producing regions in the world, on a per-square-mile basis.



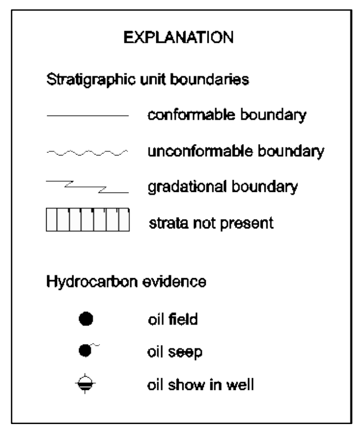


Figure 3-39. *Stratigraphic column of the Los Angeles-Santa Monica-San Pedro assessment area, showing stratigraphic units, hydrocarbon attributes, and petroleum geologic plays defined for this assessment.*

EXPLORATION AND PRODUCTION STATUS

Onshore Los Angeles basin is one of the most prolific oil provinces in the world on a per-square-mile basis, and so far has produced about 9 Bbbl of oil. There are two major trends (each with about 3 Bbbl of originally recoverable oil) in the southern part of the onshore basin that trend into the offshore area. The Newport-Inglewood trend (along the fault zone with the same name) and the Wilmington trend merge southward into State waters; several of the State fields are in this area. Further south the trend borders the Federal part of the Oceanside basin. To the northwest, the Wilmington trend may extend into Santa Monica basin. Exploration opportunities have been limited by access restrictions, particularly in the Santa Monica basin part of the LA-SM-SP assessment area. Only two fields (Beta, producing and Beta NW non-producing) have been discovered in the southern Federal offshore part of the area. Most exploratory wells have been on the periphery of the Federal area and have not tapped the thickest parts of the basins.

Seismic-reflection data coverage is moderately dense to dense throughout most of the area. Thirty-three shallow coreholes were drilled in the northern part of the Santa Monica basin, 16 of which were in State water (fig. 3-38). Another 115 coreholes were drilled in the San Pedro area, 58 of which were in State water. In the San Pedro area 32 deep exploratory wells were drilled, two-thirds of which were within the only two oil fields discovered within the federal assessment area. No exploratory wells or coreholes have been drilled in the deeper parts of the Santa Monica and San Pedro basins. The only production from this assessment area is from the Beta oilfield (ongoing at the time of this assessment). State offshore areas were removed from leasing in the mid-1970's; similarly a Federal leasing moratorium was put in effect in the late 1980's. However, numerous oil fields have existed in the onshore part of the Los Angeles basin for more than a century. Several prolific trends are associated with fault systems that have created anticlinal and fault traps. The Newport–Inglewood trend and the Wilmington trend have each produced in excess of 3 Bbbl of oil as of the time of this assessment (fig. 3-40). This trend extends southward into the offshore area and includes some fields in State waters.

PLAYS

Six geologic plays were defined in the assessment area; five of these were assessed. Four of the plays (San Onofre Breccia, Modelo, Upper Miocene Sandstone and Puente Fan Sandstone) were defined on the basis of reservoir rock stratigraphy. The Dume Thrust Fault play was defined based on expected fault trapping style. Only the Federal portion of the plays has been assessed. A Pliocene Clastic play was originally defined to include accumulations in Pliocene clastic strata (see Dunkel and Piper, 1997). The assessed plays are described in the following sections.

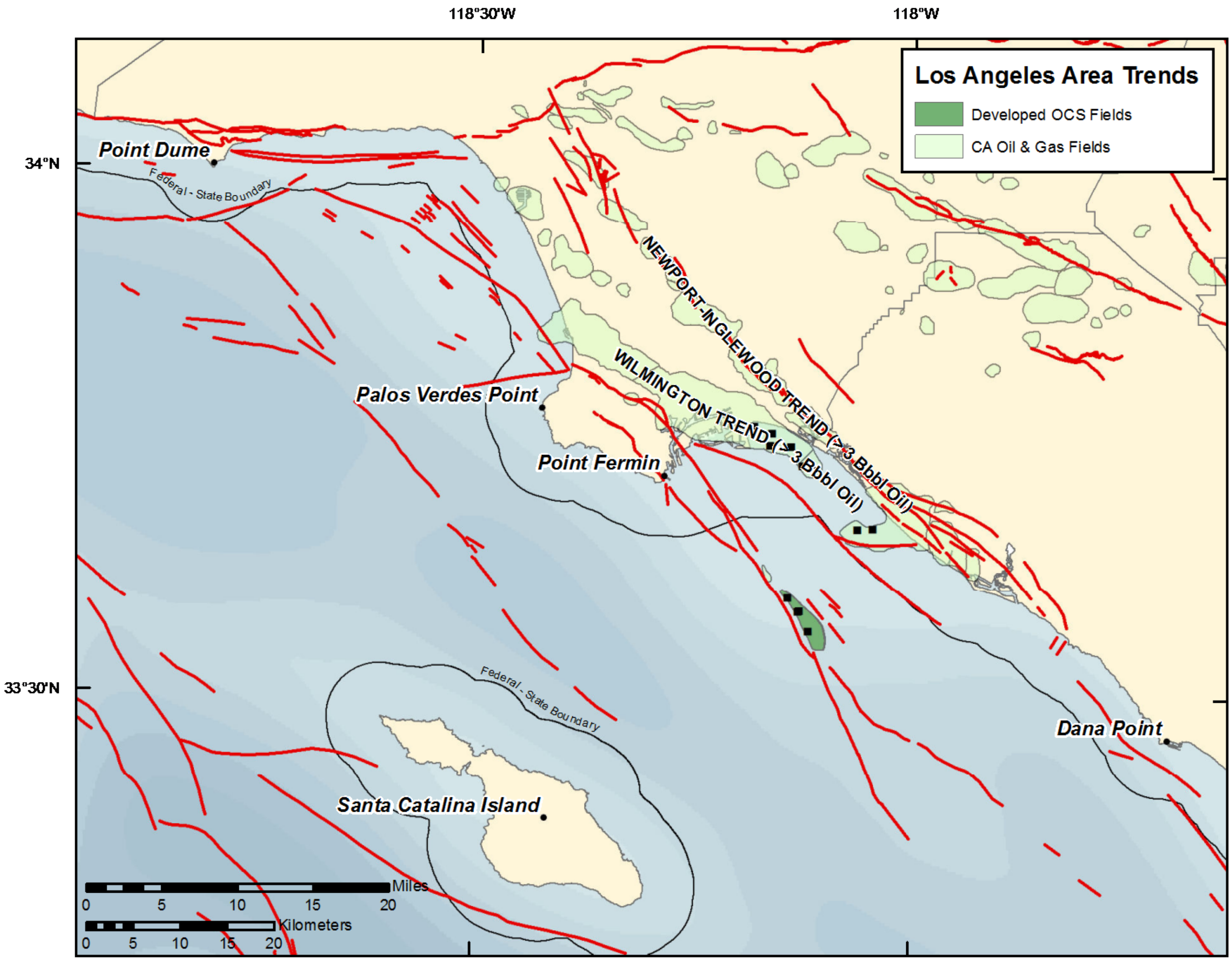


Figure 3-40. *Major oil-producing trends in the Los Angeles-Santa Monica-San Pedro area.*

Puente Fan Sandstone Play

The Puente Fan Sandstone play is defined to include accumulations of oil and associated gas in middle Miocene to lower Pliocene fan sandstones of the Puente and Repetto Formations. The play is established, based on onshore production from numerous fields, and offshore production from the Beta field. The play exists west of the Newport-Inglewood fault zone from Point Dume to Dana Point (fig. 3-38), and encompasses an area of about 275 square miles. The main reservoir section (Puente) ranges from 2,000 to 3,000 feet below seafloor in the northern part of the play, and 4,000 to 5,000 feet below seafloor in the southern part.

Source rocks include a lower middle Miocene "nodular shale" that exists over much of the assessment area, and interbedded Miocene pelagic mudstones and shales within the Puente Formation (fig. 3-39). Onshore, these rocks are rich in marine kerogen; total organic carbon averages 4 percent and is as high as 16 percent in the Puente Formation (Jeffrey and others, 1991). High heat flows in the Los Angeles basin has generated moderate-low gravity (<25 °API), high sulphur oil.

Reservoir rocks are middle Miocene to lower Pliocene sandstones of the Puente and Tarzana fans. Porosities in producing reservoirs range from 17 to 33 percent (Crouch, 1990; Sorensen and others, 1993).

Expected trap types include fault and faulted anticlinal traps along the Palos Verdes fault zone, as found in the Beta field in the southern part of the play area. Seals may be provided by interbedded shales within the fans.

Coreholes drilled in the play encountered oil and gas shows. Offshore oil seeps occur in the northern part of the play. Onshore and offshore fields have produced about 8 billion barrels of oil from geologically analogous reservoir rocks.

Upper Miocene Sandstone Play

The Upper Miocene Sandstone Play is defined as a frontier play that includes accumulations of oil and associated gas in distal Puente Fan sandstones on the San Pedro shelf (fig. 3-38). It is similar to the Puente Fan Sandstone play; however, the more distal location west of the Palos Verdes fault zone result in finer grain size and thinner section of overlying Pliocene strata. There is also a possibility of Monterey-type rocks within this play. It exists over much of the San Pedro shelf, covering an area of about 240 square miles. Depth to reservoir rocks in the play ranges from 600 to 5,000 feet, and averages 3,000 feet.

Source rocks include the basal nodular shale and interbedded shales and mudstones of the Puente Formation (fig. 3-39). Total organic carbon averages 4 percent and is as high as 16 percent in shales within the Puente Formation. Oil is expected to be generated at 8,000 feet burial depth and to be primarily low gravity, high-sulphur oil. The relatively thin Neogene section west of the Palos Verdes fault zone (maximum of 7,000 feet), suggests that petroleum generation from within the Puente Formation is less likely.

Reservoir rocks are distal Puente Fan sands that have been deposited onto the uplifted strata west of the Palos Verdes fault. Sufficient reservoir thickness exists, but is less than half of that in the Puente Fan Sandstone play and expected to be finer-grained.

Traps are expected to include anticlinal and fault traps along the abundant northwest-trending faults. Turbidite sandstone channel traps may also exist. Interbedded and overlying mudstones and shales are expected to provide seals.

Five offshore exploratory wells were drilled along the eastern edge of the San Pedro shelf; no significant accumulations of hydrocarbons have been discovered.

Modelo Play

The Modelo play is a conceptual play, defined to include accumulations of oil and associated gas in structural and fault traps of the Modelo formation. The Modelo formation is stratigraphically equivalent to the Monterey Formation of central California and the western Santa Barbara-Ventura basin. However, it is generally used to refer to more clastic-rich rocks that do not have the same fracture characteristics of the more siliceous Monterey lithology. These rocks are similar to "Modelo" strata in the eastern Santa Barbara-Ventura basin, and are likely to have been deposited in more near-shore environments. The Modelo play exists in the deeper parts of the northern and central assessment area from Point Dume to Santa Catalina Island, and covers an area of about 350 square miles. Depth to reservoir rocks ranges from seafloor to about 15,00 feet below seafloor.

Source rocks include the lower middle Miocene nodular shale and interbedded middle to upper Miocene mudstones and shales of Modelo or Monterey strata (fig. 3-39). In the Los Angeles basin these rocks are rich in marine kerogen (Jeffrey and others, 1991; Philippi, 1975). Total organic carbon is about 4 percent. High heat flow has generated low-gravity, high-sulphur oil as shallow as 8,000 feet burial depth. In the central San Pedro basin, there is about 8,000 feet of overburden, and in the Santa Monica basin there is up to 12,000 feet of overburden, so abundant oil generation is likely.

Reservoir rocks include clastic strata of the Modelo Formation, and fractured shales of Monterey strata within the play. Both rock types exist in coastal outcrops to the north of the play area. Most of the potential is expected to be in fine-grained clastics within the Modelo Formation.

Strata are relatively undeformed compared to other plays in the area; fewer, but larger anticlinal or fault traps may exist. Interbedded mudstones and shales may provide seals for structural or stratigraphic traps.

Dume Thrust Fault Play

The Dume Thrust Fault play is a frontier play that is defined to include accumulations of oil and associated gas in fault traps along the Dume and Malibu Coast faults (fig. 3-38). Much of the play is in State waters; only the Federal portion (about 150 square miles) is considered for this assessment. The depth to reservoir rocks ranges from seafloor to about 15,000 feet below seafloor.

Source rocks are the middle Miocene nodular shale and interbedded middle to upper Miocene mudstones and shales of the Modelo or Monterey Formation (fig. 3-39). Onshore, in the Los Angeles basin, these rocks have a high marine kerogen content and total organic carbon of about 4 percent (Jeffrey and others, 1991; Philippi, 1975). High heat flow allows generation of oil at about 8,000 feet burial depth. The expected source rocks for this play are buried about 12,000 feet, and are expected to be a prolific source of low to medium gravity, high sulphur oil.

Reservoir rocks include fractured Catalina schist, clastic rocks of the Topanga Group, San Onofre Breccia, Modelo, and Repetto Formations, and fractured shales of the Monterey Formation (fig. 3-39). Monterey strat have been penetrated by one exploratory well and several coreholes. Other possible reservoir rocks exist in outcrop onshore or are presumed to exist by extrapolation of seismic interpretation from Santa Monica Bay. Outcrops show the existence of laumontite (chemical cement in pore spaces), and this may suggest a degraded reservoir quality.

Primary trapping mechanism is the stacked reverse (thrust) faults of the Dume and Malibu Coast fault system. This fault zone is a part of the southern boundary fault system of the Transverse Ranges Province. The western Transverse Ranges have rotated about 120 degrees clockwise and, in combination with the eastern Transverse Ranges are an impediment to relative Pacific and North American plate motion. The combined reverse fault system is among the most active in the world, and an incipient convergent margin.

Two exploratory wells have been drilled in the Federal offshore area of this play and five wells were drilled in State waters. Tar was observed in one well, and oil shows in another.

San Onofre Breccia Play

The Sano Onofre Breccia play is a frontier play that 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 the overlying nodular shale. The paly exists in non-continuous subareas, which encompass about 275 square miles (fig. 3-38). Depth to the reservoir section ranges from about 2,000 to 11,000 feet burial depth. Rocks were eroded from and deposited adjacent to the Palos Verdes paleohigh.

The petroleum source rock for this play is the lower middle Miocene nodular shale. In the onshore Los Angeles basin this unit is marine-kerogen rich and has total organic carbon of about 4 percent, and as much as 10 percent (Jeffrey and others, 1991). High heat flow has generated oil as shallow as 8,000 feet burial depth. Oil is typically moderately low gravity (less than 25 $^{\circ}$API) and high in sulphur content.

Reservoir rocks are primarily lower Miocene sandstones and breccias of the San Onofre Breccia, and fractured Cretaceous or older Catalina Schist. The lowermost portion of the nodular shale may be fractured, and if so has some potential as a reservoir. Reservoir quality may be variable. Porosity of analogous onshore reservoirs ranges from 12 to 31 percent.

Faults and pinchouts against local basement irregularities may provide a trapping mechanism. The overlying nodular shale may provide a seal as well as a potential source and reservoir rock. Analogous fields in the onshore Los Angeles basin range from 15 to 600 acres.

ECONOMIC FACTORS

Although there is only one developed field in the Los Angeles-Santa Monica-San Pedro area, the Los Angeles basin has the largest concentration of onshore facilities on the West Coast, and there are multiple coastal access points in the San Pedro and Santa Monica areas. Future development would likely be required to share pipelines and other facilities. The number of platforms would be minimized by the use of extended-reach drilling.

RESOURCE ESTIMATES

Undiscovered Technically Recoverable Resources

Play-specific estimates of undiscovered technically recoverable resources have been developed and 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 technically recoverable resources in the Los Angeles-Santa Monica-San Pedro assessment area is estimated to be 0.89 Bbbl of oil and 1.03 Tcf of associated gas (mean estimates). The low, mean, and high estimates of resources in the assessment area are listed in table 3-25.

Table 3-25. *Estimates of Undiscovered Technically Recoverable Oil and Gas Resources of the LA–SM–SP Area geologic plays and the Basin total. Resource values are in billion barrels of oil (Bbbl) and trillion cubic feet of gas (Tcf). 95% indicates a 95 percent chance of at least the amount listed; 5% indicates a 5 percent chance of at least the amount listed. Only mean values are additive. Some total mean values may not equal the sum of the component values due to independent rounding of the tabulated values.*

Geologic Play	Oil (Bbbl)			Gas (Tcf)			BOE (Bbbl)		
	95%	Mean	5%	95%	Mean	5%	95%	Mean	5%
Puente Fan Sandstone	0.09	0.30	0.64	0.11	0.33	0.55	0.11	0.35	0.74
Upper Miocene Sandstone	0.00	0.04	0.09	0.00	0.02	0.04	0.00	0.04	0.10
Modelo	0.00	0.15	0.44	0.00	0.21	0.40	0.00	0.18	0.52
Dume Thrust Fault	0.00	0.34	0.78	0.00	0.45	1.74	0.00	0.42	1.09
San Onofre Breccia	0.00	0.07	0.16	0.00	0.03	0.08	0.00	0.08	0.17
LA–SM–SP Area	**0.10**	**0.89**	**2.16**	**0.10**	**1.03**	**2.62**	**0.12**	**1.08**	**2.62**

Undiscovered Economically Recoverable Resources

Estimates of undiscovered technically recoverable resources that may be economically recoverable have been developed for various economic scenarios. Select data used to develop the resource estimates are shown in appendix D. These estimates are shown in fig. 3-41 as price-supply curves for a range of price scenarios, and for a gas market value of 40 percent of the energy equivalent value of oil. As a result of this assessment, 0.68 Bbbl of oil and 0.82 Tcf of associated gas are estimated to be economically recoverable from the Los Angeles – Santa Monica – San Pedro assessment area under economic conditions existing as of this assessment (i.e., the $90-per-barrel economic scenario). Larger volumes of resources are expected to be economically recoverable under increasingly favorable economic conditions.

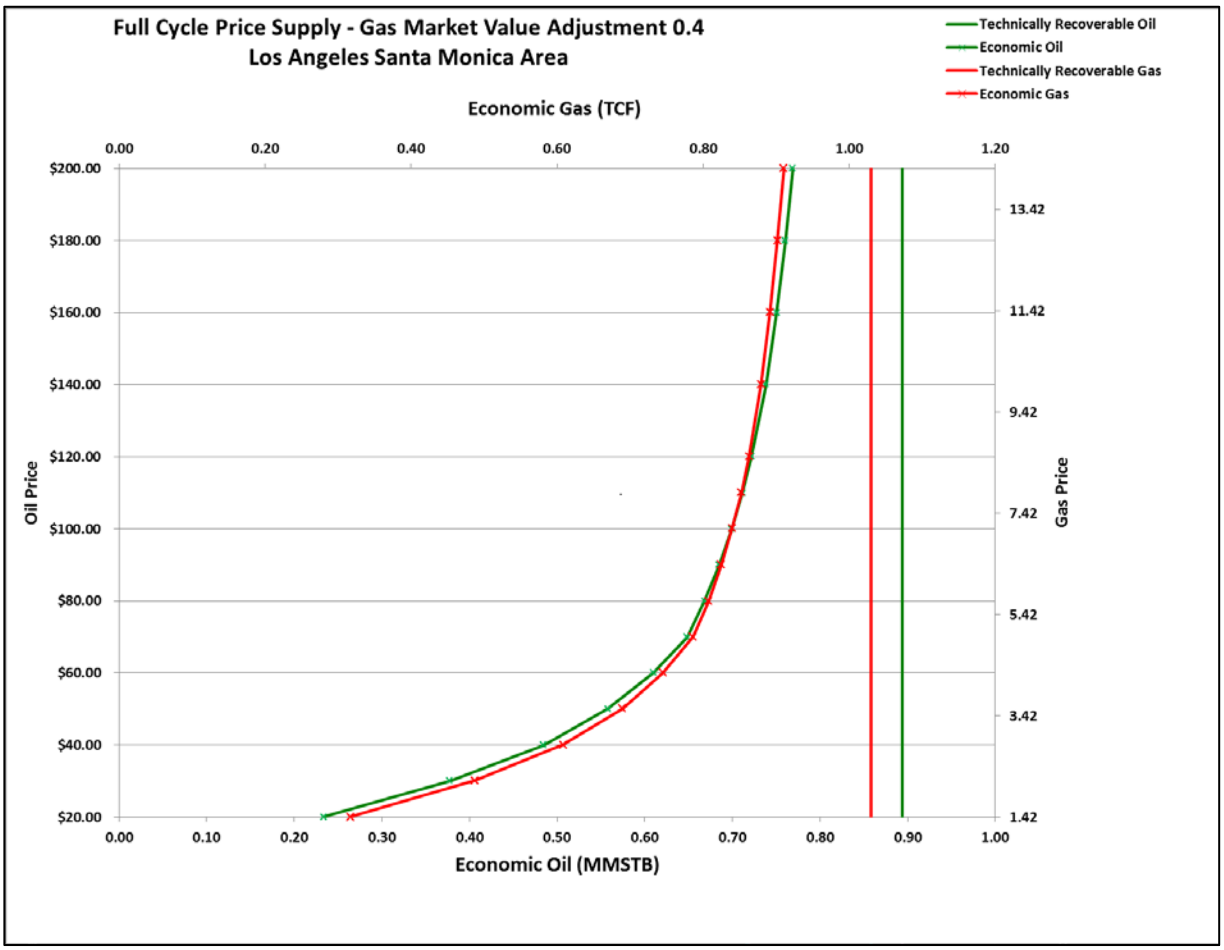


Figure 3-41. *Price-supply curves for the LA–SM–SP area. Oil prices are coupled with a specific gas price assuming a 40 percent economic value for gas relative to oil.*

Total Resource Endowment

As of this assessment, originally recoverable reserves (cumulative production plus remaining reserves) for LA−SM−SP Area were 108 MMbbl of oil and 34.8 Bcf of gas. Contingent resources were estimated to be 4.8 MMbbl of oil and 912 Mcf of gas (BOEMRE, 2010; unpublished BOEM data). These discovered resources and the undiscovered technically recoverable resources, all from the Puente Fan play, collectively compose the basin's estimated total resource endowment of 1.01 Bbbl of oil and 1.07 Tcf of gas (table 3-26).

Table 3-26. *Estimates of the total endowment of oil and gas resources in the LA−SM−SP Area. Estimates of discovered resources, including originally recoverable reserves and contingent resources, are as of January 1, 2009. Originally recoverable reserves include cumulative production and remaining reserves. Estimates of undiscovered technically 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)
Originally Recoverable Reserves	0.11	0.03	0.11
Contingent Resources	0.005	0.001	0.005
Undiscovered Technically Recoverable Resources	0.89	1.03	1.08
Total Resource Endowment	*1.01*	*1.07*	*1.20*

Additional References

Beyer, 1988
Crouch, 1990
Crouch, Bachman, and Associates, Inc., 1989a
Crouch, Bachman, and Associates, Inc., 1989b
Crouch and Suppe, 1993
Redin, 1991
Veder, 1987
Wright, 1991

OCEANSIDE BASIN

LOCATION

The Oceanside Basin assessment area is the southernmost area in the Inner Borderland province. Most of the basin is located offshore; a small, onshore part, referred to as the Capistrano syncline, was included in the 1995 assessment at the request of the USGS, which was doing the onshore and State water assessment in conjunction with MMS's federal offshore assessment. The current assessment considers only the part of the Oceanside basin that is in Federal water (fig. 3-42). The Oceanside basin is bounded on the northwest by the

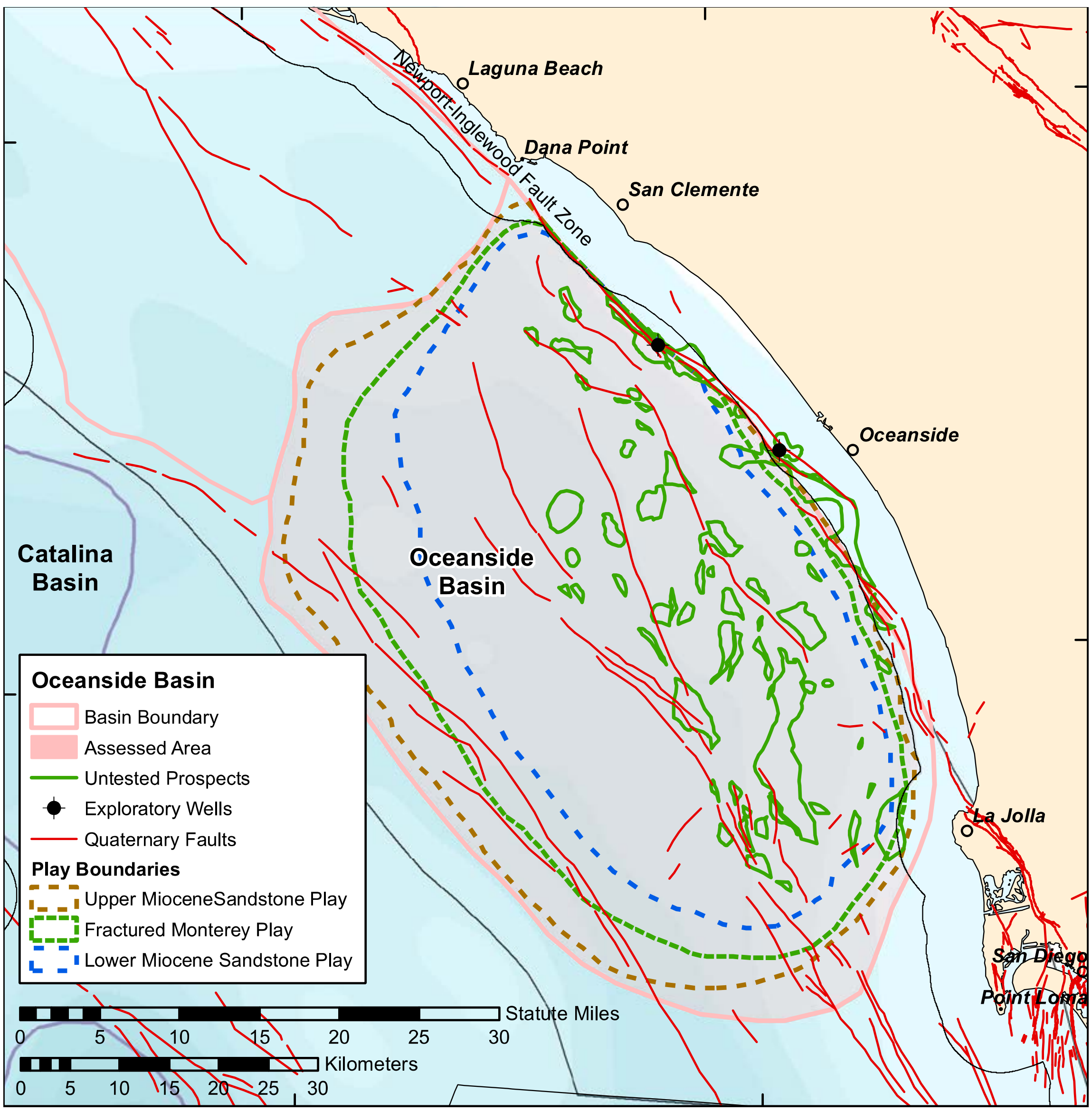


Figure 3-42. *Oceanside basin plays, exploratory wells and untested prospects.*

Dana Point sill and extends southerly about 50 miles to the vicinity of La Jolla; it is bounded on 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 300 to about 3,000 feet.

GEOLOGIC SETTING

The Oceanside basin is an asymmetrical structural trough filled with up to 11,000 feet of Cretaceous and Tertiary marine and nonmarine clastic rocks (fig. 3-43). The northwest-trending Newport-Inglewood fault zone lies offshore near the eastern margin of the basin; the fault has been a major feature in the tectonic and structural evolution of the basin. Large, compressional fault-bound 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 basin, as this is the same fault and structural trend along which several prolific oil fields exist in the onshore Los Angeles basin.

