Prospective Application of Well Stimulation Technologies in California

Authored by
Patrick Dobson (LBNL)

This section provides a brief introduction to petroleum systems, followed by a review of key hydrocarbon source rocks (typically shales) associated with petroleum systems found within onshore California sedimentary basins. Key aspects of the geology will also be discussed, such as the tectonic and structural features that have affected basin development and diagenetic processes impacting the types of minerals formed and rock properties. Where available, data describing the rock properties will be summarized. This is followed by a brief description of the Bakken Formation in the Williston Basin, from which significant unconventional shale oil production is occurring in North Dakota, along with a comparison with the Monterey Formation in California. This is followed by descriptions of the major sedimentary basins in California, along with a discussion of the results of exploration activities in deep portions of these basins, where hydrocarbon source rocks are within the oil window. The section concludes with some general observations regarding the potential application of unconventional techniques to oil-bearing shales in California.

4.1 Overview of Significant Findings

Oil-bearing sedimentary basins in California are relatively young in geologic time, but are structurally complex due to the presence of a very dynamic transform plate boundary, currently represented by the San Andreas Fault System. The dominant source rock for hydrocarbon generation in many of these basins is the Monterey Formation, a thick Miocene age sequence of marine sediments consisting of siliceous, phosphatic, organic, and clay-rich shales and mudstones, dolomites, and intercalated turbiditic sandstones. Most oil fields in California are located in reservoirs associated with structural traps at depths above where the oil is actively generated (the oil window), indicating that the oil in these petroleum systems has migrated from the source rocks to the reservoirs. While there have been few new onshore oil discoveries in the past two decades (the 30 largest onshore oil fields in California were all discovered prior to 1950; California Division of Oil, Gas and Geothermal Resources (DOGGR), 2010), the United States Geological Survey (USGS) has recently estimated that almost 10 billion barrels of oil can be recovered using existing technologies (including well stimulation methods) from the largest existing oil fields in the San Joaquin and Los Angeles Basins (Tennyson et al., 2012; Gautier et al., 2013). Much of the current well stimulation in California has occurred in diatomite reservoirs in the Monterey Formation (see Sections 2 and 4.5.2 for more details), and it is likely that this type of reservoir rock will continue to be a focus of future well stimulation activity in California.

Technological advances in well completion and stimulation techniques have led to dramatic increases in oil recovery from shale oil deposits elsewhere in the United States. Based in part on large increases in drilling and oil production in the Bakken Formation in North Dakota and the Eagle Ford Formation in Texas, the US Energy Information Administration (EIA) (2011) predicted that even larger oil resources could be tapped from the deeper portions (the active source rock) of the Monterey Formation in California, estimating that there are 15.4 billion barrels of technically recoverable oil. However, the assumptions used to develop this estimate are not supported by historical well production rates in the Monterey (Hughes, 2013), suggesting that this estimate is highly inflated, and a more recent estimate by the US EIA (2014b) has reduced the estimated unproved technically recoverable shale oil from the Monterey/Santos play to a value of 0.6 billion barrels. Recent exploration wells that have targeted deeper portions of the Monterey, where active source rocks may retain unmigrated oil, have not resulted in the identification of new oil reserves to date. The potential of discovering significant oil resources from new plays in the deep source rocks of the Monterey is highly uncertain.

4.2 Introduction to Oil Deposits

Petroleum systems require the following key elements: a source rock that contains sufficient concentrations of organic matter, a reservoir rock that accumulates the generated oil and gas, a seal rock that traps the hydrocarbons in the reservoir, and overburden rock that provides the burial depths needed for oil generation to occur (e.g., Doust, 2010; Magoon and Dow, 1994). The generation of hydrocarbons in the source rock requires the presence of abundant organic matter; the organic matter is transformed into oil and gas over time when subjected to sufficient pressure and temperature, which are related to sediment burial depth. The migration of hydrocarbons into the reservoir requires transport pathways and sufficient time. The reservoir must have a relatively impermeable barrier or “trap” so that oil can accumulate in commercial quantities without escaping, as shown on Figure 4-1. A variety of trapping mechanisms is possible, including stratigraphic traps (where an impermeable formation overlies a porous and permeable reservoir rock), structural traps (faults or folds that form a barrier to the continued upward migration of buoyant hydrocarbons), and diagenetic traps (where the alteration of the reservoir rocks associated with burial and fluid flow causes changes in flow properties of the rock).

Insoluble organic matter in the source rock (kerogen) must undergo sufficient maturation through burial and heating over time for oil and gas to be generated (McCarthy et al., 2011). The “oil window” is defined as the range of depths for which a source rock, having undergone burial and heating, will generate oil – this is a function of the type of organic matter and the integrated time-temperature history of the source rock (Fig. 4-2). This process is characterized by progressive changes in vitrinite reflectance. Vitrinite is a type of woody kerogen (a type of insoluble organic matter) that changes predictably and consistently upon heating, and its increased reflectance indicates increasing source rock maturity. The top of the oil window (where oil first is generated) corresponds to temperatures of around 50°C and a vitrinite reflectance (Ro) of 0.6 (although some workers suggest that oil generation in some of the California basins is initiated at lower vitrinite maturity levels (Walker et al., 1983; Petersen and Hickey, 1987). Higher levels of heating will result in the transformation of organic matter to natural gas; the base of the oil window (where all hydrocarbons will be transformed into gas) corresponds to a vitrinite reflectance of ~1.2. The depth to the top of the oil window depends on the burial and thermal histories of the basin. Oil can be traced back to its source rock through the use of biomarkers and stable isotopic compositions, which serve as chemical fingerprints that link it to the organic matter (kerogen) from which it was generated (Kruge, 1986; McCarthy et al., 2011; Peters et al., 2007; 2013).

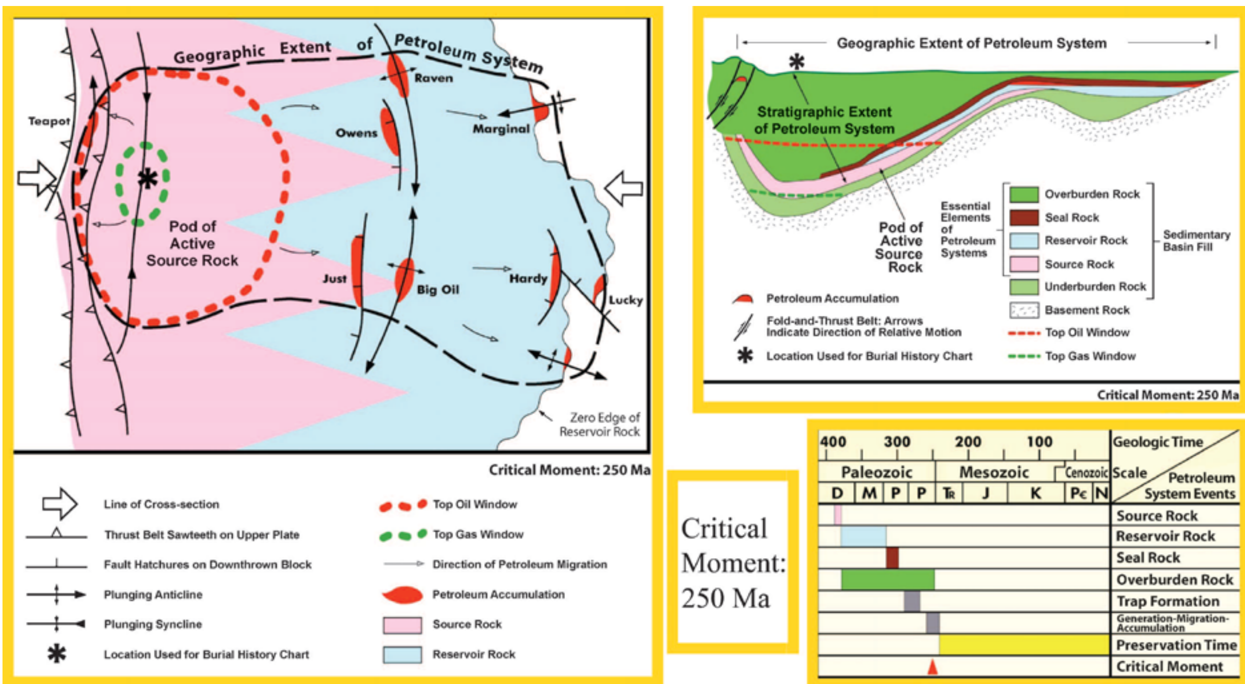

Figure 4-1. Example of a hypothetical petroleum system showing plan view map, cross section, and timeline for system formation. Figure taken from Doust (2010), which was modified from Magoon and Dow (1994).

In the case of an unconventional shale oil system, the source rock also serves as the reservoir rock, because the oil stays trapped within the source rock due to its low permeability. Producing oil from low permeability source rocks requires reservoir stimulation techniques such as those discussed in Section 2.

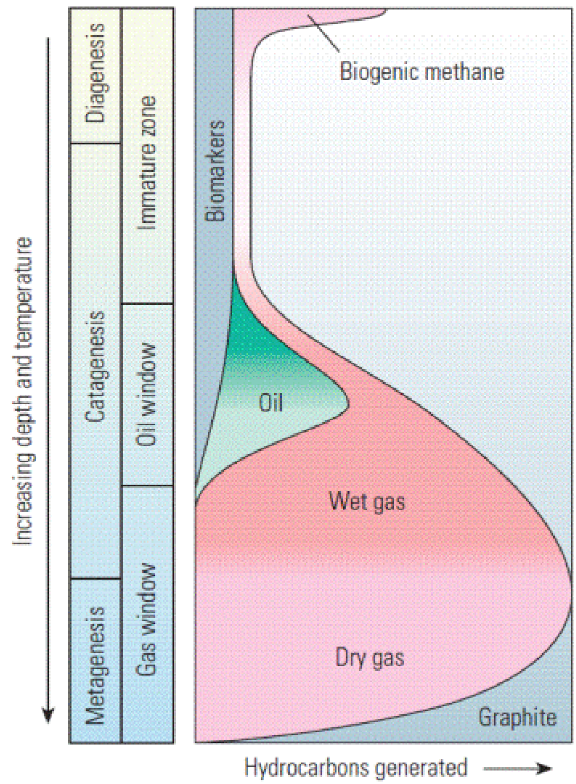

Figure 4-2. Thermal transformation of kerogen to oil and gas, depicting the location of the oil window (McCarthy et al., 2011).

There are three general categories of prospective target areas for oil production in California involving well stimulation. The first target consists of continued or increased oil production from discovered oil fields (or similar undiscovered reservoirs) that produce from formations with low permeability (also known as tight oil formations). The producing oil reservoirs in these fields generally lie above the oil window, indicating that the oil has migrated upwards from deeper source rocks and is now contained by structural, stratigraphic, and/or diagenetic traps, as shown on Figure 4-3. The largest fields in California, situated in the San Joaquin and Los Angeles Basins, have produced billions of barrels of oil, and the USGS estimates that there are over 9 billion barrels of additional oil that could be recovered from these two basins using current technology, which might include well stimulation technologies such as hydraulic fracturing (Gautier et al., 2013; Tennyson et al., 2012). Of these producing fields, many have oil sourced from the Miocene Monterey Formation (or Monterey Formation-equivalent rocks), a formation that contains organic, siliceous, phosphatic, and clay-rich shales, diatomites, and dolomites (Section 4.4.1). A significant fraction of these fields also have oil reservoirs in the Monterey Formation, often hosted in diatomites, fractured siliceous shales, or in interbedded sandy turbidite deposits; the oil has migrated from the deeper active source rock into shallower reservoirs with overlying seals. To date, most of the hydraulic fracturing well stimulation activity in California has been in the Monterey Formation diatomites in South Belridge, Lost Hills, and Elk Hills fields of the San Joaquin Basin (Agiddi, 2004; Martinez et al., 1994; Rowe et al., 2004; Strubhar et al., 1984; Wright et al., 1995). It is possible that hydraulic fracturing well stimulation methods, or others adapted from unconventional shale oil production in other regions, could be applied more widely in the Monterey Formation to increase oil recovery and production.

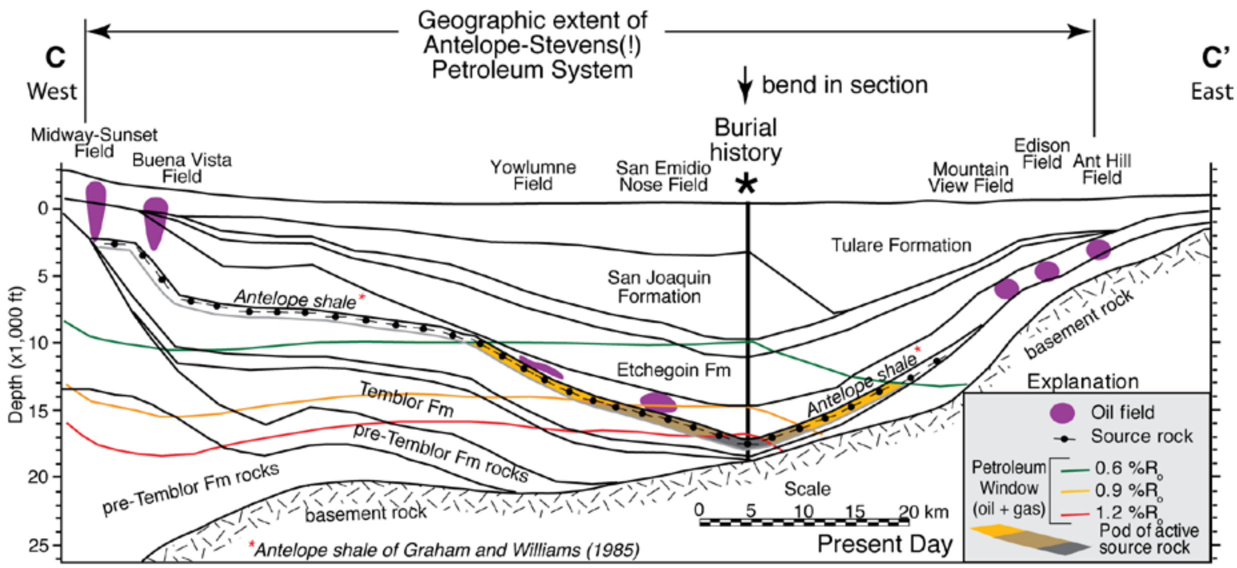

Figure 4-3. Cross section depicting the Antelope-Stevens Petroleum System in the southern San Joaquin Valley (Magoon et al., 2009). The Antelope Shale and Stevens Sand are subunits of the Monterey Formation. Note that the bulk of the oil fields are located on the margins of the basin, and that the oil appears to have migrated updip from the source region (below the top of the petroleum window) in the center of the basin.

A second target area consists of organic-rich shales located deep in the basins within the oil window. (These areas correspond to the active source rock colored according to the different vitrinite reflectance contours (Ro values) in Figure 4-3). These zones have not been a major target for oil exploration in California. However, these shales have been the source rocks for much of the oil that has been discovered and produced in California. Depending on how much oil still remains in these rocks, there may be significant potential associated with these rocks. Exploitation of the source rock would constitute a true shale oil play. This target corresponds to the Monterey shale oil play described by US EIA (2011) – however, estimates of the potential size of recoverable oil associated with this target are highly uncertain (see Sections 4.6 and 4.7).

A third potential target would be oil-bearing shales in basins where little oil production has occurred. Very little published information is available about these basins, except for some data relating to the presence and distribution of potential source rocks.

4.3 Sedimentary Basins in California

Most of the Neogene (the time period spanning between 23 to 2.6 million years before present) sedimentary basins in California (Behl, 1999) consist of marine depositional environments located along the continental margin as shown on Figure 4-4. All of the oil and gas fields in California are located in these basins (DOGGR, 1982; 1992; 1998). The basins are typically formed and bounded by faults, with many of the faults associated with the San Andreas Fault System. More detailed descriptions of many of these basins will be presented in Section 4.5.

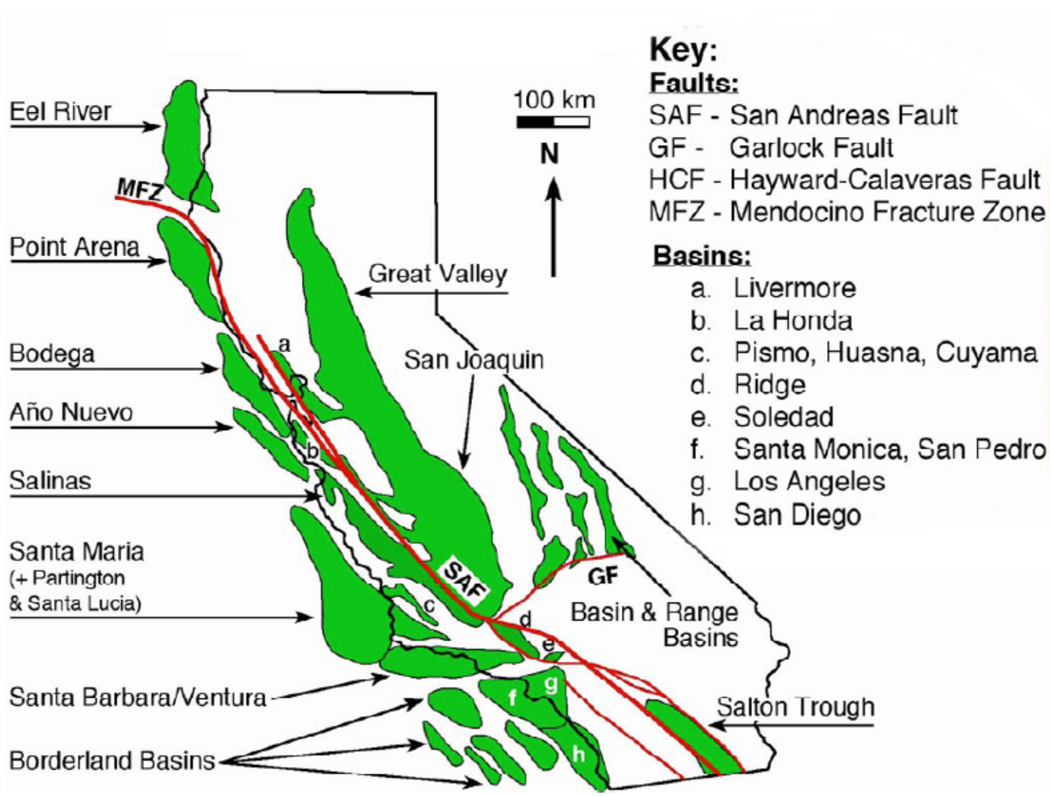

Figure 4-4. Neogene sedimentary basins in and along the coastal margins of California (from Behl, 1999).

The oil-bearing sedimentary basins in California are filled with mostly marine sediments, which consist of both biogenic (produced by marine organisms) and clastic (derived by erosion of existing rocks) materials. In each basin, distinct packages of sedimentary rocks have been identified as formations, which are composed of rock units that represent a similar time-depositional sequence and have distinctive and continuous characteristics that allow them to be mapped. Formations can be divided into subunits, known as members, which in turn have specific lithologic characteristics. The same geologic formations can often be found in adjacent basins; they would represent units that were deposited at the same time, and presumably under similar conditions. A discussion of key source rock formations (dominated by organic-rich shales) in California is presented in Section 4.4; descriptions of the main sedimentary basins where these rocks were deposited are given in Section 4.5.

4.3.1 Structural Controls

Oil reservoirs in California have a complex structural history that resulted in folding and faulting. The most important aspect of these processes is that they took place along the margins of the North American continent over time periods when the tectonic forces caused a radical change of the Pacific and North American plate boundary from a subduction zone to a strike-slip margin in the region that is now California. The result was the formation of a number of structural depressions (basins) where sediments with a wide range of compositions were deposited. These sediments were subjected to burial and then deformation (faulting and folding). The following technical discussion describes these processes.

Regional tectonism plays a large role in the creation of sedimentary basins in California and the distribution of sedimentary facies within these basins (Graham, 1987). In many cases, faulting accompanied basin formation and filling, and played an integral role in the types and rates of sedimentation. The dynamic tectonic environment of the California continental margin has contributed to the structurally complex nature of many of these sedimentary basins, and has led to the creation of structural traps (faults and folds) in many of the oil and gas fields. Wright (1991) finds that over 90 percent of the oil found in oil fields in the Los Angeles Basin is associated with anticlinal or fault traps, associated (in turn) with Miocene and younger tectonism. Ingersoll and Rumelhart (1999) and Ingersoll (2008) have postulated a three-stage tectonic evolution of the Los Angeles Basin (Fig. 4-5) involving transrotation (simultaneous occurrence of strike-slip faulting and rotation) between 18 and 12 million years ago (Ma), transtension (simultaneous occurrence of strike-slip faulting and extension) between 12 and 6 Ma, and transpression (simultaneous occurrence of strike-slip faulting and compression) from 6 Ma to the present.

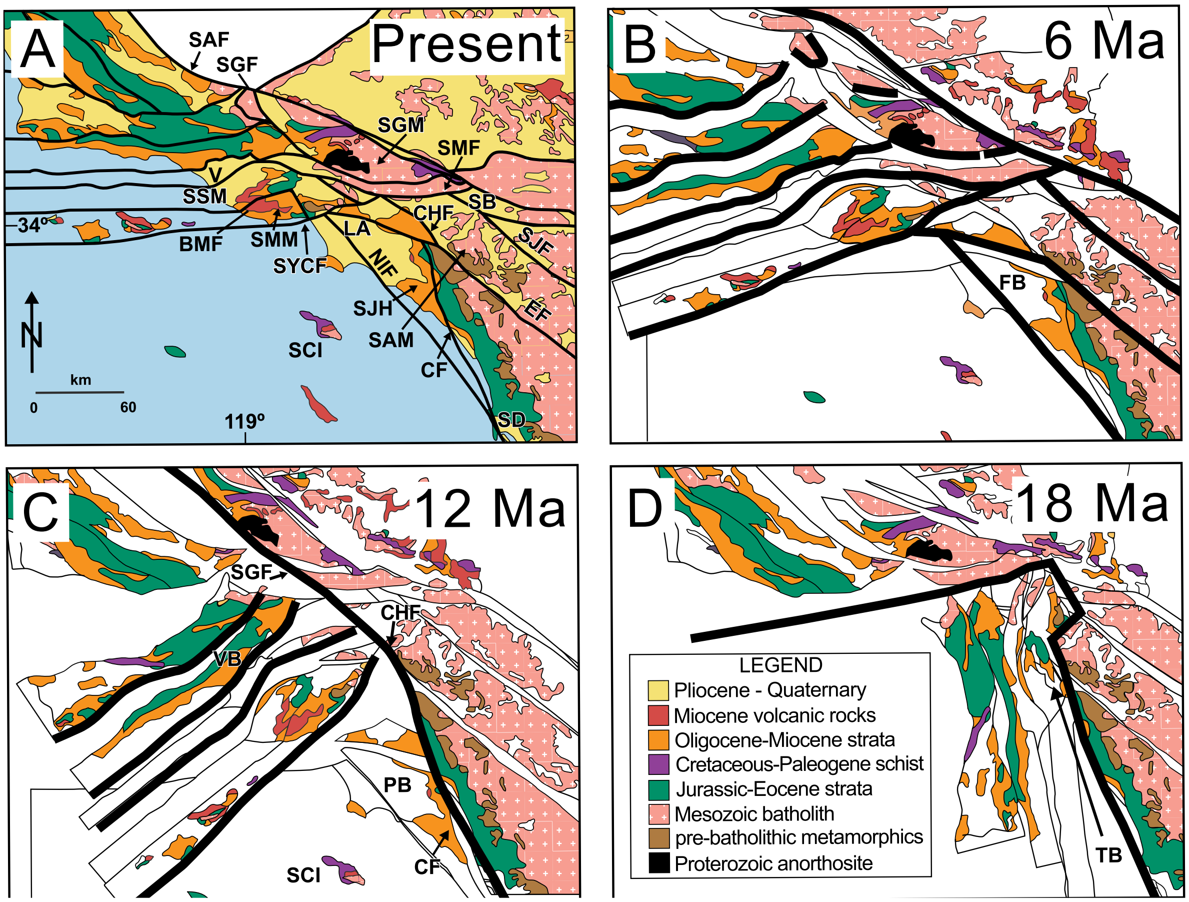

Figure 4-5. Three-stage tectonic evolution of the Los Angeles Basin. A – Present day structural setting, B, C, D – Palinspastic reconstructions of basin at 6, 12, and 18 Ma (details described in Ingersoll and Rumelhart, 1999).

Other California basins have experienced complex tectonic histories related to strike-slip movement along the San Andreas Fault. Graham (1978) described the role of wrench tectonics in the formation of the Salinas Basin, where right-lateral offset along the Rinconada-Reliz fault zone (located parallel to and between the San Andreas and San Gregorio-Hosgri faults) led to the formation of en echelon depressions and uplifts. A shift from transtension to transpression in this region followed the deposition of the Miocene Monterey Formation (Colgan et al., 2012; Titus et al., 2007).

Faults and fractures play a critical role in the migration and accumulation of hydrocarbons (Fig. 4-6) in many California oil fields (Chanchani et al., 2003; Dholakia et al., 1998; Dunham and Blake, 1987; Finkbeiner et al., 1997). Compressive stresses can lead to the development of folds, which can form structural traps with effective cap rocks when the formations deform plastically. Under similar forces, more brittle rocks develop fractures, which can provide flow pathways for upward hydrocarbon migration by providing fracture permeability—this is especially important when matrix permeabilities are low in clay-rich shales and siliceous mudstones (Hickman and Dunham, 1992).

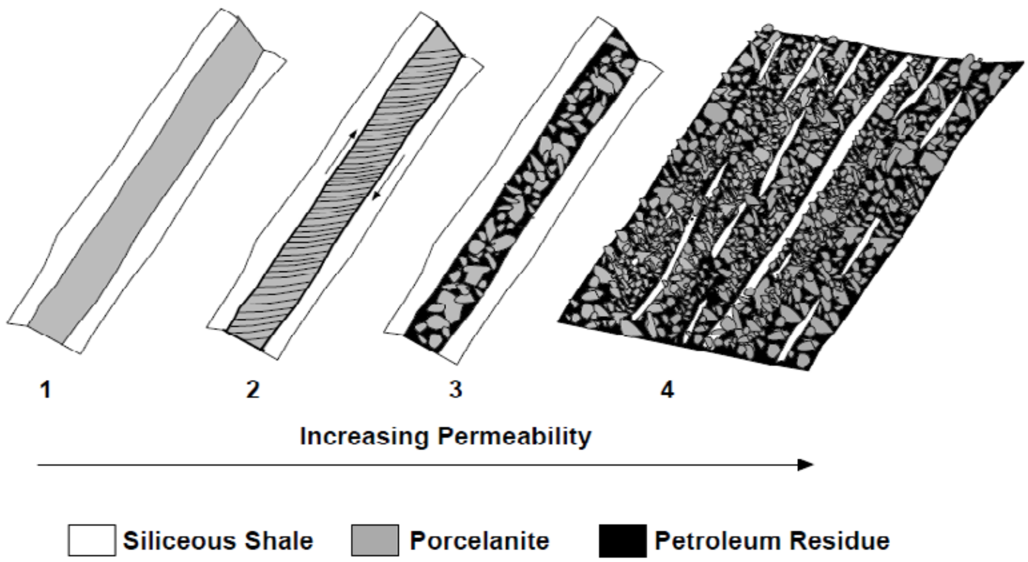

Figure 4-6. Schematic depiction of the development of bed-parallel faulting in the more brittle porcelanite layers in the Monterey Formation, which leads to the formation of petroleum-filled breccia zones (Dholakia et al., 1998).

4.3.2 Diagenetic Controls

As sediments are progressively buried over time, they undergo compaction and heating, and reductions in matrix permeability and porosity (Zieglar and Spotts, 1978) during diagenesis, a process that represents the chemical, physical, and biological changes that transform sediments into sedimentary rocks. In addition to these physical changes, mineralogical and textural changes occur in many sedimentary rocks. For instance, silica-rich diatomaceous sediments, such as those that occur in the Monterey Formation, undergo significant mineralogic changes that affect their physical properties (Behl and Garrison, 1994; Behl, 1998; Chaika and Dvorkin, 2000; Chaika and Williams, 2001; Eichhubl and Behl, 1998; Isaacs et al., 1983; Isaacs, 1980, 1981c, 1982; Keller and Isaacs, 1985; Pisciotto, 1981). Changes in temperature result in the transformation from opal-A to opal-CT to microcrystalline quartz. This transformation is also affected by the amount of detrital minerals mixed with the silica phase (Fig. 4-7). This can lead to a significant change in physical properties from a diatomite, which has very high (>60%) porosity, to porcelanites and cherts, which have much lower porosities; all of these rocks have intrinsically low matrix permeabilities. The porcelanites and cherts are much more brittle than diatomite, and thus often develop natural fractures that can conduct fluid (Behl, 1998; Eichhubl and Behl, 1998; Hickman and Dunham, 1992). Contrasts in rock properties associated with these changes in mineralogy in the Monterey Formation can result in the formation of diagenetic oil traps, such as those observed in the Rose oil field, where the top of the reservoir in the McLure shale member occurs at the transition from opal-CT to quartz (Ganong et al., 2003).

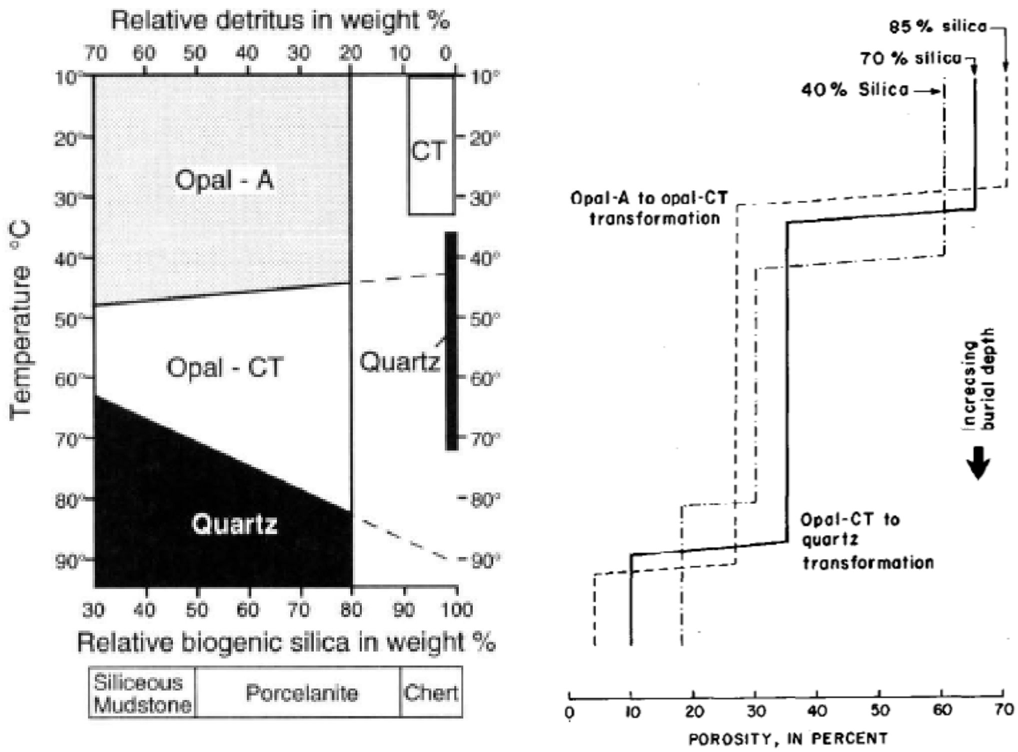

Figure 4-7. (a) Sediment composition and temperature effects on silica phase changes in the Monterey Formation (Behl and Garrison, 1994). (b) Changes in porosity as a function of silica phase transformation and burial (Isaacs, 1981c).

4.4 Primary Oil Source Rocks in California

As described above, each basin with oil has at least one source rock unit. In California basins, the dominant source rocks are in the Monterey Formation. However, the source rocks in some basins may include other geologic units. The various units identified as including source rock in California are discussed below.

4.4.1 Monterey Formation

The Miocene Monterey Formation is dominated by deep water marine sediments, comprising siliceous, phosphatic, and calcareous materials, along with a significant organic component, making it one of the major hydrocarbon source rocks in California (Behl, 1999; Bramlette, 1946; Graham and Williams, 1985; Isaacs, 1989; Tennyson and Isaacs, 2001). It forms extensive deposits within many of the Neogene sedimentary basins in California, including all of the major oil-producing regions (Fig. 4-4).

4.4.1.1 Lithologic variability of the Monterey Formation.

The main lithologies encountered (Figs. 4-8 and 4-9) include thinly laminated beds of chert, siliceous mudstone, porcelanite, phosphatic shale, clay shale, and dolomite (Behl, 1999; Bramlette, 1946; Dunham and Blake, 1987; Isaacs et al., 1983; Isaacs, 1980). While many of these lithologic units have informally been called "shales", they are more appropriately classified as mudstones, given that they are fine-grained but are relatively poor in actual clay mineral content (e.g., Behl, 1999; MacKinnon, 1989). Areas closer to the continental margin (e.g., the San Joaquin and Los Angeles Basins) have higher amounts of terriginous clastic input and contain turbiditic sandstones (Link and Hall, 1990; Redin, 1991). These coarser grained deposits form important subunits within the Monterey, such as the Stevens and Santa Margarita sandstones (e.g., Magoon et al., 2009). The unit is characterized by its wide range in lithologic variability (Fig. 4-10). This variability can be characterized through studies of outcrops and cores, but is most easily achieved in the subsurface through the use of geochemical (e.g., Hertzog et al., 1989) and integrated formation evaluation (e.g., Zalan et al., 1998) logging tools.

A variety of different lithological characterizations have been developed for the Monterey, based upon the varying amounts of silica, carbonate, and detrital minerals present (e.g., Carpenter, 1989; Dunham and Blake, 1987; Isaacs, 1981a, 1981b). In general, the lower portion of the Monterey is carbonate-rich, the middle section has abundant phosphatic, organic-rich shales, and the upper section tends to be dominated by siliceous mudstones, porcelanite, chert, and diatomite (Behl, 1999; Govean and Garrison, 1981; Isaacs et al., 1983; Isaacs, 1981b). A type section of the Monterey in the southwestern San Joaquin basin, at Chico Martinez Creek, is over 6,000 ft (1,830 m) thick, and consists of four major shale subunits: the Gould, Devilwater, McDonald, and Antelope shales (Mosher et al., 2013).

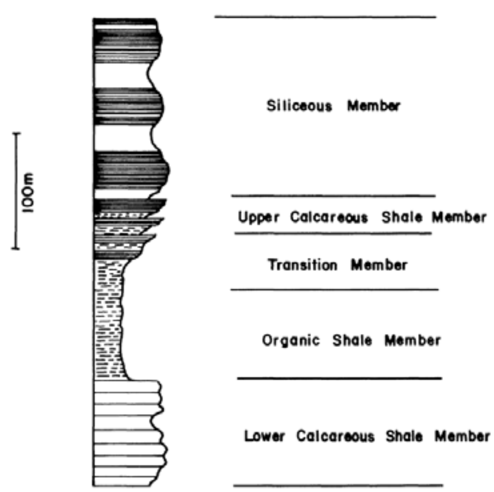

Figure 4-8. Generalized stratigraphic section of the Monterey Formation from the Santa Barbara coastal region (Isaacs, 1980). Open pattern depicts massive units, broken stipple indicates irregularly laminated beds, and thinly lined pattern denotes finely laminated units.

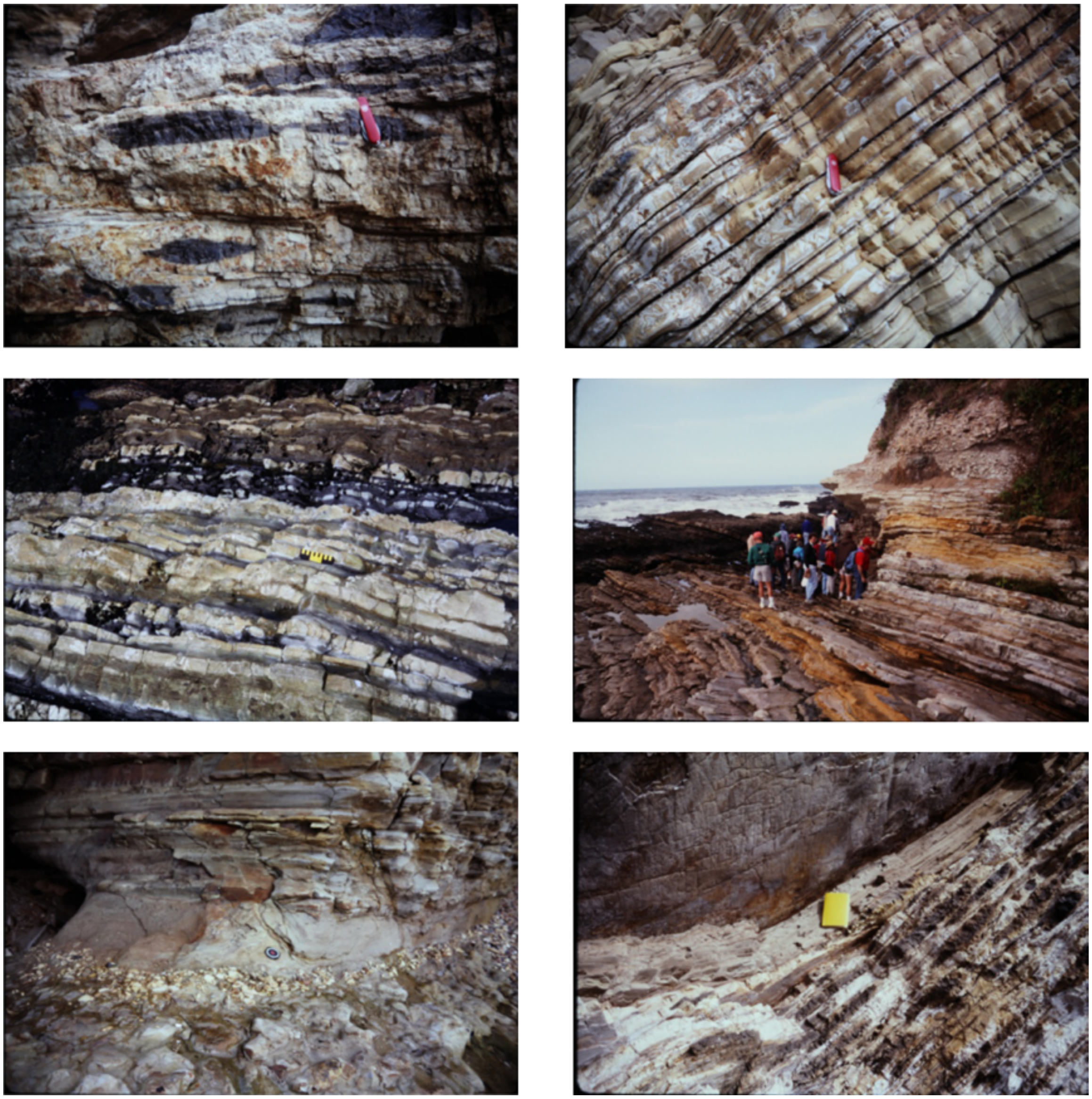

Figure 4-9. Photographs of the main types of lithologies found in the Monterey Formation. Upper left – dark lenses of chert within porcelanite, Point Buchon; Upper right – Porcelanite with thin organic-rich clay shale interbeds, Point Buchon; Middle left – Interbedded phosphatic mudstones and dolomites, Shell Beach; Middle right – Orange dolomitic layers interbedded with siliceous shales and porcelanite, Montana de Oro State Park; Lower left – Pebbly phosphatic hardground, Montana de Oro State Park; Lower right – Sandy turbidite lens (with yellow field book) between fractured chert and porcelanite layers, Point Buchon. These localities are described in Bohacs and Schwalbach (1992). Photos: P. Dobson.

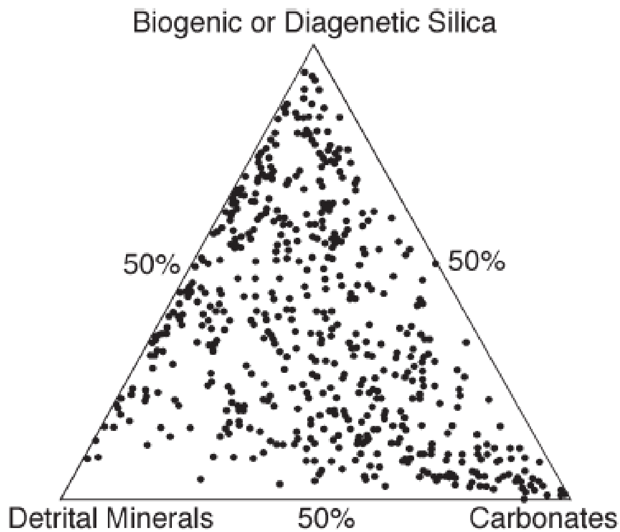

Figure 4-10. Lithologic variability of the Monterey Formation (Behl, 1999).

One of the main constituents of these marine sedimentary rocks comprises silica-rich diatoms. The physical properties of these diatoms are dramatically impacted by diagenetic processes, which result in a progressive change (with increasing temperature and burial depth) from opal-A to opal-CT to microcrystalline quartz (Fig. 4-7). This transformation results in significant changes in porosity, permeability, Young's elastic modulus (the ratio of longitudinal stress to longitudinal strain), and the brittleness of the rocks, with cherts and siliceous mudstones particularly susceptible to fracturing (Hickman and Dunham, 1992; Isaacs, 1984).

In addition to being an important oil reservoir, the Monterey Formation is also a major petroleum source rock (Graham and Williams, 1985; Isaacs, 1989, 1992a; Peters et al., 2013, 2007; Tennyson and Isaacs, 2001). The Monterey contains several organic-rich shale intervals with elevated total organic carbon (TOC), including the Reef Ridge, McLure, Antelope, McDonald, Devilwater, and Gould shales. Graham and Williams (1985) reported TOC values for the Monterey in the San Joaquin Basin ranging from 0.40 to 9.16 wt. %, with a mean value of 3.43 wt. %; higher TOC values with unit averages ranging between 4 and 8% TOC (6 and 13% organic matter) were reported for the Santa Maria Basin and the Santa Barbara coast by Isaacs (1987). TOC abundances are generally highest in the phosphatic shale section in the Middle Monterey (Fig. 4-11), where reduced dilution with biogenic sediments occurs (Bohacs et al., 2005). This TOC-rich portion of the Monterey would be the most likely target for unconventional shale oil. The kerogen in the Monterey has been interpreted to be mostly of marine origin (Tennyson and Isaacs, 2001).

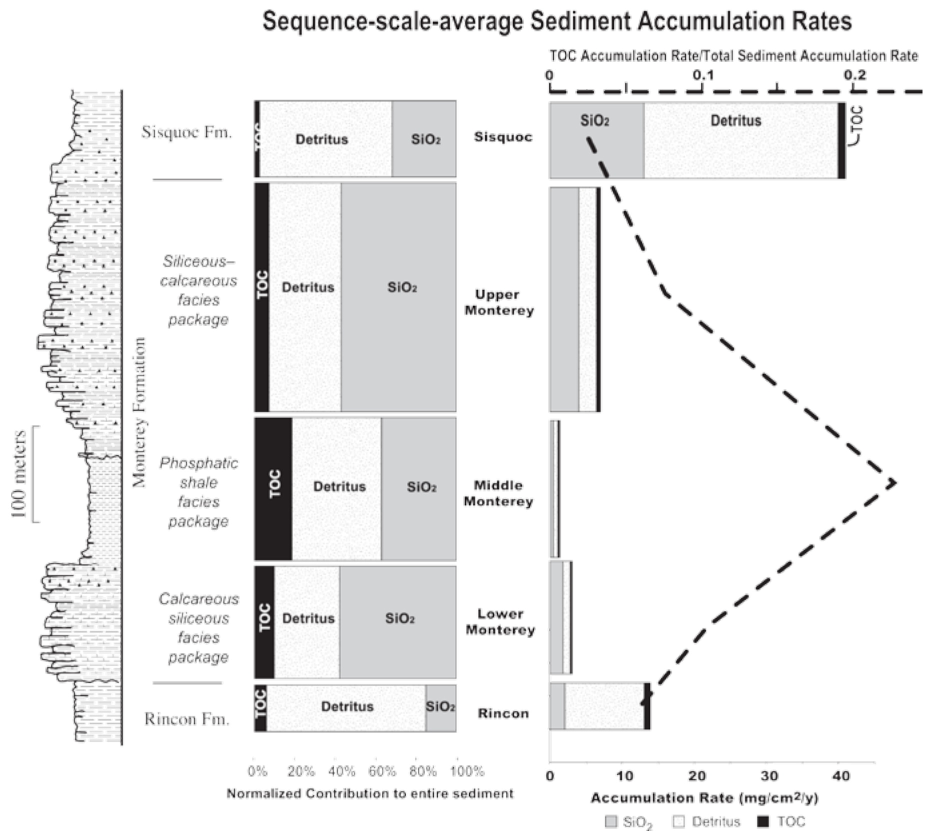

Figure 4-11. Distribution of organic matter, detrital sediments, and biogenic silica accumulations as a function of stratigraphic position in the Monterey Formation (Bohacs et al., 2005).