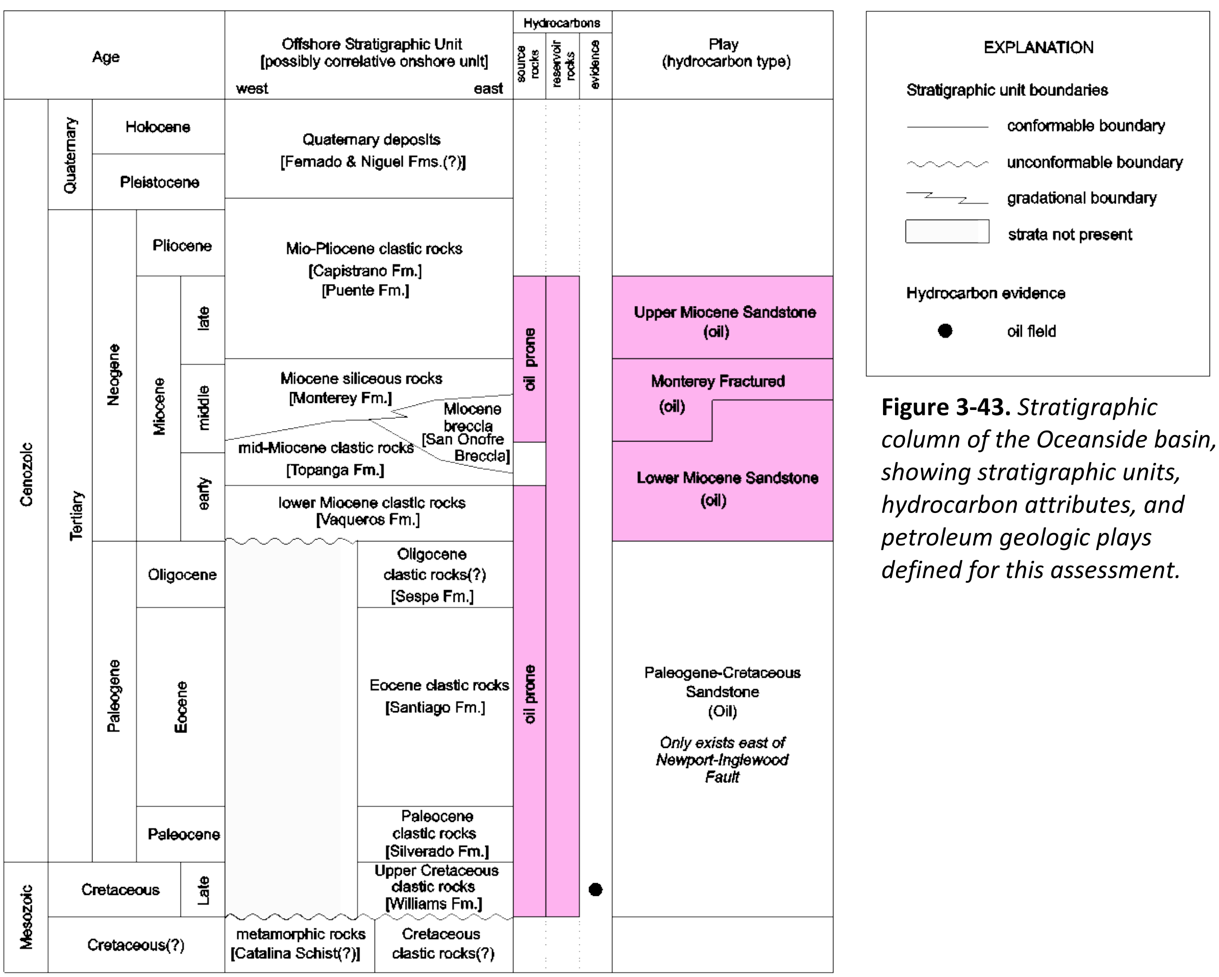


Figure 3-43. *Stratigraphic column of the Oceanside basin, showing stratigraphic units, hydrocarbon attributes, and petroleum geologic plays defined for this assessment.*

EXPLORATION

Onshore Los Angeles basin is one of the most prolific oil provinces in the world on a per-square-mile basis, and so far has produced about 9 Bbbl of oil. The Newport-Inglewood Trend and associated Wilmington Trend in the Los Angeles Basin have each produced over 3 billion barrels of oil. The Newport-Inglewood fault zone extends offshore down to San Diego where it continues onshore at La Jolla (figs. 3-42, 3-44). The Newport-Inglewood fault zone is the eastern boundary of the Inner Borderland province. The producing area is along the northern part of that trend, onshore and in State waters. The southern part of the trend borders Oceanside basin, and has only been tested by two exploratory stratigraphic test wells (Mobil San Clemente #1 and Shell Oceanside #1). 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. MMS mapping in the Oceanside Basin shows large structures along that trend and along associated trends further offshore (fig. 3-42). The 2011 BOEM assessment gives an estimate of over 1 billion barrels of oil and over 1 trillion cubic feet of natural gas for Oceanside basin. These estimates include geologic risk (possibility that the assessed plays will not be successful). If exploration drilling proves the existence of the plays, the estimates will increase.

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 significant wells was drilled in 1981 as an extension to the San Clemente field, and it was dry.

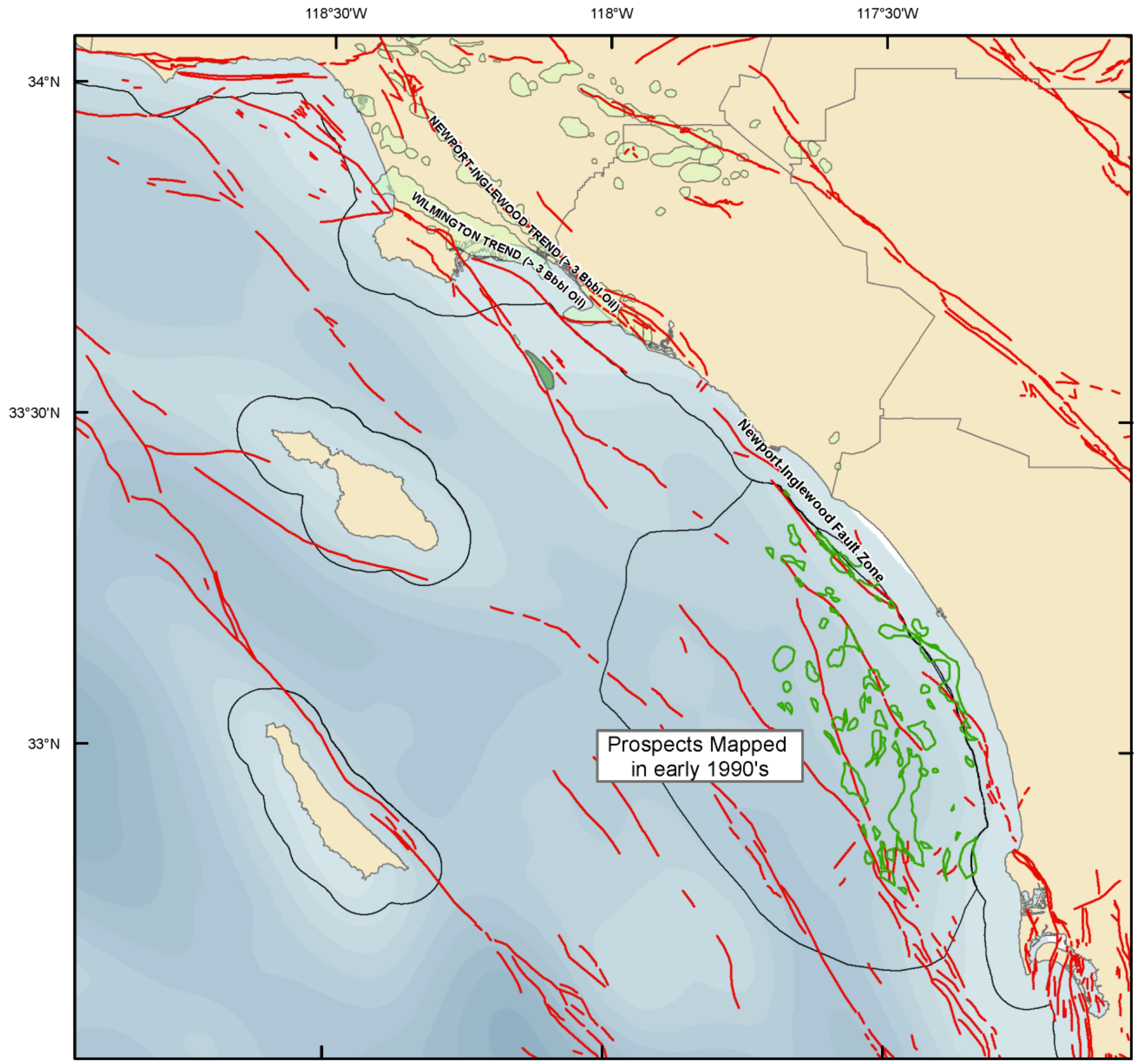


Figure 3-44. *Major oil-producing trends and mapped prospects in the Oceanside basin area.*

PLAYS

Four petroleum geologic plays were defined for the 1995 assessment, based on reservoir rock stratigraphy (figs. 3-42, 3-43): The Upper Miocene Sandstone play; the Fractured Monterey play; the Lower Miocene Sandstone play; and the Paleogene-Cretaceous Sandstone play. The Upper Miocene Sandstone, Fractured Monterey, 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. Rocks of the Paleogene-Cretaceous Sandstone play exist onshore and offshore east of the Newport-Inglewood fault zone; it is an established play because hydrocarbon accumulations have been discovered in the play onshore. The Newport – Inglewood fault zone lies approximately on the Federal-State boundary. Although potential reservoirs along the fault zone could be sourced from these rocks, it is considered as a minor constituent, and this play was removed from the current assessment.

Upper Miocene Sandstone Play

The Upper Miocene Sandstone play of the Oceanside 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. 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.

The primary petroleum source rocks for this play is considered to be the Monterey Formation. 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 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 basin. The Monterey is buried between 5,000 and 8,500 feet (corresponding to temperatures of about 185 to 270 ˚F, respectively), sufficient for petroleum generation.

Potential reservoir rocks in this play are upper Miocene channel and fan turbidite sandstones of the Capistrano Formation (fig. 3-43); these are probable stratigraphic equivalents to Puente Formation sandstones and lower “Repetto” strata in the Los Angeles basin. The Capistrano Formation contains sand-rich units that are regionally extensive across the 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–are evident within the Capistrano Formation 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. Both of the coreholes that were drilled in the offshore part of the basin penetrated rocks of this play. No shows of hydrocarbons were encountered.

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.

Fractured Monterey Play

The Fractured Monterey play of the Oceanside 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 basin (fig. 3-42). 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.

The Monterey Formation is considered to be both source rock and reservoir rock for this play (fig. 3-43) 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 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 basin. The Monterey is buried between 5,000 and 8,500 feet (corresponding to temperatures of about 185 to 270 °F, respectively) sufficient to permit petroleum generation throughout the formation.

Potential reservoir rocks in this play include fractured shale, dolomitic limestone, sandstone, siltstone, and chert of the Monterey Formation (fig. 3-43). Monterey rocks in the offshore Oceanside 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 higher in clastic content (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. One of the coreholes (Mobil San Clemente) that was drilled in the offshore part of the basin penetrated rocks of the Monterey Formation. No shows of hydrocarbons were encountered.

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.

Lower Miocene Sandstone Play

The Lower Miocene Sandstone play of the Oceanside 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 in the eastern two-thirds of the (fig. 3-42). 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.

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. 3-43). Monterey rocks in other California coastal basins are rich in organic matter, and similar rocks are presumed to exist in the Oceanside basin. The Monterey is buried between 5,000 and 8,500 feet, sufficient to permit petroleum generation. The other potential sources deeper; any organic-rich shales could generate petroleum to source this play.

Potential reservoir rocks in this play include sandstones, siltstones, and conglomerates of the Vaqueros and Topanga Formations and the San Onofre Breccia (fig. 3-43). 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 sandstones 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.

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 basin.

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.

Economic Factors

There are no developed fields in the Oceanside basin; however there are multiple viable coastal access points. Any future development would likely be required to share pipelines and other facilities. The number of platforms could be minimized by the use of extended-reach drilling.

Resource Estimates

Undiscovered Technically Recoverable Resources

Play-specific estimates of undiscovered technically 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 technically recoverable resources in the Oceanside Basin assessment area is estimated to be 1.06 Bbbl of oil and 1.12 Tcf of associated gas (mean estimates). The low, mean, and high estimates of resources in the assessment area are listed in table 3-27.

Table 3-27. *Estimates of Undiscovered Technically Recoverable Oil and Gas Resources of the Oceanside basin geologic plays and the Basin total. Resource values are in billion barrels of oil (Bbbl) and trillion cubic feet of gas (Tcf). 95% indicates a 95 percent chance of at least the amount listed; 5% indicates a 5 percent chance of at least the amount listed. Only mean values are additive. Some total mean values may not equal the sum of the component values due to independent rounding of the tabulated values.*

Geologic Play	Oil (Bbbl)			Gas (Tcf)			BOE (Bbbl)		
	95%	Mean	5%	95%	Mean	5%	95%	Mean	5%
Upper Miocene Sandstone	0.00	0.50	1.31	0.00	0.26	0.67	0.00	0.55	1.43
Fractured Monterey	0.00	0.39	1.01	0.00	0.44	1.01	0.00	0.47	1.19
Lower Miocene Sandstone	0.00	0.17	0.67	0.00	0.42	1.48	0.00	0.25	0.94
Oceanside Basin	**0.00**	**1.06**	**2.94**	**0.00**	**1.12**	**3.51**	**0.00**	**1.26**	**3.56**

Undiscovered Economically Recoverable Resources

Estimates of the portion of the technically recoverable resources that can be economically recovered under various economic scenarios were developed by including the effects of current and expected future economic factors. Select data used to develop the resource estimates are shown in appendix D. These estimates are shown in fig. 3-45 as price-supply curves for a range of price scenarios, and for a gas market value of 40 percent of the energy equivalent value of oil. As a result of this assessment, 0.88 Bbbl of oil and 0.93 Tcfof associated gas are estimated to be economically recoverable from the Oceanside Basin assessment area under economic conditions existing as of this assessment (i.e., the $90-per-barrel economic scenario). Larger volumes of resources are expected to be economically recoverable under increasingly favorable economic conditions.

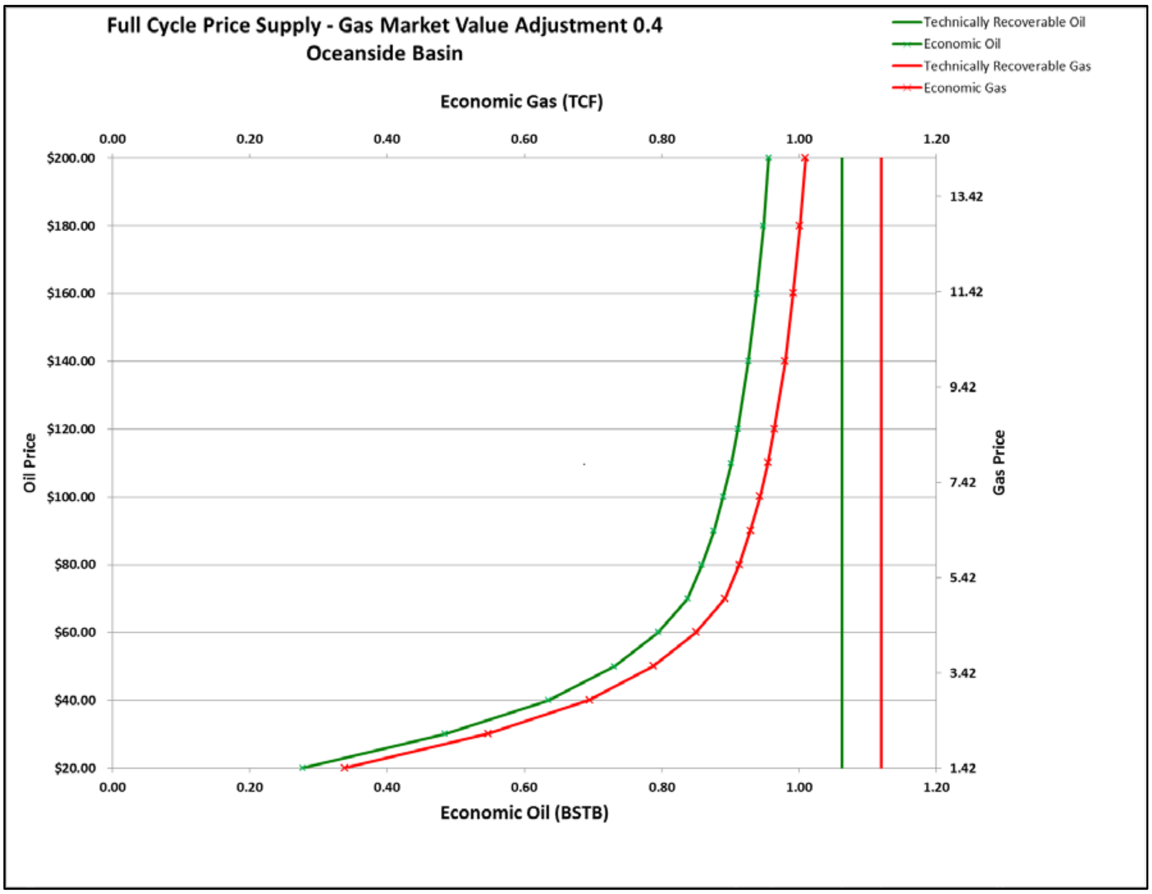


Figure 3-45. *Price-supply curves for the Oceanside basin. Oil prices are coupled with a specific gas price assuming a 40 percent economic value for gas relative to oil.*

ADDITIONAL REFERENCES

Crouch, 1993
Crouch and Suppe, 1993
Crouch, Bachman, and Associates, 1989a
Vedder, 1987
Wright, 1991

OUTER BORDERLAND PROVINCE

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 (Patton Escarpment); to the east, it is bounded by the Santa Cruz-Catalina ridge and the Thirtymile bank (fig. 3-46).

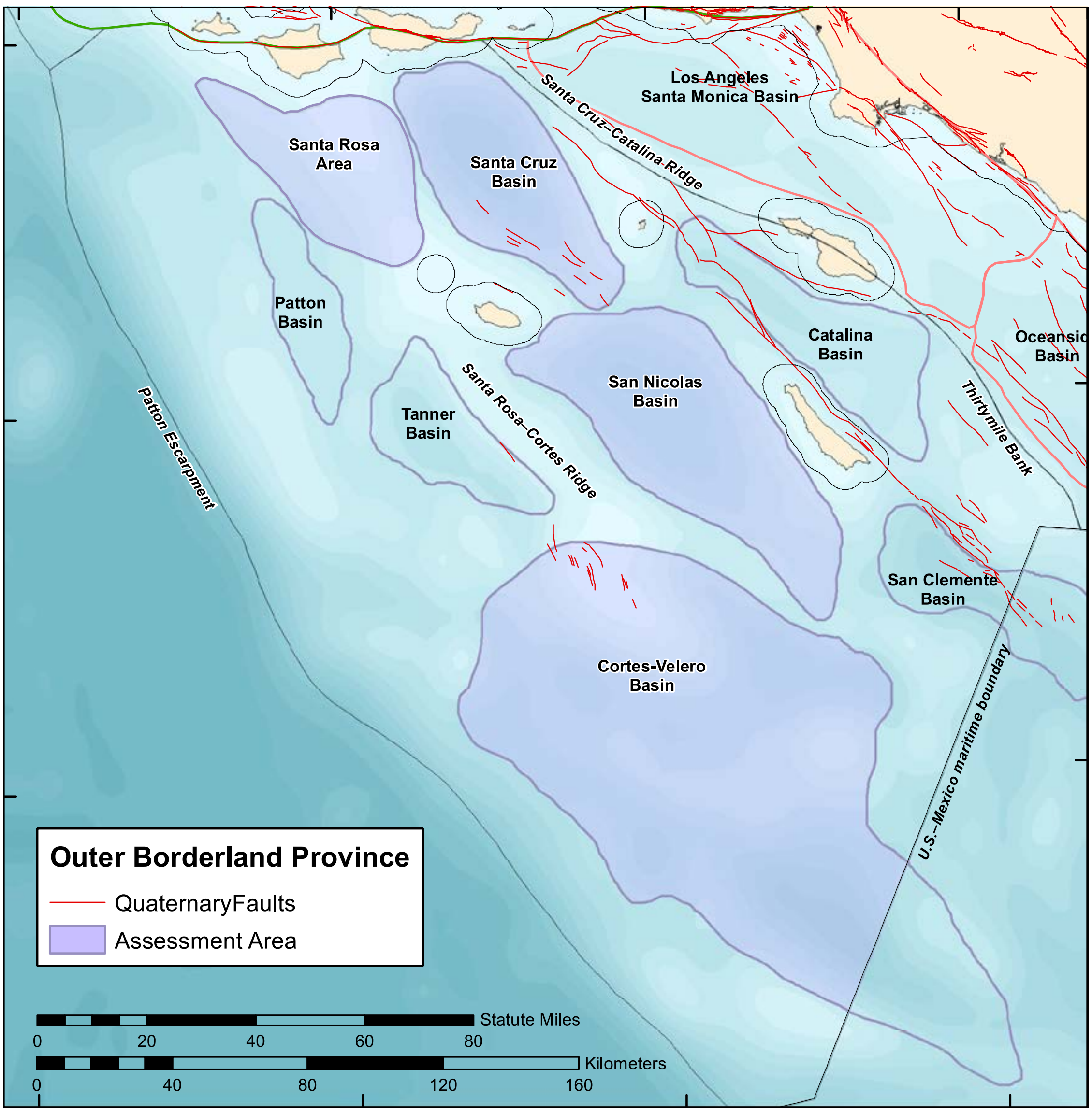


Figure 3-46. *Outer Borderland basins and areas. Assessed basins are colored purple.*

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, San Nicolas basin, Cortes basin, Velero basin, and Long basin. The Santa Rosa area was a part of the Santa Cruz basin during the Cretaceous and Paleogene, but has since been uplifted. For purposes of assessment, the two have been combined. 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, Tanner, Catalina, and San Clemente basins.

GEOLOGIC SETTING

Upper Cretaceous and Tertiary rocks are present in most of the geologic basins and areas in the province. Many of the existing basin geometries in this province formed during the Miocene as the result of extension and rotation of the continental borderland. Its distal location and intervening islands and ridges resulted in a relatively sediment-starved and therefore thinner Neogene section compared to the Inner Borderland province, and it is considered as a separate province for assessment purposes. 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 AND DISCOVERY STATUS

A deep stratigraphic test well (OCS-CAL 75-70 No. 1) was drilled on Cortes Bank in 1975 (Paul and others, 1976) and nine exploratory oil and gas wells were 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). Most of these wells are drilled on the peripheries of basins or on banks and are of limited use in interpreting the nature and extent of strata within the basins. This is probably because deep-water drilling was difficult and expensive at the time the wells were drilled. No appreciable hydrocarbon shows were encountered, although there are weak indications of hydrocarbons. Recent reviews of digital seismic data do show amplitude and other anomalies that are suggestive of the presence of gas, which may be associated with oil. These deep and distal basins may be a prospective target for methane hydrates, as they receive relatively little clastic sedimentation and are expected to be rich in organic compounds.

Stratigraphic and paleontologic data from the offshore wells and a relatively sparse grid of 2-D seismic data obtained in the 1970's and 1980's are the bases for interpretation of the offshore geology. No newer data exists than that used for the 1995 assessment.

Outer Borderland Province Plays

Three basins/areas were assessed. Well data from peripheral banks and ridges indicate the presence of lower Miocene, Paleogene, and Cretaceous strata. Younger strata exist, but are eroded off on the structurally elevated areas. In areas where younger section is sufficiently thick to be considered as capable of oil entrapment, plays have been defined to incorporate that section. In all three areas a Lower Miocene Sandstone play and a Paleogene-Cretaceous play are defined. In each case expected source rocks are organic mudstones and shales interbedded with reservoir sandstones. In the Santa Rosa-Santa Cruz area and the San Nicolas basin a middle Miocene Fractured Monterey play is defined; as with similar Monterey plays it is considered self-sourcing. In the San Nicolas basin, sufficient younger section exists to define an Upper Miocene Sandstone play sourced primarily from the underlying Monterey section.

Because of their distal position relative to the southern California mainland, sediments that are middle Miocene and younger are expected to be clastic-sediment starved, and therefore highly enriched in pelagic sedimentation from microscopic plants and animals. Although these younger sediments are therefore expected to be rich in the organic nutrients that make up oil and gas, they are not buried deep enough for thermogenic generation of oil or gas. However, these basins are also considered to have high potential for biogenic generation of natural gas hydrates. Natural gas hydrate potential of the Pacific Region is covered in a separate assessment. For information on natural gas hydrates, see the BOEM website (http://www.boem.gov/Oil-and-Gas-Energy-Program/Resource-Evaluation/Gas-Hydrates/GH-RA-Pacific.aspx).

Economic Factors

There is no oil and gas infrastructure within this province, and it is far from shore. Because of its remoteness, any future development would likely utilize a floating offshore storage and treatment facility, from which tankers could offload production. Should there be multiple platforms or subsea completions in a given area, these facilities could be shared among them. The number of platforms would be minimized by use of extended-reach drilling technology.

Resource Estimates

Undiscovered Technically Recoverable Resources

Estimates of the total volume of undiscovered technically recoverable resources within the Outer Borderland basins were developed by statistically aggregating the constituent play estimates within each basin. Estimates of the total volume of undiscovered technically recoverable resources in the province were developed by statistically aggregating all constituent basin estimates within the province. As a result of this assessment, the total volume of undiscovered technically recoverable resources in the Outer Borderland province is estimated to be 1.20 Bbbl of oil and 2.24 Tcf of associated gas (mean estimates). The low, mean and high estimates of resources are listed in table 3-28 for each of the basins and the province total.

Table 3-28. *Estimates of Undiscovered Technically Recoverable Oil and Gas Resources of the Outer Borderland Province by assessment area. Resource values are in billion barrels of oil (Bbbl) and trillion cubic feet of gas (Tcf). 95% indicates a 95 percent chance of at least the amount listed; 5% indicates a 5 percent chance of at least the amount listed. Only mean values are additive. Some total mean values may not equal the sum of the component values due to independent rounding of the tabulated values.*

Geologic Basin/Area	Oil (Bbbl)			Gas (Tcf)			BOE (Bbbl)		
	95%	Mean	5%	95%	Mean	5%	95%	Mean	5%
S. Cruz–S. Rosa	0.00	0.40	1.42	0.00	0.69	2.63	0.00	0.52	1.89
San Nicolas	0.00	0.49	1.84	0.00	0.79	3.17	0.00	0.63	2.40
Cortes–Velero–Long	0.00	0.31	1.28	0.00	0.76	3.11	0.00	0.45	1.84
Outer Borderland	**0.00**	**1.20**	**3.09**	**0.00**	**2.24**	**5.91**	**0.00**	**1.60**	**4.14**

Undiscovered Economically Recoverable Resources

Estimates of the portion of the technically recoverable resources that can be economically recovered under various economic scenarios were developed by including the effects of current and expected future economic factors. These estimates are listed in table 3-29 for each of the basins and the province total. As a result of this assessment, 0.31 Bbbl of oil and 0.57 Tcf 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 $90-per-barrel economic scenario). Larger volumes of resources are expected to be economically recoverable under increasingly favorable economic conditions (fig. 3-47).