Key processes affecting the distribution and mineralogy of the Monterey involve original facies variations associated with the deposition of sediments and subsequent diagenetic processes, which had a profound impact on siliceous materials. These facies variations depend on paleoceanographic conditions which control the relative amounts of biogenic production of diatoms, coccoliths, and foraminifera relative to clastic sedimentation (Behl, 1999; Bohacs and Schwalbach, 1992).

4.4.1.2 Physical Properties of the Monterey

The physical properties of a rock are critical in determining if a rock can serve as a reservoir rock and how it might be stimulated by hydraulic fracturing. The porosity of a rock represents the open pore and fracture volume of a rock. The matrix and fracture porosity not only provide storage volumes for fluids, but they also provide potential pathways for fluid flow in rocks provided the pores and fractures are interconnected. The permeability of a rock measures the ability of a rock to transmit fluids; the goal of well stimulation is to improve well production by enhancing the permeability of the surrounding reservoir rock. The ability to stimulate a rock through hydraulic methods depends on the ability to shear or dilate existing fractures (causing them to open), or to create new fractures. The strength and elasticity and spatial variations of these properties of the rock will determine how hydraulic fractures will develop. Young's modulus, the ratio of longitudinal stress to longitudinal strain, is used to estimate the rigidity of a rock. The total organic content determines whether a particular lithology could serve as a potential hydrocarbon source rock.

Physical properties (porosity, permeability, total organic content (TOC), Young's elastic modulus) have been determined for a variety of Monterey rock samples. Note that the presence of natural fractures in the more brittle lithologies of the Monterey would result in a fracture permeability that would have a significant impact on oil migration (Behl, 1998; Eichhubl and Behl, 1998; Hickman and Dunham, 1992).

The Newlove 110 well (API 08222212) in the Orcutt field was the subject of a detailed hydrofracture research study conducted jointly by Unocal and the Japan National Oil Company (Shemeta et al., 1994). Prior to the hydrofracture, the well had a thick section of continuous core sampled from the Monterey section (which extends from 2,030 to 2,805 ft (619 to 855 m) in the well). Core Laboratories drilled 239 one-inch-diameter (2.54 cm) core plugs parallel to bedding from this core between the depths of 2,412 and 2,820 ft (735 and 860 m) and measured horizontal air permeability, helium porosity, fluid saturation, and grain density. The porosities ranged from 3.7 to 37%, with an arithmetic average of 22.8% and a median value of 23.4% (Fig. 4-12a). Matrix horizontal air-permeability values ranged from 0.00 md to 5,080 md, with an arithmetic average of 99.6 md, a geometric average of 2.59 md, a median value of 1.67 md, and a harmonic average of 0.12 md (Fig. 4-12b). Grain density values ranged from 2.19 to 2.96 g/cm^3, with an arithmetic average of 2.50 g/cm^3 and a median value of 2.49 g/cm^3.

Isaacs (1984) reports the physical properties of three different siliceous Monterey Formation lithologies that illustrate the effects of diagenesis. Opal-A bearing diatomaceous mudstones have porosities ranging from 50-70%, matrix permeabilities from 1-10 md, and grain densities of 2.2-2.4 g/cm^3. Opal-CT porcelanites have porosities ranging from 30-40%, matrix permeabilities from <0.01 to 0.1 md, and grain densities of 2.2-2.35 cm^3. Quartz porcelanites have porosities of 10-20%, matrix permeabilities of <0.01 md, and grain densities of 2.1-2.4 g/cm^3. Chaika and Williams (2001) observed that permeability reductions associated with silica phase transformation at increasing depth of burial in the Monterey appear to have two different trends: (1) a silica-rich host rock that has an abrupt porosity reduction (from 55 to 45%) associated with the change from opal-A to opal-CT, lending itself to a more brittle, fractured rock below this transition, and (2) a more gradual porosity reduction associated with this transformation for siliceous shales and mudstones with a higher abundance of detrital minerals. This second, more clay-rich rock tends to retain higher matrix porosity, which could lead to higher volumes of hydrocarbon storage.

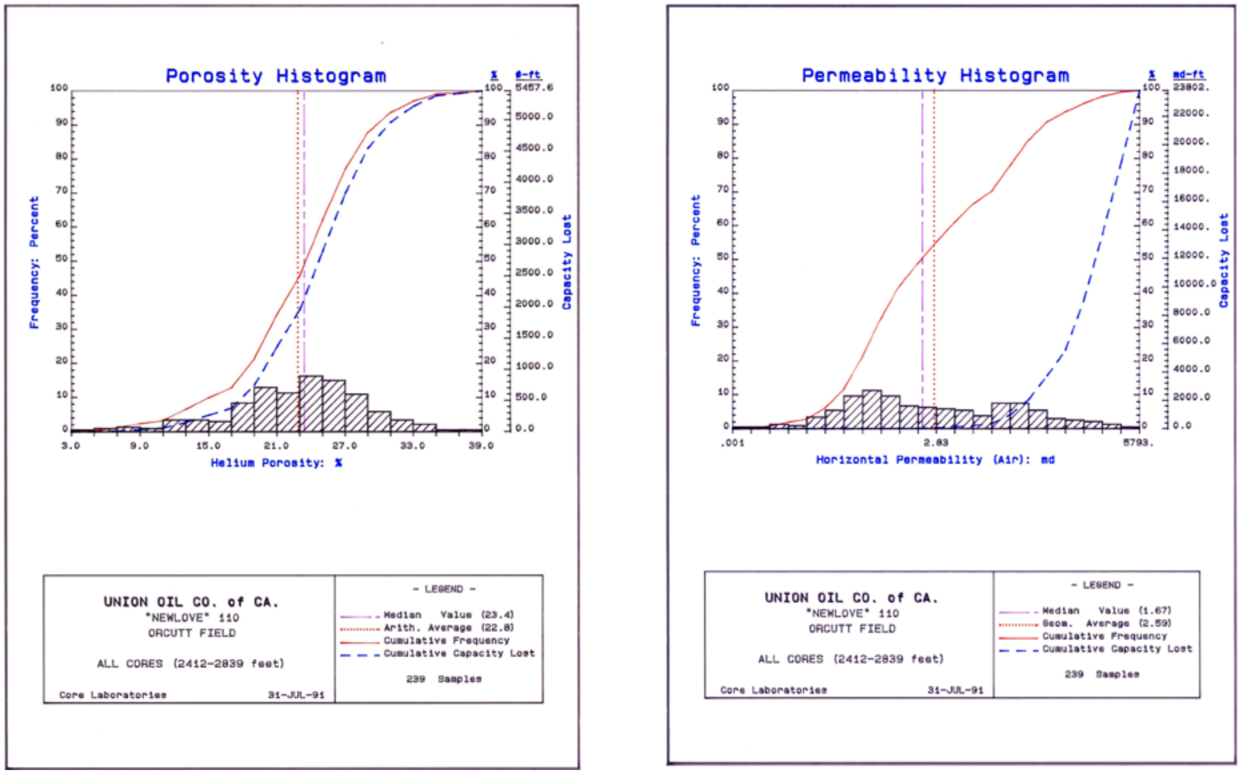

Figure 4-12. Helium porosity (a) and horizontal air permeability (b) measurements of 239 Monterey Formation core samples from the Newlove 110 well, Orcutt oil field, Santa Maria basin. The Core Laboratories report can be found on the DOGGR website at:
http://owr.conservation.ca.gov/WellRecord/083/08322212/08322212 Core Analysis.pdf

Measurements of physical properties were conducted on samples of the Antelope Shale member of the Monterey Formation in the Buena Vista Hills field, located between the giant Elk Hills and Midway-Sunset fields in the SW portion of the San Joaquin Basin (Montgomery and Morea, 2001). Four different rock types were studied: opal-CT porcelanite, opal-CT porcelanite/siltstone, clay-poor sandstone, and sandstone/siltstone. The porcelanite samples (399) had an average porosity of 33.8%, a median permeability of 0.1 md, and an average density of 2.31 g/cm^3; the porcelanite/siltstone samples (451) had an average porosity of 25.7%, a median permeability of 0.07 md, and an average density of 2.36 g/cm^3; the sandstones (19) had an average porosity of 21.1%, a mean permeability of 6.3 md, and an average density of 2.62 g/cm^3; and the sandstone/siltstone samples (57) had an average porosity of 20.8%, a mean permeability of 0.16 md, and an average density of 2.57 g/cm^3.

Liu et al. (1997) analyzed a number of Monterey core samples from the Santa Maria Basin. They reported lithotype, porosity, density, and TOC values (Table 4-1) for 10 Monterey Formation samples obtained from two wells (with sample depths ranging from 4,560 to 5,553 ft (1390 to 1693 m) in the Santa Maria Basin (Liu, 1994).

Table 4-1. Physical properties of Monterey core samples from the Santa Maria Basin (Liu et al., 1997).

Lithology	Number of core samples	Porosity (%)	Grain density (g/cm^3)	Total organic carbon (wt. %)
Porcelanite	2	10-11.4	2.14-2.17	2.28-2.4
Siliceous shale	1	4.3	2.24	6.81
Shale	3	18-21	2.02-2.35	8.19-18.2
Siliceous dolomite	3	11-19	2.38-2.70	0.52-8.12
Dolomite	1	3.0	2.72	0.19

Morea (1998) performed reservoir characterization studies of siliceous shales and mudstones from the Antelope and Brown shale members of the Monterey Formation from the Buena Vista Hills field. As part of this study, seven core samples recovered from depths ranging from 4,191 to 4,799.3 ft (1277.4 to 1462.8 m) were analyzed for Young's modulus. These samples, consisting of porcelanite and clayey porcelanite, have values ranging from 1,172,000 psi up to 2,724,000 psi (8.8 to 18.9 GPa), with an average value of 1,990,000 psi (13.7 GPa).

At the Belridge oil field, diatomites corresponding to the uppermost portion of the Monterey Formation are an important oil reservoir rock. Schwartz (1988) reports that the diatomites have elevated porosities ranging from 54 to 70%, permeabilities ranging from 0.00 to 7 md, and grain densities from 2.2 to 2.5 g/cm^3. Similar rock-property values (55-60 % porosity, 0.03 to 0.3 md permeability, and 2.2 to 2.5 g/cm^3 grain density) are reported for this unit by De Rouffignac and Bondor (1995). These properties vary as a function of stratigraphic depth and are related to cyclical changes in biogenic and clastic sedimentation (Schwartz, 1988). Bowersox (1990) reports lower effective porosities (36.7 to 55.4%) and higher permeabilities (1.86-103 md) for the producing diatomite intervals. The highly porous diatomites are soft rocks that have very low Young's modulus values as follows: 20,000 - 500,000 psi (0.14 – 3.4 GPa) (Allan et al., 2010); 50,000 – 200,000 psi (0.34 – 1.4 GPa) (Wright et al., 1995); 25,000 – 80,000 psi (0.17 – 0.55 GPa) (De Rouffignac and Bondor, 1995); ~100,000 psi (0.69 GPa) (Vasudevan et al., 2001). In spite of the low rigidity of these rocks as indicated by the low Young's modulus values, diatomite units have been successfully subjected to hydraulic stimulation to increase oil production from this highly porous but low-permeability lithology (Allan et al., 2010; Wright et al., 1995).

In conclusion, the different lithologies of the Monterey Formation exhibit a wide range of physical properties. Silica-rich diatomites have the highest porosities of any Monterey lithology (typically > 50%), but with diagenesis, these rocks are converted into porcelanites, which have significantly lower porosities (generally 20-40%). All of the Monterey lithologic units have intrinsically low matrix permeabilities (typically less than a millidarcy). However, the porcelanites, siliceous shales and mudstones, and dolomite units are quite brittle, and often develop natural fractures, which can lead to higher fracture permeability for these rock types. Most of the shale (clay-rich) lithologies in the Monterey Formation have TOC values greater than 2%, making them prospective hydrocarbon source rocks. The organic-rich phosphatic shales found within the Middle Monterey (Fig. 4-11) are the most prospective source rocks (and most likely unconventional oil shale target) within the Monterey Formation.

4.4.2 Vaqueros Formation

The Vaqueros Formation is an early to mid-Miocene marine sedimentary unit consisting of sandstones and shales, typically found in basins on the western side of the San Andreas Fault (Dibblee, 1973). The lower portion of this unit is the Soda Lake Shale Member, consisting of shale, claystone, and siltstone. This is overlain by the Painted Rock Sandstone Member. Lillis (1994) used biomarkers and stable isotopic compositions to conclude that much of the oil produced from the Cuyama Basin comes from the Soda Lake Shale source rock (see Section 4.5.5 for more details).

4.4.3 Tumey and Kreyenhagen Formations

The Tumey Formation, an Eocene age unit that just overlies the Kreyenhagen Formation, contains a thin calcareous shale and is often combined with the Kreyenhagen in stratigraphic sections (Milam, 1985; Peters et al., 2007). The Kreyenhagen Formation is a shale-rich formation of Eocene age that serves as a source rock for hydrocarbons in the San Joaquin Basin, and has a thickness of over 1,000 ft (305 m) at its type section at Reef Ridge, just south of Coalinga (Von Estorff, 1930). It consists of shales, laminated sandstones and shales, siltstones, and pebbly green sands (Isaacson and Blueford, 1984; Johnson and Graham, 2007; Milam, 1985). In some locations, it contains a turbiditic sandstone that can exceed over 1,600 ft (488 m) in thickness known as the Point of Rocks sandstone; in these areas, the lowermost Kreyenhagen member is known as the Gredal Shale member, and the uppermost Kreyenhagen member is the Welcome Shale member (Dibblee, 1973; Johnson and Graham, 2007). Hydrocarbons derived from the Kreyenhagen and Tumey Formations have been chemically distinguished from the Monterey on the basis of isotope geochemistry and biomarkers (Clauer et al., 2014; Lillis and Magoon, 2007; Peters et al., 1994; 2013).

4.4.4 Moreno Formation

The Moreno Formation is a shale-rich formation of Cretaceous-Paleocene age (McGuire, 1988). It consists of four members that represent different clastic depositional facies. The base of this unit consists of the Dosados Member (and lower portion of the Tierra Loma Member), which consists of silty shales and turbidites with interbedded sandstones. The rest of the Tierra Loma member consists of brown to maroon shales. This is in turn overlain by the Marca Shale Member, consisting of diatomaceous and siliceous shales. The uppermost section of the Moreno is formed by the Dos Palos Shale Member, formed by clay shales, silty shales, and glauconitic sandstones (the Cima Sandstone) and siltstones. The stratigraphic section of the Moreno Formation, exposed in Escarpado Canyon in the Panoche Hills on the western margin of the central San Joaquin Valley, has a thickness of around 800 m (Fig. 4-13). He et al. (2014) have characterized the geochemical signature of oils sourced from this formation.

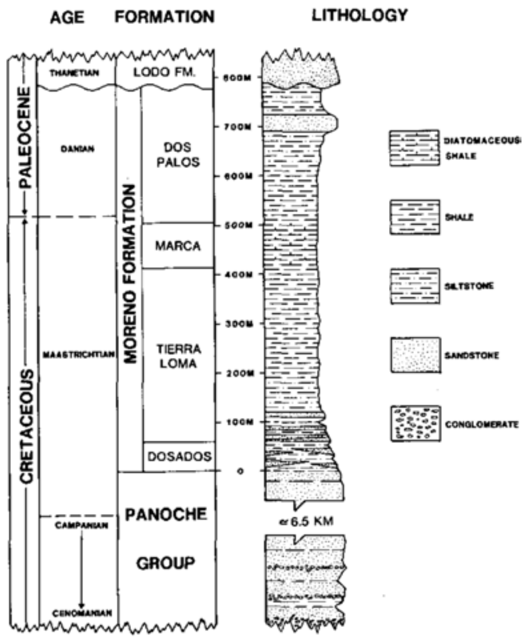

Figure 4-13. Stratigraphic column of the Moreno Formation, Escarbado Canyon, Panoche Hills, western margin of the central San Joaquin Basin (McGuire, 1988).

4.4.5 Comparison of the Monterey Formation with the Bakken Formation

The Monterey Formation in California can be compared with the Bakken Formation in North Dakota, which has seen a dramatic increase in drilling and oil production over the past five years (Fig. 4-14). The Bakken, along with the Eagle Ford Formation of Texas, are two of the largest producing unconventional shale oil units in the United States (US EIA, 2014a). The introduction of horizontal drilling and hydraulic stimulation techniques to these fields has led to near-quantum leap in oil production from these tight oil units. The jump in oil production from the Bakken and Eagle Ford through the use of unconventional well completion and stimulation techniques led to the identification of the Monterey as a potential next big shale oil target (US EIA, 2011). Thus, a comparison between the nature of the Bakken and Monterey Formations can provide insights into assessing the possible increases in oil production in California resulting from implementation of well stimulation methods.

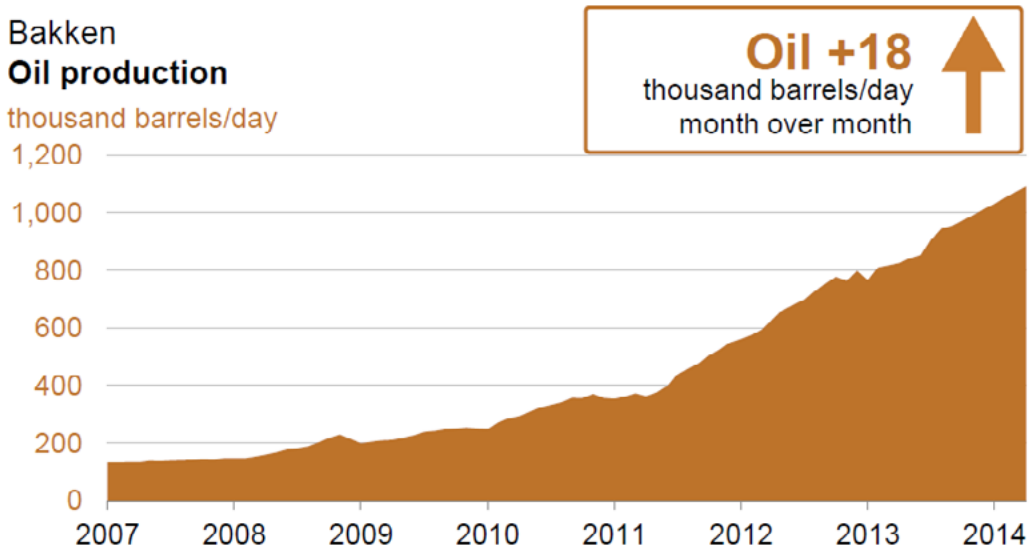

Figure 4-14. Increases in oil production from the Bakken Formation (US EIA, 2014a).

The Upper Devonian-Lower Mississippian Bakken Formation is a shale oil unit located in the Williston Basin, and found in North Dakota, Montana, Saskatchewan, and Manitoba (Gaswirth et al., 2013). It consists of three main zones: an upper unit, consisting of an organic-rich black shale; a middle unit, consisting of a silty dolostone or limestone to sandstone; and a lower unit, consisting of an organic black shale (Pitman et al., 2001). A fourth unit has been proposed for the Bakken, the Pronghorn unit, which underlies the lower shale unit and consists of a sandy unit previously known as the Sanish (LeFever et al., 2011). The Bakken has a maximum thickness of 160 ft (49 m) in the central portion of the basin (Fig. 4-15). The unit generally has a total thickness of less than 100 ft (30 m) (Lefever, 2008). The main target for production has been the middle dolomitic zone, while the upper and lower shales are considered the primary source rocks for hydrocarbons found in the Bakken. The shales are organic rich, with TOC values ranging from less than 1% up to 35%, and averaging around 11 wt. % (Webster, 1984). The Bakken petroleum system is located below the top of the oil generation window (Fig. 4-16), so hydrocarbons sourced from the shale unit are not required to have undergone significant migration (only into the adjacent dolomite unit (Sonnenberg et al., 2011)). This type of petroleum system is called a continuous petroleum accumulation (Nordeng, 2009). Unconventional techniques (horizontal drilling into the middle Bakken combined with multiple zone well stimulation) have been employed to maximize oil production from this formation (Jabbari and Zeng, 2012). Around 450 million barrels of oil have been produced using these techniques from the Bakken and Three Forks Formations in the Williston Basin between 2008 and 2013 (Gaswirth et al., 2013). The successful production of oil from the Bakken has prompted discussions regarding the possible recovery of oil from other shale oil formations such as the Monterey (Price and LeFever, 1992).

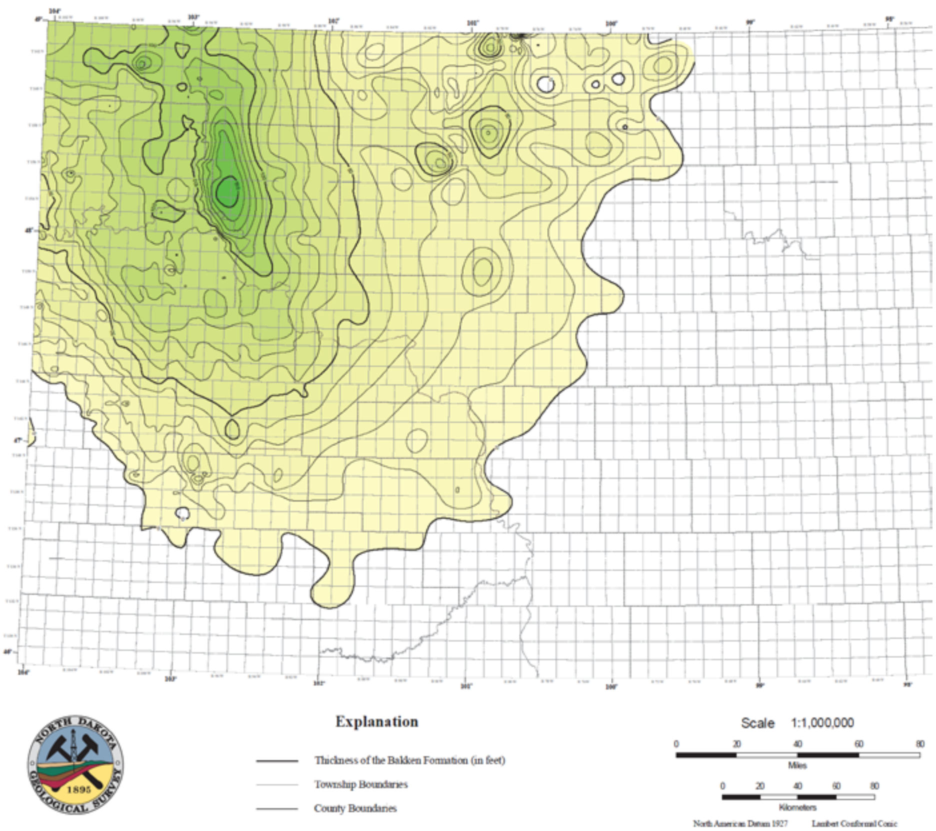

Figure 4-15. Isopach map of the Bakken Formation (Lefever, 2008).

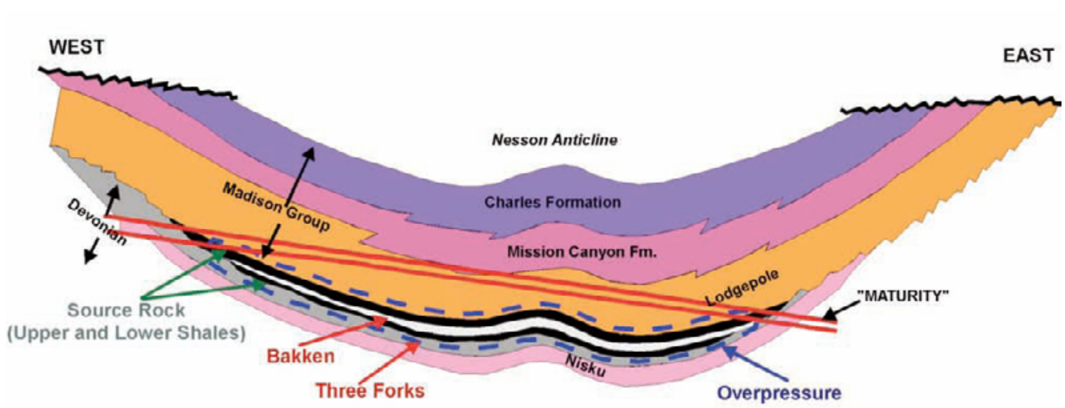

Figure 4-16. Schematic EW cross section of the Bakken petroleum system. Note that the Bakken lies below the top of the oil window (Sonnenberg et al., 2011).

4.4.5.1 Physical Properties

Core samples from the Middle Bakken unit obtained from the Parshall field have porosities ranging from 1-11% and permeabilities that average 0.0042 md (Simenson et al., 2011); a similar range of values of 1.1 to 10.2% (porosity) and <0.001 to 0.215 md (permeability) were reported by Ramakrishna et al. (2010). Production sweet spots involve areas with enhanced porosity and the presence of natural fractures (Pitman et al., 2001; Sonnenberg et al., 2011). Log-derived Young's modulus values for the Middle Bakken are around 7 GPa (Ramakrishna et al., 2010).

4.4.5.2 Similarities and Differences Between the Monterey and the Bakken Formations

The range of permeabilities of the Bakken dolomite reservoir unit (Middle Bakken) is similar to the permeability of porcelanites in the Monterey. The porosities of most of the Monterey lithologies, while varying significantly as a function of burial depth and degree of diagenesis, tend to be higher than those in the Middle Bakken dolomite.

The ages of these deposits are very different. The Monterey is Miocene in age and is still actively producing hydrocarbons, while the Bakken is much older (Upper Devonian-Lower Mississippian) in age.

The thicknesses of these units are dramatically different. The Bakken is typically less than 100 ft (30 m) in thickness, with a maximum thickness of 160 ft (49 m), and the producing middle dolomitic unit is generally less than 50 ft (15 m) thick, with a maximum thickness of around 90 ft (27 m). In contrast, the type section of the Monterey in the San Joaquin Basin is about 6,000 ft (1,830 m) thick (Mosher et al., 2013), and even greater thicknesses can be encountered in some of the basin depocenters. It is important to note that the organic-rich phosphatic shale portion of the Monterey, which would be the primary candidate for an unconventional oil resource in this formation, is considerably thinner (Figure 4-11).

The lithologic variability of the Bakken and Monterey are quite different. The Bakken Formation consists primarily of two distinct lithologies: (1) organic-rich shale, which makes up the upper and lower members of the Bakken (serving as the source rock), and (2) dolomite, which is the primary rock type of the producing middle Bakken member. In contrast, the Monterey consists of organic-rich, silicecous, and carbonate-rich shales and mudstones, porcelanite and diatomite, as well as interfingering sandstone turbidite bodies.

The structural setting of the Williston Basin in which the Bakken Formation resides is much less complex than those corresponding to the main sedimentary basins in California. The Williston Basin is an intracratonic basin that is not structurally controlled (Sloss, 1987), whereas the Neogene sedimentary basins in California are tectonically controlled, with faults and folds strongly influencing the trapping and accumulation of hydrocarbons in many of the major oil fields (Wright, 1991). The presence of wrench fault structures, combined with a basement of highly deformed Mesozoic subduction complex rocks, has led to the creation of numerous trapping structures in many of the oil regions in California (Graham, 1987).

Because of the extreme variability of the Monterey, where bed lithologies vary on a centimeter scale, and diagenesis has dramatically affected rock physical properties, effective hydraulic stimulation methods vary significantly for different portions of the Monterey (El Shaari et al., 2011).

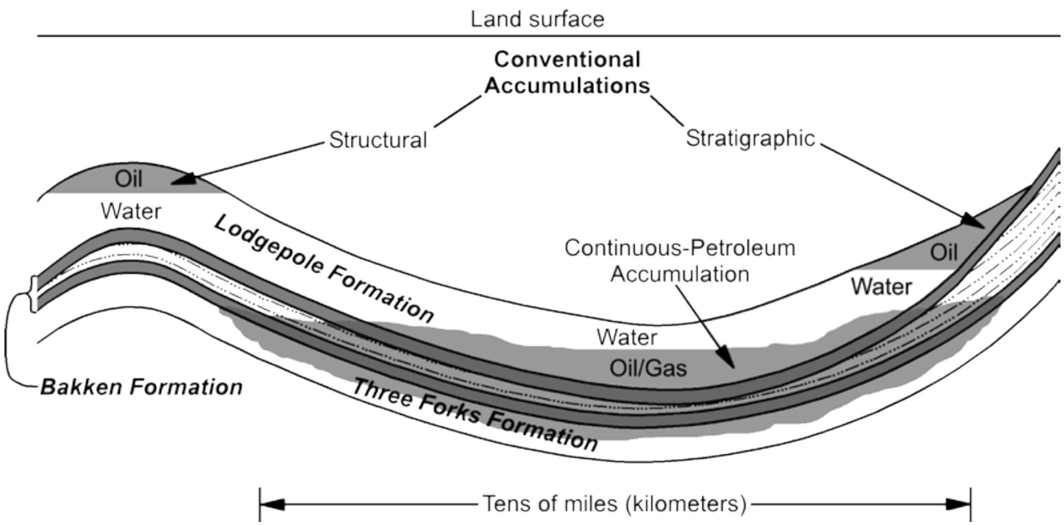

Figure 4-17. Schematic cross section illustrating conventional oil reservoirs (with migrating oil) and a continuous petroleum accumulation, as illustrated by the Bakken petroleum system (Nordeng, 2009).

The style of oil accumulation for the discovered resources associated with the Monterey Formation is different from that in the Bakken Formation. The producing oil fields that are hosted in the Monterey represent a conventional oil system where the oil has migrated from the source rock up into a reservoir zone that is capped by a trapping feature (structural, stratigraphic, or diagenetic trap). In contrast, the Bakken petroleum system represents a continuous petroleum accumulation (Fig. 4-17), where the oil is formed from organic-rich shales and migrates locally into an adjacent formation (the dolomite of the Middle Bakken) that is slightly more permeable and porous than the source shales (Nordeng, 2009). We note that the dolomite still has low enough permeability so that it requires stimulation for commercial production. The absence of faults and extensive fractures precludes hydrocarbon migration away from this region. It is possible that a similar type of oil accumulation could exist within the deeper portions of the Monterey, but significant amounts of oil that have been generated from these depocenters (areas where thickest accumulations of sediment have occurred) have migrated and accumulated to form the main oil fields in California. The complex tectonic history for sedimentary basins in California, and the presence of natural fractures in the siliceous mudstones in the Monterey, would both indicate that oil generated in the basin depocenters would migrate via higher permeability fracture and fault pathways.

4.5 Oil-producing Sedimentary Basins in California

California is one of the largest oil producing states in the U.S., and hosts several giant (> 1 billion barrels of oil) oil fields. Detailed information on these oil fields can be found in DOGGR (1982; 1992; 1998) and on the DOGGR website http://www.conservation.ca.gov/dog/Pages/Index.aspx. Below is a summary of selected sedimentary basins in California (Fig. 4-18), including the two most prolific oil-producing regions (the San Joaquin and Los Angeles Basins), several regions with abundant oil production (the Ventura and Santa Maria Basins), and two basins with a few significant oil fields (the Salinas and Cuyama Basins). The Sacramento Basin has almost exclusively gas production (the Brentwood field is the exception (Ditzler and Vaughan, 1968)), and thus is not included in this discussion.

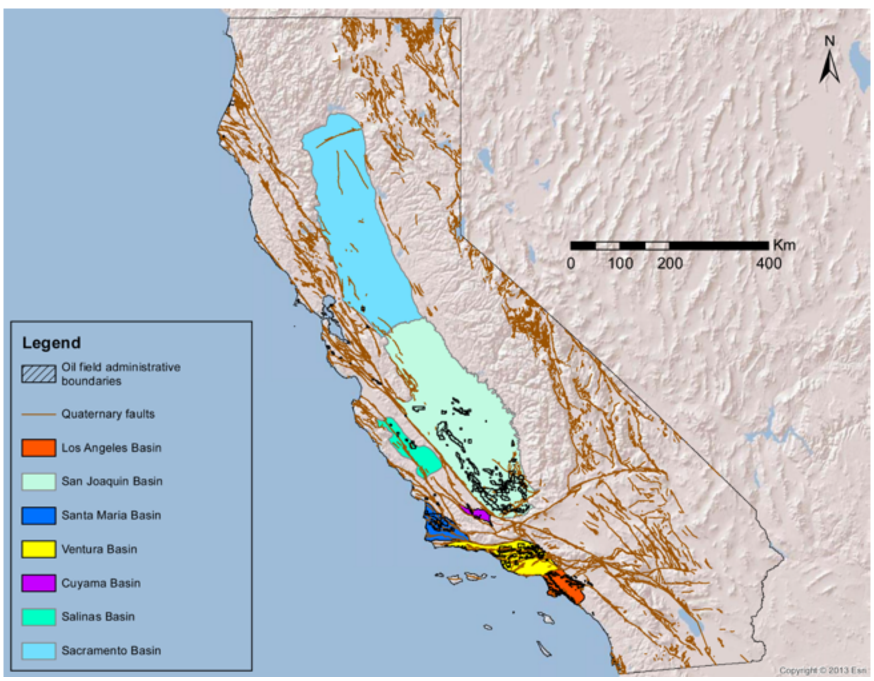

Figure 4-18. Map of major sedimentary basins and associated oil and gas fields in California.

For each of the basins described in this section, figures were generated that depict the basin boundaries, mapped Quaternary faults, the locations of active oil fields, the areal extent of the main source rocks, and where these rocks lie within the oil window (see

Figs. 4-19, 4-23, 4-24, 4-25, 4-26, 4-29, 4-31, 4-32, 4-35, and 4-36). The existing oil fields would correspond to the first type of well stimulation target mentioned in Section 4.2, whereas the deeper source rocks located within the oil window would constitute the second "unconventional shale oil" target.

4.5.1 Los Angeles Basin

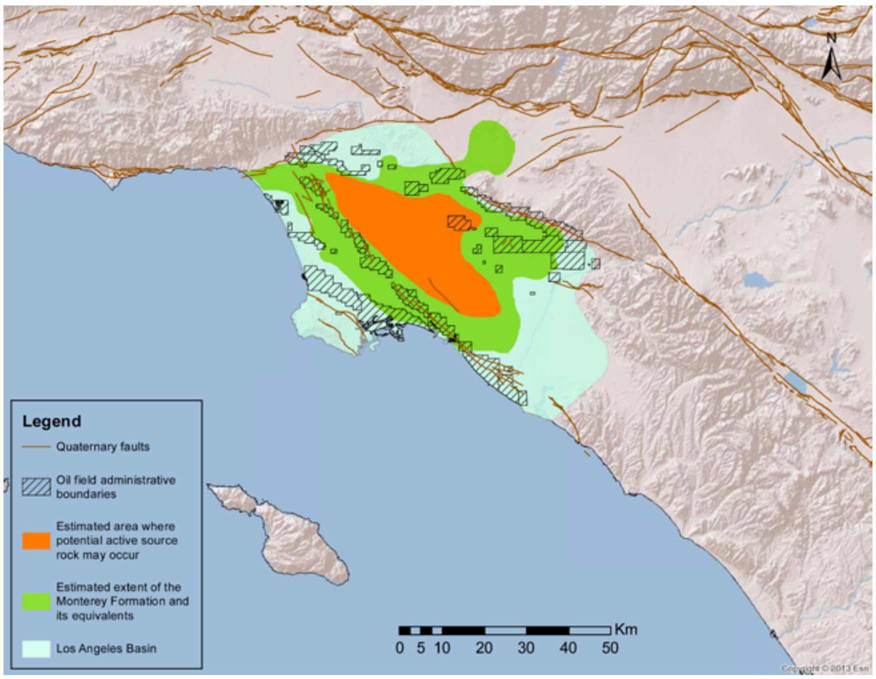

Figure 4-19. Map of the Los Angeles Basin with outlines of producing oil fields. The orange shaded area depicts where deep source rocks within the oil window are located. Data from DOGGR, Wright (1991), and Gautier (2014).

The Los Angeles Basin is an active margin Neogene sedimentary basin (Fig. 4-19) that has undergone transrotation, transtension, and more recently, transpression (Fig. 4-5) in response to active faulting over the past 18 Ma (Beyer, 1988; Ingersoll and Rumelhart, 1999). This complex deformational history has led to folding and faulting, creating structural traps for hydrocarbons (Wright, 1991). For example, the supergiant Wilmington oil field is hosted by a faulted, doubly plunging anticline (Mayuga, 1970; Montgomery, 1998). Sedimentation in this basin has been dominated by submarine fan deposits (Redin, 1991). Thick accumulations of Miocene and Pliocene sandstones of the Puente and Repetto Formations serve as the primary oil reservoir rocks. Organic-rich Miocene shales, also described as nodular organic shales, serve as the source rock for these prolific oil fields (Behl and Morita, 2007; Beyer, 1988; Hoots et al., 1935; Lanners, 2013; Walker et al., 1983); these shales are interpreted to be time correlative with the Monterey

Formation. Cross sections of four oil fields, West Beverly Hills, East Beverly Hills, Inglewood, and Huntington (Fig. 4-20) depict the oil reservoir rocks, the structural traps, and the underlying source rocks (Lanners, 2013).

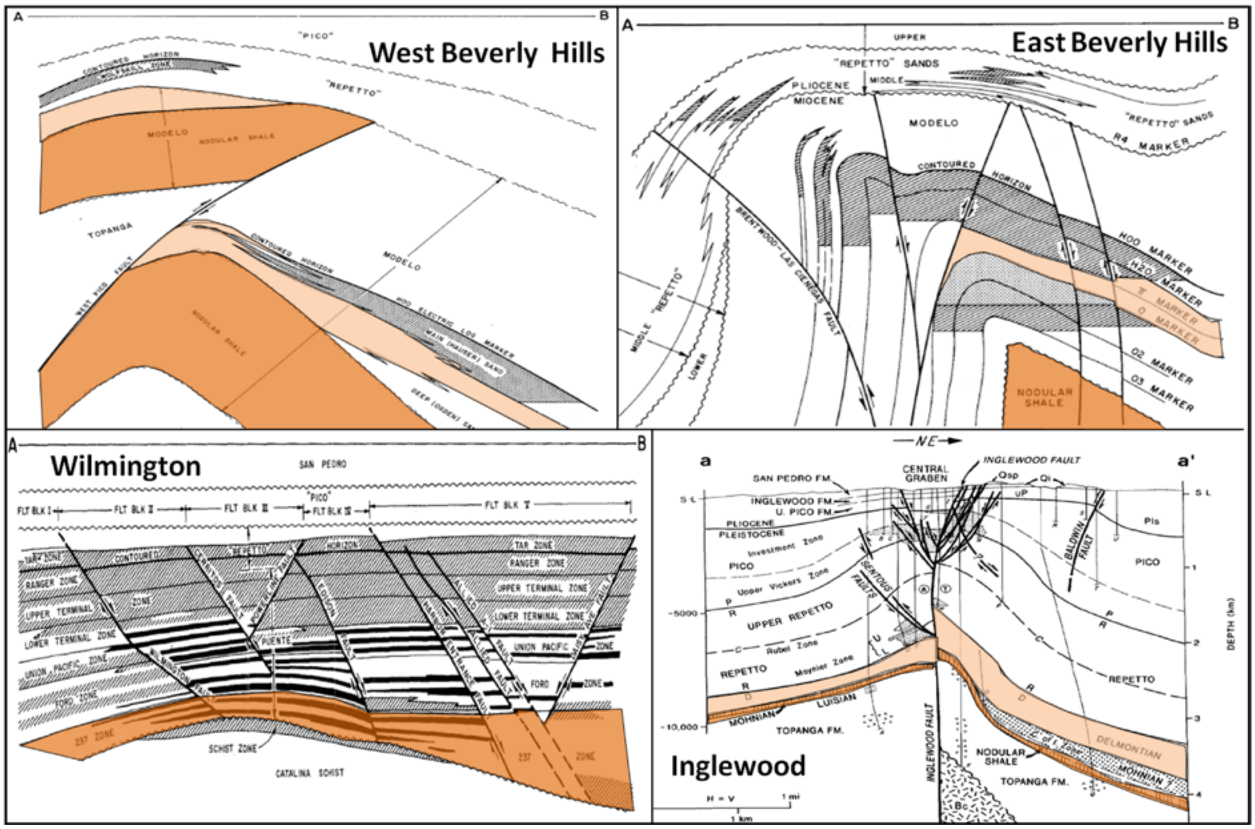

Figure 4-20. Cross-sections of the West Beverly Hills, East Beverly Hills, Wilmington, and Inglewood oil fields (Lanners, 2013). Dark-shaded areas depict location of main oil reservoir sections, orange-shaded areas depict organic-rich source rocks of Miocene age.

The USGS has recently conducted an assessment of the recoverable oil from of the ten giant (each with accumulations greater than 1 billion barrels of oil) oil fields in the Los Angeles Basin (Gautier et al., 2013). Based upon a probabilistic assessment of the original oil in place, the amount of oil produced, and expected recovery factors employing existing oil field technology, the USGS calculated a mean estimate of an additional 3.2 billion barrels of oil that could be recovered from these fields. According to Gautier et al. (2013), the recovery of this quantity of oil in place in these fields would require the "unrestricted application of current best-practice technology, including improved imaging and widespread application of directional drilling, combined with extensive water, steam, and CO_2 floods"; it does not indicate whether hydraulic and acid stimulation methods would be applied. This estimate does not include potential contributions from the other 58 existing oil fields in the basin, nor does it consider the discovery of new conventional fields, nor resources derived from unconventional sources, such as shale oil.

4.5.2 San Joaquin Basin

The San Joaquin Basin is located in the southern portion of the Great Valley, a large topographic depression between the Sierra Nevada and the Coast Ranges (Fig. 4-21). It first formed as a forearc basin (located between the subduction zone and the volcanic arc (the Sierra Nevada batholith represent the intrusive roots of this system)) during the Mesozoic and was associated with subduction along the continental margin. A change from a convergent to a transform plate boundary during the Cenozoic led to periods of subsidence and uplift (Goodman and Malin, 1992; Hosford Scheirer and Magoon, 2008; Schwochow, 1999). The basin is filled with a thick sequence of Cretaceous to Quaternary sediments, with mixed marine and continental sources (Hosford Scheirer and Magoon, 2008; Johnson and Graham, 2007; Schwochow, 1999)

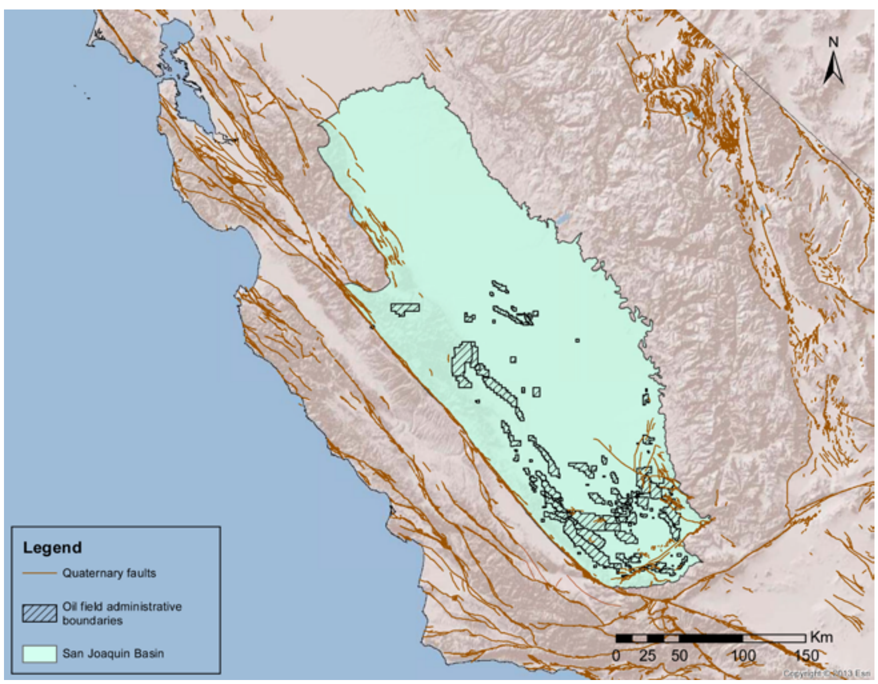

Figure 4-21. The San Joaquin Basin and producing oil fields (Oil field data from DOGGR).