Table 3-29. *Estimates of undiscovered economically recoverable oil and gas resources in the Outer Borderland Province as of January 1, 2009 for three economic scenarios, by assessment area. Oil prices are coupled with a specific gas price assuming a 40 percent economic value for gas relative to oil.*

Geologic	$60/bbl, $4.27/Mcf		$90/bbl, $6.41/Mcf		$120/bbl, $8.54/Mcf	
Basin/Area	Oil (Bbbl)	Gas (Tcf)	Oil (Bbbl)	Gas (Tcf)	Oil (Bbbl)	Gas (Tcf)
S. Cruz–S. Rosa	0.07	0.15	0.12	0.23	0.15	0.28
San Nicolas	0.16	0.28	0.18	0.32	0.19	0.34
Cortes-Velero-Long	0.00	0.01	0.00	0.02	0.01	0.04
Outer Borderlands	**0.23**	**0.44**	**0.31**	**0.57**	**0.35**	**0.65**

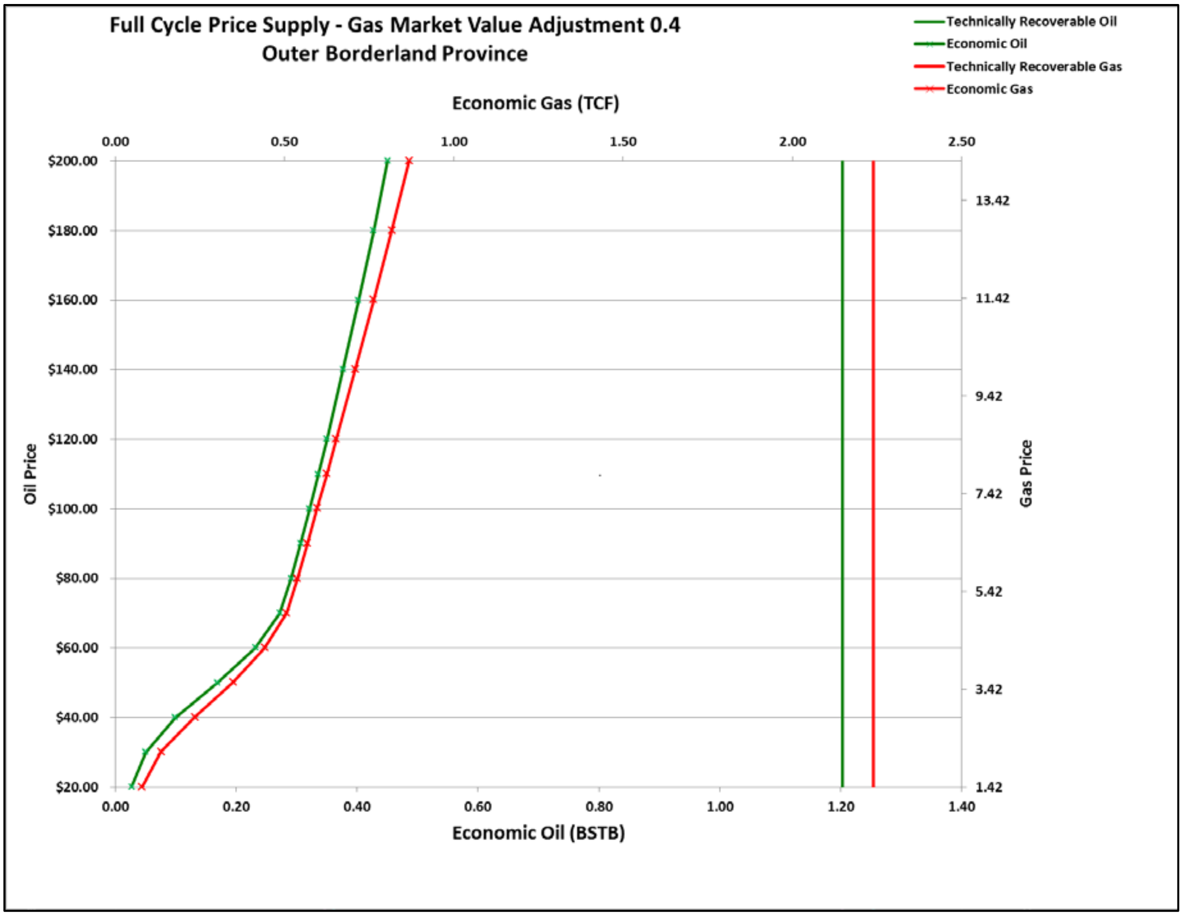


Figure 3-47. *Price-supply curves for the Outer Borderland province. Oil prices are coupled with a specific gas price assuming a 40 percent economic value for gas relative to oil.*

ADDITIONAL REFERENCES FOR OUTER BORDERLAND PROVINCE

Crouch and Suppe, 1993
Vedder, 1987

Santa Cruz-Santa Rosa Area

Location

The Santa Cruz-Santa Rosa assessment area occupies the northern portion of the Outer Borderland province (fig. 3-46). 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 (fig. 3-48).

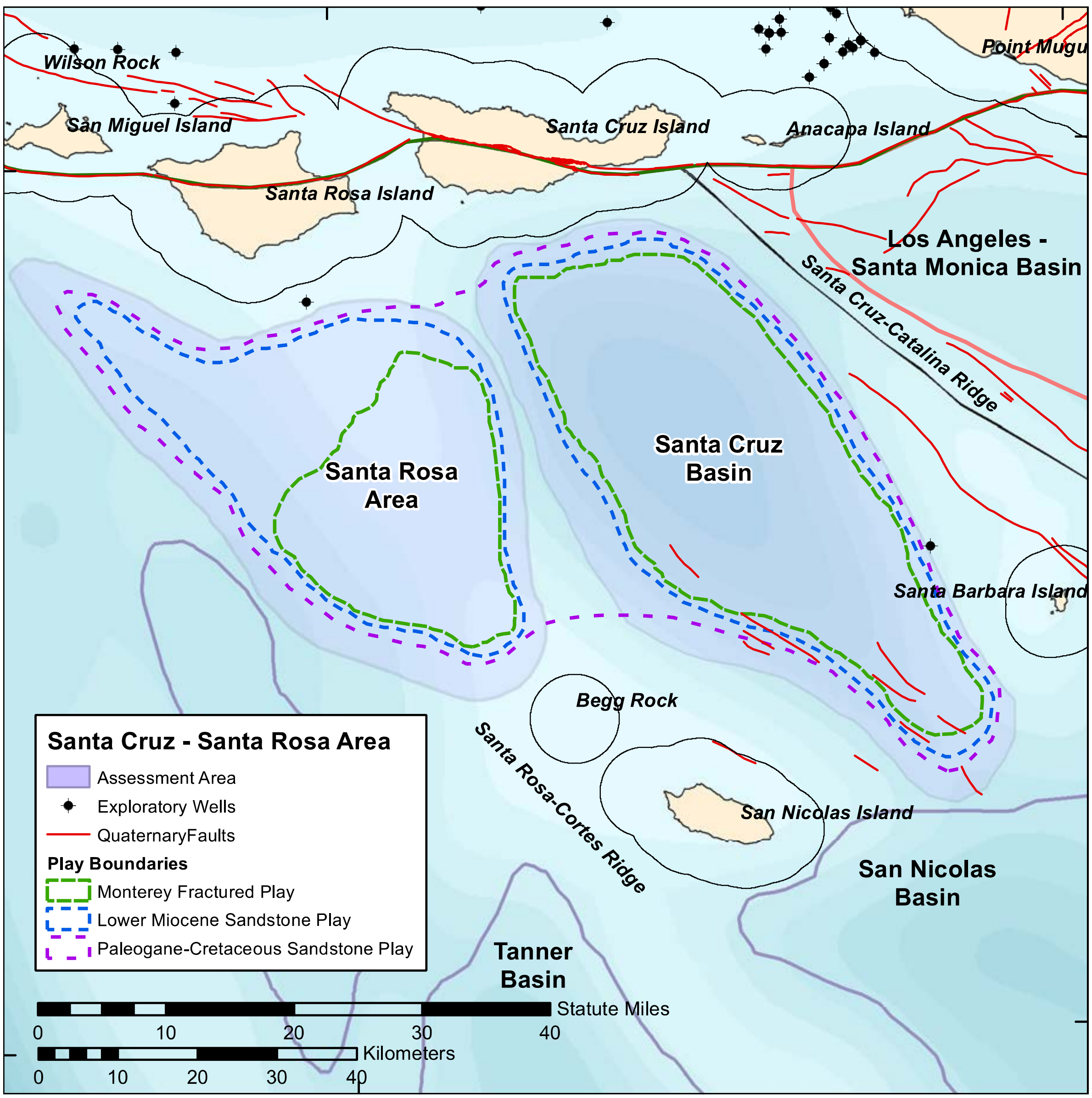


Figure 3-48. *Santa Cruz-Santa Rosa area plays and adjacent exploratory wells.*

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. 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. 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

Prior to late Miocene, the Santa Cruz basin and Santa Rosa area were one continuous basin. Up to 6,000 feet of Upper Cretaceous, Paleogene, and Miocene clastic strata were deposited. The western part of the area was uplifted. As a result, the Santa Cruz basin is asymmetrical, with the main depocenters to the east. The resulting Santa Cruz basin is an elongate, northwest-trending basin, which contains up to approximately 9,000 feet of Upper Cretaceous through Quaternary strata. Post-Miocene compression 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. Upper Miocene and younger strata are very thin or nonexistent within the Santa Rosa area due to extremely low depositional rates and erosion. A number of relatively small, low relief structures, which may contain oil and gas, exist in the area.

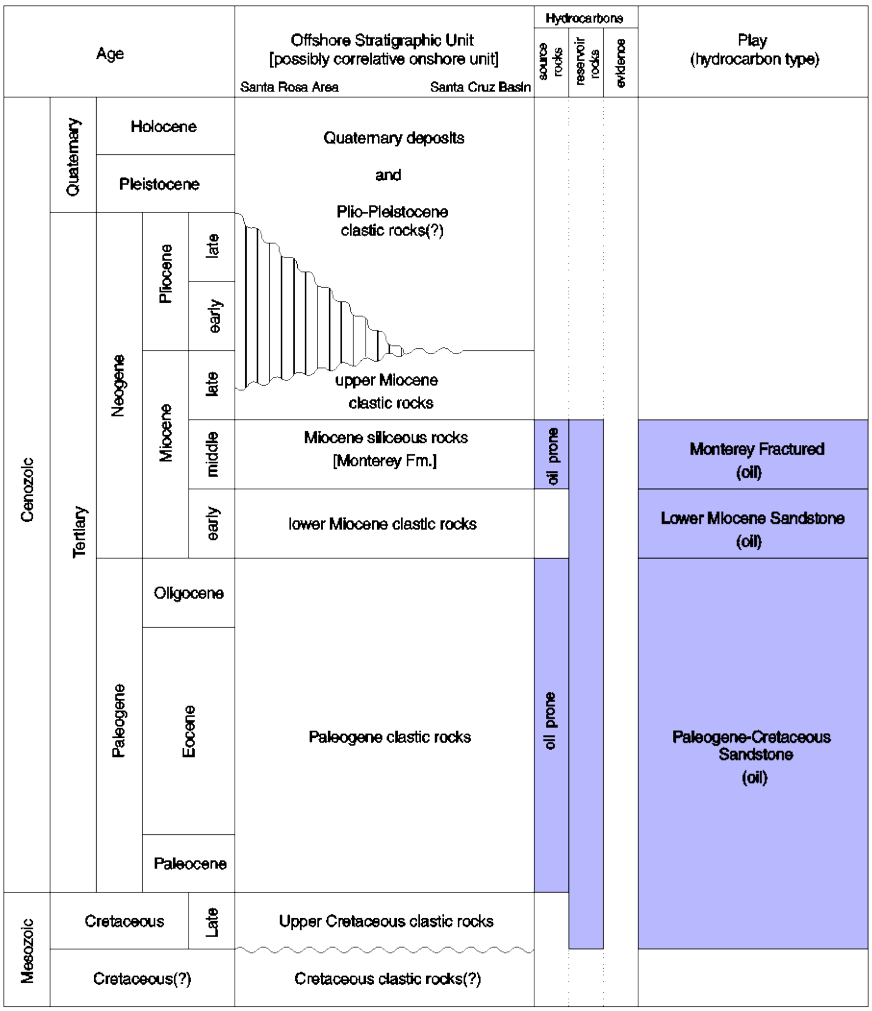
EXPLORATION

No exploratory wells have been drilled within the Santa Cruz–Santa Rosa assessment area; one well (OCS-P 289 #1) was drilled across a fault immediately east of the Santa Cruz basin, and another well (OCS-P 0245 #1) was drilled across a fault 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 locally younger strata are present in the Santa Cruz–Santa Rosa assessment 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

Three petroleum geologic plays were defined in the Santa Cruz-Santa Rosa assessment area based on reservoir rock stratigraphy ([figs. 3-48](), [3-49]()): The Fractured Monterey play, a Lower Miocene Sandstone play, and a Paleogene–Cretaceous Sandstone play.



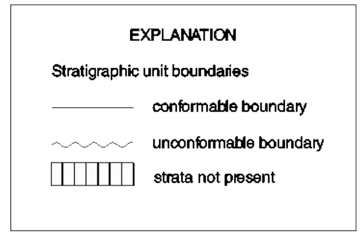


Fig 3-49. *Stratigraphic column of the Santa Cruz-Santa Rosa area, showing stratigraphic units, hydrocarbon attributes, and petroleum geologic plays defined for this assessment.*

The Fractured Monterey and Lower Miocene Sandstone play are confined to the Santa Cruz basin proper and the Santa Rosa area proper and have been assessed separately in each area. The Paleogene-Cretaceous Sandstone play exists within and between both areas and has been assessed for both areas together.

The plays in the Santa Cruz-Santa Rosa assessment area are all 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.

Fractured Monterey Play

The Fractured Monterey play of the Santa Cruz basin and the Santa Rosa area is a conceptual plays consisting of accumulations of oil and associated gas in middle Miocene fractured siliceous rocks of the Monterey Formation. 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, and 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.

The Monterey Formation is considered to be both petroleum source rock and reservoir rock for this play by analogy with Monterey rocks in the offshore Santa Barbara−Ventura and Santa Maria basins and the onshore San Joaquin basin. Monterey rocks in other California coastal basins are rich in organic matter, and similar rocks are presumed to exist in the Santa Cruz–Santa Rosa area. 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 this play is predicted to be of moderate (less than 30 °API) gravity.

Potential reservoir rocks include middle Miocene fractured, siliceous and calcareous shales and cherts, and perhaps some basal clastic rocks of the Monterey Formation. 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 charts 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.

Neither of the exploratory wells adjacent to the Santa Cruz-Santa Rosa assessment area penetrated rocks similar to those included in this play. 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.

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.

Lower Miocene Sandstone Play

The Lower Miocene Sandstone play of the Santa Cruz basin and the Santa Rosa area is a conceptual play consisting of accumulations of oil and associated gas in lower Miocene clastic rocks. Because the play is confined to the Santa Cruz basin proper and the Santa Rosa area proper, it has been individually assessed in each area. The play encompasses an area of about 750 square miles in each basin. Burial depth for reservoir rocks in the play in this basin ranges from 3,000 to 6,500 feet in the Santa Cruz basin and 2,000 to 4,500 in the Santa Rosa area.

The primary potential petroleum source rocks for this play are Paleogene mudstones and shales (fig. 3-49). 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 this play.

Potential reservoir rocks include lower Miocene sandstones (fig. 3-49). Lower Miocene strata penetrated in the wells adjacent to the basin (OCS-P 0245 #1, OCS-P 0289 #1), and in the wells drilled 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 aerially 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 the plays are small to moderate anticlinal folds and associated reverse-fault traps.

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.

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. Estimates of undiscovered technically recoverable resources in each play have been developed using the subjective assessment method using a combination of play-specific and analog data.

Paleogene-Cretaceous Sandstone Play

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 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.

The primary potential petroleum source rocks for this play are Paleogene mudstones and shales described in the previous section.

Potential reservoir rocks in this play are Paleogene and Cretaceous sandstones. 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 quite high; on average, sandstone composes approximately 50 percent of the total Paleogene section. Based on seismic mapping and well correlations, rocks inferred to be of Paleogene and Cretaceous age are aerially 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.

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. 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.

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.

Economic Factors

There is no oil and gas infrastructure within the Outer Borderland province, and it is far from shore. Because of its remoteness, any future development would likely utilize a floating offshore storage and treatment facility, from which tankers could offload production. Should there be multiple platforms or subsea completions in a given area, these facilities could be shared among them. The number of platforms would be minimized by use of extended-reach drilling technology.

Resource Estimates

Undiscovered Technically Recoverable Resources

Play-specific estimates of undiscovered technically recoverable resources were developed and 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 technically recoverable resources in the Santa Cruz-Santa Rosa assessment area is estimated to be 0.40 Bbbl of oil and 0.69 Tcf of associated gas (mean estimates). The majority of these resources (67 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 3-30.

Table 3-30. *Estimates of Undiscovered Technically Recoverable Oil and Gas Resources of the Santa Cruz-Santa Rosa area geologic plays and the Basin total. Resource values are in billion barrels of oil (Bbbl) and trillion cubic feet of gas (Tcf). 95% indicates a 95 percent chance of at least the amount listed; 5% indicates a 5 percent chance of at least the amount listed. Only mean values are additive. Some total mean values may not equal the sum of the component values due to independent rounding of the tabulated values.*

Geologic Play	Oil (Bbbl)			Gas (Tcf)			BOE (Bbbl)		
	95%	Mean	5%	95%	Mean	5%	95%	Mean	5%
S. Cruz Fractured Monterey	0.00	0.20	0.52	0.00	0.22	0.88	0.00	0.24	0.67
S. Cruz Lower Miocene Ss	0.00	0.08	0.24	0.00	0.19	0.70	0.00	0.11	0.36
S. Rosa Fractured Monterey	0.00	0.03	0.13	0.00	0.04	0.21	0.00	0.04	0.16
S. Rosa Lower Miocene Ss	0.00	0.02	0.12	0.00	0.06	0.40	0.00	0.04	0.19
Paleogene-Cretaceous Ss	0.00	0.07	0.28	0.00	0.18	1.23	0.00	0.11	0.50
Sta. Cruz-Sta. Rosa Area	**0.00**	**0.40**	**1.42**	**0.00**	**0.69**	**2.63**	**0.00**	**0.52**	**1.89**

Undiscovered Economically Recoverable Resources

Estimates of the portion of the technically recoverable resources that can be economically recovered under various economic scenarios were developed by including the effects of current and expected future economic factors. Select data used to develop the resource estimates are shown in appendix D. These estimates are shown in fig. 3-50 as price-supply curves for a range of price scenarios, and for a gas market value of 40 percent of the energy equivalent value of oil. As a result of this assessment, 0.12 Bbbl of oil and 0.23 Tcf 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 $90-per-barrel economic scenario). Larger volumes of resources are expected to be economically recoverable under increasingly favorable economic conditions.

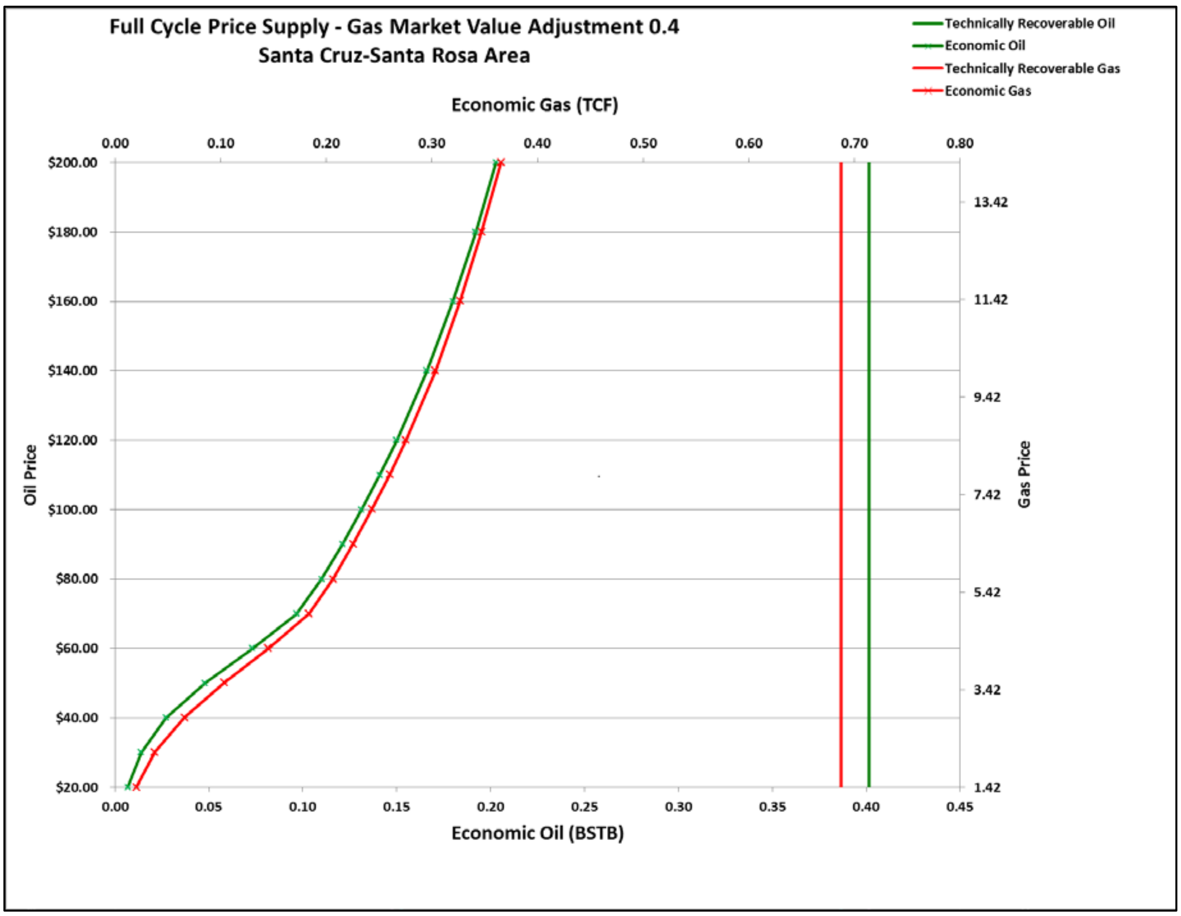


Figure 3-50. *Price-supply curves for the Santa Cruz-Santa Rosa area. Oil prices are coupled with a specific gas price assuming a 40 percent economic value for gas relative to oil.*

San Nicolas Basin

Location

The San Nicolas Basin assessment area is located immediately southeast of San Nicolas Island in the Outer Borderland province (fig. 3-46). The basin is bounded on the east by the San Clemente ridge and on the west by the Santa Rosa-Cortes ridge. It is about 70 miles long by 10 to 30 miles in wide 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 (fig. 3-51).

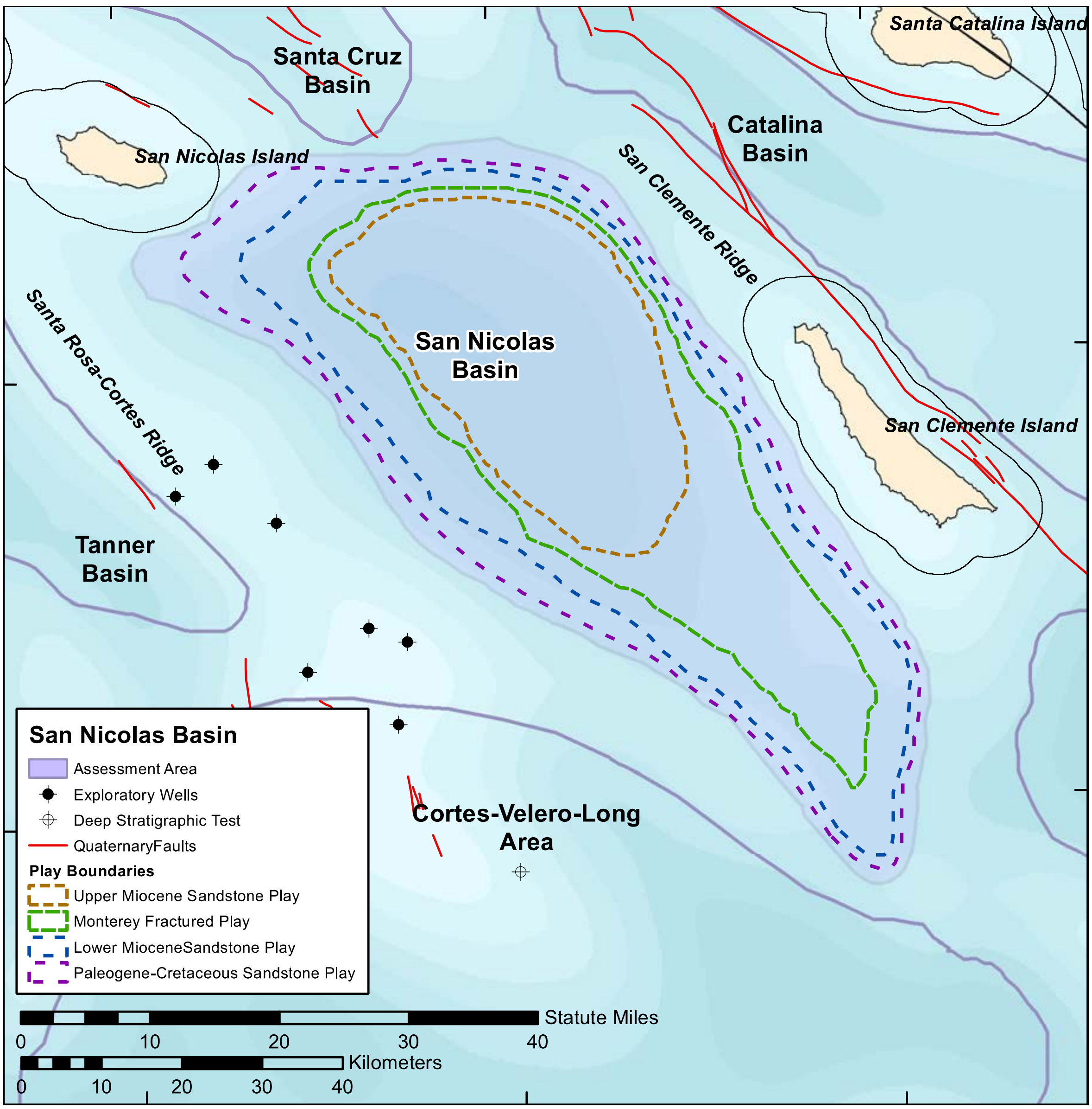


Figure 3-51. *San Nicolas basin plays and nearby exploratory wells.*

GEOLOGIC SETTING

The San Nicolas basin is an elongate, northwest-trending basin, which contains up to 12,000 feet of Upper Cretaceous through Quaternary strata (figs. 3-51, 3-52). 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.

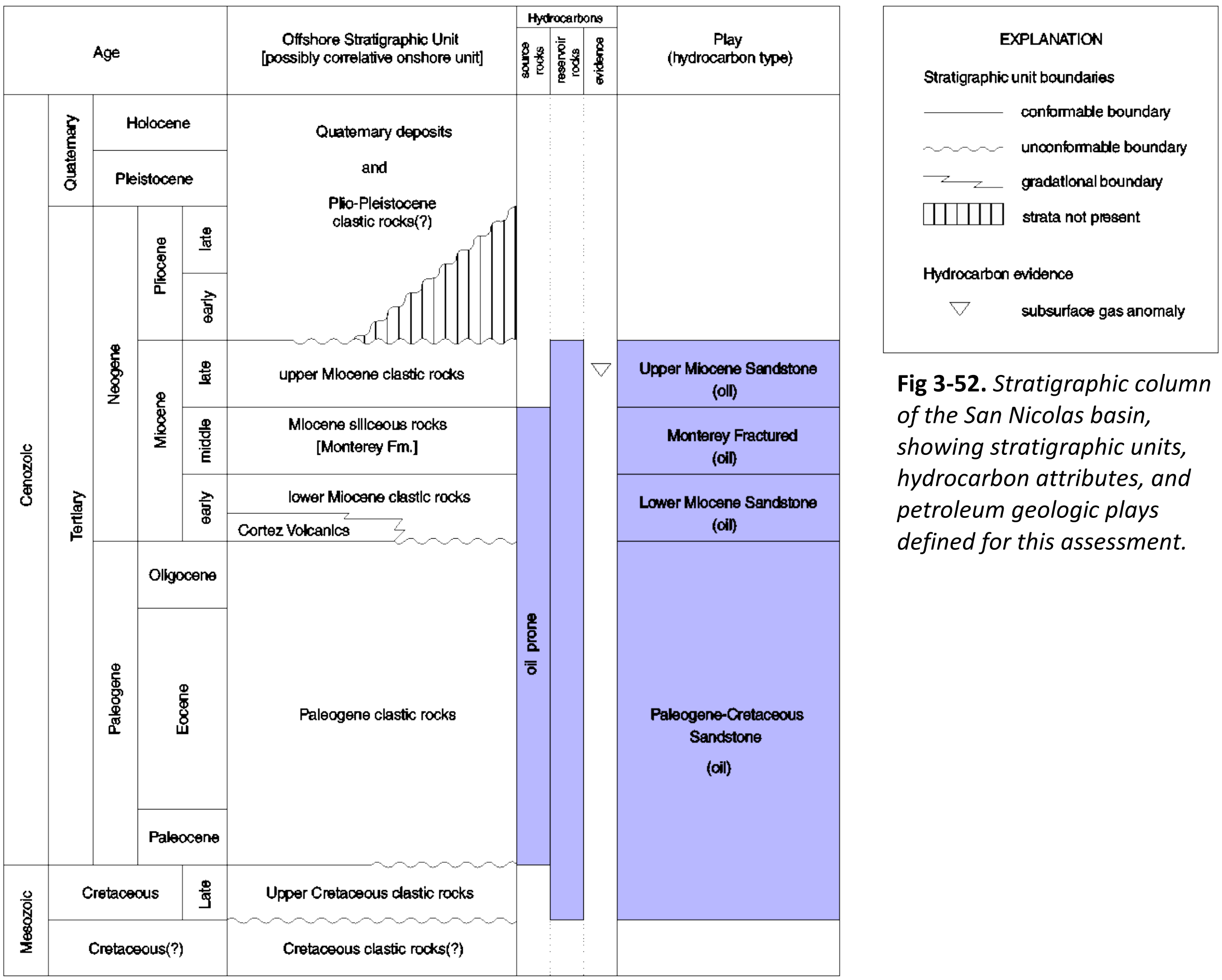


Fig 3-52. *Stratigraphic column of the San Nicolas basin, showing stratigraphic units, hydrocarbon attributes, and petroleum geologic plays defined for this assessment.*

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 the absence of significant unconformities within the post-lower Miocene section 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 evident on seismic profiles.

PLAYS

Four petroleum geologic plays have been defined in the San Nicolas basin on the basis of reservoir rock stratigraphy (fig. 3-52). The plays consist of Upper Miocene Sandstone, Fractured Monterey, Lower Miocene Sandstone, and Paleogene-Cretaceous Sandstone plays. 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.

Upper Miocene Sandstone Play

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. 3-51). The depth to reservoir rocks in the play ranges from 1,000 to 5,000 feet below the seafloor.

Potential petroleum source rocks for this play are middle Miocene shales of the Monterey Formation. The type and amount of organic matter within Monterey rocks of the San Nicolas 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 San Nicolas basin. The Monterey is buried no more than 6,000 feet; however, the existence of “diagenetic reflectors” on seismic profiles suggests that temperatures conducive to silica diagenesis and petroleum generation have been attained in Monterey rocks. By analogy with other Monterey-sourced oil, 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. Seismic profiles suggest that the average thickness of the unit upper Miocene section is about 2,000 feet, and maximum thickness is about 4,000 feet. Potential reservoir sandstones should have good to excellent porosity and permeability based on burial depth and depositional history.

Strata penetrated by the wells included fine- to medium-grained sandstones with log-derived porosities of 23 to 32 percent and good permeability.

Northwest-trending, relatively low relief, simple anticlines are the dominant trap. 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.

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 evident on seismic profiles.

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.

Fractured Monterey Play

The Fractured Monterey 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. 3-51). The depth to reservoir rocks in the play ranges from 3,600 to 6,500 feet below the seafloor.

The Monterey Formation is considered to be both petroleum source rock and reservoir rock for this play by analogy with Monterey rocks in the offshore Santa Barbara–Ventura and Santa Maria basins and the onshore San Joaquin basin. 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 Monterey is buried no more than 6,000 feet; however, the existence of “diagenetic reflectors” on seismic profiles suggests that temperatures conducive to silica diagenesis and petroleum generation have been attained in Monterey rocks. By analogy with other areas, 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. 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. Anticlinal traps are expected to be the dominant type.

None of the exploratory wells adjacent to the San Nicolas basin penetrated rocks similar to those included in this play because middle Miocene and younger strata have been eroded 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.

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.

Lower Miocene Sandstone Play

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. 3-51). The depth to reservoir rocks in the play ranges from 4,000 to 8,500 feet, and averages 7,500 feet below the seafloor.

The primary potential petroleum source rocks for this play are Paleogene and lower Miocene mudstones and shales (fig. 3-52). 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. 3-52). 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 aerially 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.

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.

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.

Paleogene-Cretaceous Sandstone Play

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. 3-51). The depth to reservoir rocks in the play ranges from 8,000 to 11,000 feet and averages 9,000 feet below the seafloor.

The primary potential petroleum source rocks for this play are Paleogene mudstones and shales (fig. 3-52). 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. 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. 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 aerially extensive throughout the 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.

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.

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.

ECONOMIC FACTORS

There is no oil and gas infrastructure within the Outer Borderland province, and it is far from shore. Because of its remoteness, any future development would likely utilize a floating offshore storage and treatment facility, from which tankers could offload production. Should there be multiple platforms or subsea completions in a given area, these facilities could be shared among them. The number of platforms would be minimized by use of extended-reach drilling technology.

RESOURCE ESTIMATES

Undiscovered Technically recoverable Resources

Play-specific estimates of undiscovered technically recoverable resources were developed and 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 technically recoverable resources in the San Nicolas basin is estimated to be 0.49 Bbbl of oil and 0.79 Tcf of associated gas (mean estimates). The low, mean, and high estimates of resources in the assessment area are listed in table 3-31.

Undiscovered Economically Recoverable Resources

Estimates of the portion of the technically recoverable resources that can be economically recovered under various economic scenarios were developed by including the effects of current and expected future economic factors. Select data used to develop the resource estimates are shown in appendix D. These estimates are shown in fig. 3-53 as price-supply curves for a range of price scenarios, and for a gas market value of 40 percent of the energy equivalent value of oil. As a result of this assessment, 0.18 Bbbl of oil and 0.32 Tcf 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 $90-per-barrel economic scenario). Larger volumes of resources are expected to be economically recoverable under increasingly favorable economic conditions.

Table 3-31. *Estimates of Undiscovered Technically Recoverable Oil and Gas Resources of the San Nicolas basin geologic plays and the Basin total. Resource values are in billion barrels of oil (Bbbl) and trillion cubic feet of gas (Tcf). 95% indicates a 95 percent chance of at least the amount listed; 5% indicates a 5 percent chance of at least the amount listed. Only mean values are additive. Some total mean values may not equal the sum of the component values due to independent rounding of the tabulated values.*

Geologic Play	Oil (Bbbl)			Gas (Tcf)			BOE (Bbbl)		
	95%	Mean	5%	95%	Mean	5%	95%	Mean	5%
Upper Miocene Sandstone	0.00	0.07	0.29	0.00	0.04	0.19	0.00	0.08	0.32
Fractured Monterey	0.00	0.20	0.68	0.00	0.23	0.72	0.00	0.24	0.80
Lower Miocene Sandstone	0.00	0.12	0.51	0.00	0.30	1.08	0.00	0.18	0.70
Paleogene-Cretaceous Ss	0.00	0.09	0.44	0.00	0.23	0.75	0.00	0.13	0.57
San Nicolas Basin	**0.00**	**0.49**	**1.84**	**0.00**	**0.79**	**3.17**	**0.00**	**0.63**	**2.40**

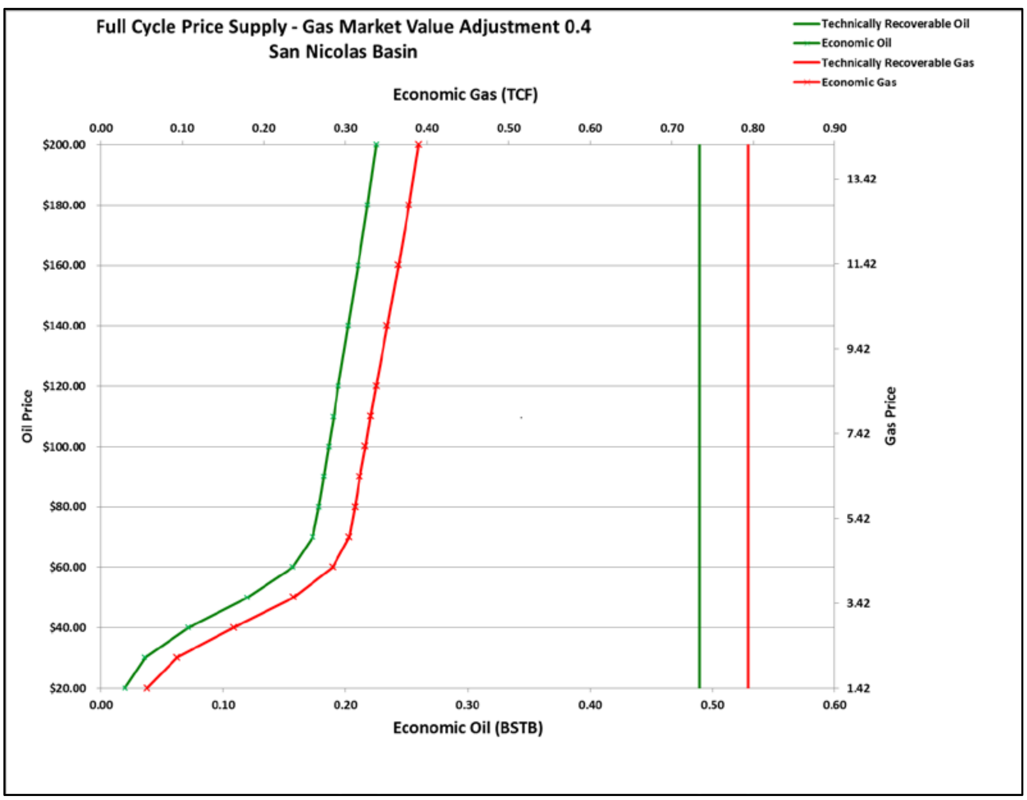


Figure 3-53. *Price-supply curves for the San Nicolas basin. Oil prices are coupled with a specific gas price assuming a 40 percent economic value for gas relative to oil.*

Cortes–Velero–Long Area

Location

The Cortes–Velero–Long assessment area is located in the southern part of the Outer Borderland province (fig. 3-46). 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. 3-54). It is approximately 95 miles long, from 30 to 60 miles wide, and encompasses approximately 4,800 square miles. The water depth within the area ranges from 4,500 to 6,000 feet.

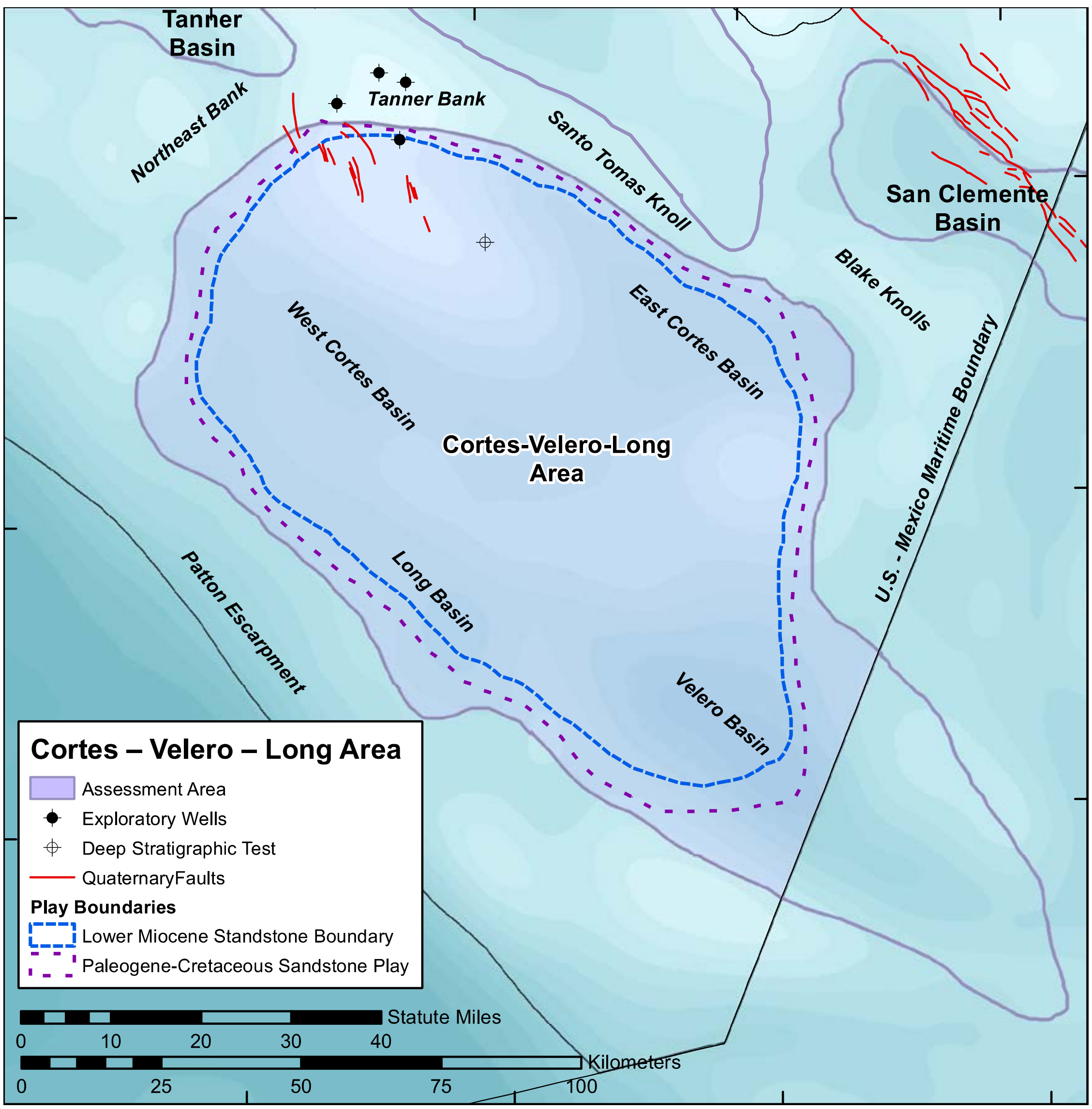


Figure 3-54. *Cortes-Velero-Long area plays and exploratory wells.*

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.

GEOLOGIC SETTING

The basins within the Cortes–Velero–Long assessment area are northwest trending and contain up to 7,000 feet of Upper Cretaceous through Miocene marine clastic rocks (fig. 3-55). This remote area of the continental borderland has lacked a source of significant clastic sediment since the middle Miocene, and this has resulted in the deposition of thin sequences of predominantly biogenic (rather than terrestrial) sediment since that time. It 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

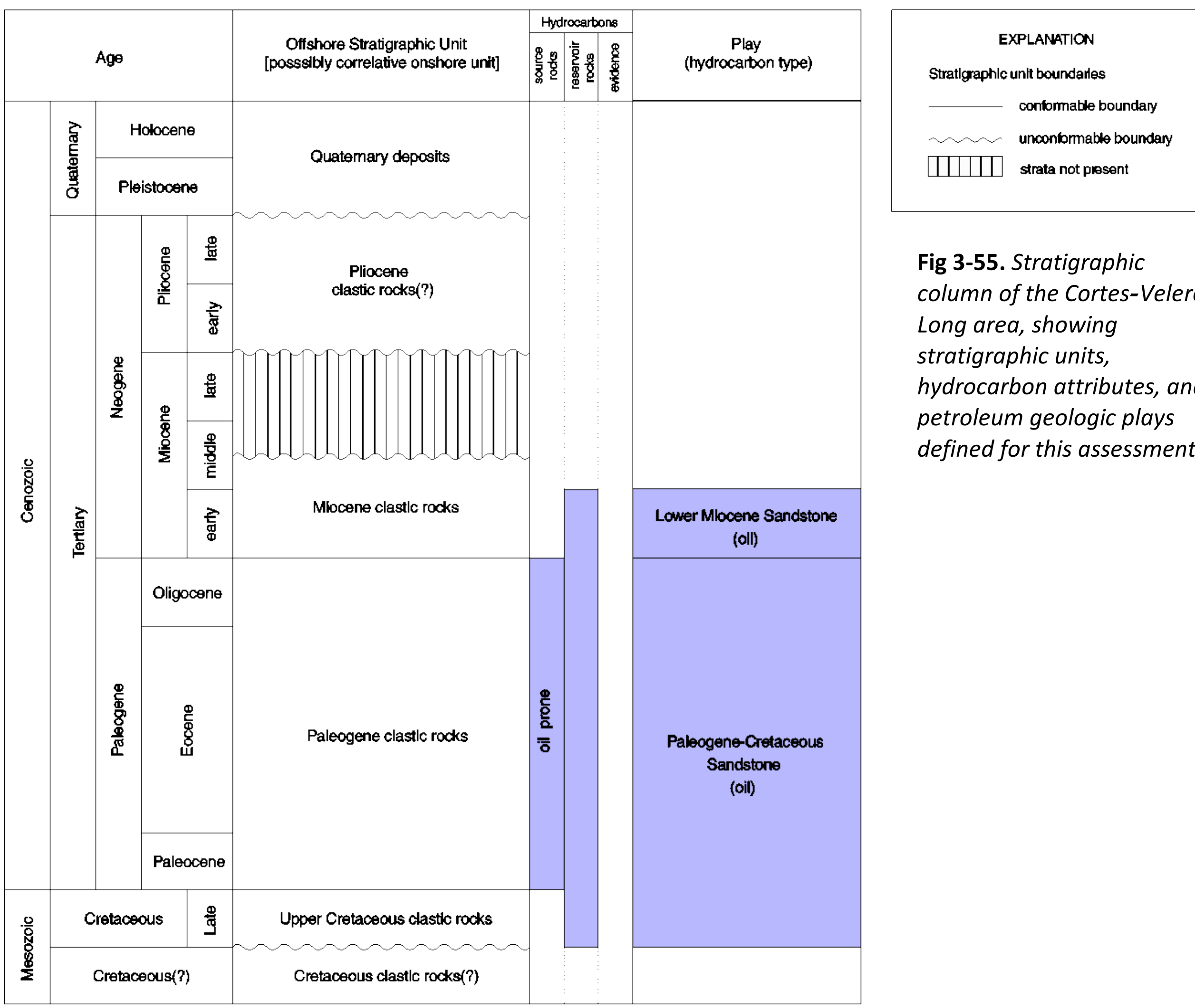


Fig 3-55. *Stratigraphic column of the Cortes-Velero-Long area, showing stratigraphic units, hydrocarbon attributes, and petroleum geologic plays defined for this assessment.*

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 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 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.

Lower Miocene Sandstone Play

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. 3-54). The depth to reservoir rocks in the play ranges from 1,000 to 4,500 feet and averages 3,000 feet below the seafloor.

The primary potential petroleum source rocks for this play are Paleogene mudstones and shales (fig. 3-55). 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. 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. 3-55). 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.

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 weak gas shows) were encountered in lower Miocene and other rocks in some of the wells.

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.

Paleogene-Cretaceous Sandstone Play

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. 3-54). The depth to reservoir rocks in the play ranges from 4,000 to 8,000 feet and averages 5,500 feet below the seafloor.

The primary potential petroleum source rocks for this play are Paleogene mudstones and shales described in the previous section. 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. 3-55). 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. Sandstone composes approximately 50 percent of the total Paleogene section. Based on seismic mapping and well correlations, similar rocks of Paleogene and Cretaceous age are inferred to be 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.

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.

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.

ECONOMIC FACTORS

There is no oil and gas infrastructure within the Outer Borderland province, and it is far from shore. Because of its remoteness, any future development would likely utilize a floating offshore storage and treatment facility, from which tankers could offload production. Should there be multiple platforms or subsea completions in a given area, these facilities could be shared among them. The number of platforms would be minimized by use of extended-reach drilling technology.

RESOURCE ESTIMATES

Undiscovered Technically Recoverable Resources

Play-specific estimates of undiscovered technically recoverable resources were developed and 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 Cortes−Velero−Long assessment area is estimated to be 0.31 Bbbl of oil and 0.76 Tcf of associated gas (mean estimates). The low, mean, and high estimates of resources in the assessment area are listed in table 3-32.

Undiscovered Economically Recoverable Resources

Estimates of the portion of the technically recoverable resources that can be economically recovered under various economic scenarios were developed by including the effects of current and expected future economic factors. Select data used to develop the resource estimates are shown in appendix D. These estimates are shown in fig. 3-56 as price-supply curves for a range of price scenarios, and for a gas market value of 40 percent of the energy

Table 3-32. *Estimates of Undiscovered Technically Recoverable Oil and Gas Resources of the Cortes-Velero basin geologic plays and the Basin total. Resource values are in billion barrels of oil (Bbbl) and trillion cubic feet of gas (Tcf). 95% indicates a 95 percent chance of at least the amount listed; 5% indicates a 5 percent chance of at least the amount listed. Only mean values are additive. Some total mean values may not equal the sum of the component values due to independent rounding of the tabulated values.*

Geologic Play	Oil (Bbbl)			Gas (Tcf)			BOE (Bbbl)		
	95%	Mean	5%	95%	Mean	5%	95%	Mean	5%
Lower Miocene Sandstone	0.00	0.18	0.56	0.00	0.44	2.20	0.00	0.26	0.95
Paleogene-Cretaceous Ss	0.00	0.13	0.56	0.00	0.32	1.82	0.00	0.19	0.89
Cortes-Velero Basin	**0.00**	**0.31**	**1.28**	**0.00**	**0.76**	**3.11**	**0.00**	**0.45**	**1.84**

equivalent value of oil. As a result of this assessment, 3.4 MMbbl of oil and 24.6 Bcf of associated gas are estimated to be economically recoverable from the Cortes-Velero-Long assessment area under economic conditions existing as of this assessment (i.e., the $90-per-barrel economic scenario). Larger volumes of resources are expected to be economically recoverable under increasingly favorable economic conditions. For this small amount of economically recoverable resources there may be no commercial interest in conventional oil and gas exploration. However, the possibility remains that there may be significant methane hydrate resources as exploration targets (for more information, see www.boem.gov /Oil-and-Gas-Energy-Program/Resource-Evaluation/Gas-Hydrates/GH-RA-Pacific.aspx).

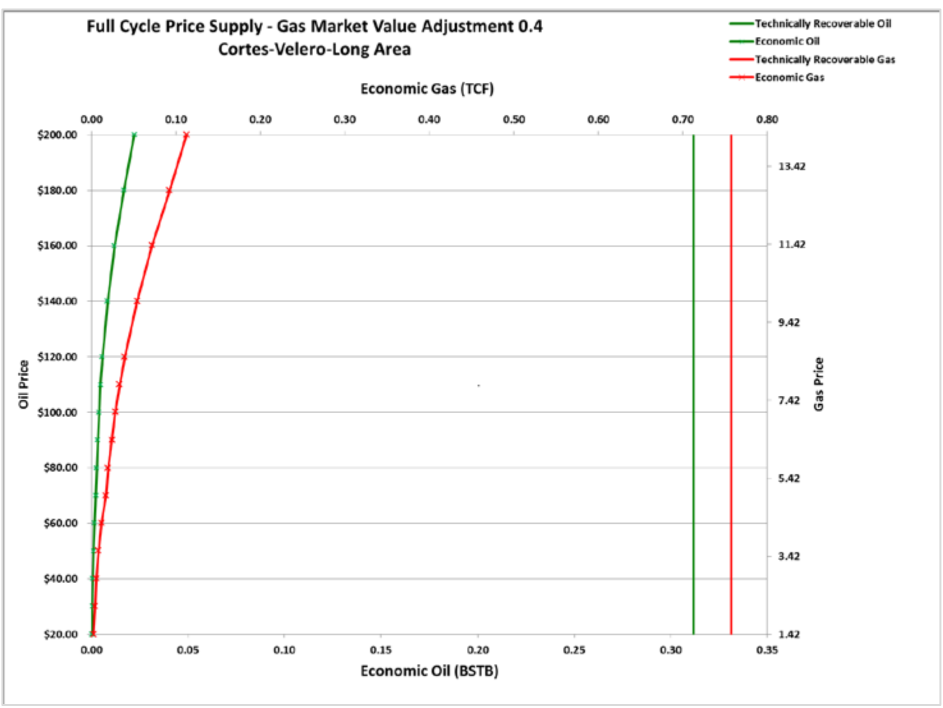


Figure 3-56. *Price-supply curves for the Cortes-Velero-Long area. Oil prices are coupled with a specific gas price assuming a 40 percent economic value for gas relative to oil.*

4 SUMMARY AND DISCUSSION OF RESULTS

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.

REGIONAL RESULTS

Based on this assessment, the total volume of undiscovered, technically recoverable oil is estimated to range from 6.73 to 14.30 Bbbl with a mean estimate of 10.20 Bbbl. The total volume of undiscovered, technically recoverable gas is estimated to range from 10.10 Tcf to 23.75 Tcf with a mean estimate of 16.10 Tcf.

The total volume of undiscovered technically recoverable resources that is estimated to be economically recoverable under approximate economic and technological conditions as of the date of this assessment ($90 per barrel oil and $6.41 per Mcf gas) is 7.43 Bbbl of oil and 9.90 Tcf of gas (mean values). Larger volumes of resources are estimated to be economically recoverable under more favorable economic conditions.

The total resource endowment of the Region is composed of discovered resources (originally recoverable reserves plus contingent resources) and undiscovered technically recoverable resources. It is useful for comparing basins or regions in terms of their hydrocarbon richness prior to human intervention. The estimated resource endowment of the Pacific Region is 13.06 Bbbl of oil and 18.98 Tcf of gas (mean values). Of this, about 80 percent is estimated to be undiscoveredtechnically recoverable resources.

GEOGRAPHIC DISTRIBUTION OF RESOURCES

UNDISCOVERED TECHNICALLY RECOVERABLE RESOURCES

The low, mean and high estimates of the undiscovered technically recoverable resources in each assessment area are listed in table 4-1. The distribution among the assessment areas is illustrated in fig. 4-1. Nearly 80 percent of the combined oil-equivalent resources of the Region are estimated to be oil. Half of the undiscovered technically recoverable oil and one-third of the undiscovered technically recoverable gas is expected to be in the Central California Province. Each of five basins (Point Arena, Bodega, Santa Maria, Santa Barbara-Ventura, and Oceanside) is estimated to contain more than 1 Bbbl of undiscovered oil. Each of seven basins/areas (Washington-Oregon, Eel River, Point Arena, Bodega, Santa Barbara-Ventura, Los Angeles-Santa Monica-San Pedro, and Oceanside) is estimated to contain more than 1 Tcf of undiscovered gas. With the exception of the Pacific Northwest Province, most of the gas is expected to be associated gas.