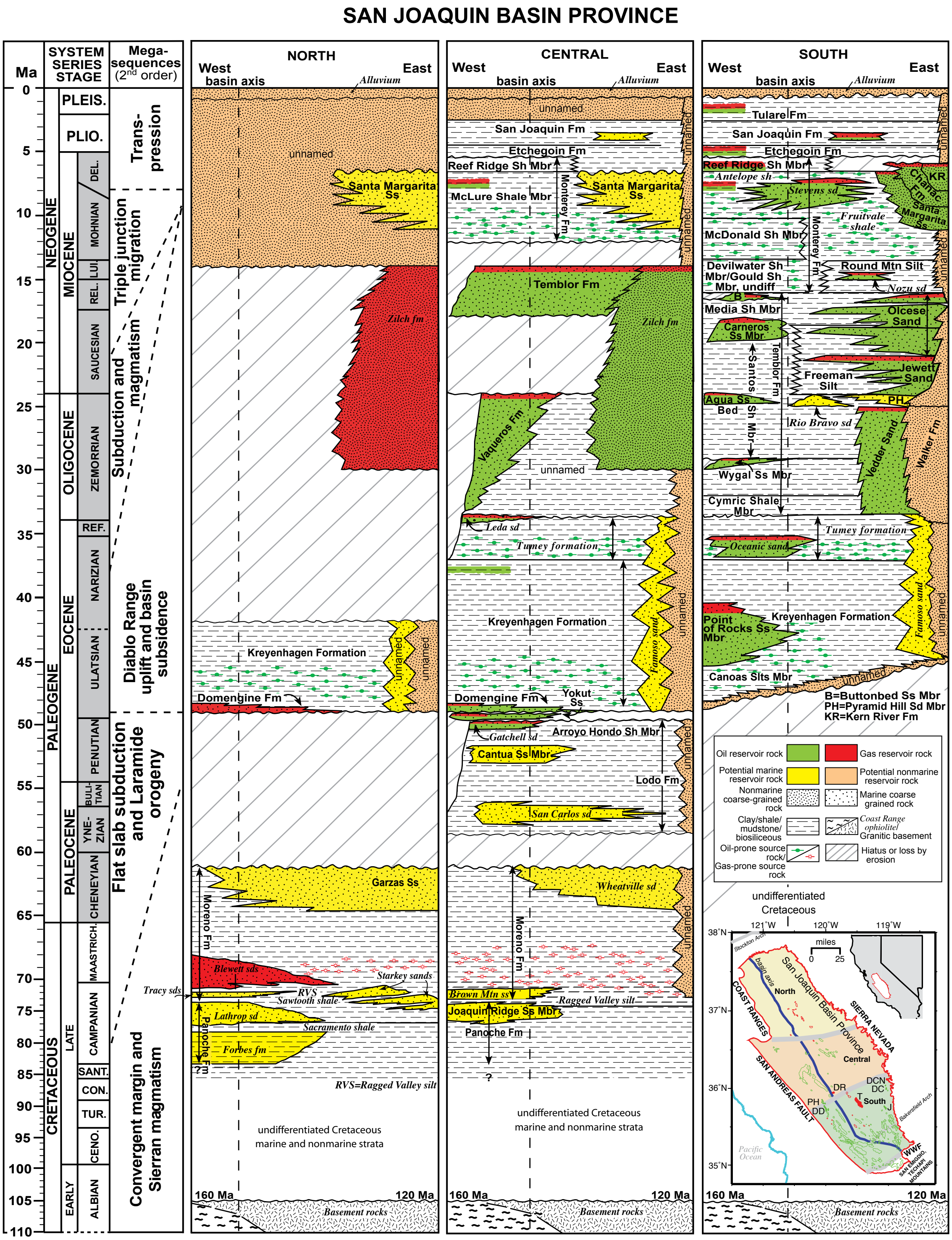

Figure 4-22. Summary stratigraphic sections for the San Joaquin Basin, highlighting relative locations of source and reservoir rocks (Hosford Scheirer and Magoon, 2008

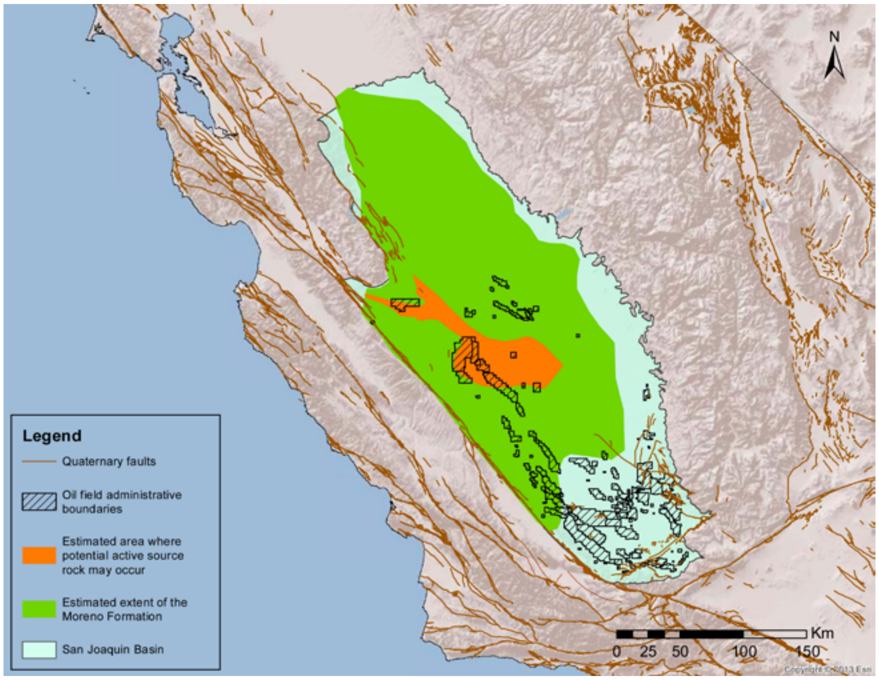

Figure 4-23. Distribution and estimated active source area of the Moreno Formation in the San Joaquin Basin (Magoon et al., 2009).

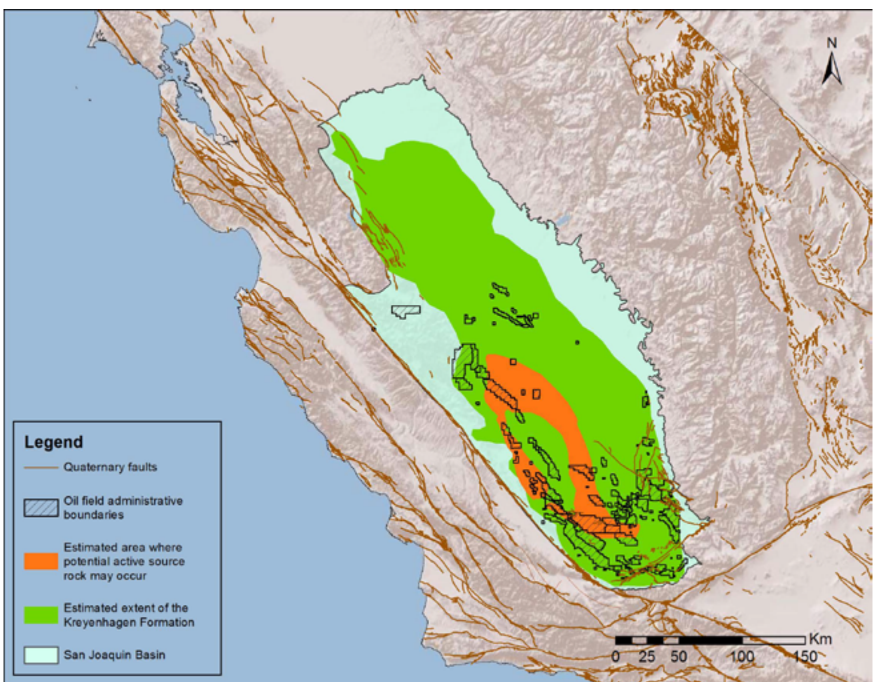

Figure 4-24. Distribution and estimated active source area of the Kreyenhagen in the San Joaquin Basin (Magoon et al., 2009).

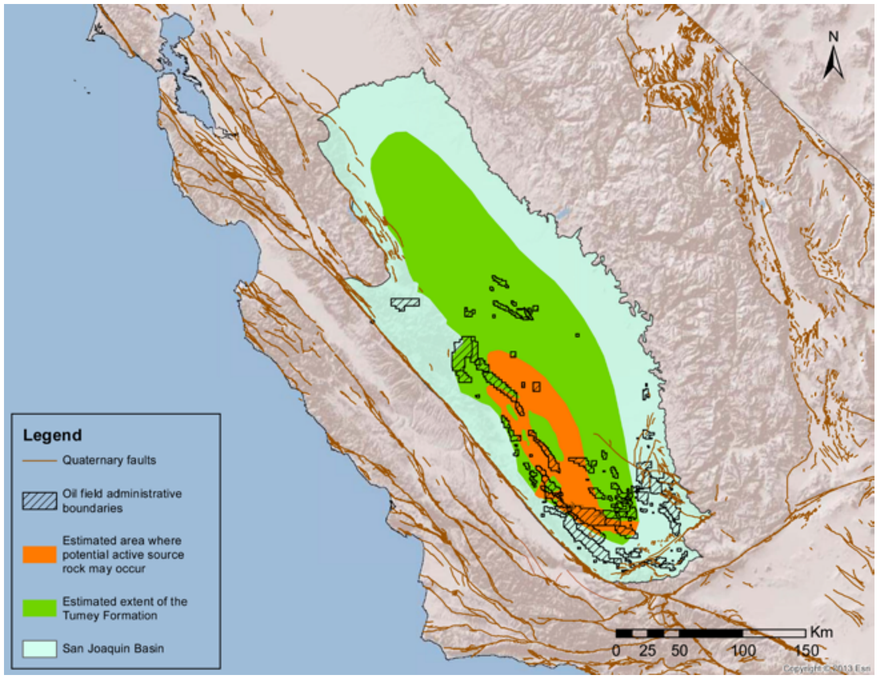

Figure 4-25. Distribution and estimated active source area of the Tumey in the San Joaquin Basin (Magoon et al., 2009).

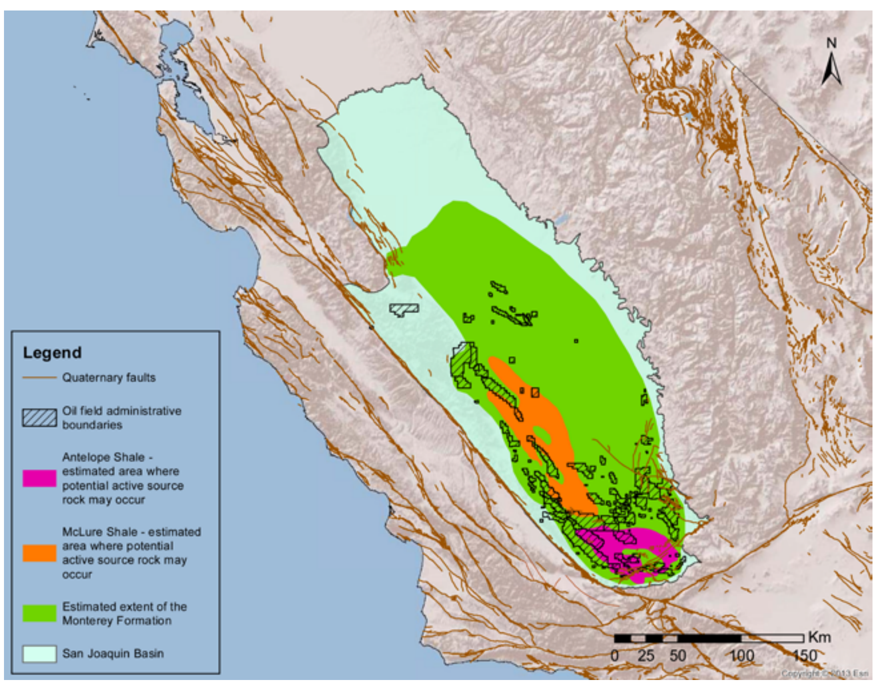

Figure 4-26. Distribution and estimated active source area of the Monterey in the San Joaquin Basin (Magoon et al., 2009).

The Monterey is the dominant source rock for producing oil fields in the San Joaquin Basin and also serves as a reservoir rock for many oil fields. However, many of these reservoirs are located above the oil window (Fig. 4-3), and the kerogen present at reservoir depths is thermally immature, suggesting that the oil migrated updip from deeper in the basin (Graham and Williams, 1985; Kruge, 1986).

In several fields in the San Joaquin, such as South Belridge and Lost Hills, significant oil production occurs from the upper Monterey diatomite unit (Bowersox, 1990; Schwartz, 1988). These reservoir rocks have high matrix porosities, but low permeabilities (see Section 4.4.1.1 for more details). Directional wells targeting specific pay zones coupled with hydraulic fracturing (Fig. 4-27) have been employed to improve hydrocarbon recovery from the South Belridge and Lost Hills fields (Allan et al., 2010; El Shaari et al., 2011; Emanuele et al., 1998; Wright et al., 1995). While some oil production occurs from low-permeability diatomite and fractured siliceous mudstones in the Monterey at the Midway-Sunset field, the most productive intervals are interbedded turbidite sands (Fig. 4-28) (Link and Hall, 1990; Mercer, 1996; Underwood and Kerley, 1998). These sands have much more favorable reservoir properties (porosity ~33%, permeabilities between 800-4,000 md) than the Monterey lithologies that surround them (Link and Hall, 1990).

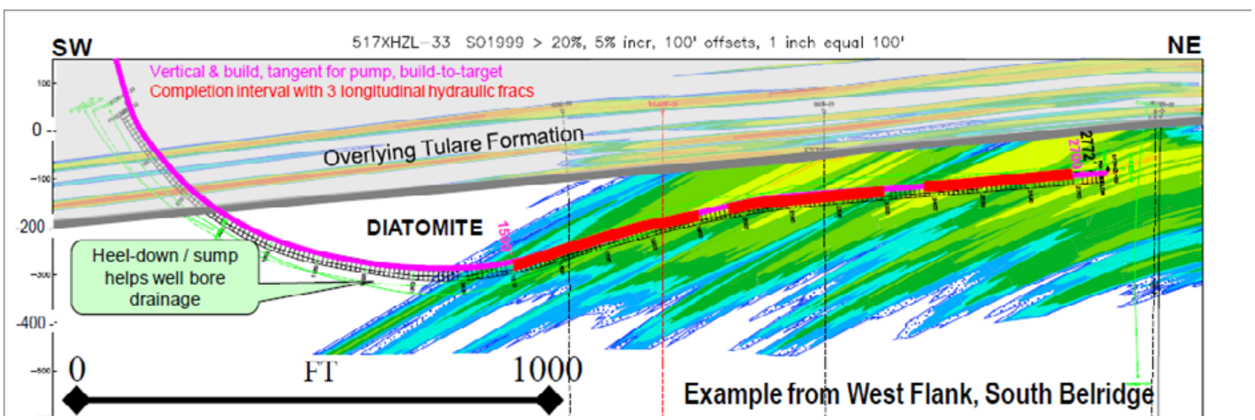

Figure 4-27. Schematic of directional well for the South Belridge field targeting the top of the diatomite unit, oriented longitudinally along the flanks of the anticline, with hydraulic fracturing to improve well performance (Allan and Lalicata, 2012).

Production also occurs from diagenetically transformed diatomite, porcelanite, in the Elk Hills field (Reid and McIntyre, 2001). Oil production out of the Antelope shale member of the Monterey at the Buena Vista Hills field (mostly consisting of porcelanite) has been hampered by low primary recovery values of 4-6%. Attempts to stimulate the reservoir using hydraulic stimulation techniques led to the generation of a complex system of fractures, which seemed to increase flow tortuosity near the well bore. The failure to stimulate longer vertical fractures was thought to be due in part to the wide contrast in rock strength on a bed-to-bed scale, leading to delamination and poor transmission of proppants into the fracture network (Montgomery and Morea, 2001). Enhanced oil recovery using CO_2 flooding was proposed as a means to improve oil recovery in this field.

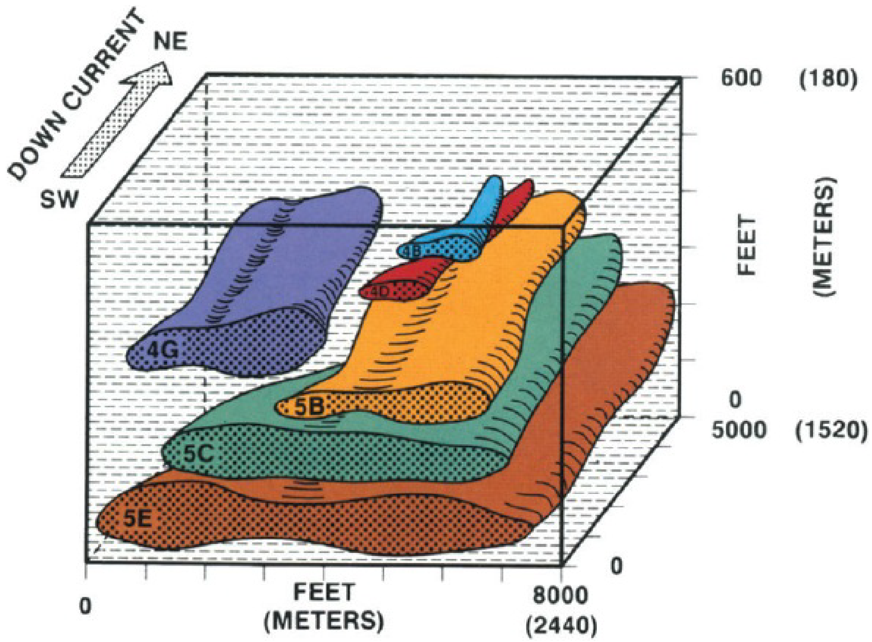

Figure 4-28. Block diagram depicting location of Webster sand turbidite lobes within the Antelope Shale Member of the Monterey Formation in the Midway-Sunset field (Link and Hall, 1990).

The USGS has recently conducted an assessment of the recoverable oil from nine major oil fields in the San Joaquin Basin (Tennyson et al., 2012). Based upon a probabilistic assessment of the original oil in place, the amount of oil produced, and expected recovery factors employing existing oil field technology, the USGS calculated a mean estimate of an additional 6.5 billion barrels of oil that could be recovered from these existing fields. Tennyson et al. (2012) note that "much of the potential reserves could come from improved recovery in diatomite reservoirs of the Monterey Formation". Given that the increased production of oil from Monterey diatomite reservoirs in the San Joaquin (such as at South Belridge) has been associated with most of the well hydrofracturing conducted in California (see Section 3), this increased recovery would certainly require similar well stimulation methods. This estimate does not include potential contributions from the other oil fields in the basin, nor does it consider the discovery of new conventional fields, nor resources derived from unconventional sources, such as shale oil. Results of exploratory drilling in deeper portions of the San Joaquin Basin, which would test the viability of the Monterey Formation source rock oil play, are discussed in Section 4.6.

4.5.3 Santa Maria Basin

The Santa Maria Basin is located along the coast of California between Point Arguello and San Luis Obispo (Fig. 4-29). It is bounded by the San Rafael Mountains and Sur-Nacimiento fault to the northeast and the Santa Ynez Mountains and Santa Ynez fault to the south (Sweetkind et al., 2010; Tennyson and Isaacs, 2001; Tennyson, 1995). Changes in plate interactions have led to a complex tectonic evolution of this basin, with episodes of extension and subsidence, shortening and uplift, and rotation (McCrory et al., 1995). It contains a thick sequence of Neogene sediments, most of which are Miocene and younger. The Monterey Formation is the principal source rock for oil fields in this basin, and most of the production occurs from fractured siliceous mudstone, porcelanite, chert, and dolomite in the Monterey (Isaacs, 1992b; MacKinnon, 1989; Tennyson and Isaacs, 2001). Fractured diagenetic dolomites have been identified as a significant component of some of the producing oil fields from this basin (Roehl and Weinbrandt, 1985). Oil fields in this basin are localized in faulted anticline structures, and deeper synclines are interpreted to represent the source region for the migrated hydrocarbons produced from these fields (Fig. 4-30). A brief description of the results of deep exploration drilling in the Santa Maria Basin is presented in Section 4.6.

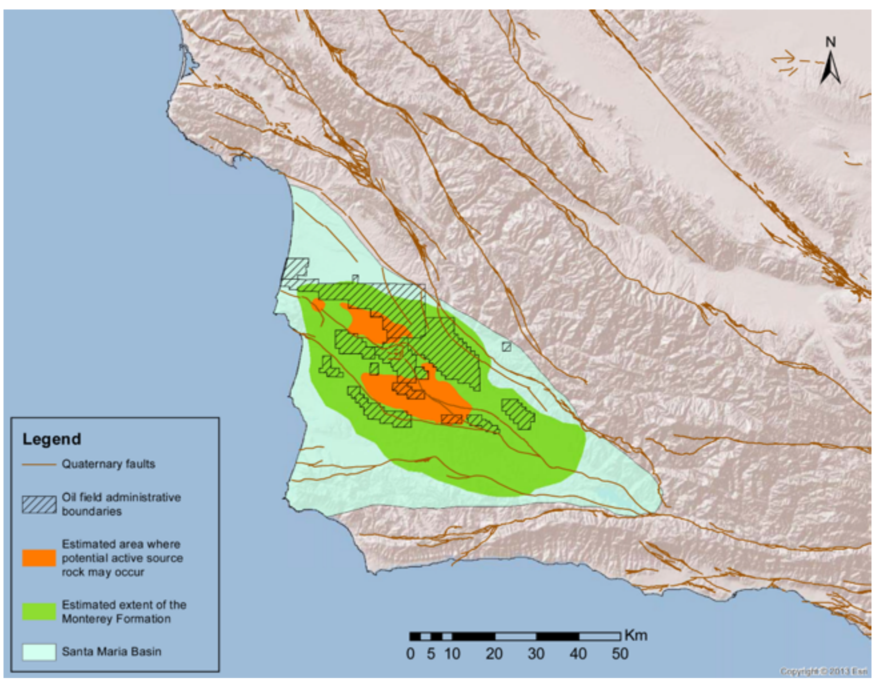

Figure 4-29. Santa Maria Basin and producing oil fields (Oil field data from DOGGR). Distribution of Monterey Formation (green) and portion below top of oil window (~6,700 feet depth - Tennyson and Isaacs, 2001) highlighted in orange) determined using data from Sweetkind et al. (2010).