Table 4-1. *Undiscovered Technically Recoverable Oil and Gas Resources of the Pacific OCS Region by basin/area and province. Resource values are in billion barrels of oil (Bbbl) and trillion cubic feet of gas (Tcf). 95% indicates a 95 percent chance of at least the amount listed; 5% indicates a 5 percent chance of at least the amount listed. Only mean values are additive. Some total mean values may not equal the sum of the component values due to independent rounding of the tabulated values.*

Assessment Area	Oil (Bbbl)			Gas (Tcf)			BOE (Bbbl)		
	Low	Mean	High	Low	Mean	High	Low	Mean	High
Pacific Northwest Province									
Washington–Oregon Area	0.00	0.40	1.14	0.00	2.23	5.76	0.00	0.80	2.17
Eel River Basin	0.01	0.07	0.17	0.28	1.52	2.59	0.06	0.34	0.63
Total Province	*0.03*	*0.47*	*1.23*	*0.88*	*3.76*	*7.50*	*0.19*	*1.14*	*2.56*
Central California Province									
Point Arena Basin	1.00	2.01	3.46	0.99	2.10	3.85	1.18	2.38	4.14
Bodega Basin	0.50	1.40	2.67	0.50	1.52	3.06	0.59	1.68	3.21
Año Nuevo Basin	0.22	0.71	1.46	0.22	0.75	1.54	0.26	0.84	1.73
Santa Maria–Partington Basin	0.41	1.11	2.34	0.31	0.84	1.83	0.47	1.26	2.66
Total Province	*3.34*	*5.23*	*7.53*	*3.18*	*5.21*	*7.67*	*3.90*	*6.16*	*8.89*
Santa Barbara–Ventura Basin Province									
Santa Barbara–Ventura Basin	0.34	1.34	3.50	0.53	2.74	7.01	0.44	1.83	4.75
Total Province	*0.34*	*1.34*	*3.50*	*0.53*	*2.74*	*7.01*	*0.44*	*1.83*	*4.75*
Inner Borderland Province									
Los Angeles–Santa Monica–San Pedro Area	0.10	0.89	2.16	0.10	1.03	2.62	0.12	1.08	2.62
Oceanside Basin	0.00	1.06	2.94	0.00	1.12	3.51	0.00	1.26	3.56
Total Province	*0.21*	*1.96*	*4.23*	*0.21*	*2.15*	*4.83*	*0.24*	*2.34*	*5.09*
Outer Borderland Province									
Santa Cruz-Santa Rosa Area	0.00	0.40	1.42	0.00	0.69	2.63	0.00	0.52	1.89
San Nicolas Basin	0.00	0.49	1.84	0.00	0.79	3.18	0.00	0.63	2.40
Cortes–Velero–Long Area	0.00	0.31	1.28	0.00	0.76	3.11	0.00	0.45	1.84
Total Province	*0.00*	*1.20*	*3.09*	*0.00*	*2.24*	*5.91*	*0.00*	*1.60*	*4.14*
Total Pacific OCS Region	*6.73*	*10.20*	*14.30*	*10.10*	*16.10*	*23.75*	*8.53*	*13.07*	*18.52*

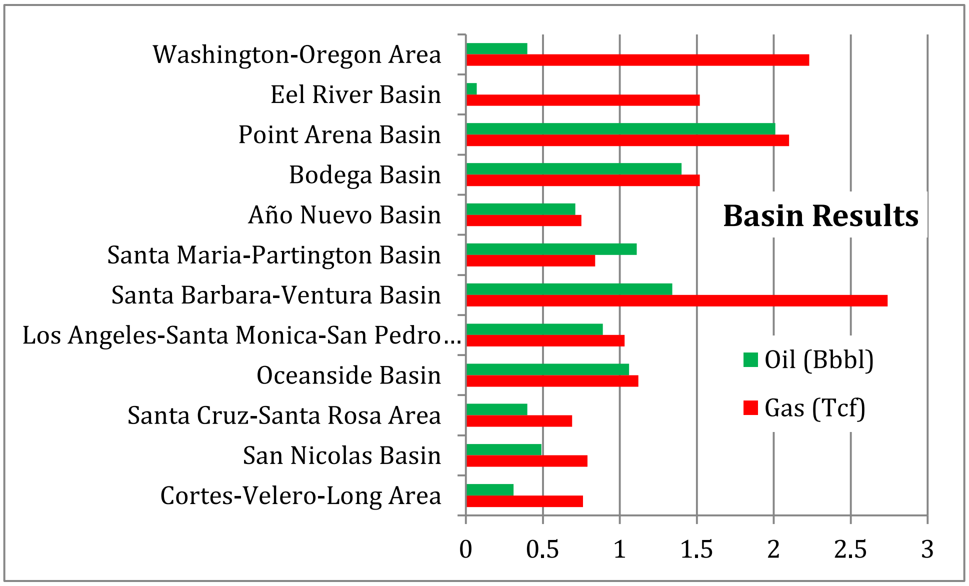


Figure 4-1. *Undiscovered technically recoverable oil and gas resources by basin (mean values).*

Undiscovered Economically Recoverable Resources

Mean estimates of the undiscovered economically recoverable resources in each assessment area of the Region are listed, for three economic scenarios, in table 4-2. The distribution of undiscovered economically recoverable oil and gas resources among the assessment areas is illustrated in fig. 4-2 and 4-3. Resource estimates for the $90-per-barrel economic scenario (which assumes prices of $90.00 per bbl of oil and $6.41 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. The gas price is set at 40 percent of the energy equivalent value of oil, which is higher than current gas prices, but is the closest of the economic scenarios that was run for this assessment.

Nearly three quarters of the undiscovered technically recoverable oil resources of the Region (73 percent on the basis of mean estimates and the $90-per-barrel economic scenario) is estimated to be economically recoverable at economic and technological conditions existing as of this assessment. These resources include large volumes of oil (greater than 1 Bbbl) in Point Arena basin, Bodega basin, and Santa Barbara–Ventura basin. Estimates for Santa Maria basin and Oceanside basin are still relatively large (each more than 0.80 Bbbl). At the more favorable economic conditions for the current assessment relative to that in 1995, the estimates for the relatively deep-water Point Arena and Oceanside-Capistrano basins have increased relative to the other basins.

More than one half of the undiscovered technically recoverable gas resources of the Region (61 percent on the basis of mean estimates and the $90-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, Point Arena and Bodega basins.

The current economic conditions are sufficient that only relatively small incremental increases in resource estimates (both oil and gas) result from still higher prices. For the Pacific Region as a whole, estimates for oil are up only 5 percent, and estimates for gas are up 6 percent for the $120-per-barrel price scenario as compared to the $90-per-barrel scenario. For areas with existing infrastructure (relatively low costs), increases are significantly less (e.g., an increase of only 1.6 percent for oil and 3 percent for gas in Santa Barbara–Ventura basin).

Table 4-2. *Mean estimates of undiscovered economically recoverable oil and gas resources in the Pacific OCS Region as of January,1, 2009 for three economic scenarios, by basin/area and province. Oil prices are coupled with a specific gas price assuming a 40 percent economic value for gas relative to oil.*

Assessment Area	$60/bbl, $4.27/Mcf			$90/bbl, $6.41/Mcf			$120/bbl, $8.54/Mcf		
	Oil (Bbbl)	Gas (Tcf)	BOE (Bbbl)	Oil (Bbbl)	Gas (Tcf)	BOE (Bbbl)	Oil (Bbbl)	Gas (Tcf)	BOE (Bbbl)
Pacific Northwest Province									
Washington–Oregon Area	0.21	0.73	0.34	0.24	0.88	0.40	0.26	0.98	0.43
Eel River Basin	0.03	0.18	0.06	0.04	0.29	0.09	0.04	0.37	0.11
Total Province	*0.24*	*0.91*	*0.40*	*0.28*	*1.18*	*0.49*	*0.30*	*1.34*	*0.54*
Central California Province									
Point Arena Basin	1.15	1.19	1.36	1.33	1.38	1.58	1.43	1.48	1.69
Bodega Basin	1.19	1.30	1.42	1.26	1.37	1.50	1.29	1.40	1.54
Año Nuevo Basin	0.60	0.64	0.72	0.63	0.67	0.75	0.65	0.69	0.77
Santa Maria–Partington Basin	0.68	0.51	0.77	0.81	0.61	0.92	0.87	0.65	0.99
Total Province	*3.61*	*3.62*	*4.25*	*4.04*	*4.03*	*4.75*	*4.24*	*4.22*	*4.99*
Santa Barbara–Ventura Basin Province									
Santa Barbara–Ventura Basin	1.19	2.23	1.59	1.25	2.37	1.67	1.27	2.44	1.70
Total Province	*1.19*	*2.23*	*1.59*	*1.25*	*2.37*	*1.67*	*1.27*	*2.44*	*1.70*
Inner Borderland Province									
Los Angeles–Santa Monica–San Pedro Area	0.61	0.74	0.74	0.68	0.82	0.83	0.72	0.86	0.88
Oceanside Basin	0.81	0.87	0.96	0.88	0.93	1.04	0.91	0.96	1.08
Total Province	*1.40*	*1.59*	*1.69*	*1.56*	*1.75*	*1.87*	*1.63*	*1.83*	*1.96*
Outer Borderland Province									
Santa Cruz-Santa Rosa Area	0.08	0.17	0.11	0.12	0.23	0.16	0.15	0.28	0.20
San Nicolas Basin	0.16	0.30	0.22	0.18	0.32	0.24	0.19	0.34	0.25
Cortes–Velero–Long Area	0.003	0.02	0.01	0.003	0.02	0.01	0.01	0.04	0.01
Total Province	*0.23*	*0.44*	*0.31*	*0.31*	*0.57*	*0.41*	*0.35*	*0.65*	*0.47*
Total Pacific OCS Region	*6.67*	*8.80*	*8.24*	*7.43*	*9.90*	*9.19*	*7.79*	*10.49*	*9.66*

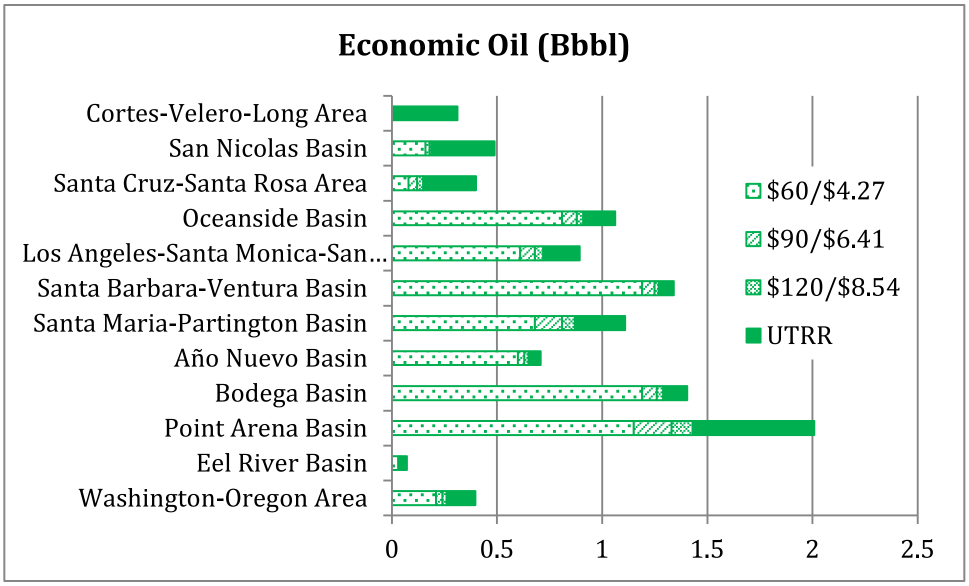


Figure 4-2. *Undiscovered economically recoverable oil resources by basin (mean values).*

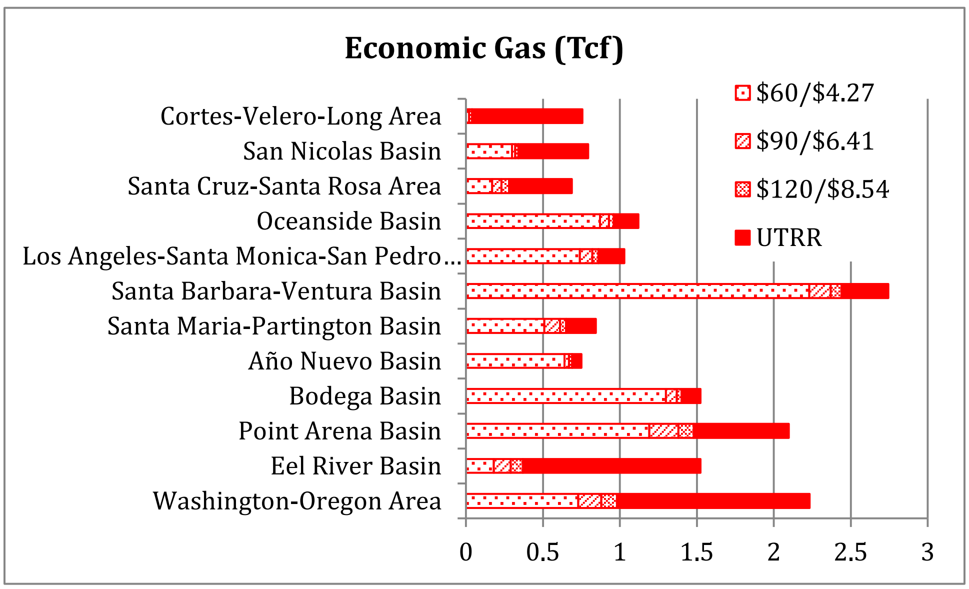


Figure 4-3. *Undiscovered economically recoverable gas resources by basin (mean values).*

Total Resource Endowment

When the discovered resources are added to the estimates of undiscovered resources, it gives a measure of the "richness" of a basin in terms of its hydrocarbon resources. From the tabulated results (table 4-3, fig. 4-4) it can be seen that the Santa Barbara–Ventura basin is estimated to have the richest resource endowment, and much of that is currently under development. Santa Maria–Partington basin is estimated to be the second richest basin. More than half of that endowment is already discovered, although most of those resources are currently unleased.

Table 4-3. *Resources by category for geographic basins and provinces. The total resource endowment gives a measure of the richness of the basin in hydrocarbon resources.*

Assessment Area	Discovered Resources						Undiscovered Technically Recoverable Resources			Total Resource Endowment		
	Originally Recoverable Reserves			Contingent Resources								
	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	0.40	2.23	0.80	0.40	2.23	0.80
Eel River Basin	0	0	0	0	0	0	0.07	1.52	0.34	0.07	1.52	0.34
Total Province	*0*	*0*	*0*	*0*	0	*0*	*0.47*	*3.76*	1.14	*0.47*	*3.76*	*1.14*
Central California Province												
Point Arena Basin	0	0	0	0	0	0	2.01	2.10	2.38	2.01	2.10	2.38
Bodega Basin	0	0	0	0	0	0	1.40	1.52	1.68	1.40	1.52	1.68
Año Nuevo Basin	0	0	0	0	0	0	0.71	0.75	0.84	0.71	0.75	0.84
Sta. Maria-Partington Basin	0.33	0.18	0.36	1.06	0.42	1.13	1.11	0.84	1.26	2.49	1.44	2.75
Total Province	*0.33*	*0.18*	*0.36*	*1.06*	*0.42*	*1.13*	*5.23*	*5.21*	*6.16*	*6.61*	*5.81*	*7.65*
Santa Barbara–Ventura Basin Province												
Sta. Barbara–Ventura Basin	1.13	1.73	1.43	0.21	0.40	0.29	1.34	2.74	1.83	2.68	4.88	3.55
Total Province	*1.13*	*1.73*	*1.43*	*0.21*	*0.40*	*0.29*	*1.34*	*2.74*	*1.83*	*2.68*	*4.88*	*3.55*
Inner Borderland Province												
LA–SM–SP Area	0.11	0.03	0.11	0.005	0.001	0.005	0.89	1.03	1.08	1.01	1.07	1.20
Oceanside Basin	0	0	0	0	0	0	1.06	1.12	1.26	1.06	1.12	1.26
Total Province	*0.11*	*0.03*	*0.11*	*0.005*	*0.001*	*0.005*	*1.96*	*2.15*	*2.34*	*2.07*	*2.19*	*2.46*
Outer Borderland Province												
Sta. Cruz-Sta. Rosa Area	0	0	0	0	0	0	0.40	0.69	0.52	0.40	0.69	0.52
San Nicolas Basin	0	0	0	0	0	0	0.49	0.79	0.63	0.49	0.79	0.63
Cortes–Velero–Long Area	0	0	0	0	0	0	0.31	0.76	0.45	0.31	0.76	0.45
Total Province	*0*	*0*	*0*	*0*	*0*	*0*	*1.20*	*2.24*	*1.60*	*1.20*	*2.24*	*1.60*
Total Pacific OCS Region	***1.56***	***1.95***	***1.91***	***1.27***	***0.83***	***1.42***	***10.20***	***16.10***	***13.07***	***13.06***	***18.98***	***16.44***

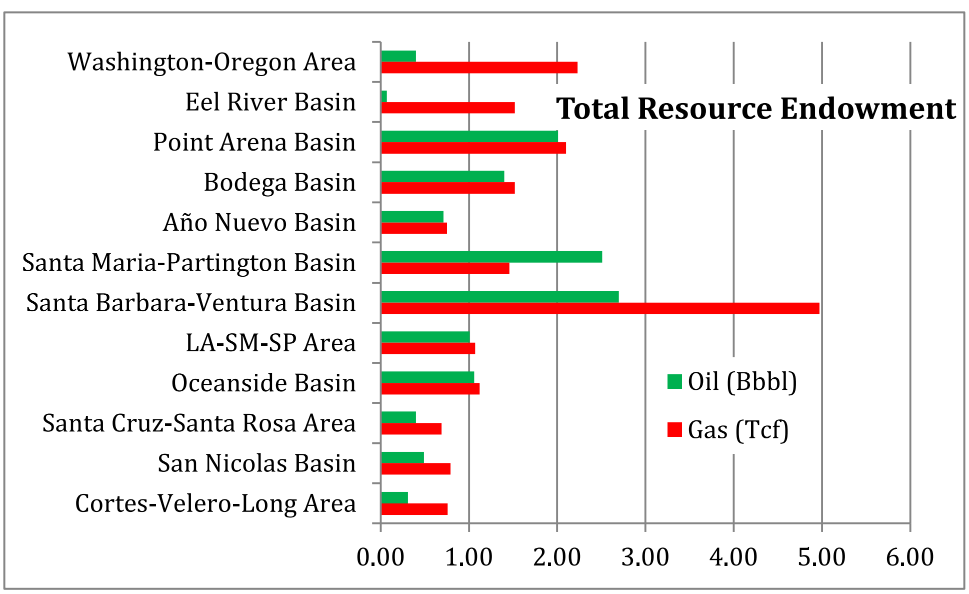


Figure 4-4. *Total resource endowment by geologic basin.*

GEOLOGIC DISTRIBUTION OF RESOURCES

The petroleum geologic framework of the region provided the basis for the delineation of assessment provinces, assessment areas and petroleum geologic plays. The provinces, basins/areas, and plays that were defined for the 1995 assessment have in some cases been modified or merged. For this assessment, the Pacific OCS Region is divided into five assessment provinces: Pacific Northwest, Central California, Santa Barbara-Ventura, Inner Borderland, and Outer Borderland (fig.3-2). Each province comprises one or more assessment areas (geologic basins or areas) within which petroleum geologic plays have been defined. Forty-five plays have been defined and described; 41 of these have been formally assessed (table 4-4). Areas and plays that lack sufficient petroleum geologic data, or for which data suggest that petroleum potential is negligible, have not been assessed. Several late Tertiary submarine fans exist within the Region; these areas of deep-sea sedimentation lack sufficient data and have not been assessed.

Table 4-4. *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	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

Table 4-4. *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]
	Santa Barbara−Ventura Basin Province			
Santa Barbara−Ventura Basin	Pico-Repetto Sandstone	Established	Mixed	Neogene Clastic
	Monterey Fractured	Established	Oil	Neogene Fractured
	RMT−SAV	Established	Mixed	Neogene-Cretaceous
	Gaviota-Sacate-Matilija	Established	Mixed	Paleogene-Cretaceous
	Cretaceous-Paleocene	Established	Mixed	Paleogene-Cretaceous
	Inner Borderland Province			
LA−SM−SP Area	Pliocene Clastic[4]	Conceptual	Oil	Neogene Clastic
	Puente Fan Sandstone	Established	Oil	Neogene Clastic
	Upper Miocene Sandstone	Frontier	Oil	Neogene Clastic
	Modelo	Frontier	Oil	Neogene Clastic
	Dume Thrust Fault	Frontier	Oil	Neogene Clastic
	San Onofre Breccia	Frontier	Oil	Neogene Clastic
Oceanside-Capistrano Basin	Upper Miocene Sandstone	Conceptual	Oil	Neogene Clastic
	Monterey Fractured	Conceptual	Oil	Neogene Fractured
	Lower Miocene Sandstone	Conceptual	Oil	Neogene Clastic
	Outer Borderland Province			
Santa Cruz-Santa Rosa Area	Monterey Fractured	Conceptual	Oil	Neogene Fractured
	Lower Miocene Sandstone	Conceptual	Oil	Neogene Clastic
	Paleogene-Cretaceous Sandstone	Conceptual	Oil	Paleogene-Cretaceous
San Nicolas Basin	Upper Miocene Sandstone	Conceptual	Oil	Neogene Clastic
	Monterey Fractured	Conceptual	Oil	Neogene Fractured
	Lower Miocene Sandstone	Conceptual	Oil	Neogene Clastic
	Paleogene-Cretaceous Sandstone	Conceptual	Oil	Paleogene-Cretaceous
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 Cretaceous through Miocene melange.

[4] Not formally assessed.

Distribution of Resources by Exploration and Discovery Status of Plays

The 41 assessed plays in the Pacific OCS Region consist of 7 established plays, 18 frontier plays, and 16 conceptual plays (table 4-4). Mean estimates of the undiscovered conventionally recoverable oil and gas resources in each play class are listed in table 4-5 and illustrated in fig. 4-5.

Approximately three quarters of the undiscovered technically 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. Approximately one quarter of the undiscovered technically recoverable oil and gas resources in the Region is estimated to exist in established plays where hydrocarbon accumulations have been discovered.

Table 4-5. *Estimates of undiscovered technically recoverable resources (mean values) by exploration and discovery status of plays. 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 Defined	 Assessed	Oil (Bbbl)	Gas (Tcf)	BOE (Bbbl)
Established *plays in which hydrocarbon accumulations have been discovered*	8	7	2.68	4.41	3.47
Frontier *plays in which hydrocarbon accumulations have not been discovered, but in which hydrocarbons have been detected*	19	18	4.96	7.28	6.26
Conceptual *plays in which hydrocarbons have not been detected, but for which data suggest that hydrocarbon accumulations may exist*	18	16	2.55	4.41	3.34
Total	*45*	*41*	*10.20*	*16.10*	*13.07*

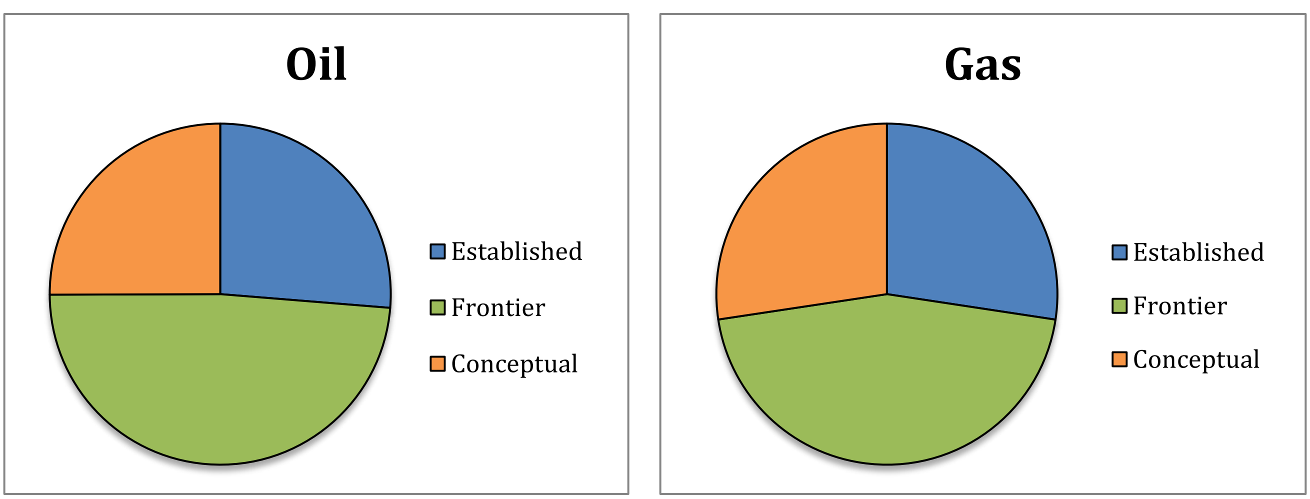


Figure 4-5. *Distribution of undiscovered technically recoverable resources by exploration and discovery status of plays.*

Distribution of Resources by Hydrocarbon Type of Plays

The 41 assessed plays consist of 31 oil plays and 10 mixed plays; no gas plays were defined (table 4-4). Mean estimates of the undiscovered technically recoverable oil and gas resources in each play class are listed in table 4-6 and illustrated in fig. 4-6.

The majority of the undiscovered technically recoverable oil and gas resources in the Region are estimated to exist in oil plays. More than one third of the undiscovered technically recoverable gas resources (some of which is nonassociated gas) and a small volume of undiscovered technically recoverable oil resources is estimated to exist in mixed plays.

Table 4-6. *Estimates of undiscovered technically recoverable resources (mean values) by predominant hydrocarbon type of plays. 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 Defined	Number of Plays Assessed	Oil (Bbbl)	Gas (Tcf)	BOE (Bbbl)
Oil *plays that contain predominantly crude oil and associated gas*	34	31	9.15	10.30	10.98
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	1.05	5.80	2.08
Total	*45*	*41*	*10.20*	*16.10*	*13.07*

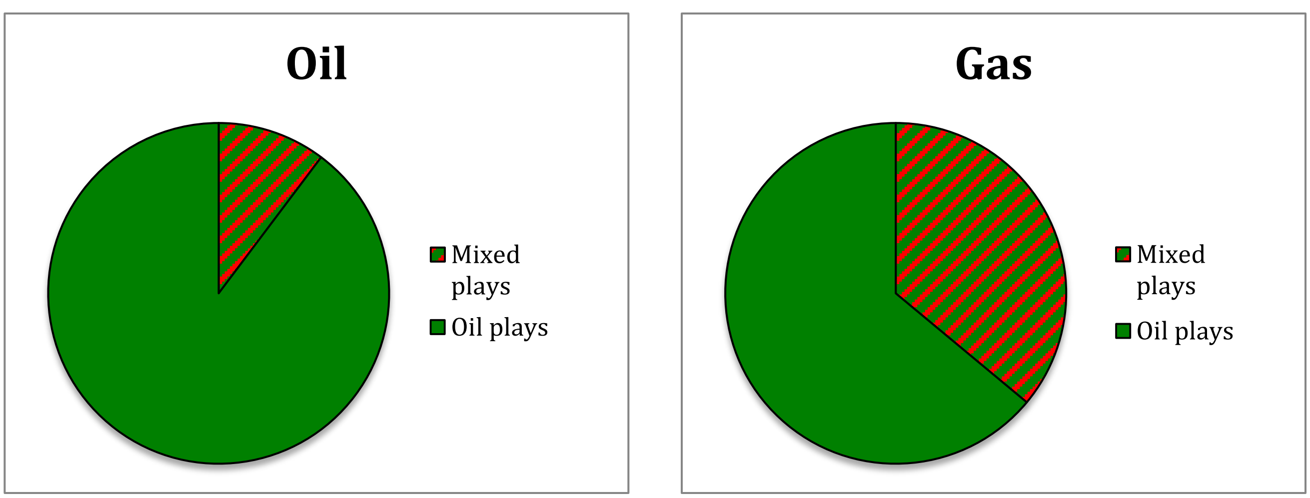


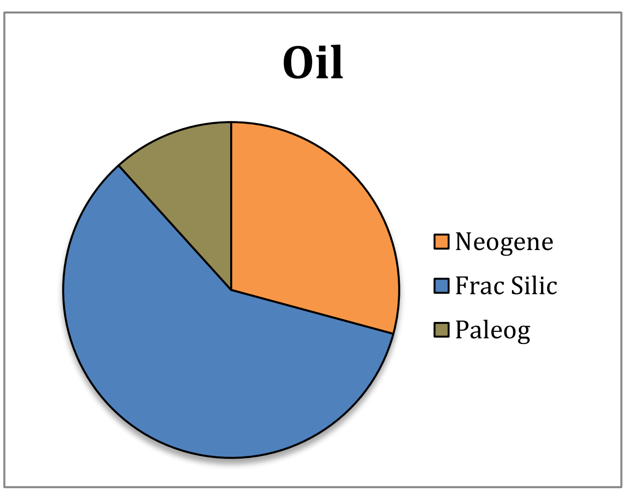
Figure 4-6. *Distribution of undiscovered technically recoverable resources by predominant hydrocarbon type of plays.*

DISTRIBUTION OF RESOURCES BY RESERVOIR ROCKS OF PLAYS

The 41 assessed plays consist of 22 plays having Neogene clastic reservoir rocks, 8 plays having Neogene fractured siliceous reservoir rocks, 11 plays having Paleogene-Cretaceous reservoir rocks, (one play has reservoir rocks ranging from late Cretaceous to early Neogene; the Neogene resources are small, and it is included in the Paleogene-Cretaceous group). No plays having melange reservoir rocks were assessed (table 4-4). Mean estimates of the undiscovered conventionally recoverable oil and gas resources in each play class are listed in table 4-7 and illustrated in fig. 4-7.

Table 4-7. *Estimates of undiscovered technically recoverable resources (mean values) by predominant reservoir rock type of plays. 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 Defined	Number of Plays Assessed	Oil (Bbbl)	Gas (Tcf)	BOE (Bbbl)
Neogene Clastic *plays having reservoir rocks that consist of Miocene and/or Pliocene sandstone, siltstone, shale, and/or breccia*	23	22	2.98	6.81	4.19
Neogene Fractured Siliceous *plays having reservoir rocks that consist of Miocene fractured chert, siliceous shale, porcelanite, dolomite, and/or limestone*	8	8	6.03	5.83	7.07
Paleogene-Cretaceous Clastic *plays having reservoir rocks that consist of Cretaceous through Oligocene sandstone, siltstone, and/or shale*	12	11	1.19	3.46	1.81
Melange *plays having reservoir rocks that consist of Cretaceous through Miocene melange*	2	0	N/A	N/A	N/A
Total	*45*	*41*	*10.20*	*16.10*	*13.07*



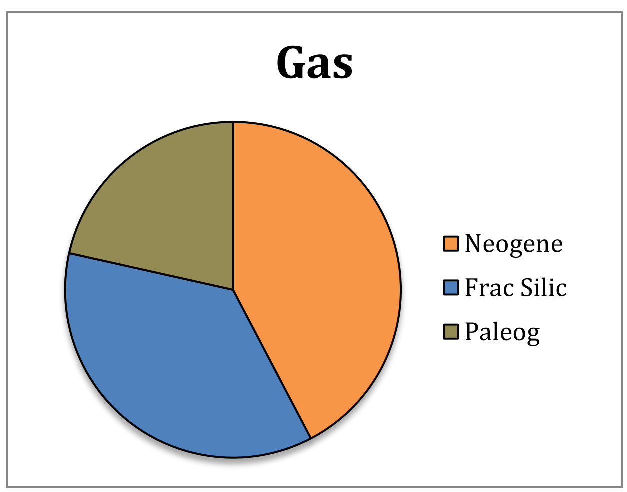


Figure 4-7. *Distribution of undiscovered technically recoverable resources by predominant reservoir rock of plays.*

The 22 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 8 assessed plays having fractured siliceous rocks are estimated to contain more than one-half of the undiscovered technically recoverable oil and one-third of the undiscovered technically recoverable gas. The 10 assessed plays having Paleogene-Cretaceous reservoir rocks are estimated to contain relatively small volumes of undiscovered conventionally recoverable oil and gas resources.

Importance of Fractured Monterey Resources

In areas where naturally fractured Monterey shale is known to exist, it is the most important source and reservoir for oil. Although only 8 of the 41 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 (59 percent) of the undiscovered technically recoverable oil resources and about one third (36 percent) of the undiscovered technically recoverable gas resources in the Region. If discovered resources are included, the contribution of fractured siliceous rocks is similar. As shown in tables 4-8 and 4-9, 60 percent of the oil in the Santa Barbara basin total resource endowment is expected to be from the Fractured Monterey play. In the Central California province, 88 percent of oil is expected to be from this play, most of which is yet to be discovered. For the Pacific OCS Region as a whole, 63 percent of the total endowment of oil is expected to be from fractured Monterey.

Table 4-8. *Discovered Resources, Undiscovered Resources, and Total Resource Endowment that are from Fractured Monterey plays.*

Geologic Province	Discovered Resources: Originally Recoverable Reserves			Discovered Resources: Contingent Resources			Undiscovered Technically 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)
Central California	0.33	0.18	0.36	1.04	0.41	1.12	4.45	4.21	5.20	5.82	4.80	6.68
Santa Barbara	0.73	1.08	0.93	0.10	0.14	0.13	0.76	0.70	0.89	1.60	1.92	1.94
Inner Borderland	0	0	0	0	0	0	0.39	0.44	0.47	0.39	0.44	0.47
Outer Borderland	0	0	0	0	0	0	0.43	0.49	0.51	0.43	0.49	0.51
Pacific OCS	**1.06**	**1.26**	**1.29**	**1.15**	**0.55**	**1.24**	**6.03**	**5.83**	**7.07**	**8.24**	**7.64**	**9.59**

Table 4-9. *Percent of Discovered Resources, Undiscovered Resources, and Total Resource Endowment that are from Fractured Monterey plays.*

Geologic Province	Discovered Resources: Originally Recoverable Reserves			Discovered Resources: Contingent Resources			Undiscovered Technically Recoverable Resources			Total Resource Endowment		
	Oil	Gas	BOE	Oil	Gas	BOE	Oil	Gas	BOE	Oil	Gas	BOE
Central California	100	100	100	99	98	99	85	81	84	88	83	87
Santa Barbara	65	63	65	48	33	44	57	25	48	60	39	55
Inner Borderland	0	0	0	0	0	0	20	20	20	19	20	19
Outer Borderland	0	0	0	0	0	0	36	22	32	36	22	32
Pacific OCS	**68**	**65**	**67**	**90**	**66**	**88**	**59**	**36**	**54**	**63**	**40**	**59**

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., technically recoverable or 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.

Here a comparison is made of resource estimates from this and four previous MMS assessments of the Pacific OCS Region from 1995 through 2006. (The earlier assessments done in 1987 (Mast and others, 1989; Cooke and Dellagiarino, 1990), in 1989, and in 1990 (Cooke, 1991), used significantly different methodology than the 1995 and later assessments.) At the time of the 1995 assessment, additional data and a comprehensive petroleum geological analysis 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 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) led to the consideration of additional and possibly larger pools in many plays.

The 1999 publication was updated to reflect additional production that had occurred, but involved no recalculation of undiscovered resources. In 2003 and 2006, no changes were made in technically recoverable resources; however a revised economic analysis methodology and updated economic information led to revisions in estimates of economically recoverable resources. These results were used in other publications, but no official assessment was published.

This 2011 assessment publication represents the first revision in plays and technically recoverable resources since the 1995 assessment, and the first full assessment publication for the Pacific Region since that time. The changes included merging two assessment areas into one (Los Angeles basin and Santa Monica-San Pedro area), removing a play from the Oceanside basin that is primarily in State waters and onshore, and merging two minor plays in the Santa Barbara–Ventura basin. In the Santa Maria–Partington basin, an updated interpretation of discovered fields led to a change in the resource distribution for the

Monterey play. Finally, all plays were subjected to the same methodology for assessing technically recoverable resources, and in fact, the same as used by all Regions for this assessment. This change removed an inconsistency that had led to doubt about the comparability among the plays since the 1995 assessment.

UNDISCOVERED TECHNICALLY RECOVERABLE RESOURCES

Comparable estimates of the volume of technically recoverable oil and gas resources in the Region for the 1995 through 2011 assessments are illustrated in fig. 4-10. These estimates have shown a small decrease in Regional totals; the greatest decrease was for gas for the 2011 assessment. This significant decrease is primarily due to revisions in the Santa Barbara–Ventura basin that led to a decrease in prospectiveness of both oil and gas. An increase in estimated oil resources for the Santa Maria basin offset the decrease in Santa Barbara–Ventura oil, but not gas.

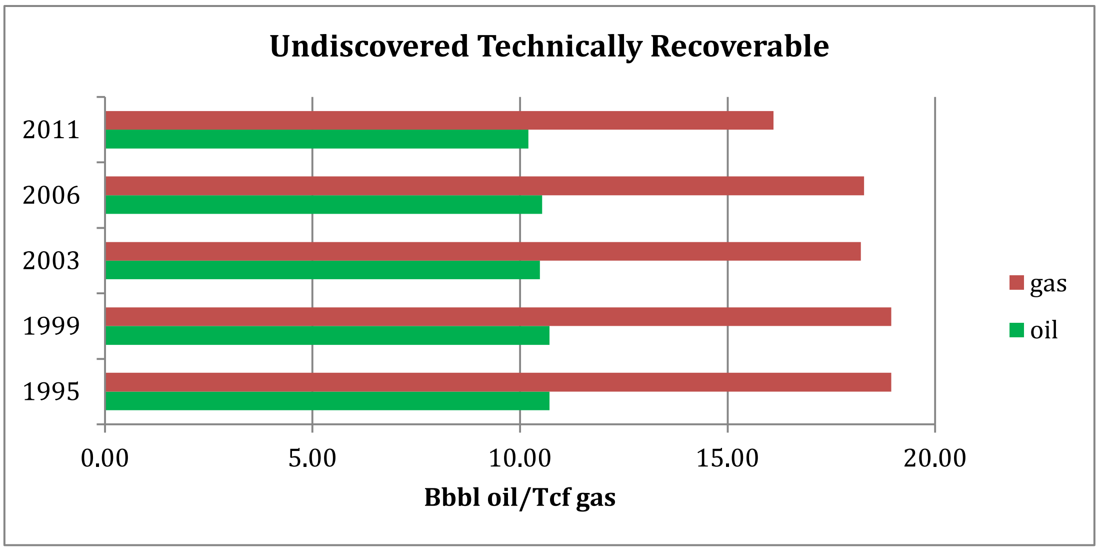


Figure 4-10. Comparison of POCS Regional total estimates of undiscovered technically recoverable oil and gas for assessments from 1995 to 2011.

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 "$30-per-barrel economic scenario" is the only price scenario that is reported for assessments dating to 1995, and is illustrated in fig. 4-11. These estimates have consistently declined since that assessment. The decline from the 1995 and 1999 results to the 2006 results may be in part due to economic modeling changes. However, much of the decline since 2006, and perhaps the earlier decline as well, may be attributable to increased costs of exploration and production activities that track the increase in actual oil and gas prices, which are currently much higher than 30 dollars per barrel oil.

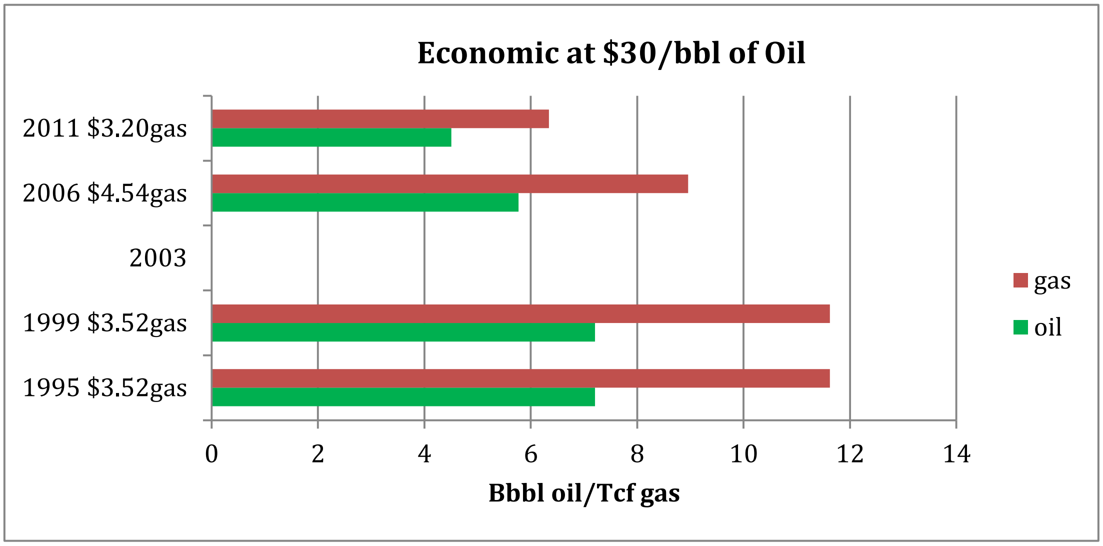


Figure 4-11. Comparison of POCS Regional total estimates of undiscovered economically recoverable oil and gas for assessments from 1995 to 2011. Results are for the $30-per-barrel economic scenario. Gas prices used in the modeling are indicated next to the assessment year. No $30 results were reported for the 2003 estimates.

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Appendix A
ABBREVIATIONS AND SYMBOLS USED IN THIS DOCUMENT

Abbreviations and Acronyms

API	American Petroleum Institute
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
BOEM	Bureau of Ocean Energy Management
BOEMRE	Bureau of Ocean Energy Management, Regulation and Enforcement
BSTB	billion (10^9) standard barrels
cf	cubic feet
DOI	Department of the Interior
E & D	exploratory and delineation
EIA	Energy Information Administration
Fm.	Formation
Fms.	Formations
GERM	Geologic and Economic Resource Model
GOR	gas-to-oil ratio
GRASP	Geologic Resource Assessment Program
GSM	Gaviota−Sacate−Matilija
LA−SM−SP	Los Angeles−Santa Monica–San Pedro
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
NR	not reported
OCS	Outer Continental Shelf
PRESTO	Probabilistic Resource Estimates Offshore
RMT−SAV	Rincon-Monterey-Topanga-Sespe-Alegria-Vaqueros
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 Celsius, a unit of measurement of temperature

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 petroleum geologic plays of the Pacific OCS Region. The minimum accumulation size considered in the probability analysis is one million barrels 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	1.0
Excellent	The factor is virtually assured to be	0.95
Very Good	The factor is very probably	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	0.2 or 0.3
Very Poor	The factor is very probably not	0.1

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.

<u>To estimate the Average Prospect Chance</u>:

- 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 exploration 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
EIA (1995)	1973-1991 U.S. average success ratio for exploration wells	0.256
MMS (1995)	Success ratio of Santa Maria basin OCS exploration wells	0.70

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PETROLEUM GEOLOGIC PROBABILITY ANALYSIS FORM

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**
.______	**HYDROCARBON FILL**		**D.**______
1.______	source presence	(adequate organic content, organic quality, & volume of source rock)	d_1.______
2.______	maturation	(enough time & temperature for maturation, & adequate volume of mature source rock)	d_2.______
3.______	migration	(adequate primary expulsion from source rock, secondary migration to traps, & paleodrainage area of source rock)	d_3.______
4.______	preservation	(freedom from flushing, biodegradation, diffusion, or thermal overmaturation)	d_4.______
5.______	recovery	(adequate drive, concentration (not too dispersed or diluted), & oil viscosity for effective recovery)	d_5.______
.______	**RESERVOIR ROCK**		**E.**______
1.______	reservoir presence	(sufficient areal distribution & net thickness of reservoir rock)	e_1.______
2.______	reservoir quality	(sufficient porosity, permeability, & continuity of reservoir rock)	e_2.______
.______	**TRAP**		**F.**______
1.______	trap presence	(adequate area & height of closures)	f_1.______
2.______	seal presence	(adequate thickness & lithology of top & lateral seals)	f_2.______
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 TECHNICALLY RECOVERABLE RESOURCES

This appendix presents select petroleum geologic data and information used to develop estimates of the volume of undiscovered technically recoverable oil and gas resources in petroleum geologic plays of the Pacific OCS Region (see *Methodology* section). The following describes the categories and types of data. Multiple values (minimum, median, mean, 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.

Size of Accumulation

Productive Area of Pool: the lateral (areal) extent of individual pools, expressed in acres

Pay Thickness: the vertical extent (thickness) of hydrocarbon-bearing rock, expressed in feet

Reservoir Rock Volume: the hydrocarbon-filled volume of individual pools, expressed in acre-feet (used for some fractured shale plays, where pay thickness does not apply)

Proportion Gas Bearing: the portion of the pool volume of mixed pools that is filled with crude oil and associated gas, expressed as a decimal fraction

Probability all Gas: the portion of the number of pools that contain predominantly nonassociated gas and may contain condensate, expressed as a decimal fraction

Probability all Oil: the portion of the number of pools that contain predominantly crude oil and associated gas, expressed as a decimal fraction
(The remaining fraction are Mixed Pools, which contain crude oil, associated gas, and nonassociated gas, and may contain condensate, 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

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 Rocks: 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

For more information, see Appendix B

Number of Accumulations

Number of Prospects: the number of prospects that are estimated to exist

Number of Pools: the number of pools (containing hydrocarbon) that are estimated to exist

Range of BOE Pool Sizes

Largest Pool BOE: Range of estimated total hydrocarbon content (expressed in barrels of oil equivalent) of the largest likely pool

Smallest Pool BOE: Range of estimated total hydrocarbon content (expressed in barrels of oil equivalent) of the smallest likely pool

The number of discovered pools, and the largest and smallest discovered pools are given in BOE for comparison purposes.

Washington-Oregon Area, Growth Fault Play

Poolsize factors				
	Minimum	Median	Mean	Maximum
Productive Area of Pool (acres)	12	237	410	6,742
Pay Thickness (feet)	40	200	234	900
Proportion Gas Bearing (fraction)	0.4	0.7	0.68	0.9
Oil Recovery Factor (bbl per acre-foot)	55	175	196	550
Gas/Oil Ratio (cf per bbl)	200	2,000	2,748	20,000
Gas Recovery Factor (MMcf per acre-foot)	200	425	440	900
Condensate Yield (bbl per acre foot)	0.001	0.003	0.003	0.01
Probability All Gas (fraction)	0.1	0.1	0.1	0.1
Probability All Oil (fraction)	0.7	0.7	0.7	0.7
Resulting BOE Pool Size (Mbbl)	45	9,248	22,978	2,744,900
Prospect Chance Factors				
	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	
	Minimum	Median	Mean	Maximum
Number of Prospects	37	70	74	140
Resulting Number of Pools	0	10	9	47
Range of BOE Pool Sizes				
	Minimum 95%	Median 50%	Mean	Maximum 5%
Resulting Largest Pool BOE (Mbbl)	25,769	87,868	154,610	523,780
Resulting Smallest Pool BOE (Mbbl)	85	481	522	1,123
Number of Discovered Pools	0			

Washington-Oregon Area, Neogene Fan Sandstone Play

Poolsize factors				
	Minimum	Median	Mean	Maximum
Productive Area of Pool (acres)	3	75	161	3,540
Pay Thickness (feet)	20	140	170	900
Proportion Gas Bearing (fraction)	0.4	0.7	0.68	0.9
Oil Recovery Factor (bbl per acre-foot)	55	175	196	550
Gas/Oil Ratio (cf per bbl)	200	2000	2,748	20,000
Gas Recovery Factor (MMcf per acre-foot)	200	425	440	900
Condensate Yield (bbl per acre foot)	0.001	0.003	0.003	0.01
Probability All Gas (fraction)	0.55	0.55	0.55	0.55
Probability All Oil (fraction)	0.25	0.25	0.25	0.25
Resulting BOE Pool Size (Mbbl)	4.9	1,138	4,035	3,045,907
Prospect Chance Factors				
	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	
	Minimum	Median	Mean	Maximum
Number of Prospects	320	520	537	830
Resulting Number of Pools	0	81	64	205
Range of BOE Pool Sizes				
	Minimum 95%	Median 50%	Mean	Maximum 5%
Resulting Largest Pool BOE (Mbbl)	22,489	91,840	240,550	1,666,700
Resulting Smallest Pool BOE (Mbbl)	5.7	16	0	45
Number of Discovered Pools	0			

Washington-Oregon Area, Neogene Shelf Sandstone Play

Poolsize factors				
	Minimum	Median	Mean	Maximum
Productive Area of Pool (acres)	3.3	75	164	3,608
Pay Thickness (feet)	20	75	461	300
Proportion Gas Bearing (fraction)	0.4	0.7	0.68	0.9
Oil Recovery Factor (bbl per acre-foot)	55	175	196	550
Gas/Oil Ratio (cf per bbl)	200	2000	2,748	20,000
Gas Recovery Factor (MMcf per acre-foot)	200	425	440	900
Condensate Yield (bbl per acre foot)	0.001	0.003	0.003	0.01
Probability All Gas (fraction)	0.2	0.2	0.2	0.2
Probability All Oil (fraction)	0.6	0.6	0.6	0.6
Resulting BOE Pool Size (Mbbl)	100	962	3,071	599,262
Prospect Chance Factors				
	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	
	Minimum	Median	Mean	Maximum
Number of Prospects	805	1,310	1,353	2,100
Resulting Number of Pools	60	102	81	256
Range of BOE Pool Sizes				
	Minimum 95%	Median 50%	Mean	Maximum 5%
Resulting Largest Pool BOE (Mbbl)	20,247	76,228	102,050	414,580
Resulting Smallest Pool BOE (Mbbl)	5.2	13	16	37
Number of Discovered Pools	0			

Washington-Oregon Area, Paleogene Sandstone Play

Poolsize factors				
	Minimum	Median	Mean	Maximum
Productive Area of Pool (acres)	3.3	75	161	3,540
Pay Thickness (feet)	20	75	85	300
Proportion Gas Bearing (fraction)	0.4	0.7	0.68	0.9
Oil Recovery Factor (bbl per acre-foot)	10	110	130	500
Gas/Oil Ratio (cf per bbl)	200	2000	2,748	20,000
Gas Recovery Factor (MMcf per acre-foot)	200	425	440	900
Condensate Yield (bbl per acre foot)	0.001	0.003	0.003	0.01
Probability All Gas (fraction)	0.8	0.8	0.8	0.8
Probability All Oil (fraction)	0.05	0.05	0.05	0.05
Resulting BOE Pool Size (Mbbl)	2.9	457	1,228	141,083
Prospect Chance Factors				
	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	
	Minimum	Median	Mean	Maximum
Number of Prospects	295	480	506	770
Resulting Number of Pools	0	70	61	196
Range of BOE Pool Sizes				
	Minimum 95%	Median 50%	Mean	Maximum 5%
Resulting Largest Pool BOE (Mbbl)	6016	21,110	26,438	88,389
Resulting Smallest Pool BOE (Mbbl)	3.4	9	12	25
Number of Discovered Pools	0			

Eel River Basin, Neogene Fan Sandstone Play

Poolsize factors				
	Minimum	Median	Mean	Maximum
Productive Area of Pool (acres)	5.1	103	203	3,292
Pay Thickness (feet)	20	140	171	900
Proportion Gas Bearing (fraction)	0.4	0.7	0.68	0.9
Oil Recovery Factor (bbl per acre-foot)	55	175	196	550
Gas/Oil Ratio (cf per bbl)	200	2000	2,748	20,000
Gas Recovery Factor (MMcf per acre-foot)	200	425	440	900
Condensate Yield (bbl per acre foot)	0.001	0.003	0.003	0.01
Probability All Gas (fraction)	0.8	0.8	0.8	0.8
Probability All Oil (fraction)	0.05	0.05	0.05	0.05
Resulting BOE Pool Size (Mbbl)	7.2	1,220	3,427	903,512
Prospect Chance Factors				
	Play Chance	Prospect Chance	Average Chance	
Hydrocarbon Fill	1	0.8		
Reservoir Rock	1	0.8		
Trap	1	0.8		
Overall	1	0.5	0.5	
	Minimum	Median	Mean	Maximum
Number of Prospects	46	75	77	120
Resulting Number of Pools	10	38	38	80
Range of BOE Pool Sizes				
	Minimum 95%	Median 50%	Mean	Maximum 5%
Resulting Largest Pool BOE (Mbbl)	9,600	25,892	53,085	102,580
Resulting Smallest Pool BOE (Mbbl)	9.9	44	47	96
Number of Discovered Pools	0			

Eel River Basin, Neogene Shelf Sandstone Play

Poolsize factors				
	Minimum	Median	Mean	Maximum
Productive Area of Pool (acres)	5.4	100	213	3,433
Pay Thickness (feet)	21	74	85	289
Proportion Gas Bearing (fraction)	0.4	0.7	0.68	0.9
Oil Recovery Factor (bbl per acre-foot)	55	175	196	550
Gas/Oil Ratio (cf per bbl)	200	2000	2,748	20,000
Gas Recovery Factor (MMcf per acre-foot)	200	425	440	900
Condensate Yield (bbl per acre foot)	0.001	0.003	0.003	0.01
Probability All Gas (fraction)	0.8	0.8	0.8	0.8
Probability All Oil (fraction)	0.05	0.05	0.05	0.05
Resulting BOE Pool Size (Mbbl)	6.8	650	1,799	317,964
Prospect Chance Factors				
	Play Chance	Prospect Chance	Average Chance	
Hydrocarbon Fill	0.95	0.8		
Reservoir Rock	0.95	0.6		
Trap	1	0.8		
Overall	0.9	0.4	0.36	
	Minimum	Median	Mean	Maximum
Number of Prospects	180	300	308	480
Resulting Number of Pools	0	117	111	229
Range of BOE Pool Sizes				
	Minimum 95%	Median 50%	Mean	Maximum 5%
Resulting Largest Pool BOE (Mbbl)	10,810	35,281	49,052	207,970
Resulting Smallest Pool BOE (Mbbl)	7.3	14	17	35
Number of Discovered Pools	0			

Eel River Basin, Paleogene Sandstone Play

Poolsize factors				
	Minimum	Median	Mean	Maximum
Productive Area of Pool (acres)	3.3	75	160	3,473
Pay Thickness (feet)	20	45	46	100
Proportion Gas Bearing (fraction)	0.4	0.7	0.68	0.9
Oil Recovery Factor (bbl per acre-foot)	10	110	130	500
Gas/Oil Ratio (cf per bbl)	200	2000	2,748	20,000
Gas Recovery Factor (MMcf per acre-foot)	200	425	440	900
Condensate Yield (bbl per acre foot)	0.001	0.003	0.003	0.01
Probability All Gas (fraction)	0.2	0.2	0.2	0.2
Probability All Oil (fraction)	0.5	0.5	0.5	0.5
Resulting BOE Pool Size (Mbbl)	1.1	366	1,086	127,196
Prospect Chance Factors				
	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	
	Minimum	Median	Mean	Maximum
Number of Prospects	70	115	120	180
Resulting Number of Pools	0	0	10	58
Range of BOE Pool Sizes				
	Minimum 95%	Median 50%	Mean	Maximum 5%
Resulting Largest Pool BOE (Mbbl)	1,829	5,991	11,259	36,467
Resulting Smallest Pool BOE (Mbbl)	2.3	15	16	35
Number of Discovered Pools	0			