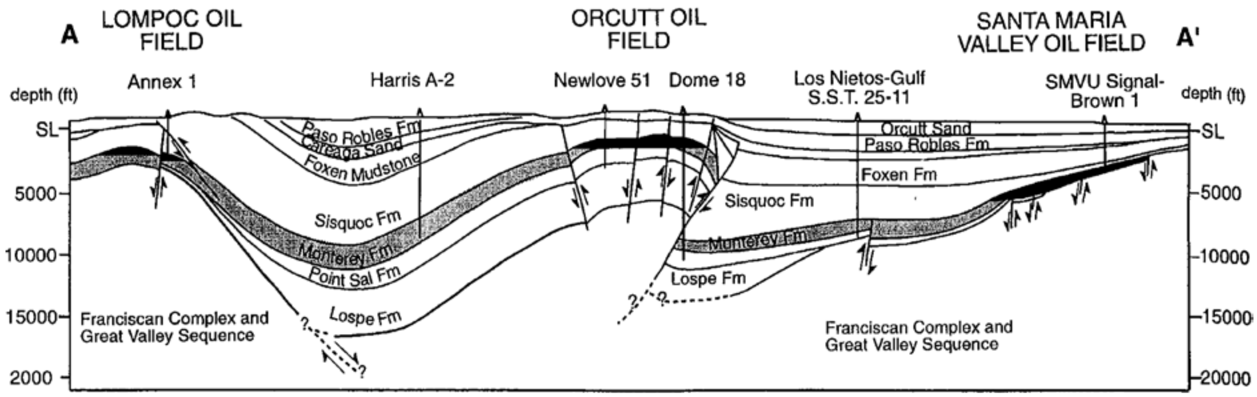

Figure 4-30. NS cross section through the Santa Maria Basin (Tennyson and Isaacs, 2001). Oil fields are located in faulted anticlinal traps – oil presumed to be generated in deeper synclines.

4.5.4 Ventura Basin

The Ventura Basin (and the adjacent offshore Santa Barbara Basin) is a structurally complex faulted and folded synclinal trough between the Santa Ynez Mountains to the north and the Santa Monica Mountains and Channel Islands to the south (Fig. 4-31) (Dibblee, 1988; Keller, 1988; 1995; Nagle and Parker, 1971; Tennyson and Isaacs, 2001). It contains a thick sequence (up to 36,000 ft (11,000 m) of Upper Cretaceous, Tertiary, and Quaternary sediments. In the primary depocenter, the Plio-Pleistocene sedimentary section can reach thicknesses of up to 20,000 ft (6,100 m) (Dibblee, 1988; Nagle and Parker, 1971) (Fig. 4-32). Most of the oil accumulations in the basin are associated with faulted anticlinal traps (Keller, 1988; Nagle and Parker, 1971; Tennyson and Isaacs, 2001). While the main source rock for this basin is thought to be the Monterey, the overlying Sisquoc Formation and the underlying Rincon shale may also be sources of hydrocarbons. The Monterey is age-correlative with the Modelo Formation, which contains a much higher proportion of sandstone (Nagle and Parker, 1971). The most prolific oil fields in this basin produce from sandstones from the Pliocene Pico and Repetto Formations (Keller, 1988; Nagle and Parker, 1971; Tennyson and Isaacs, 2001). Production from the fractured Monterey is limited to a few fields, including the offshore South Elwood and Hondo fields (Tennyson and Isaacs, 2001).

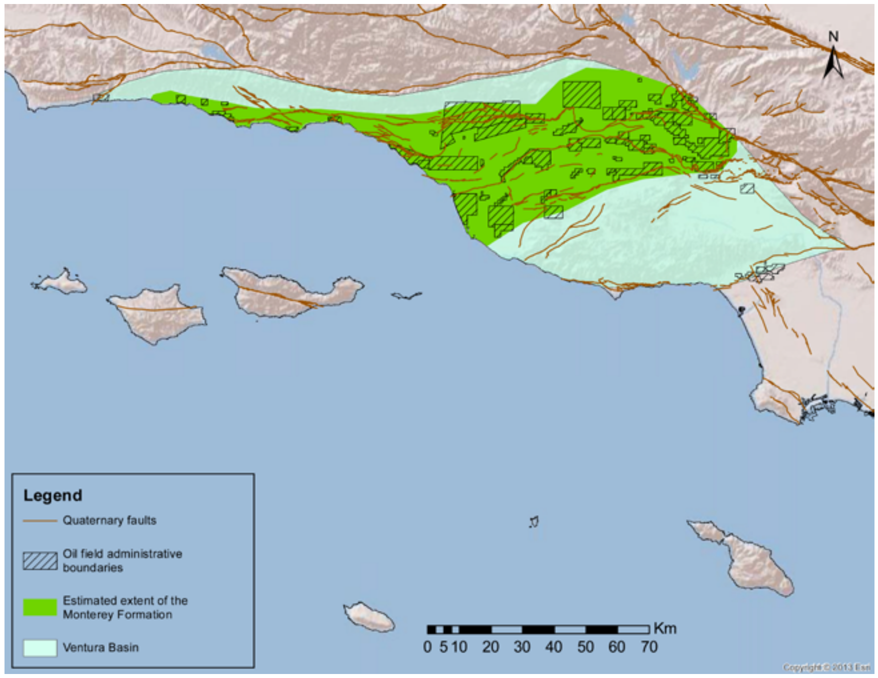

Figure 4-31. The Ventura Basin and producing oil fields (Oil field data from DOGGR). Distribution of the Monterey (green) from Nagle and Parker (1971). No data were available to constrain the distribution of the active source rock for this basin.

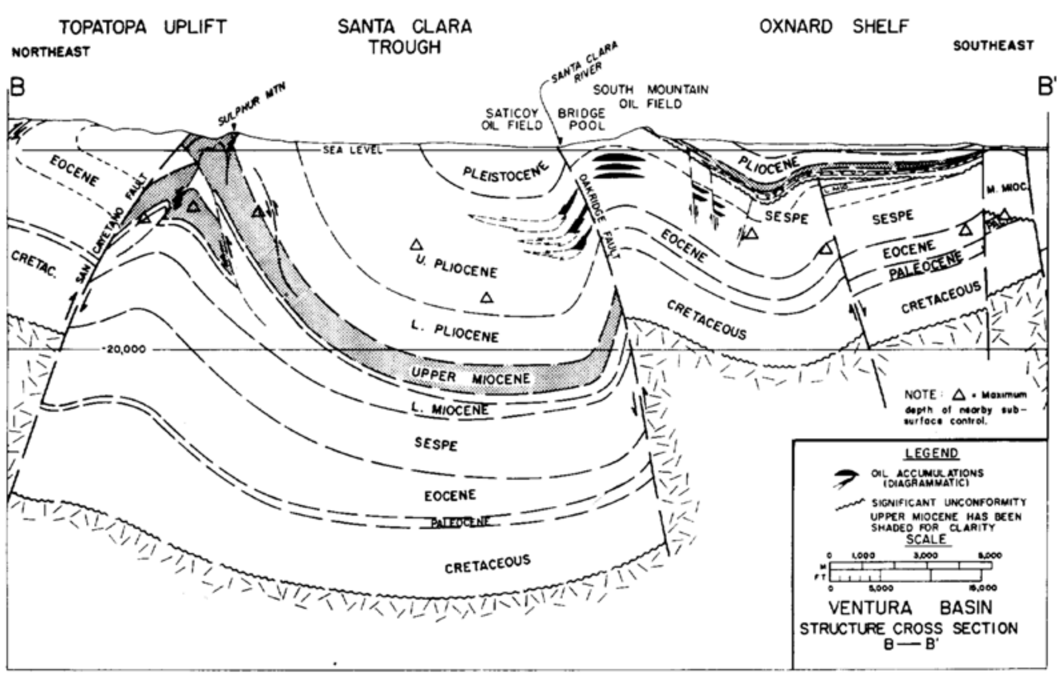

Figure 4-32. NE-SW cross-section through the Ventura Basin (Nagle and Parker, 1971).

4.5.5 Cuyama Basin

The Cuyama Basin is a Neogene basin located in the southern Coast Ranges in central California, just west of the San Andreas Fault (Fig. 4-33). The basin contains nonmarine and marine sediments, and has been affected by strike-slip and thrust faulting (Baldwin, 1971).

In the Cuyama Basin, the Saltos shale forms the lower part of the Monterey Formation, while the Whiterock Bluff shale forms the upper section. The Branch Canyon sandstone is intercalated with both of these shale units, and is more abundant in the SE portion of the basin, which had a larger input of terrigenous sediments (Lagoe, 1982; 1984; 1985). The Saltos shale has a larger terrigenous sedimentary component than the Whiterock Bluff shale and consists of interbedded sandstones, mudstones, and impure carbonates. In contrast, the Whiterock Bluff shale is dominated by biogenic sediments, and consists of siliceous and diatomaceous shales and mudstones with minor dolomitic interbeds (Lagoe, 1985).

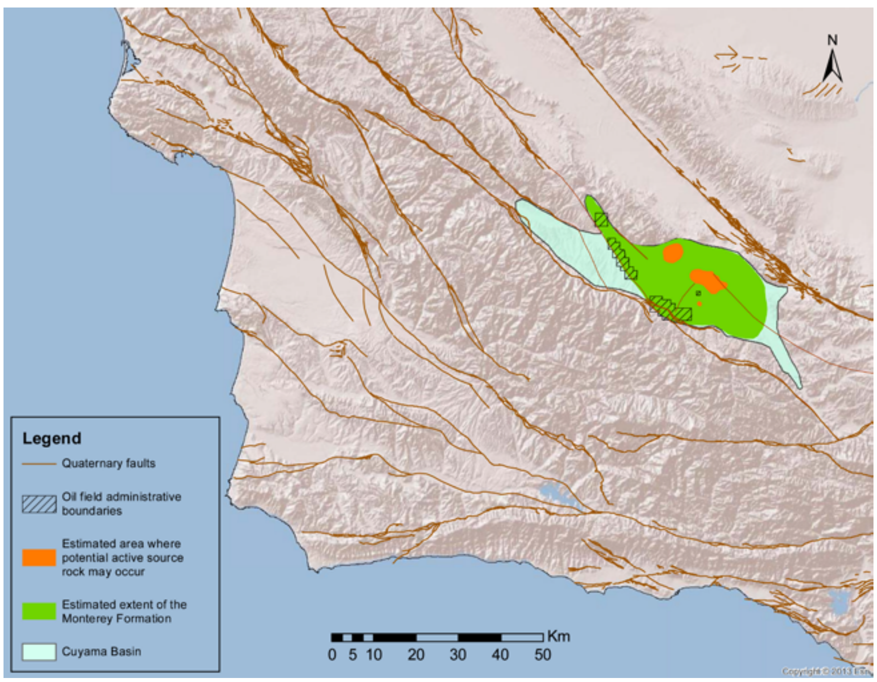

Figure 4-33. Cuyama Basin and associated oil fields (DOGGR), along with distribution of Monterey source rock (Sweetkind et al., 2013) and portion below top of oil window (~2.7 km depth based on data from Lillis (1994)).

Oil production from this basin is predominantly from the Painted Rock Sandstone member of the Miocene Vaqueros Formation, which underlies the Monterey Formation (Fig. 4-34) (Isaacs, 1992a). Based on carbon stable isotope compositions and biomarker data, Lillis (1994) determined that the source rock is the Soda Lake shale member of the Early Miocene Vaqueros Formation. The distribution of the Soda Lake shale member and the portion of this unit that lies within the oil window are depicted in Figure 4-35.

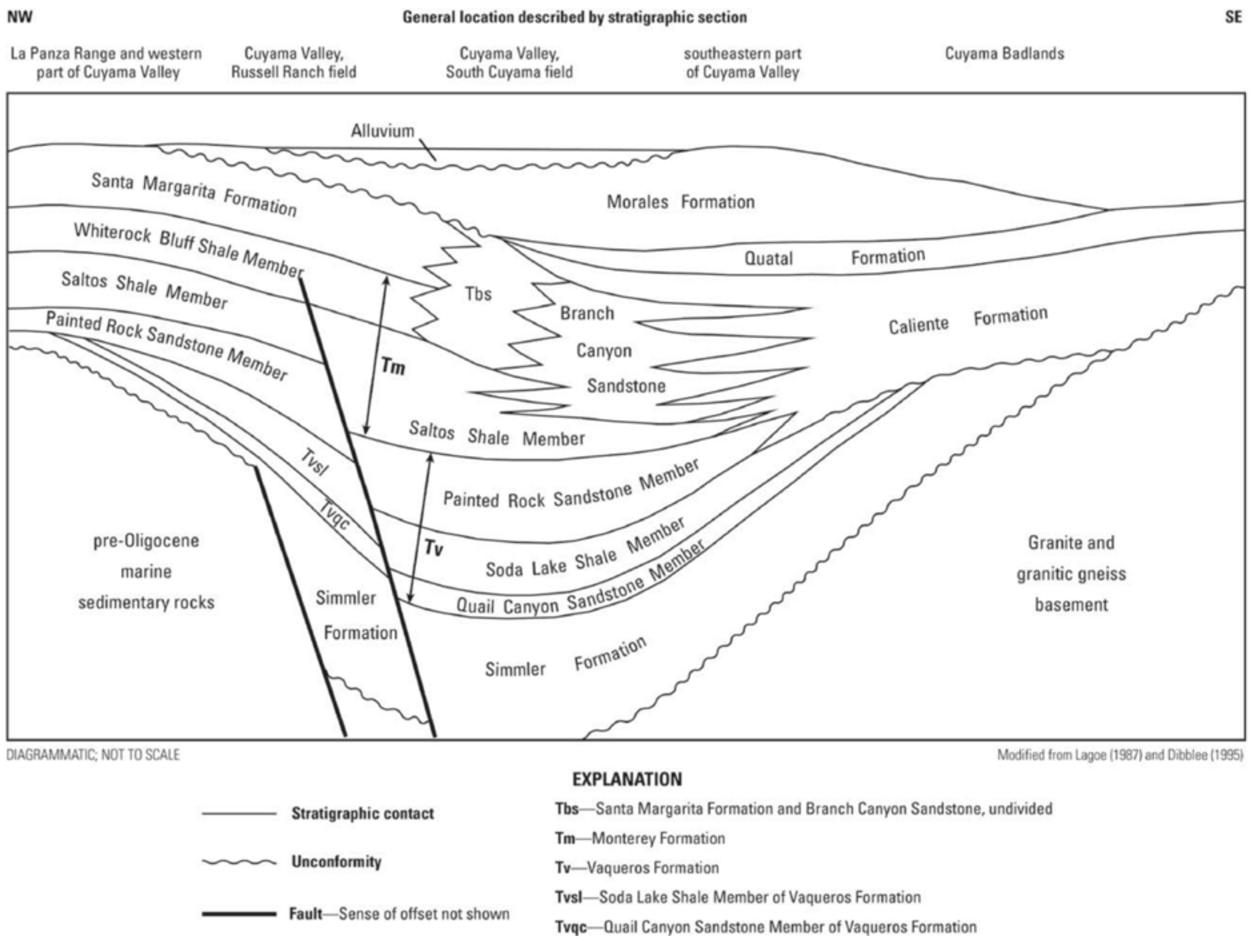

Figure 4-34. Diagrammatic NW–SE stratigraphic section across the Cuyama Basin (Sweetkind et al., 2013).

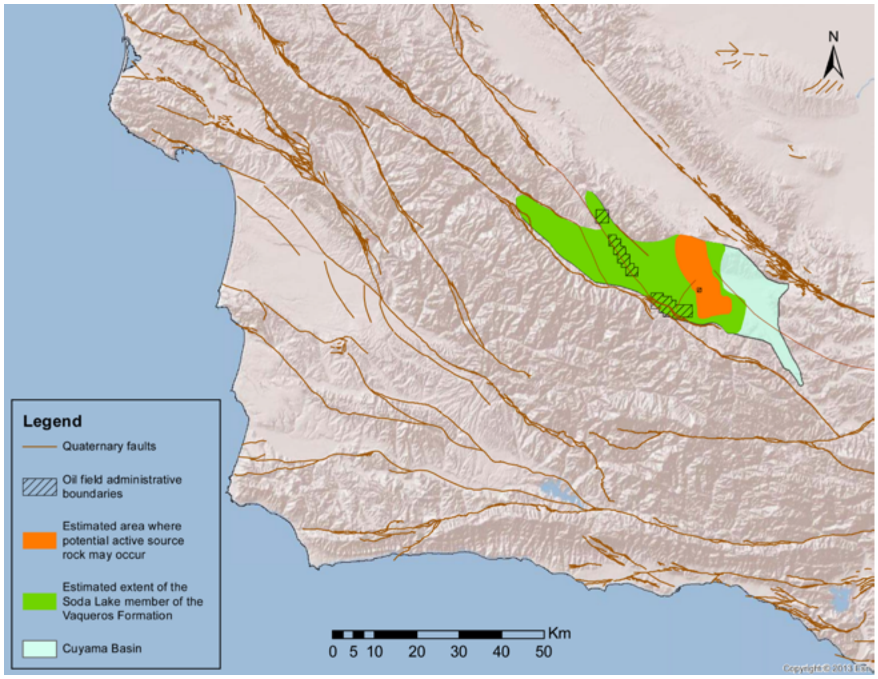

Figure 4-35. Cuyama Basin and associated oil fields (DOGGR), along with distribution of Vaqueros source rock (Sweetkind et al., 2013) and portion below top of oil window (~2.5 km depth based on data from Lillis (1994)).

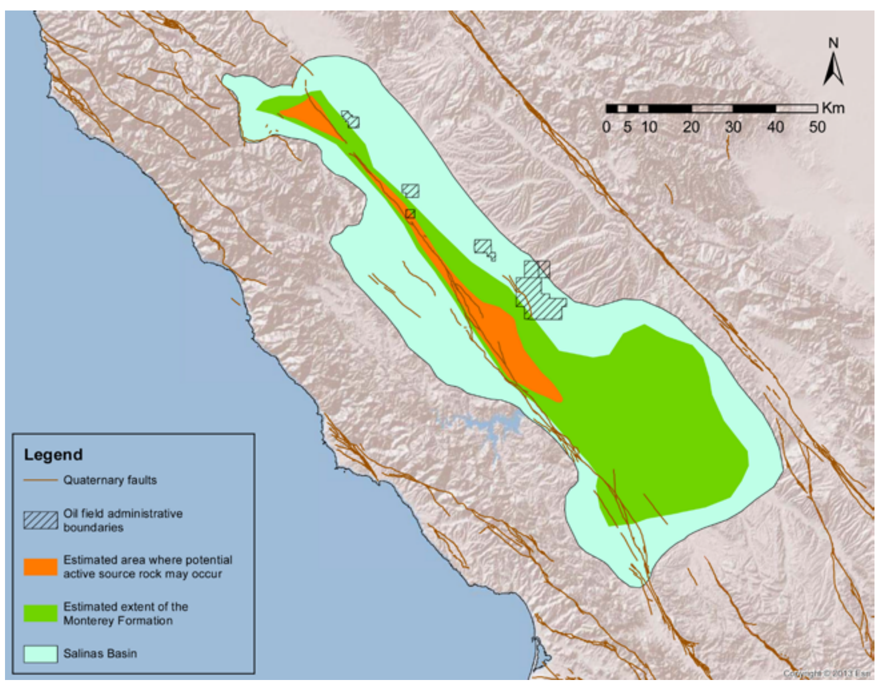

Figure 4-36. Salinas Basin and associated oil fields (DOGGR), along with distribution of source rock (green) and portion below top of oil window (~2,000 m - Menotti and Graham, 2012), with data from Durham (1974) and Menotti and Graham (2012).

4.5.6 Salinas Basin

The Salinas Basin is a Neogene basin dominated by wrench tectonics, with mid-Miocene subsidence associated with transtension and subsequent uplift, folding, and faulting associated with transpression (Colgan et al., 2012; Durham, 1974; Graham, 1978; Menotti and Graham, 2012) (Figure 4-36). The period of basin subsidence coincided with deposition of a thick sequence (up to 3 km) of Monterey Formation sediments (Menotti et al., 2013). Laminated marine shales from the lower portion of the Monterey have elevated total organic carbon contents (TOC), with moderately laminated shales having average TOC values of 3.12% and well-laminated hemipelagic Monterey sediments having an average TOC value of 4.59%, making them good candidates for oil source rocks (Mertz, 1989). The Salinas Basin contains a single large oil field, the San Ardo field (Baldwin, 1976; Isaacs, 1992a). A cross section through this field (Fig. 4-37) illustrates the important role that structural features play in the migration and trapping of oil (Menotti and Graham, 2012).