Point Arena Basin, Neogene Sandstone Play

Poolsize factors				
	Minimum	Median	Mean	Maximum
Productive Area of Pool (acres)	16	261	470	7,888
Pay Thickness (feet)	10	63	83	375
Proportion Gas Bearing (fraction)	0.4	0.7	0.68	0.9
Oil Recovery Factor (bbl per acre-foot)	55	175	196	550
Gas/Oil Ratio (cf per bbl)	300	1,000	1,181	3,500
Gas Recovery Factor (MMcf per acre-foot)	0.01	0.01	0.01	0.01
Condensate Yield (bbl per acre foot)	0.001	0.001	0.001	0.001
Probability All Gas (fraction)	0	0	0	0
Probability All Oil (fraction)	1	1	1	1
Resulting BOE Pool Size (Mbbl)	20	3,396	9,279	1,559,996
Prospect Chance Factors				
	Play Chance	Prospect Chance	Average Chance	
Hydrocarbon Fill	0.9	0.6		
Reservoir Rock	1	0.9		
Trap	0.7	0.6		
Overall	0.6	0.3	0.18	
	Minimum	Median	Mean	Maximum
Number of Prospects	45	55	56	70
Resulting Number of Pools	0	13	10	37
Range of BOE Pool Sizes				
	Minimum 95%	Median 50%	Mean	Maximum 5%
Resulting Largest Pool BOE (Mbbl)	13,026	39,743	74,578	233,.330
Resulting Smallest Pool BOE (Mbbl)	36	184	206	453
Number of Discovered Pools	0			

Point Arena Basin, Fractured Monterey Play

Poolsize factors				
	Minimum	Median	Mean	Maximum
Reservoir Rock Volume (acre-feet)	733	96,724	367,572	15,679,770
Proportion Gas Bearing (fraction)	0.4	0.7	0.68	0.9
Oil Recovery Factor (bbl per acre-foot)	30	49	50.1	80
Gas/Oil Ratio (cf per bbl)	250	880	1,009	3,000
Gas Recovery Factor (MMcf per acre-foot)	0.01	0.01	0.01	0.01
Condensate Yield (bbl per acre foot)	0.001	0.001	0.001	0.001
Probability All Gas (fraction)	0	0	0	0
Probability All Oil (fraction)	1	1	1	1
Resulting BOE Pool Size (Mbbl)	26	5,461	21,741	1,377,278
Prospect Chance Factors				
	Play Chance	Prospect Chance	Average Chance	
Hydrocarbon Fill	1	0.8		
Reservoir Rock	1	0.8		
Trap	1	0.7		
Overall	1	0.4	0.4	
	Minimum	Median	Mean	Maximum
Number of Prospects	210	240	239	270
Resulting Number of Pools	56	96	96	139
Range of BOE Pool Sizes				
	Minimum 95%	Median 50%	Mean	Maximum 5%
Resulting Largest Pool BOE (Mbbl)	118,880	472,410	516,530	1,134,600
Resulting Smallest Pool BOE (Mbbl)	28	51	60	114
Number of Discovered Pools	0			

Point Arena Basin, Pre-Monterey Play

Poolsize factors				
	Minimum	Median	Mean	Maximum
Productive Area of Pool (acres)	9.9	189	354	5,806
Pay Thickness (feet)	8	45	56	375
Proportion Gas Bearing (fraction)	0.4	0.7	0.68	0.9
Oil Recovery Factor (bbl per acre-foot)	20	110	141	600
Gas/Oil Ratio (cf per bbl)	250	1,100	1,364	5,000
Gas Recovery Factor (MMcf per acre-foot)	0.01	0.01	0.01	0.01
Condensate Yield (bbl per acre foot)	0.001	0.001	0.001	0.001
Probability All Gas (fraction)	0	0	0	0
Probability All Oil (fraction)	1	1	1	1
Resulting BOE Pool Size (Mbbl)	3.5	1,138	3,504	1,241,396
Prospect Chance Factors				
	Play Chance	Prospect Chance	Average Chance	
Hydrocarbon Fill	0.7	0.7		
Reservoir Rock	1	0.6		
Trap	1	0.7		
Overall	0.7	0.3	0.21	
	Minimum	Median	Mean	Maximum
Number of Prospects	240	275	276	330
Resulting Number of Pools	0	77	58	128
Range of BOE Pool Sizes				
	Minimum 95%	Median 50%	Mean	Maximum 5%
Resulting Largest Pool BOE (Mbbl)	17,138	51,737	105,860	544,570
Resulting Smallest Pool BOE (Mbbl)	4.9	22	24	59
Number of Discovered Pools	0			

Bodega Basin, Neogene Sandstone Play

Poolsize factors				
	Minimum	Median	Mean	Maximum
Productive Area of Pool (acres)	16	261	470	7,888
Pay Thickness (feet)	10	63	83	375
Proportion Gas Bearing (fraction)	0.4	0.7	0.68	0.9
Oil Recovery Factor (bbl per acre-foot)	55	175	196	550
Gas/Oil Ratio (cf per bbl)	300	1,000	1,181	3,500
Gas Recovery Factor (MMcf per acre-foot)	0.01	0.01	0.01	0.01
Condensate Yield (bbl per acre foot)	0.001	0.001	0.001	0.001
Probability All Gas (fraction)	0	0	0	0
Probability All Oil (fraction)	1	1	1	1
Resulting BOE Pool Size (Mbbl)	24	3,414	9,199	1,138,444
Prospect Chance Factors				
	Play Chance	Prospect Chance	Average Chance	
Hydrocarbon Fill	0.9	0.6		
Reservoir Rock	1	0.8		
Trap	0.7	0.6		
Overall	0.6	0.3	0.18	
	Minimum	Median	Mean	Maximum
Number of Prospects	30	37	38	45
Resulting Number of Pools	0	8	7	27
Range of BOE Pool Sizes				
	Minimum 95%	Median 50%	Mean	Maximum 5%
Resulting Largest Pool BOE (Mbbl)	8,564	31,869	53,698	186,570
Resulting Smallest Pool BOE (Mbbl)	45	219	251	567
Number of Discovered Pools	0			

Bodega Basin, Fractured Monterey Play

Poolsize factors				
	Minimum	Median	Mean	Maximum
Reservoir Rock Volume (acre-feet)	1103	103,379	337,302	11,726,050
Proportion Gas Bearing (fraction)	0.4	0.7	0.68	0.9
Oil Recovery Factor (bbl per acre-foot)	30	49	50.1	80
Gas/Oil Ratio (cf per bbl)	250	880	1,009	3,000
Gas Recovery Factor (MMcf per acre-foot)	0.01	0.01	0.01	0.01
Condensate Yield (bbl per acre foot)	0.001	0.001	0.001	0.001
Probability All Gas (fraction)	0	0	0	0
Probability All Oil (fraction)	1	1	1	1
Resulting BOE Pool Size (Mbbl)	37	5,841	19,913	1,110,761
Prospect Chance Factors				
	Play Chance	Prospect Chance	Average Chance	
Hydrocarbon Fill	1	0.8		
Reservoir Rock	1	0.8		
Trap	1	0.8		
Overall	1	0.5	0.5	
	Minimum	Median	Mean	Maximum
Number of Prospects	75	120	129	200
Resulting Number of Pools	21	62	64	126
Range of BOE Pool Sizes				
	Minimum 95%	Median 50%	Mean	Maximum 5%
Resulting Largest Pool BOE (Mbbl)	74,883	222,980	330,190	774,040
Resulting Smallest Pool BOE (Mbbl)	40	76	88	166
Number of Discovered Pools	0			

Bodega Basin, Pre-Monterey Play

Poolsize factors				
	Minimum	Median	Mean	Maximum
Productive Area of Pool (acres)	11	207	369	5,594
Pay Thickness (feet)	33	125	147	470
Proportion Gas Bearing (fraction)	0.5	0.6	0.6	0.7
Oil Recovery Factor (bbl per acre-foot)	20	110	141	600
Gas/Oil Ratio (cf per bbl)	250	1,100	1,364	5,000
Gas Recovery Factor (MMcf per acre-foot)	0.01	0.01	0.01	0.01
Condensate Yield (bbl per acre foot)	0.001	0.001	0.001	0.001
Probability All Gas (fraction)	0	0	0	0
Probability All Oil (fraction)	1	1	1	1
Resulting BOE Pool Size (Mbbl)	17	3,451	9,476	1,537,784
Prospect Chance Factors				
	Play Chance	Prospect Chance	Average Chance	
Hydrocarbon Fill	0.7	0.6		
Reservoir Rock	1	0.7		
Trap	1	0.7		
Overall	0.7	0.3	0.21	
	Minimum	Median	Mean	Maximum
Number of Prospects	125	165	167	220
Resulting Number of Pools	0	45	35	92
Range of BOE Pool Sizes				
	Minimum 95%	Median 50%	Mean	Maximum 5%
Resulting Largest Pool BOE (Mbbl)	32,576	84,144	145,800	267,700
Resulting Smallest Pool BOE (Mbbl)	23	100	111	237
Number of Discovered Pools	0			

Año Nuevo Basin, Neogene Sandstone Play

Poolsize factors				
	Minimum	Median	Mean	Maximum
Productive Area of Pool (acres)	12	200	368	5,065
Pay Thickness (feet)	10	63	83	375
Proportion Gas Bearing (fraction)	0.5	0.6	0.6	0.7
Oil Recovery Factor (bbl per acre-foot)	55	175	196	550
Gas/Oil Ratio (cf per bbl)	300	1,000	1,181	3,500
Gas Recovery Factor (MMcf per acre-foot)	0.01	0.01	0.01	0.01
Condensate Yield (bbl per acre foot)	0.001	0.001	0.001	0.001
Probability All Gas (fraction)	0	0	0	0
Probability All Oil (fraction)	1	1	1	1
Resulting BOE Pool Size (Mbbl)	12	2,614	7,207	568,698
Prospect Chance Factors				
	Play Chance	Prospect Chance	Average Chance	
Hydrocarbon Fill	1	0.7		
Reservoir Rock	1	0.8		
Trap	0.95	0.6		
Overall	0.95	0.3	0.285	
	Minimum	Median	Mean	Maximum
Number of Prospects	25	43	45	73
Resulting Number of Pools	0	13	13	38
Range of BOE Pool Sizes				
	Minimum 95%	Median 50%	Mean	Maximum 5%
Resulting Largest Pool BOE (Mbbl)	7,669	27,829	45,073	158,150
Resulting Smallest Pool BOE (Mbbl)	23	128	142	313
Number of Discovered Pools	0			

Año Nuevo Basin, Fractured Monterey Play

Poolsize factors				
	Minimum	Median	Mean	Maximum
Reservoir Rock Volume (acre-feet)	1,505	103,379	312,811	8,534,075
Proportion Gas Bearing (fraction)	0.4	0.7	0.68	0.9
Oil Recovery Factor (bbl per acre-foot)	30	49	50.1	80
Gas/Oil Ratio (cf per bbl)	250	880	1,009	3,000
Gas Recovery Factor (MMcf per acre-foot)	0.01	0.01	0.01	0.01
Condensate Yield (bbl per acre foot)	0.001	0.001	0.001	0.001
Probability All Gas (fraction)	0	0	0	0
Probability All Oil (fraction)	1	1	1	1
Resulting BOE Pool Size (Mbbl)	55	5,848	18,490	809,160
Prospect Chance Factors				
	Play Chance	Prospect Chance	Average Chance	
Hydrocarbon Fill	1	0.9		
Reservoir Rock	1	0.9		
Trap	1	0.7		
Overall	1	0.6	0.6	
	Minimum	Median	Mean	Maximum
Number of Prospects	31	59	61	112
Resulting Number of Pools	8	36	37	85
Range of BOE Pool Sizes				
	Minimum 95%	Median 50%	Mean	Maximum 5%
Resulting Largest Pool BOE (Mbbl)	51,103	136,750	200,110	509,330
Resulting Smallest Pool BOE (Mbbl)	60	125	134	242
Number of Discovered Pools	0			

Año Nuevo Basin, Pre-Monterey Play

Poolsize factors				
	Minimum	Median	Mean	Maximum
Productive Area of Pool (acres)	10	191	365	5,770
Pay Thickness (feet)	10	50	60	235
Proportion Gas Bearing (fraction)	0.5	0.6	0.6	0.7
Oil Recovery Factor (bbl per acre-foot)	30	130	165	600
Gas/Oil Ratio (cf per bbl)	250	1,100	1,364	5,000
Gas Recovery Factor (MMcf per acre-foot)	0.01	0.01	0.01	0.01
Condensate Yield (bbl per acre foot)	0.001	0.001	0.001	0.001
Probability All Gas (fraction)	0	0	0	0
Probability All Oil (fraction)	1	1	1	1
Resulting BOE Pool Size (Mbbl)	7.9	1,551	4,455	476,475
Prospect Chance Factors				
	Play Chance	Prospect Chance	Average Chance	
Hydrocarbon Fill	1	0.7		
Reservoir Rock	0.6	0.6		
Trap	1	0.7		
Overall	0.6	0.3	0.18	
	Minimum	Median	Mean	Maximum
Number of Prospects	57	82	84	115
Resulting Number of Pools	0	20	15	54
Range of BOE Pool Sizes				
	Minimum 95%	Median 50%	Mean	Maximum 5%
Resulting Largest Pool BOE (Mbbl)	8,970	26.003	43,524	122,830
Resulting Smallest Pool BOE (Mbbl)	12	58	64	140
Number of Discovered Pools	0			

Santa Maria-Partington Basin, Basal Sisquoc Play

Poolsize factors				
	Minimum	Median	Mean	Maximum
Productive Area of Pool (acres)	40	300	442	2,300
Pay Thickness (feet)	9	45	59	245
Proportion Gas Bearing (fraction)	0.5	0.6	0.6	0.7
Oil Recovery Factor (bbl per acre-foot)	55	175	196	550
Gas/Oil Ratio (cf per bbl)	250	880	1,009	3,000
Gas Recovery Factor (MMcf per acre-foot)	0.01	0.01	0.01	0.01
Condensate Yield (bbl per acre foot)	0.001	0.001	0.001	0.001
Probability All Gas (fraction)	0	0	0	0
Probability All Oil (fraction)	1	1	1	1
Resulting BOE Pool Size (Mbbl)	35	2,888	6,055	204,731
Prospect Chance Factors				
	Play Chance	Prospect Chance	Average Chance	
Hydrocarbon Fill	1	0.9		
Reservoir Rock	1	0.95		
Trap	1	0.7		
Overall	1	0.6	0.6	
	Minimum	Median	Mean	Maximum
Number of Prospects	25	25	25	25
Resulting Number of Pools	3	15	15	25
Range of BOE Pool Sizes				
	Minimum 95%	Median 50%	Mean	Maximum 5%
Resulting Largest Pool BOE (Mbbl)	8,723	23,281	31,834	92,098
Resulting Smallest Pool BOE (Mbbl)	65	284	313	653
Number of Discovered Pools	0			

Santa Maria-Partington Basin, Fractured Monterey Play

Poolsize factors				
	Minimum	Median	Mean	Maximum
Productive Area of Pool (acres)	10	450	1,324	20,000
Pay Thickness (feet)	200	440	461	1,000
Proportion Gas Bearing (fraction)	0	0	0	0
Oil Recovery Factor (bbl per acre-foot)	30	49	50.3	80
Gas/Oil Ratio (cf per bbl)	200	650	740	2,200
Gas Recovery Factor (MMcf per acre-foot)	220	425	436	800
Condensate Yield (bbl per acre foot)	0	0	0	0
Probability All Gas (fraction)	0	0	0	0
Probability All Oil (fraction)	1	1	1	1
Resulting BOE Pool Size (Mbbl)	75	13,159	34,603	1,578,877
Prospect Chance Factors				
	Play Chance	Prospect Chance	Average Chance	
Overall	1	0.6	0.6	
	Minimum	Median	Mean	Maximum
Number of Prospects	40	80		160
Resulting Number of Pools (incl. discoveries)	30	61	64	120
Range of BOE Pool Sizes				
	Minimum 95%	Median 50%	Mean	Maximum 5%
Resulting Largest Pool BOE (Mbbl)	100,390	416,080	463,460	904,470
Resulting Smallest Pool BOE (Mbbl)	95	353	432	1,020
Number of Discovered Pools	12			
Largest Discovered Pool BOE (Mbbl)	746,374			
Smallest Discovered Pool BOE (Mbbl)	11,794			

Santa Maria-Partington Basin, Paleogene Sandstone Play

Poolsize factors				
	Minimum	Median	Mean	Maximum
Productive Area of Pool (acres)	10	191	369	5,770
Pay Thickness (feet)	14	72	92	375
Proportion Gas Bearing (fraction)	0.5	0.6	0.6	0.7
Oil Recovery Factor (bbl per acre-foot)	20	110	141	600
Gas/Oil Ratio (cf per bbl)	250	2,000	2,930	15,000
Gas Recovery Factor (MMcf per acre-foot)	.01	.01	.01	.01
Condensate Yield (bbl per acre foot)	.001	.001	.001	.001
Probability All Gas (fraction)	0	0	0	0
Probability All Oil (fraction)	1	1	1	1
Resulting BOE Pool Size (Mbbl)	6.4	2,192	7,361	1,237,256
Prospect Chance Factors				
	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	
	Minimum	Median	Mean	Maximum
Number of Prospects	23	33	34	46
Resulting Number of Pools	0	0	1	20
Range of BOE Pool Sizes				
	Minimum 95%	Median 50%	Mean	Maximum 5%
Resulting Largest Pool BOE (Mbbl)	2,849	16,055	34,528	130,900
Resulting Smallest Pool BOE (Mbbl)	21	130	161	403
Number of Discovered Pools	0			

Santa Maria-Partington Basin, Breccia Play

Poolsize factors				
	Minimum	Median	Mean	Maximum
Productive Area of Pool (acres)	20	200	343	2,000
Pay Thickness (feet)	20	100	132	500
Proportion Gas Bearing (fraction)	0.5	0.6	0.6	0.7
Oil Recovery Factor (bbl per acre-foot)	70	180	194	450
Gas/Oil Ratio (cf per bbl)	250	880	1009	3,000
Gas Recovery Factor (MMcf per acre-foot)	.01	.01	.01	.01
Condensate Yield (bbl per acre foot)	.001	.001	.001	.001
Probability All Gas (fraction)	0	0	0	0
Probability All Oil (fraction)	1	1	1	1
Resulting BOE Pool Size (Mbbl)	38	4,513	10,348	413,138
Prospect Chance Factors				
	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	0.0225	
	Minimum	Median	Mean	Maximum
Number of Prospects	31	38	38	45
Resulting Number of Pools	0	0	1	18
Range of BOE Pool Sizes				
	Minimum 95%	Median 50%	Mean	Maximum 5%
Resulting Largest Pool BOE (Mbbl)	4,560	22,605	33,010	97,377
Resulting Smallest Pool BOE (Mbbl)	93	436	508	1,141
Number of Discovered Pools	0			

Santa Barbara-Ventura Basin, Pico-Repetto Sandstone Play

Poolsize factors				
	Minimum	Median	Mean	Maximum
Productive Area of Pool (acres)	10	300	778	10,000
Pay Thickness (feet)	60	240	277	1,000
Proportion Gas Bearing (fraction)	0.3	0.3	0.3	0.3
Oil Recovery Factor (bbl per acre-foot)	55	240	298	1000
Gas/Oil Ratio (cf per bbl)	100	900	1,265	8,000
Gas Recovery Factor (MMcf per acre-foot)	200	300	425	900
Condensate Yield (bbl per acre foot)	0	0	0	0
Probability All Gas (fraction)	0.3	0.3	0.3	0.3
Probability All Oil (fraction)	0.5	0.5	0.5	0.5
Resulting BOE Pool Size (Mbbl)	78	17,866	56,243	4,613,816
Prospect Chance Factors				
	Play Chance	Prospect Chance	Average Chance	
Overall	1	0.2	0.2	
	Minimum	Median	Mean	Maximum
Number of Prospects	8	19		47
Resulting Number of Pools (incl. discoveries)	5	9	10	20
Range of BOE Pool Sizes				
	Minimum 95%	Median 50%	Mean	Maximum 5%
Resulting Largest Pool BOE (Mbbl)	42,373	179,240	316,050	1,282,000
Resulting Smallest Pool BOE (Mbbl)	218	1,314	1,539	3,609
Number of Discovered Pools	5			
Largest Discovered Pool BOE (Mbbl)	301,390			
Smallest Discovered Pool BOE (Mbbl)	1,266			

Santa Barbara-Ventura Basin, Fractured Monterey Play

Poolsize factors				
	Minimum	Median	Mean	Maximum
Productive Area of Pool (acres)	10	300	728	9,000
Pay Thickness (feet)	150	600	792	3,000
Proportion Gas Bearing (fraction)	0	0	0	0
Oil Recovery Factor (bbl per acre-foot)	30	49	50.3	80
Gas/Oil Ratio (cf per bbl)	200	800	923	3.000
Gas Recovery Factor (MMcf per acre-foot)	220	425	436	800
Condensate Yield (bbl per acre foot)	0	0	0	0
Probability All Gas (fraction)	0	0	0	0
Probability All Oil (fraction)	1	1	1	1
Resulting BOE Pool Size (Mbbl)	64	14,355	33,843	2,126,987
Prospect Chance Factors				
	Play Chance	Prospect Chance	Average Chance	
Overall	1	0.6	0.6	
	Minimum	Median	Mean	Maximum
Number of Prospects	28	60		131
Resulting Number of Pools (incl. discoveries)	27	52	54	105
Range of BOE Pool Sizes				
	Minimum 95%	Median 50%	Mean	Maximum 5%
Resulting Largest Pool BOE (Mbbl)	106,260	319,080	415,450	846,000
Resulting Smallest Pool BOE (Mbbl)	94	462	551	1,283
Number of Discovered Pools	16			
Largest Discovered Pool BOE (Mbbl)	487,160			
Smallest Discovered Pool BOE (Mbbl)	166			

Santa Barbara-Ventura Basin, Rincon-Monterey-Topanga-Sespe-Alegria-Vaqueros Sandstone Play

Poolsize factors				
	Minimum	Median	Mean	Maximum
Productive Area of Pool (acres)	20	335	588	5,500
Pay Thickness (feet)	25	250	373	2,500
Proportion Gas Bearing (fraction)	0.2	0.2	0.2	0.2
Oil Recovery Factor (bbl per acre-foot)	20	80	104	400
Gas/Oil Ratio (cf per bbl)	100	1,500	2,653	25,000
Gas Recovery Factor (MMcf per acre-foot)	200	425	444	900
Condensate Yield (bbl per acre foot)	0	0	0	0
Probability All Gas (fraction)	0.25	0.25	0.25	0.25
Probability All Oil (fraction)	0.6	0.6	0.6	0.6
Resulting BOE Pool Size (Mbbl)	22	10,720	29,184	7,052,485
Prospect Chance Factors				
	Play Chance	Prospect Chance	Average Chance	
Overall	1	0.2	0.2	
	Minimum	Median	Mean	Maximum
Number of Prospects	35	70		132
Resulting Number of Pools (incl. discoveries)	9	21	22	44
Range of BOE Pool Sizes				
	Minimum 95%	Median 50%	Mean	Maximum 5%
Resulting Largest Pool BOE (Mbbl)	47,616	144,390	311,000	887,080
Resulting Smallest Pool BOE (Mbbl)	74	591	643	1,429
Number of Discovered Pools	7			
Largest Discovered Pool BOE (Mbbl)	72,711			
Smallest Discovered Pool BOE (Mbbl)	5,113			

Santa Barbara-Ventura Basin, Gaviota-Sacate-Matilija Sandstone Play

Poolsize factors				
	Minimum	Median	Mean	Maximum
Productive Area of Pool (acres)	20	220	338	2,500
Pay Thickness (feet)	25	250	373	2,500
Proportion Gas Bearing (fraction)	0.2	0.2	0.2	0.2
Oil Recovery Factor (bbl per acre-foot)	20	110	143	600
Gas/Oil Ratio (cf per bbl)	200	2,100	3,029	20,000
Gas Recovery Factor (MMcf per acre-foot)	200	425	444	900
Condensate Yield (bbl per acre foot)	0	0	0	0
Probability All Gas (fraction)	0.25	0.25	0.25	0.25
Probability All Oil (fraction)	0.6	0.6	0.6	0.6
Resulting BOE Pool Size (Mbbl)	33	8,478	22,898	3,429,698
Prospect Chance Factors				
	Play Chance	Prospect Chance	Average Chance	
Overall	1	0.2	0.2	
	Minimum	Median	Mean	Maximum
Number of Prospects	14	26		49
Resulting Number of Pools (incl. discoveries)	6	11	12	23
Range of BOE Pool Sizes				
	Minimum 95%	Median 50%	Mean	Maximum 5%
Resulting Largest Pool BOE (Mbbl)	23,052	81,025	148,700	539,740
Resulting Smallest Pool BOE (Mbbl)	119	742	831	1,836
Number of Discovered Pools	6			
Largest Discovered Pool BOE (Mbbl)	49,772			
Smallest Discovered Pool BOE (Mbbl)	1,686			

Los Angeles-Santa Monica-San Pedro Area, Puente Fan Sandstone Play

Poolsize factors				
	Minimum	Median	Mean	Maximum
Productive Area of Pool (acres)	16	240	536	3,500
Pay Thickness (feet)	50	155	177	500
Proportion Gas Bearing (fraction)	0.5	0.6	0.6	0.7
Oil Recovery Factor (bbl per acre-foot)	55	180	208	600
Gas/Oil Ratio (cf per bbl)	220	900	1,101	3,600
Gas Recovery Factor (MMcf per acre-foot)	0.01	0.01	0.01	0.01
Condensate Yield (bbl per acre foot)	0.001	0.001	0.001	0.001
Probability All Gas (fraction)	0	0	0	0
Probability All Oil (fraction)	1	1	1	1
Resulting BOE Pool Size (Mbbl)	82	8,739	23,767	1,147,206
Prospect Chance Factors				
	Play Chance	Prospect Chance	Average Chance	
Hydrocarbon Fill	1	0.7		
Reservoir Rock	1	0.8		
Trap	1	0.6		
Overall	1	0.3	0.3	
	Minimum	Median	Mean	Maximum
Number of Prospects	54	62	63	71
Resulting Number of Pools	3	19	19	39
Range of BOE Pool Sizes				
	Minimum 95%	Median 50%	Mean	Maximum 5%
Resulting Largest Pool BOE (Mbbl)	41,598	118,800	157,000	397,630
Resulting Smallest Pool BOE (Mbbl)	119	480	527	1,120
Number of Discovered Pools	2			
Largest Discovered Pool BOE (Mbbl)	113,890			
Smallest Discovered Pool BOE (Mbbl)	4,962			

Los Angeles-Santa Monica-San Pedro Area, Upper Miocene Sandstone Play

Poolsize factors				
	Minimum	Median	Mean	Maximum
Productive Area of Pool (acres)	7.2	109	209	2,585
Pay Thickness (feet)	30	95	109	300
Proportion Gas Bearing (fraction)	0.5	0.6	0.6	0.7
Oil Recovery Factor (bbl per acre-foot)	40	125	147	420
Gas/Oil Ratio (cf per bbl)	200	400	416	800
Gas Recovery Factor (MMcf per acre-foot)	0.01	0.01	0.01	0.01
Condensate Yield (bbl per acre foot)	0.001	0.001	0.001	0.001
Probability All Gas (fraction)	0	0	0	0
Probability All Oil (fraction)	1	1	1	1
Resulting BOE Pool Size (Mbbl)	13	1,444	3,595	257,660
Prospect Chance Factors				
	Play Chance	Prospect Chance	Average Chance	
Hydrocarbon Fill	0.8	0.3		
Reservoir Rock	1	0.8		
Trap	1	0.8		
Overall	0.8	0.2	0.16	
	Minimum	Median	Mean	Maximum
Number of Prospects	58	70	71	86
Resulting Number of Pools	0	13	11	34
Range of BOE Pool Sizes				
	Minimum 95%	Median 50%	Mean	Maximum 5%
Resulting Largest Pool BOE (Mbbl)	4,562	14,246	21,067	63,452
Resulting Smallest Pool BOE (Mbbl)	22	95	104	218
Number of Discovered Pools	0			

Los Angeles-Santa Monica-San Pedro Area, Modelo Play

Poolsize factors				
	Minimum	Median	Mean	Maximum
Productive Area of Pool (acres)	4	200	555	12,000
Pay Thickness (feet)	20	165	219	1,200
Proportion Gas Bearing (fraction)	0.5	0.6	0.6	0.7
Oil Recovery Factor (bbl per acre-foot)	20	90	112	480
Gas/Oil Ratio (cf per bbl)	200	1,100	1,427	6,850
Gas Recovery Factor (MMcf per acre-foot)	0.01	0.01	0.01	0.01
Condensate Yield (bbl per acre foot)	0.001	0.001	0.001	0.001
Probability All Gas (fraction)	0	0	0	0
Probability All Oil (fraction)	1	1	1	1
Resulting BOE Pool Size (Mbbl)	2.6	4,172	17,159	2,895,497
Prospect Chance Factors				
	Play Chance	Prospect Chance	Average Chance	
Hydrocarbon Fill	0.95	0.5		
Reservoir Rock	0.95	0.7		
Trap	1	0.6		
Overall	0.9	0.2	0.18	
	Minimum	Median	Mean	Maximum
Number of Prospects	43	58	59	78
Resulting Number of Pools	0	11	11	31
Range of BOE Pool Sizes				
	Minimum 95%	Median 50%	Mean	Maximum 5%
Resulting Largest Pool BOE (Mbbl)	13,242	63,303	127,920	520,600
Resulting Smallest Pool BOE (Mbbl)	17	146	179	453
Number of Discovered Pools	0			

Los Angeles-Santa Monica-San Pedro Area, Dume Thrust Fault Play

Poolsize factors				
	Minimum	Median	Mean	Maximum
Productive Area of Pool (acres)	6	157	392	6,182
Pay Thickness (feet)	130	370	409	1,000
Proportion Gas Bearing (fraction)	0.5	0.6	0.6	0.7
Oil Recovery Factor (bbl per acre-foot)	50	155	171	485
Gas/Oil Ratio (cf per bbl)	185	1,050	1,314	6,000
Gas Recovery Factor (MMcf per acre-foot)	0.01	0.01	0.01	0.01
Condensate Yield (bbl per acre foot)	0.001	0.001	0.001	0.001
Probability All Gas (fraction)	0	0	0	0
Probability All Oil (fraction)	1	1	1	1
Resulting BOE Pool Size (Mbbl)	87	11,233	33,477	2,633,145
Prospect Chance Factors				
	Play Chance	Prospect Chance	Average Chance	
Hydrocarbon Fill	0.95	0.7		
Reservoir Rock	1	0.8		
Trap	0.7	0.5		
Overall	0.7	0.3	0.21	
	Minimum	Median	Mean	Maximum
Number of Prospects	51	60	60	69
Resulting Number of Pools	0	16	13	38
Range of BOE Pool Sizes				
	Minimum 95%	Median 50%	Mean	Maximum 5%
Resulting Largest Pool BOE (Mbbl)	54,257	166,980	240,720	657,500
Resulting Smallest Pool BOE (Mbbl)	132	544	601	1,284
Number of Discovered Pools	0			

Los Angeles-Santa Monica-San Pedro Area, San Onofre Breccia Play

Poolsize factors				
	Minimum	Median	Mean	Maximum
Productive Area of Pool (acres)	20	200	343	2,000
Pay Thickness (feet)	20	100	132	500
Proportion Gas Bearing (fraction)	0.5	0.6	0.6	0.7
Oil Recovery Factor (bbl per acre-foot)	70	180	194	450
Gas/Oil Ratio (cf per bbl)	150	400	434	1,000
Gas Recovery Factor (MMcf per acre-foot)	0.01	0.01	0.01	0.01
Condensate Yield (bbl per acre foot)	0.001	0.001	0.001	0.001
Probability All Gas (fraction)	0	0	0	0
Probability All Oil (fraction)	1	1	1	1
Resulting BOE Pool Size (Mbbl)	37	4,137	9,419	334,412
Prospect Chance Factors				
	Play Chance	Prospect Chance	Average Chance	
Hydrocarbon Fill	1	0.7		
Reservoir Rock	1	0.8		
Trap	0.95	0.6		
Overall	0.95	0.3	0.285	
	Minimum	Median	Mean	Maximum
Number of Prospects	23	28	28	33
Resulting Number of Pools	0	8	8	22
Range of BOE Pool Sizes				
	Minimum 95%	Median 50%	Mean	Maximum 5%
Resulting Largest Pool BOE (Mbbl)	7,354	28,070	37,383	111,230
Resulting Smallest Pool BOE (Mbbl)	77	359	409	902
Number of Discovered Pools	0			

Oceanside Basin, Upper Miocene Sandstone Play

Poolsize factors				
	Minimum	Median	Mean	Maximum
Productive Area of Pool (acres)	9	221	498	8,908
Pay Thickness (feet)	50	155	177	500
Proportion Gas Bearing (fraction)	0.5	0.6	0.6	0.7
Oil Recovery Factor (bbl per acre-foot)	55	180	208	600
Gas/Oil Ratio (cf per bbl)	200	500	525	1,300
Gas Recovery Factor (MMcf per acre-foot)	0.01	0.01	0.01	0.01
Condensate Yield (bbl per acre foot)	0.001	0.001	0.001	0.001
Probability All Gas (fraction)	0	0	0	0
Probability All Oil (fraction)	1	1	1	1
Resulting BOE Pool Size (Mbbl)	39	6,898	20,128	1,625,714
Prospect Chance Factors				
	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	
	Minimum	Median	Mean	Maximum
Number of Prospects	63	88	90	124
Resulting Number of Pools	0	37	27	83
Range of BOE Pool Sizes				
	Minimum 95%	Median 50%	Mean	Maximum 5%
Resulting Largest Pool BOE (Mbbl)	68,400	169,890	255,970	562,480
Resulting Smallest Pool BOE (Mbbl)	53	230	245	511
Number of Discovered Pools	0			

Oceanside Basin, Fractured Monterey Play

Poolsize factors				
	Minimum	Median	Mean	Maximum
Reservoir Rock Volume (acre-feet)	685	72,545	449,400	8,526,200
Proportion Gas Bearing (fraction)	0.5	0.6	0.6	0.7
Oil Recovery Factor (bbl per acre-foot)	20	33	34	55
Gas/Oil Ratio (cf per bbl)	200	940	1,136	4,600
Gas Recovery Factor (MMcf per acre-foot)	0.01	0.01	0.01	0.01
Condensate Yield (bbl per acre foot)	0.001	0.001	0.001	0.001
Probability All Gas (fraction)	0	0	0	0
Probability All Oil (fraction)	1	1	1	1
Resulting BOE Pool Size (Mbbl)	16	3,073	18,084	613,099
Prospect Chance Factors				
	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	
	Minimum	Median	Mean	Maximum
Number of Prospects	64	90	92	137
Resulting Number of Pools	0	32	26	76
Range of BOE Pool Sizes				
	Minimum 95%	Median 50%	Mean	Maximum 5%
Resulting Largest Pool BOE (Mbbl)	48,227	218,280	222,470	417,370
Resulting Smallest Pool BOE (Mbbl)	18	40	45	90
Number of Discovered Pools	0			

Oceanside Basin, Lower Miocene Sandstone Play

Poolsize factors				
	Minimum	Median	Mean	Maximum
Productive Area of Pool (acres)	5.6	185	491	11,083
Pay Thickness (feet)	12	100	130	530
Proportion Gas Bearing (fraction)	0.5	0.6	0.6	0.7
Oil Recovery Factor (bbl per acre-foot)	30	145	169	550
Gas/Oil Ratio (cf per bbl)	200	1,500	2,438	12,000
Gas Recovery Factor (MMcf per acre-foot)	0.01	0.01	0.01	0.01
Condensate Yield (bbl per acre foot)	0.001	0.001	0.001	0.001
Probability All Gas (fraction)	0	0	0	0
Probability All Oil (fraction)	1	1	1	1
Resulting BOE Pool Size (Mbbl)	5.6	3,851	15,356	2,649,378
Prospect Chance Factors				
	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	
	Minimum	Median	Mean	Maximum
Number of Prospects	99	130	134	175
Resulting Number of Pools	0	0	16	75
Range of BOE Pool Sizes				
	Minimum 95%	Median 50%	Mean	Maximum 5%
Resulting Largest Pool BOE (Mbbl)	47,186	137,550	250,280	581,710
Resulting Smallest Pool BOE (Mbbl)	11	78	84	201
Number of Discovered Pools	0			

Santa Cruz Basin, Fractured Monterey Play

Poolsize factors				
	Minimum	Median	Mean	Maximum
Reservoir Rock Volume (acre-feet)	4017	115,290	353,631	4,988,500
Proportion Gas Bearing (fraction)	0.5	0.6	0.6	0.7
Oil Recovery Factor (bbl per acre-foot)	25	40	41	65
Gas/Oil Ratio (cf per bbl)	200	940	1,136	4,600
Gas Recovery Factor (MMcf per acre-foot)	0.01	0.01	0.01	0.01
Condensate Yield (bbl per acre foot)	0.001	0.001	0.001	0.001
Probability All Gas (fraction)	0	0	0	0
Probability All Oil (fraction)	1	1	1	1
Resulting BOE Pool Size (Mbbl)	116	5,825	17,317	505,292
Prospect Chance Factors				
	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	
	Minimum	Median	Mean	Maximum
Number of Prospects	40	55	56	75
Resulting Number of Pools	0	18	13	47
Range of BOE Pool Sizes				
	Minimum 95%	Median 50%	Mean	Maximum 5%
Resulting Largest Pool BOE (Mbbl)	32,793	116,030	133,150	291,450
Resulting Smallest Pool BOE (Mbbl)	130	279	309	609
Number of Discovered Pools	0			

Santa Cruz Basin, Lower Miocene Sandstone Play

Poolsize factors				
	Minimum	Median	Mean	Maximum
Productive Area of Pool (acres)	7.8	157	315	4,300
Pay Thickness (feet)	12	100	130	530
Proportion Gas Bearing (fraction)	0.5	0.6	0.6	0.7
Oil Recovery Factor (bbl per acre-foot)	30	145	169	550
Gas/Oil Ratio (cf per bbl)	200	1,500	2,438	12,000
Gas Recovery Factor (MMcf per acre-foot)	0.01	0.01	0.01	0.01
Condensate Yield (bbl per acre foot)	0.001	0.001	0.001	0.001
Probability All Gas (fraction)	0	0	0	0
Probability All Oil (fraction)	1	1	1	1
Resulting BOE Pool Size (Mbbl)	8.2	3,253	9,891	1,023,333
Prospect Chance Factors				
	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	
	Minimum	Median	Mean	Maximum
Number of Prospects	40	54	56	74
Resulting Number of Pools	0	0	11	46
Range of BOE Pool Sizes				
	Minimum 95%	Median 50%	Mean	Maximum 5%
Resulting Largest Pool BOE (Mbbl)	18,263	54,845	88,864	251,240
Resulting Smallest Pool BOE (Mbbl)	19	126	141	620
Number of Discovered Pools	0			

Santa Rosa Area, Fractured Monterey Play

Poolsize factors				
	Minimum	Median	Mean	Maximum
Reservoir Rock Volume (acre-feet)	1,591	49,311	142,271	1,785,500
Proportion Gas Bearing (fraction)	0.5	0.6	0.6	0.7
Oil Recovery Factor (bbl per acre-foot)	25	40	41	65
Gas/Oil Ratio (cf per bbl)	200	940	1,136	4,600
Gas Recovery Factor (MMcf per acre-foot)	0.01	0.01	0.01	0.01
Condensate Yield (bbl per acre foot)	0.001	0.001	0.001	0.001
Probability All Gas (fraction)	0	0	0	0
Probability All Oil (fraction)	1	1	1	1
Resulting BOE Pool Size (Mbbl)	45	2,489	6,972	162,731
Prospect Chance Factors				
	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	
	Minimum	Median	Mean	Maximum
Number of Prospects	16	31	33	63
Resulting Number of Pools	0	0	5	39
Range of BOE Pool Sizes				
	Minimum 95%	Median 50%	Mean	Maximum 5%
Resulting Largest Pool BOE (Mbbl)	7.015	24,938	37,881	98,617
Resulting Smallest Pool BOE (Mbbl)	51	116	132	276
Number of Discovered Pools	0			

Santa Rosa Area, Lower Miocene Sandstone Play

Poolsize factors				
	Minimum	Median	Mean	Maximum
Productive Area of Pool (acres)	16	225	453	5,276
Pay Thickness (feet)	12	100	130	530
Proportion Gas Bearing (fraction)	0.5	0.6	0.6	0.7
Oil Recovery Factor (bbl per acre-foot)	30	145	169	550
Gas/Oil Ratio (cf per bbl)	200	1,500	2,438	12,000
Gas Recovery Factor (MMcf per acre-foot)	0.01	0.01	0.01	0.01
Condensate Yield (bbl per acre foot)	0.001	0.001	0.001	0.001
Probability All Gas (fraction)	0	0	0	0
Probability All Oil (fraction)	1	1	1	1
Resulting BOE Pool Size (Mbbl)	20	4,806	14,240	1,556,771
Prospect Chance Factors				
	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	
	Minimum	Median	Mean	Maximum
Number of Prospects	16	26	28	45
Resulting Number of Pools	0	0	2	126
Range of BOE Pool Sizes				
	Minimum 95%	Median 50%	Mean	Maximum 5%
Resulting Largest Pool BOE (Mbbl)	8,028	41,612	68,337	239,210
Resulting Smallest Pool BOE (Mbbl)	52	305	348	788
Number of Discovered Pools	0			

Santa Cruz-Santa Rosa Area, Paleogene-Cretaceous Sandstone Play

Poolsize factors				
	Minimum	Median	Mean	Maximum
Productive Area of Pool (acres)	15	219	395	5,237
Pay Thickness (feet)	10	80	122	670
Proportion Gas Bearing (fraction)	0.5	0.6	0.6	0.7
Oil Recovery Factor (bbl per acre-foot)	50	100	214	700
Gas/Oil Ratio (cf per bbl)	200	1,600	2,439	12,000
Gas Recovery Factor (MMcf per acre-foot)	0.01	0.01	0.01	0.01
Condensate Yield (bbl per acre foot)	0.001	0.001	0.001	0.001
Probability All Gas (fraction)	0	0	0	0
Probability All Oil (fraction)	1	1	1	1
Resulting BOE Pool Size (Mbbl)	13	4,781	14,761	1,641,207
Prospect Chance Factors				
	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	
	Minimum	Median	Mean	Maximum
Number of Prospects	67	80	80	96
Resulting Number of Pools	0	0	7	47
Range of BOE Pool Sizes				
	Minimum 95%	Median 50%	Mean	Maximum 5%
Resulting Largest Pool BOE (Mbbl)	29,050	86,293	145,860	421,950
Resulting Smallest Pool BOE (Mbbl)	29	193	212	474
Number of Discovered Pools	0			

Santa Nicolas Basin, Upper Miocene Sandstone Play

Poolsize factors				
	Minimum	Median	Mean	Maximum
Productive Area of Pool (acres)	12	253	581	8,486
Pay Thickness (feet)	40	115	461	350
Proportion Gas Bearing (fraction)	0.5	0.6	0.6	0.7
Oil Recovery Factor (bbl per acre-foot)	45	150	166	450
Gas/Oil Ratio (cf per bbl)	200	500	525	1,300
Gas Recovery Factor (MMcf per acre-foot)	0.01	0.01	0.01	0.01
Condensate Yield (bbl per acre foot)	0.001	0.001	0.001	0.001
Probability All Gas (fraction)	0	0	0	0
Probability All Oil (fraction)	1	1	1	1
Resulting BOE Pool Size (Mbbl)	29	4,949	14,167	1,086,052
Prospect Chance Factors				
	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	
	Minimum	Median	Mean	Maximum
Number of Prospects	21	33	34	53
Resulting Number of Pools	0	0	6	34
Range of BOE Pool Sizes				
	Minimum 95%	Median 50%	Mean	Maximum 5%
Resulting Largest Pool BOE (Mbbl)	16,031	58,330	87,558	271,640
Resulting Smallest Pool BOE (Mbbl)	55	275	302	646
Number of Discovered Pools	0			

Santa Nicolas Basin, Fractured Monterey Play

Poolsize factors				
	Minimum	Median	Mean	Maximum
Reservoir Rock Volume (acre-feet)	620	75,193	385,734	8,496,800
Proportion Gas Bearing (fraction)	0.5	0.6	0.6	0.7
Oil Recovery Factor (bbl per acre-foot)	25	40	41	65
Gas/Oil Ratio (cf per bbl)	200	940	1,136	4,600
Gas Recovery Factor (MMcf per acre-foot)	0.01	0.01	0.01	0.01
Condensate Yield (bbl per acre foot)	0.001	0.001	0.001	0.001
Probability All Gas (fraction)	0	0	0	0
Probability All Oil (fraction)	1	1	1	1
Resulting BOE Pool Size (Mbbl)	18	3,845	18,911	807,912
Prospect Chance Factors				
	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	
	Minimum	Median	Mean	Maximum
Number of Prospects	21	42	45	82
Resulting Number of Pools	0	14	13	51
Range of BOE Pool Sizes				
	Minimum 95%	Median 50%	Mean	Maximum 5%
Resulting Largest Pool BOE (Mbbl)	18,932	111,930	172,410	478,610
Resulting Smallest Pool BOE (Mbbl)	21	51	62	148
Number of Discovered Pools	0			

Santa Nicolas Basin, Lower Miocene Sandstone Play

Poolsize factors				
	Minimum	Median	Mean	Maximum
Productive Area of Pool (acres)	10	255	590	9,137
Pay Thickness (feet)	12	100	128	530
Proportion Gas Bearing (fraction)	0.5	0.6	0.6	0.7
Oil Recovery Factor (bbl per acre-foot)	30	145	169	550
Gas/Oil Ratio (cf per bbl)	200	1,500	2,438	12,000
Gas Recovery Factor (MMcf per acre-foot)	0.01	0.01	0.01	0.01
Condensate Yield (bbl per acre foot)	0.001	0.001	0.001	0.001
Probability All Gas (fraction)	0	0	0	0
Probability All Oil (fraction)	1	1	1	1
Resulting BOE Pool Size (Mbbl)	10	5,353	18,142	1,780,387
Prospect Chance Factors				
	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	
	Minimum	Median	Mean	Maximum
Number of Prospects	38	60	62	96
Resulting Number of Pools	0	0	10	56
Range of BOE Pool Sizes				
	Minimum 95%	Median 50%	Mean	Maximum 5%
Resulting Largest Pool BOE (Mbbl)	35,372	112,470	179,240	501,740
Resulting Smallest Pool BOE (Mbbl)	22	154	170	387
Number of Discovered Pools	0			

Santa Nicolas Basin, Paleogene-Cretaceous Play

Poolsize factors				
	Minimum	Median	Mean	Maximum
Productive Area of Pool (acres)	16	277	530	6,763
Pay Thickness (feet)	10	80	122	670
Proportion Gas Bearing (fraction)	0.5	0.6	0.6	0.7
Oil Recovery Factor (bbl per acre-foot)	50	180	214	700
Gas/Oil Ratio (cf per bbl)	200	1,600	2,439	12,000
Gas Recovery Factor (MMcf per acre-foot)	0.01	0.01	0.01	0.01
Condensate Yield (bbl per acre foot)	0.001	0.001	0.001	0.001
Probability All Gas (fraction)	0	0	0	0
Probability All Oil (fraction)	1	1	1	1
Resulting BOE Pool Size (Mbbl)	24	6,095	19,868	2,240,107
Prospect Chance Factors				
	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	
	Minimum	Median	Mean	Maximum
Number of Prospects	31	54	56	95
Resulting Number of Pools	0	0	7	45
Range of BOE Pool Sizes				
	Minimum 95%	Median 50%	Mean	Maximum 5%
Resulting Largest Pool BOE (Mbbl)	25,039	91,436	158,280	527,120
Resulting Smallest Pool BOE (Mbbl)	42	233	261	588
Number of Discovered Pools	0			

Cortes-Velero-Long Area, Lower Miocene Sandstone Play

Poolsize factors				
	Minimum	Median	Mean	Maximum
Productive Area of Pool (acres)	8.1	217	496	10,920
Pay Thickness (feet)	12	100	121	530
Proportion Gas Bearing (fraction)	0.5	0.6	0.6	0.7
Oil Recovery Factor (bbl per acre-foot)	30	145	166	550
Gas/Oil Ratio (cf per bbl)	200	1,600	2,439	12,000
Gas Recovery Factor (MMcf per acre-foot)	0.01	0.01	0.01	0.01
Condensate Yield (bbl per acre foot)	0.001	0.001	0.001	0.001
Probability All Gas (fraction)	0	0	0	0
Probability All Oil (fraction)	1	1	1	1
Resulting BOE Pool Size (Mbbl)	9.1	4,324	14,189	1,933,868
Prospect Chance Factors				
	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	
	Minimum	Median	Mean	Maximum
Number of Prospects	76	110	115	172
Resulting Number of Pools	0	0	18	91
Range of BOE Pool Sizes				
	Minimum 95%	Median 50%	Mean	Maximum 5%
Resulting Largest Pool BOE (Mbbl)	47,132	130,290	225,190	500,480
Resulting Smallest Pool BOE (Mbbl)	16	97	110	249
Number of Discovered Pools	0			

Cortes-Velero-Long Area, Paleogene-Cretaceous Sandstone Play

Poolsize factors				
	Minimum	Median	Mean	Maximum
Productive Area of Pool (acres)	10	251	572	10,918
Pay Thickness (feet)	10	80	113	670
Proportion Gas Bearing (fraction)	0.5	0.6	0.6	0.7
Oil Recovery Factor (bbl per acre-foot)	50	180	213	700
Gas/Oil Ratio (cf per bbl)	200	1,600	2,439	12,000
Gas Recovery Factor (MMcf per acre-foot)	0.01	0.01	0.01	0.01
Condensate Yield (bbl per acre foot)	0.001	0.001	0.001	0.001
Probability All Gas (fraction)	0	0	0	0
Probability All Oil (fraction)	1	1	1	1
Resulting BOE Pool Size (Mbbl)	19	5,407	19,529	2,883,405
Prospect Chance Factors				
	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	
	Minimum	Median	Mean	Maximum
Number of Prospects	76	105	106	150
Resulting Number of Pools	0	0	10	65
Range of BOE Pool Sizes				
	Minimum 95%	Median 50%	Mean	Maximum 5%
Resulting Largest Pool BOE (Mbbl)	47,424	141,680	253,990	651,650
Resulting Smallest Pool BOE (Mbbl)	29	148	159	363
Number of Discovered Pools	0			

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 an exploratory or delineation (E & D) well 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 production-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

Production Well Drilling Time: the period of time to drill a production well, expressed in days per well

Oil Production Parameters

These parameters are used to estimate the production profile of a well using a standard production decline equation (e.g., reference?).

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)

Gas Production Parameters

These parameters are used to estimate the production profile of a well using a standard production decline equation (e.g., reference?).

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)

Transportation and 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 transportation 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 oil gravity differences 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 (based on water depth), 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 (e.g., $90 per bbl of 32°API oil), based on the expected gravity of the oil, expressed as an increased (+) or decreased (-) value in dollars per barrel

Washington−Oregon Area

Exploration Parameters	Minimum	Most Probable	Maximum
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
Production Well Drilling Time (days per well)	8	20	46

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

Exploration Parameters			
	Minimum	Most Probable	Maximum
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
Production Well Drilling Time (days per well)		?	
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

Exploration Parameters	Minimum	Most Probable	Maximum
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	Minimum	Most Probable	Maximum
Platform Size (slots)	18		60
Water Depth (feet)	350		3,250
Production Well Depth (feet)	4,000	10,000	25,000
Production Well Drilling Time (days per well)		?	
Oil Production Parameters	Minimum	Most Probable	Maximum
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	Minimum	Most Probable	Maximum
Gas-to-Oil Proportion (cf per bbl)		1,055	
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)		20	
Branchline Length (miles)		15	
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	

Bodega Basin

Exploration Parameters	Minimum	Most Probable	Maximum
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			
	Minimum	Most Probable	Maximum
Platform Size (slots)	18		60
Water Depth (feet)	100	350	750
Production Well Depth (feet)	5,000	10,000	19,000
Production Well Drilling Time (days per well)		?	
Oil Production Parameters			
	Minimum	Most Probable	Maximum
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			
	Minimum	Most Probable	Maximum
Gas-to-Oil Proportion (cf per bbl)		1,104	
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)		12	
Branchline Length (miles)		15	
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	

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			
	Minimum	Most Probable	Maximum
Platform Size (slots)	18		60
Water Depth (feet)	225	350	1,250
Production Well Depth (feet)	5,000	10,000	19,500
Production Well Drilling Time (days per well)		?	
Oil Production Parameters			
	Minimum	Most Probable	Maximum
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			
	Minimum	Most Probable	Maximum
Gas-to-Oil Proportion (cf per bbl)		1,079	
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)		7.5	
Branchline Length (miles)		15	
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	

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	Minimum	Most Probable	Maximum
Platform Size (slots)	18		60
Water Depth (feet)	200		2,300
Production Well Depth (feet)	6,000	10,000	14,000
Production Well Drilling Time (days per well)		?	
Oil Production Parameters	Minimum	Most Probable	Maximum
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	Minimum	Most Probable	Maximum
Gas-to-Oil Proportion (cf per bbl)		944	
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)		30	
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	

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
Production Well Drilling Time (days per well)		?	
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)	0.2	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)		2,499	
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)		N/A	
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)		+ 0.40	

Los Angeles-Santa Monica-San Pedro Area

Exploration Parameters			
	Minimum	Most Probable	Maximum
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			
	Minimum	Most Probable	Maximum
Platform Size (slots)	18		60
Water Depth (feet)	200	750	1,700
Production Well Depth (feet)	5,000	10,000	19,000
Production Well Drilling Time (days per well)		?	
Oil Production Parameters			
	Minimum	Most Probable	Maximum
Oil Well Recovery (MMbbl per well)		2.6	
Initial Oil Rate (bbl per day per well)		1,200	
Oil Produced Before Decline (fraction)	0.2	0.225	0.25
Initial Oil Decline Rate (fraction per year)	0.2	0.225	0.25
Oil Hyperbolic Decline Coefficient		N/A	
Gas Production Parameters			
	Minimum	Most Probable	Maximum
Gas-to-Oil Proportion (cf per bbl)		1,022	
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)		5	
Branchline Length (miles)		5	
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	

Oceanside-Capistrano Basin

Exploration Parameters			
	Minimum	Most Probable	Maximum
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			
	Minimum	Most Probable	Maximum
Platform Size (slots)	18		60
Water Depth (feet)	300	1,000	2,000
Production Well Depth (feet)	7,500	11,000	24,000
Production Well Drilling Time (days per well)		?	
Oil Production Parameters			
	Minimum	Most Probable	Maximum
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)	0.2	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			
	Minimum	Most Probable	Maximum
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			
	Minimum	Most Probable	Maximum
Trunkline Length (miles)		21	
Branchline Length (miles)		5	
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	

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
Production Well Drilling Time (days per well)		?	
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)		1,785	
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)		16.67	
Tax Rate (percent)		35.0	
Oil Price Adjustment (dollars per bbl)		+ 0.40	

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
Production Well Drilling Time (days per well)		?	

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)		1,667	
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)		16.67	
Tax Rate (percent)		35.0	
Oil Price Adjustment (dollars per bbl)		+ 0.40	

Cortes–Velero–Long Area

Exploration Parameters	Minimum	Most Probable	Maximum
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
Production Well Drilling Time (days per well)		?	

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)		2,672	
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)		16.67	
Tax Rate (percent)		35.0	
Oil Price Adjustment (dollars per bbl)		+ 0.40	

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 communities.

The Bureau of Ocean Energy Management

The Bureau of Ocean Energy Management (BOEM) works to manage the exploration and development of the nation's offshore resources in a way that appropriately balances economic development, energy independence, and environmental protection through oil and gas leases, renewable energy development and environmental reviews and studies.