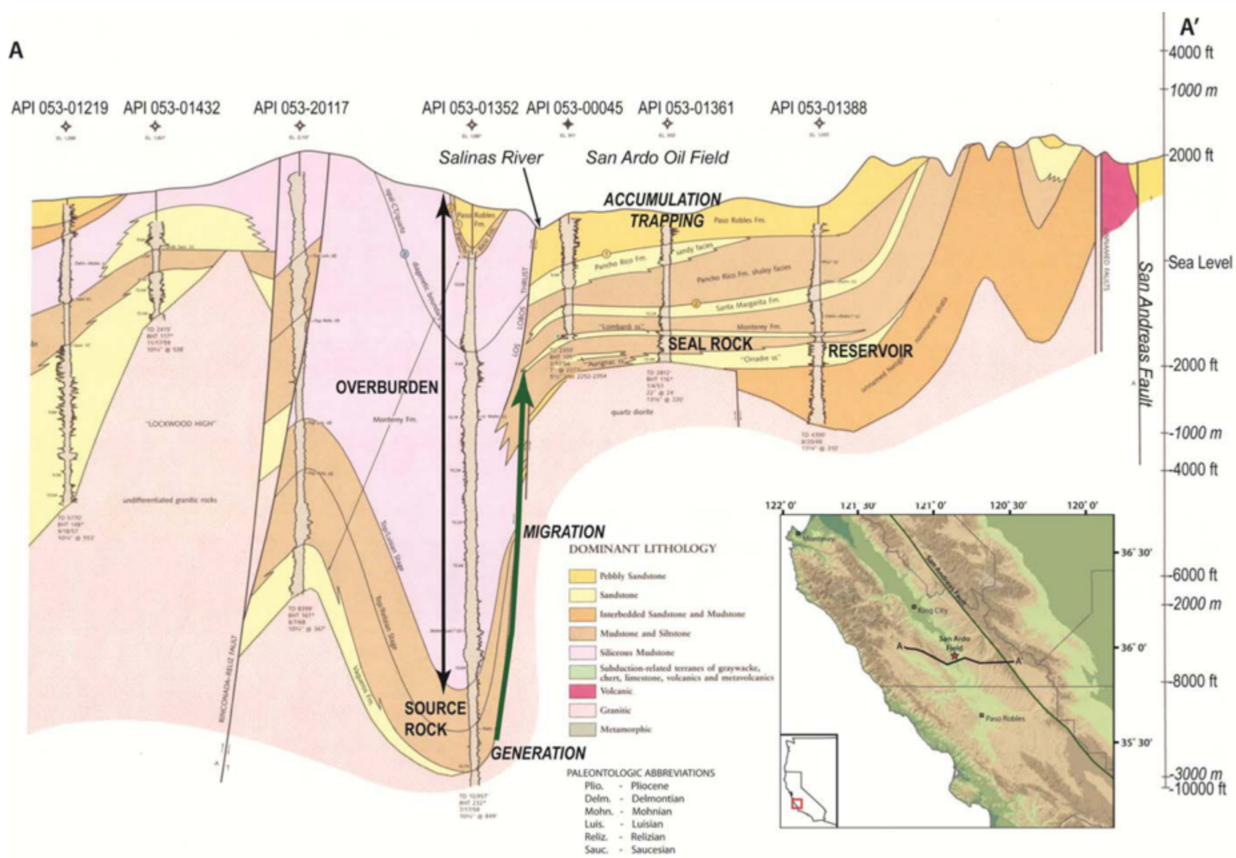

Figure 4-37. E-W cross section through the San Ardo oil field, Salinas Basin, depicting key components of the petroleum system (Menotti and Graham, 2012).

4.5.7 General Observations of Neogene Sedimentary Basins in California

While there are numerous differences between different Neogene sedimentary basins in California, they do share a number of common characteristics. They all have complex tectonic histories that have been shaped by the transform plate boundary characterized by the San Andreas Fault system. Phases of rotation, extension, and compression associated with this faulting led to episodes of basin deepening, uplift, and deformation. During the Miocene, there was extensive deposition of silica-rich fine-grained marine sediments in many of these basins, resulting in the Monterey Formation. The organic-rich phosphatic shale portion of this thick and areally extensive unit is the primary source rock for most of the major oil fields in California. The structural complexity of the basins led to the development of structural traps on the margins of the basins, where most of the producing oil reservoirs are encountered. The zones where oil generation occurs (within the oil window) are in the deeper portions of the basins. Oil has migrated from the active source rock areas into the reservoir rocks, and has been trapped by impermeable seals that overlie the reservoirs. Areas with potentially active source rock have been identified in each basin, but as discussed below in Section 4.6, exploration wells drilled into these active source rocks as a shale oil play have not yet resulted in the discovery of new oil fields in California.

4.6 Results of Exploratory Drilling of Deep Shales in California

Relatively few of the hundreds of thousands of oil wells drilled to date in California have targeted deep exploration zones (Schwochow, 1999), in part due to the higher costs, and also because many of the discovered oil fields are hosted in relatively shallow reservoirs with structural traps that lie above the oil window (Fig. 4-3). As noted in Section 4.5, source rocks within the Neogene sedimentary basins in California are found at depths typically greater than 8,000 to 10,000 feet (2.4 to 3.0 km), which marks the top of the oil window. Deep wells are needed to ascertain if these source rocks retain significant hydrocarbons and could serve as unconventional shale oil reservoir rocks.

Deep drilling beneath the existing oil reservoirs at the Elk Hills oil field (San Joaquin Basin) was conducted by the United States Department of Energy (DOE) to evaluate the prospects for hydrocarbon production from deeper reservoir intervals (Fishburn, 1990). Three deep wells were drilled, ranging in depth from 18,270 to 24,426 ft (7,455 m). While these wells did not encounter commercial quantities of hydrocarbons beneath the main production units of the field, they did have oil and gas shows. Cores of shale recovered from the Eocene Kreyenhagen Formation, the top of which was encountered at a depth of 15,700 ft (4,785 m) in the 987-25R well, exuded oil and gas from fine fractures. This shale overlies a 325 ft (99 m) thick section of oil-stained sands from the Eocene Point of Rocks sandstone, which is just above an 800 ft (244 m) thick section of salt. Measured porosity values for this sandstone range from 14-16% in this well, but are quite a bit lower (around 6%) for the same stratigraphic section in the 934-29R well, which encountered it at depths between 21,640 to 22,890 ft (6596 to 6977 m). Much higher porosities (20-35%) are observed for this unit where it is encountered at significantly shallower depths (<3000 feet) in other oil fields in the San Joaquin Basin (Schwochow, 1999), suggesting that compaction due to burial and diagenesis has led to significant porosity reduction. Average measured core permeabilities for this sandstone were around 4 md in the 987-25R well and less than 1 md in the deeper occurrence in the 934-29R well. The location of the oil window beneath the Elk Hills field based on vitrinite reflectance measurements is estimated to be between depths of 12,900 to 19,200 ft (3,930 to 5,850 m). The only oil field that has reported significant production of oil from the Point of Rocks Sandstone where it is encountered at depths greater than 9,000 ft (2,740 m) is the McKittrick field; this pool also has substantial gas production (Schwochow, 1999).

Another potential deep target consists of shales that have been displaced deeper due to thrust faulting and folding such as a fault displacement gradient fold at the Lost Hills field (Fig. 4-38) as described by Wickham (1995). Based upon a subthrust play developed for the East Lost Hills, several exploratory deep wells were drilled into the footwall. The first well, spudded in 1998, encountered a high gas pressure surge while drilling in the Temblor at a depth of 17,640 ft (5377 m), and as the crew attempted to circulate out the gas, the venting gas and hydrocarbons ignited, engulfing the rig in flames. It took more than 6 months to bring the well under control (Schwochow, 1999). However, of the 65-70 deep wells that were drilled to a depth greater than 15,000 ft (4,570 m) in the San Joaquin Basin by 1999, none proved to be commercially productive (Schwochow, 1999).

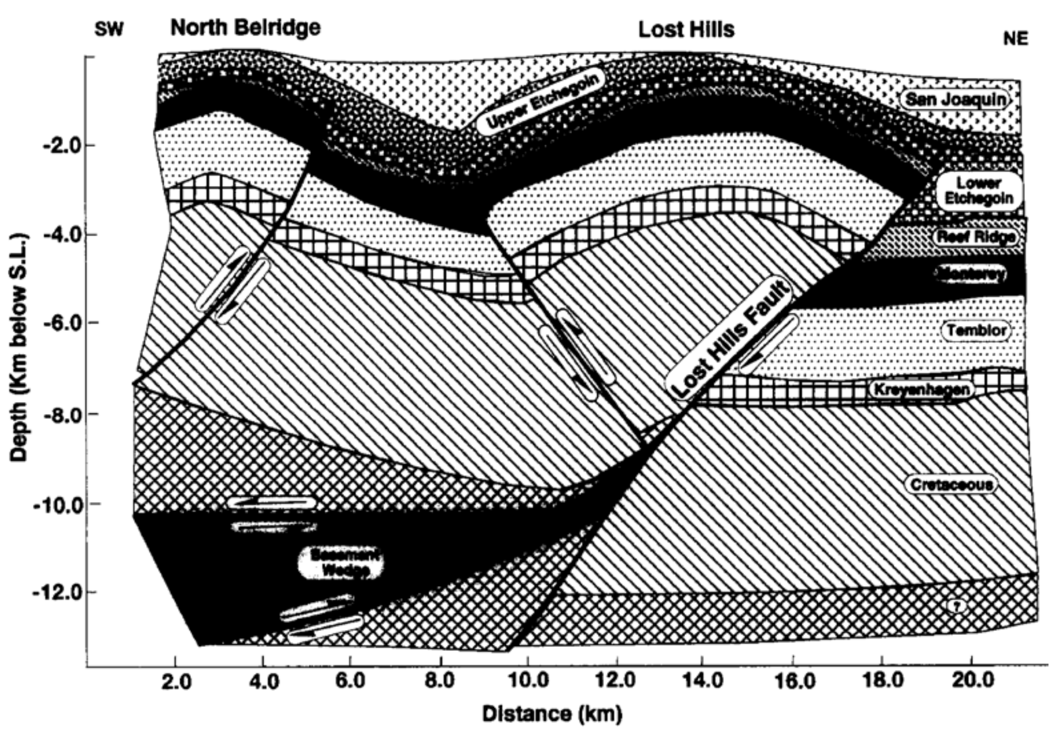

Figure 4-38. Cross section through the Lost Hills oil field constrained by seismic data depicting relative downward offset of Monterey and other units in footwall block of Lost Hills thrust fault.

Within the Santa Maria Basin in the Los Alamos field, innovative drilling techniques were used to drill a deep target (~10,000 ft true vertical depth (TVD)) in the Monterey, where a fractured siliceous shale interval had been identified (Witter et al., 2005). However, even though a highly deviated well course that intersected numerous fractures was drilled, the well did not result in sustained commercial production.

With the success of unconventional drilling and well completion methods in other oil shale areas in the U.S., there has been renewed focus on the Monterey to explore the effectiveness of using these methods (Durham, 2010, 2013; Redden, 2012). Venoco and Oxy have drilled a number of deeper wells targeting zones between 6,000 and 14,000 feet, and have employed well stimulation techniques in an attempt to increase hydrocarbon production. As part of this exploration effort, Venoco has drilled a number of deeper wells in the Semitropic field that target the Monterey, which lies below the Randolph sands of the Pliocene Etchegoin Formation, where most current production from this field occurs. One of these new wells, the Scherr Trust et al 1-22 (API 03041006), was spudded in Dec. 2010 and drilled to a depth of 14,015 ft (4272 m) (13,921 ft (4243 m) TVD) (Fig. 4-39) (http://owr.conservation.ca.gov/Well/WellDetailPage.aspx?domsapp=1andapinum=03041006). The primary target was the Monterey “N” chert; this zone was perforated (depth interval of 12,495-12,510 ft (3808-3813 m) and then fracture stimulated, but only a very limited amount of oil was produced in subsequent flow tests.

Based on reviews of DOGGR records for new wells from this field and the neighboring Bowerbank field, these deeper Monterey wells have not been very successful to date. A review of drilling results for unconventional oil reservoirs in the Monterey for a number of fields in the San Joaquin Basin from 2009 to 2013 by Burzlaff and Brewster (2014) indicates that average initial production rates are on the order of 75-150 barrels of oil per day. Projected expected ultimate recovery (EUR) from these wells is estimated to be on the order of 20,000-25,000 barrels for wells in fields on the west side of the San Joaquin Basin and about 90,000-100,000 barrels for wells located in fields on the eastern margins of the basin, with much higher gas-to-oil ratios for the west side wells. An industry report of testing of hydraulic fracturing and oil production in the Kreyenhagen indicates the presence of mobile oil (Petzet, 2012). However, no evidence has been found to suggest any further development of oil production from the Kreyenhagen.

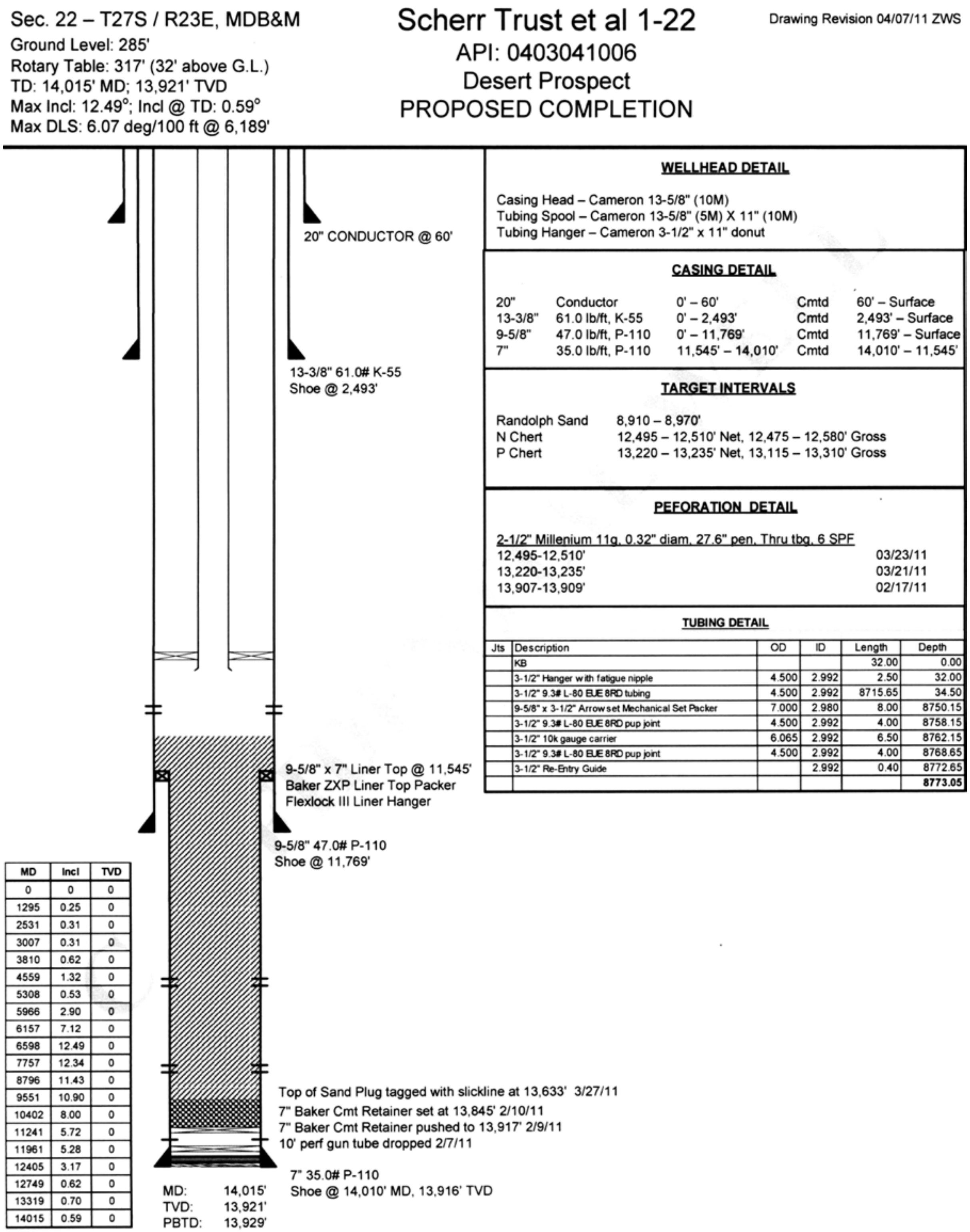

Figure 4-39. Schematic well completion diagram for Scherr Trust et al 1-22 well in Semitropic field, with Monterey "N" chert interval perforated and hydrofractured (DOGGR records).

4.7 Review of the US EIA 2011 Estimate of Monterey Source Rock Oil

US EIA (2011) estimated that there are 15.4 billion barrels of technically recoverable shale oil resources in the Monterey/Santos play in southern California. This estimate was based on the play covering an area of 1,752 square miles (4,538 km^2), with 16 wells per square mile, and each well recovering an average of 550,000 barrels of oil. This prospective play area covers parts of the San Joaquin, Los Angeles, Ventura, Santa Maria, Cuyama, and Salinas Basins, and includes offshore regions. For this play, the oil shale is located at depths varying between 8,000 and 14,000 ft (2,440 and 4,270 m) and with thicknesses ranging from 1,000 to 3,000 ft (305 to 914 m). Other estimated shale play properties include an average porosity of 11% and a TOC of 6.5 % (US EIA, 2011).

The calculated total areas of estimated active (below the top (Ro > 0.6) and above the bottom (Ro < 1.2) of the oil window) Monterey (and Monterey equivalent) source rocks for the major onshore oil basins in California (as depicted in Figures 4-18, 4-25, 4-28, 4-30, 4-32, and 4-35) are summarized in Table 4-2. The calculated areal extent of the potential unconventional Monterey resource (4532 km^2) is similar to that reported by US EIA (2011), which is 4538 km^2. Given that the onset of oil generation may begin at lower vitrinite reflectance levels in the Monterey (Walker et al., 1983; Petersen and Hickey, 1987), the extent of active oil generation may be greater, as this could extend the oil window to shallower depths.

Table 4-2. Estimated extent of potential Monterey Formation unconventional oil shale play.

Basin	Areal extent of source rock (km^2)	References
Los Angeles	455	Wright, 1991; Gautier, 2014
San Joaquin (Antelope)	1309	Magoon et al., 2009
San Joaquin (McLure)	2309	Magoon et al., 2009
Santa Maria	204	Tennyson and Isaacs, 2001; Sweetkind et al., 2010
Ventura	unconstrained	Nagle and Parker, 1971
Cuyama	33	Lillis, 1994; Sweetkind et al., 2013
Salinas	222	Durham, 1971; Menotti and Graham, 2012
Total	4532	

The assumed average oil production amount per well for the US EIA report (550,000 barrels) significantly exceeds the observed long-term cumulative productivity of wells in this formation in conventional oil fields. Hughes (2013) conducted an extensive review of all oil wells in the San Joaquin and Santa Maria Basins that were drilled since 1980 and that produce from the Monterey Formation. For wells with a production history of at least 10 years, Hughes found that the average cumulative oil production of wells with vertical and directional completions was 127,000 barrels and 97,000 barrels from the San Joaquin

Basin and 67,000 and 141,000 barrels from the Santa Maria Basin (Fig. 4-40). Based on these observed historical production rates, it is unlikely that the average recovery per well from Monterey source rocks will be as high as the average cumulative production of 550,000 barrels assumed in the US EIA report. A 4 to 5-fold increase in average well productivity relative to current production in the conventional reservoirs would need to be achieved to meet the assumed levels for unconventional production in what is essentially an unproven resource.

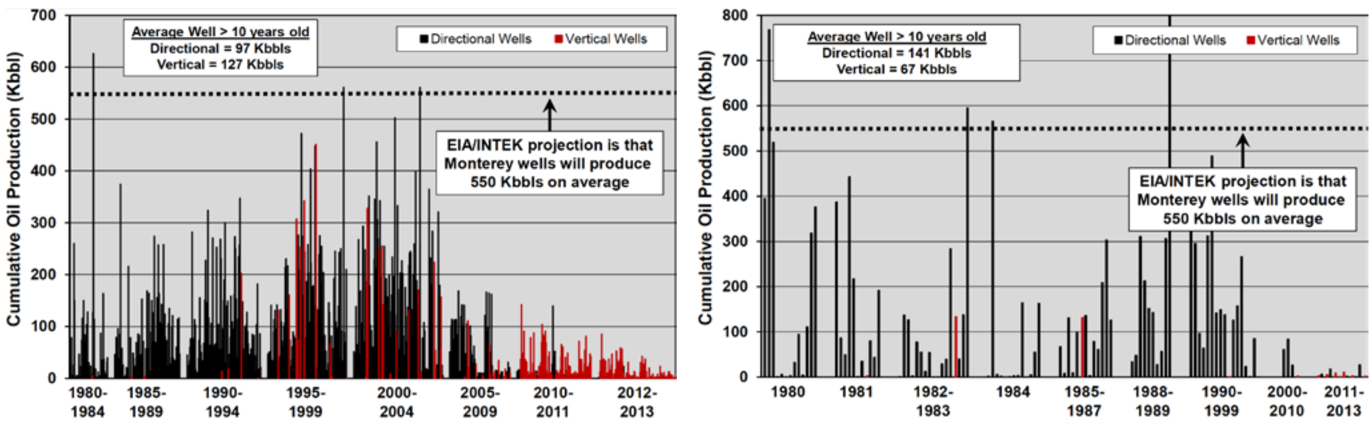

Figure 4-40. Cumulative oil production grouped by year of first production, 1980 through June 2013. Left – Monterey wells from the San Joaquin Basin; Right – Monterey wells from the Santa Maria Basin. Figures from Hughes (2013) based on data obtained from the Drillinginfo production database. Dashed line denotes average cumulative well production assumed in US EIA/INTEK report.

The US EIA (2011) estimate of total recoverable oil from the Monterey source rock appears to be overstated given that the assumed average oil recovery per well is significantly higher than historical production from wells in oil fields that have Monterey reservoir rocks. Due to a lack of operational experience, the potential recovery factor for this shale oil target is poorly constrained, but it is likely to be lower than what is currently obtained for Monterey-hosted oil reservoirs for a number of reasons, including expected lower permeability and porosity of the deeper source rocks. In addition, there is little information regarding the amounts of oil remaining in place in the deep (below oil window) portions of the Monterey. The thickness of the Monterey used in the INTEK model may also be overstated, as only a portion of the Monterey Formation has elevated organic contents which would allow it to serve as a source rock (Fig. 4-11). Well stimulation would likely be required to produce any remaining oil present in these source rocks given their intrinsically low matrix permeabilities.

The EIA Assumptions to the Annual Energy Outlook 2014 report (US EIA, 2014b) has revised the estimated unproved technically recoverable shale oil from the Monterey/Santos to a value of 0.6 billion barrels. This revision is based on new estimates of the potential area, the well density, and the production per well (Table 4-3). The biggest change in the new EIA analysis results from a nine-fold reduction in the prospective area estimate; the projected well production rate is only 20% lower than that used in the INTEK model. The revised model has also assumed the use of wells with horizontal completions, thus resulting in fewer wells per square mile.

Table 4-3. Comparison of model parameters for 2011 INTEK and 2014 EIA estimates of unproved technically recoverable oil from Monterey/Santos play.

	INTEK (2011)	**EIA (2014)**
Areal extent (mi^2)	1752	192
Wells/mi^2	16	6.4
Production/well (Kbbl oil)	550	451
Total recoverable oil (Bbbl oil)	15.4	0.6

4.8 Prognosis

The Monterey Formation (and its Miocene equivalents) is the dominant source rock for much of the oil production in California. It also serves as an important reservoir rock with significant resources of migrated oil produced from several active fields, both from interbedded turbidite sandstones (such as the Stevens sand), as well as from diatomite and fractured siliceous shale, porcelanite, and dolomite. The large areal extent of the Monterey over most of the main sedimentary basins in California, as well as its thickness (up to 6,000 ft (1,830 m)), make it a significant petroleum resource target. The Monterey is a very young unit (Miocene), and it is currently still generating hydrocarbons.

All of the sedimentary basins in California have been impacted by active tectonism, which has resulted in the development of faults and folds, which serve as key structural components for the major oil fields. Understanding the interplay between structures and fluid flow in the subsurface will be critical in discovering new resources, as well as designing well stimulation methods that interact with the natural fracture network and improve recovery rates of hydrocarbons.

Almost all of the existing major oil fields that involve the Monterey occur at depths that are shallower than the oil window. This suggests that these fields contain oil that was sourced from deeper portions of the Monterey and subsequently migrated upwards and was trapped in the shallower intervals by either structural, stratigraphic, or diagenetic traps. This is confirmed by evaluation biomarker maturity indicators, which demonstrate that the oil found in most Monterey Formation oil reservoirs in the San Joaquin was not generated in situ, but instead was sourced from deeper Monterey shales (Kruge, 1986).

For the Monterey Formation source rocks to also be reservoirs for unconventional production of oil, they would need to retain oil that was self-sourced (i.e., was formed in place and has not migrated). There is a considerable amount of the Monterey Formation within the deeper portions of major basins that lies within the oil window, but only a portion of the total thickness of this formation (primarily the organic-rich phosphatic shales in the Middle Monterey (Fig. 4-11)) would serve as a prospective unconventional oil shale target. These intervals could potentially host oil that has not migrated, and could perhaps be extracted using well stimulation methods. However, there is little published information on these deep sedimentary sections, so it is difficult to estimate the potential recoverable reserves associated with these rocks. Few deep wells have been drilled to date, and there are no reports of successful production from such depths. Reservoir quality of these rocks may be reduced through compaction and diagenesis, which would reduce porosity and permeability with depth (Schwochow, 1999).

Because of the higher depths and temperatures encountered within the oil window, compaction and diagenetic effects would result in the conversion of what was originally biogenic opal-A to opal-CT or microcrystalline quartz. This would cause a reduction in matrix porosity, but could also result in siliceous shales that are more brittle and that have developed natural fractures (Chaika and Williams, 2001). The presence of such fractures could lead to increased formation permeability that could permit upward migration of oil.

The Monterey Formation is fundamentally different from the other major low-permeability unconventional oil units, such as the Bakken, in its highly variable mineralogy, lithology, and changes in silica phase (El Shaari et al., 2011) and the structural complexity of the basins within which is it located (e.g., Wright, 1991; Ingersoll and Rumelhart, 1999). This variability makes it more challenging to discover and produce source-rock oil, as evidenced by the available information regarding the results of deep drilling in the San Joaquin Basin. There is a lack of data regarding oil saturations for the Monterey Formation at depths below the oil window. This is due in part to the lack of deep wells. One other factor is that oil-based muds are often used when drilling through shale units, as the presence of swelling clays can be problematic for wellbore stability if water-based drilling fluids are used. This could obscure the presence of naturally occurring oil in these well sections.

Within the San Joaquin Basin, there are several other deeper shale units that serve as source rocks and that could potentially host additional unconventional shale oil resources. Based on the distributions of the Moreno, Kreyenhagen, and Tumey Formations and the depth to the top and the base of oil window reported by Magoon et al. (2009), potential active source regions (with Ro > 0.6 and < 1.2) for each of these units were identified (Figs. 4-23, 4-24, and 4-25). The calculated areal extents of the potential unconventional resource plays for the Moreno, Kreyenhagen, and Tumey are 2529, 3629, and 3527 km^2, respectively. However, there is very little information available on how much generated oil these deep shale units still retain.

The potential volume of migrated oil in new conventional onshore discoveries in California is relatively small. The USGS assessed the mean of this potential for the San Joaquin Basin as 393 million barrels of additional recoverable oil (Gautier et al., 2003). Fig. 4-40, which shows the history of onshore oil field discoveries in California, provides some perspective on this assessment. Only one new field, Rose (Ganong et al., 2003), has been discovered since 1990. Hydraulic fracturing has been used to develop this field, suggesting well stimulation could play a role in producing future migrated oil discoveries.

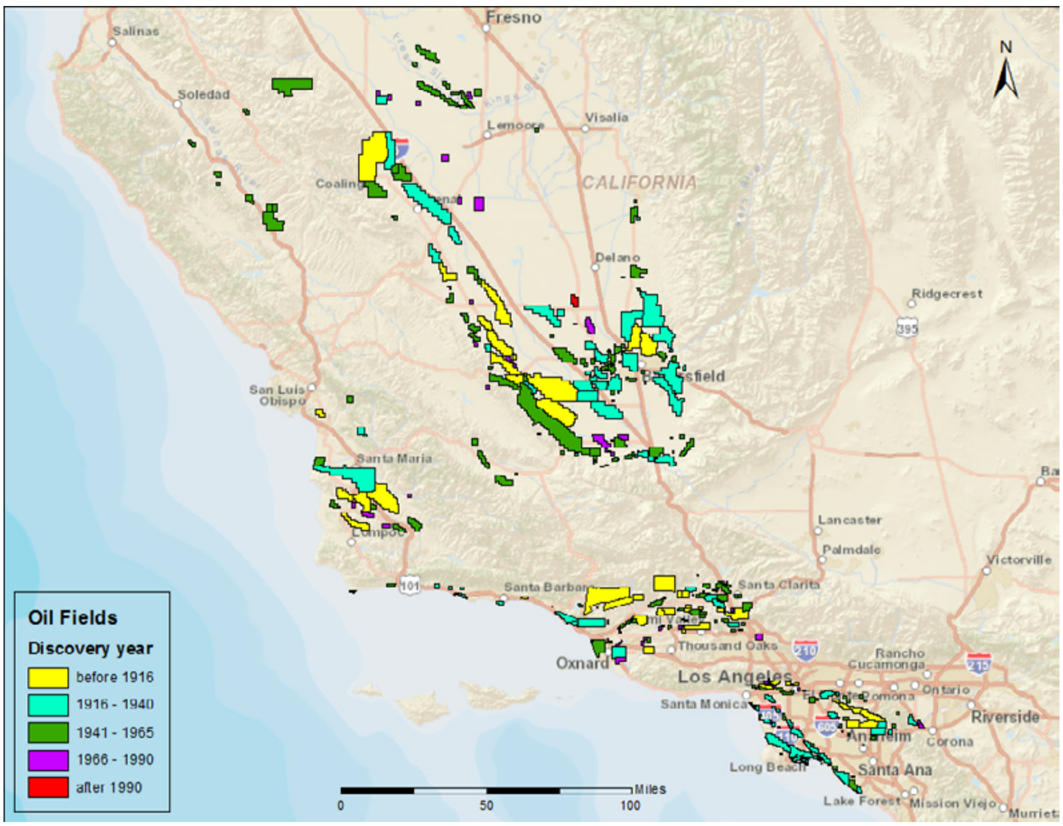

Figure 4-41. Discovery year of onshore oil fields (DOGGR, 1992; 1998; California Division of Oil and Gas, 1987; Minner et al., 2003).

Well stimulation methods could be used to a larger degree to increase the recovery efficiency of oil within the Monterey Formation from existing oil fields, as has been done in the South Belridge and Lost Hills fields, as well as oil within other geologic units. The USGS predicts that nine of the largest oil fields in the San Joaquin Basin could have 6.5 billion barrels of additional oil production using current recovery technology, with 2.8 billion barrels hosted in Monterey diatomite reservoirs (Tennyson et al., 2012). The USGS used probabilistic models to obtain a mean estimate of an additional 3.2 billion barrels of oil that could be recovered from the 10 largest oil fields in the LA basin (Gautier et al., 2013). Part of this recovery effort would likely involve well stimulation methods.

4.9 Summary

Credible estimates of the potential for increased recovery enabled by well stimulation technologies (WST) indicate that about 5 to 16 billion barrels might be produced in and near 19 existing giant fields in the San Joaquin and Los Angeles Basins where the WST and production technologies in use today work well. The 2011 US EIA estimates of about 15 billion barrels of technically recoverable oil from new plays in the Monterey Formation source rock have been revised in 2014 to a value of 0.6 billion barrels (US EIA 2014b); these estimates of unconventional oil resources are not well constrained.

There are significant resources in existing fields and estimates of these resources are relatively consistent. The USGS (Tennyson et al., 2012; Gautier et al., 2013) estimates that an additional 6.5 billion barrels and 3.2 billion barrels can be recovered from the largest fields in the San Joaquin and Los Angeles Basins, respectively, using existing oil production technology (see Figures 4-19 and 4-26).

New oil and gas production in regions removed from existing fields is more uncertain than increased production in existing oil and gas fields in the near term. There is a considerable amount of source rock including the Monterey Formation and other geologic units within the deeper portions of major basins that could potentially contain oil that has not migrated ("source" oil), and could perhaps be extracted using WST. However, there is little published information on these deep sedimentary sections, so it is difficult to estimate the potential recoverable reserves associated with these rocks. No reports of significant production of source oil from these rocks were identified.

The US EIA 2011 INTEK report has garnered considerable attention because of its large estimate of 15.4 billion barrels of technically recoverable oil in Monterey Formation source rock. Very little empirical data is available to support this analysis and the assumptions used to make this estimate appear to be consistently on the high side. INTEK estimates that the average well in low-permeability source rock in the Monterey Formation will produce 550 thousand barrels of oil. This amount greatly exceeds the production that has occurred to date from low-permeability rocks in known oil accumulations in this formation, with single-well oil production of only 67 and 141 thousand barrels in the San Joaquin and Santa Maria Basins, respectively (Hughes 2013). Consequently the INTEK estimate requires a four to five-fold increase in productivity per well from an essentially unproven resource.

In addition the Monterey Formation was formed by complex depositional processes and subsequently deformed in many tectonic events, resulting in highly heterogeneous as well as folded and faulted rocks that are difficult to characterize. INTEK posits production over an area of 4,538 km^2 (1,752 square miles), but this is almost the entire source rock area estimated in this report (note that the updated US EIA (2014b) report has reduced this areal extent significantly to 497 km^2 (192 square miles). There has not been enough exploration to know how much of the Monterey source rock has retained oil, or if the oil has largely migrated away (Hughes 2013), but it is unlikely the entire source rock area will be productive given the extreme heterogeneity in the Monterey Formation. Finally, even if significant amounts of oil do remain in the Monterey Shale, and wells reach this oil, it still remains to be determined if hydraulic fracturing of Monterey source rock will result in economically viable production. For all these reasons, the INTEK estimate of recoverable oil in Monterey Formation source rock warrants some skepticism. The EIA has issued a revised estimate (0.6 billion barrels) of this unconventional oil resource (US EIA, 2014b); this decrease is mainly due to a nine-fold reduction in the estimated potential resource area.

Although there is potential for new production from undiscovered migrated oil accumulations in the Monterey Shale, the potential is small. A major reason for the reduced potential is that the USGS assessment of (migrated) oil in new, undiscovered conventional fields in the San Joaquin Basin is less than 400 million barrels, much smaller than the estimate given above for recoverable oil from known fields.

4.10 Acknowledgments

This summary of oil-bearing shales in California results from the input and support of many people. Don Gautier (retired USGS) and Marilyn Tennyson (USGS) kindly shared their extensive knowledge of petroleum systems in California. Rick Behl (CSU Long Beach) provided many insights into the Monterey Formation, and shared the work of his students on the MARS (Monterey and Related Sediments) project. Steve Graham (Stanford), Pat McCrory (USGS), and Jim Boles (UC Santa Barbara) helped steer the author of this section in the direction of important data sources. Tess Menotti (Stanford) generously shared some of the preliminary results of her Ph.D. study of the Salinas Basin. Don Sweetkind (USGS) allowed use of the GIS data that he generated for the Santa Maria and Cuyama Basins, and Julie LeFever (North Dakota Geological Survey) shared GIS data for the Bakken Formation in the Williston Basin. Michael Golden (Lawrence Berkeley National Laboratory (LBNL)) tracked down a number of references used in this review. Dan Hawkes and Helen Prieto (LBNL) provided editorial assistance in a timely fashion, and Jane Long, Laura Feinstein (California Council on Science and Technology (CCST)), Jens Birkholzer, Preston Jordan, Curt Oldenburg, and Will Stringfellow (LBNL) provided helpful suggestions in their reviews of this section. The basin GIS figures were generated by Michelle Robertson and Craig Ulrich (LBNL)—without their long hours of work creating these figures, this report would not have been completed. Additional improvements to this section were suggested by anonymous reviewers. Many thanks to all.

4.11 References

Agiddi, D. (2004). Improved Fracture Stimulation Revitalizes the Western 31S Stevens Oil Zone, Elk Hills Field, California. SPE Paper 89412. In: Proceedings, *SPE/DOE Symposium on Improved Oil Recovery,* Tulsa, Oklahoma, April 17-21, 2004.

Allan, M.E., D.K. Gold, and D.W. Reese (2010). Development of the Belridge Field's Diatomite Reservoirs With Hydraulically Fractured Horizontal Wells: From First Attempts to Current Ultra-Tight Spacing. SPE Paper 133511. In: *SPE Annual Technical Conference and Exhibition,* Florence, Italy, September 19-22, 2010, 19 pp.

Allan, M.E., and J.J. Lalicata (2012). The Belridge Giant Oil Field - 100 Years of History and a Look to a Bright Future. AAPG Search and Discovery Article 20124, *AAPG International Convention and Exhibition,* Milan, Italy, October 23-26, 2011.

Baldwin, T.A. (1971). Petroleum Potential of California Central Coast Ranges. *Future Petroleum Provinces of the United States--Their Geology and Potential,* AAPG Memoir 15, Volume 1, 309–315.

Baldwin, T. (1976). The Salinas Valley Today and Tomorrow. In: *Tomorrow's Oil from Today's Provinces: Selected Papers Presented at the 51st Annual Meeting, AAPG Pacific Section,* San Francisco, 47–51.

Behl, R.J. (1998). Relationships between Silica Diagenesis, Deformation, and Fluid Flow in Monterey Formation Cherts, Santa Maria Basin, California. In: *Diagenesis, Deformation, and Fluid Flow in the Miocene Monterey Formation,* P. Eichhubl (ed), Pacific Section SEPM Special Publication, Book 83, 77–83.

Behl, R.J. (1999). Since Bramlette (1946): The Miocene Monterey Formation of California revisited. In: *Classic Cordillerian Concepts: A View from California,* E.M. Moores, D. Sloan, and D.L. Stout (eds), Geological Society of America Special Paper 338, 301–313.

Behl, R.J., and R.E. Garrison (1994). The Origin of Chert in the Monterey Formation of California (USA). In: *Siliceous, Phosphatic and Glauconitic Sediments of the Tertiary and Mesozoic,* A. Iijima, A.M. Abed, and R.E. Garrison (eds), Proceedings of the 29th International Geological Congress, Part C, 101–132.

Behl, R.J., and S. Morita (2007). The Monterey Formation of the Palos Verdes Hills, California: Stratigraphy and Diagenetic Implications for Burial and Uplift. In: *Geology and Paleontology of the Palos Verdes Hills, California: A 60th Anniversary Revisit to Commemorate 1946 Publication of US Geological Survey Professional Paper 207,* A.R. Brown, R.J. Shlemon, and J.D. Cooper (eds), Pacific Section SEPM Book 103, 51–72.

Beyer, L.A. (1988). Summary of Geology and Petroleum Plays Used to Assess Undiscovered Petroleum Resources of the Los Angeles Basin Province, California. *US Geological Survey Open-File Report,* 88-450L, 62 pp.

Bohacs, K.M., and J.R. Schwalbach (1992). Chapter II - Sequence Stratigraphy of Fine-Grained Rocks with Special Reference to the Monterey Formation. In: *Sequence Stratigraphy in Fine-Grained Rocks: Examples from the Monterey Formation,* J.R. Schwalbach and K.M Bohacs (eds), Pacific Section, SEPM, vol. 70, 7–19.

Bohacs, K.M., G.J Grabowski, Jr., A.R. Carroll, P.J. Mankiewicz, K.J. Miskell-Gerhardt, J.R. Schwalbach, M.B. Wegner, and J.A. Simo (2005) Production, Destruction, and Dilution – The Many Paths to Source-Rock Development. In: *The Deposition of Organic-Carbon-Rich Sediments: Models, Mechanisms, and Consequences.* SEPM Special Publication No. 82, 61-101.

Bowersox, J.R. (1990). Geology of the Belridge Diatomite, Northern South Belridge Field, Kern County, California. In: *Structure, Stratigraphy and Hydrocarbon Occurrences of the San Joaquin Basin, California,* Pacific Section, SEPM, 215–223.

Bramlette, M.N. (1946). The Monterey Formation of California and the Origin of its Siliceous Rocks. *US Geological Survey Professional Paper,* 212, 57 pp.

Burzlaff, A.A., and D.P. Brewster (2014). Unconventional Oil from California's Monterey Formation – Exploitation Results. SPE Paper 169508-MS. In: *SPE Western North American and Rocky Mountain Joint Regional Meeting,* Denver, Colorado, USA, 14 pp.

Carpenter, A.B. (1989). A Mineralogical Classification of Monterey Lithologies. In: *Oil in the California Monterey Formation Los Angeles to Santa Maria, California July 20-24, 1989,* Field Trip Guidebook T311, T. MacKinnon, J.W. Randall, and R.E. Garrison (eds), American Geophysical Union, Washington, D.C., 37–40.

Chaika, C., and J. Dvorkin (2000). Porosity Reduction During Diagenesis of Diatomaceous Rocks. *AAPG Bulletin, 84*(8), 1173–1184.

Chaika, C., and L.A. Williams (2001). Density and Mineralogy Variations as a Function of Porosity in Miocene Monterey Formation Oil and Gas Reservoirs in California. *AAPG Bulletin, 85*(1), 149–167.

Chanchani, S.K., M.D. Zoback, and C. Barton (2003). A Case Study of Hydrocarbon Transport along Active Faults and Production-Related Stress Changes in the Monterey Formation, California. In: *Fracture and In-Situ Stress Characterization of Hydrocarbon Reservoirs,* M. Ameen (ed), Geological Society, London, Special Publications, 209, 17–26. doi:10.1144/GSL.SP.2003.209.01.03

Clauer, N., M.D. Lewan, M.P. Dolan, S. Chaudhuri, and J.B. Curtis (2014). Mineralogical, Chemical and K–Ar Isotopic Changes in Kreyenhagen Shale Whole Rocks and $<2\mu$m Clay Fractions during Natural Burial and Hydrous-Pyrolysis Experimental Maturation. *Geochimica et Cosmochimica Acta, 130,* 93–112. doi:10.1016/j.gca.2014.01.007

Colgan, J.P., D.K. McPhee, K. McDougall, and J.K. Hourigan (2012). Superimposed Extension and Shortening in the Southern Salinas Basin and La Panza Range, California: A Guide to Neogene Deformation in the Salinian Block of the Central California Coast Ranges. *Lithosphere, 4*(5), 411–429. doi:10.1130/L208.1

Division of Oil and Gas (1987). Onshore Oil and Gas Seeps in California. Publication No. TR26. California Department of Conservation, Sacramento, CA. 97 pp.

Division of Oil, Gas and Geothermal Resources (DOGGR) (1982). California Oil and Gas Fields Volume III – Northern California. California Department of Conservation, Sacramento, CA. 499 pp.

Division of Oil, Gas and Geothermal Resources (DOGGR) (1992). California Oil and Gas Fields Volume II – Southern, Central Coastal, and Offshore California Oil and Gas Fields. California Department of Conservation, Sacramento, CA. 645 pp.

Division of Oil, Gas and Geothermal Resources (DOGGR) (1998). California Oil and Gas Fields Volume I - Central California. California Department of Conservation, Sacramento, CA. 330 pp.

Division of Oil, Gas and Geothermal Resources (DOGGR) (2010). 2009 Annual Report of the State Oil & Gas Supervisor. PR-06, California Department of Conservation, Sacramento, CA. 267 pp.

De Rouffignac, E., and P.L. Bondor (1995) Land Subsidence and Well Failure in the Belridge Diatomite Oil field, Kern County, California. Part I. Experiments, Model and Verification. In: *Land Subsidence. Proceedings of the Fifth International Symposium on Land Subsidence,* The Hague, October 1995, International Association of Hydrological Sciences Publication no. 234, 61–68.

Dholakia, S.K., A. Aydin, D.D. Pollard, and M.D. Zoback (1998). Fault-Controlled Hydrocarbon Pathways in the Monterey Formation, California. *AAPG Bulletin, 82*(8), 1551–1574.

Dibblee Jr., T.W. (1973). Stratigraphy of the Southern Coast Ranges near the San Andreas Fault from Cholame to Maricopa, California. *US Geological Survey Professional Paper,* 764, 45 p.

Dibblee Jr., T.W. (1988). Geology of the Ventura Basin Area. In: *Ventura Basin: Geologic Introduction and Field Trip Guidebook,* M.H. Link (ed), AAPG Pacific Section, 6–17.

Ditzler, C.C., and R.H.Vaughan (1968). Brentwood Oil and Gas Field, Contra Costa County, California. In: *Natural Gases of North America,* B.W. Beebe and B.F. Curtis (eds), AAPG Memoir 9, v.1, 104–112.

Doust, H. (2010). The Exploration Play: What Do We Mean by It? *AAPG Bulletin, 94*(11), 1657–1672. doi:10.1306/06301009168

Dunham, J.B., and G.H. Blake (1987). Guide to Coastal Outcrops of the Monterey Formation of Western Santa Barbara County, California. In: *Guide to Coastal Outcrops of the Monterey Formation of Western Santa Barbara County, California,* J.B. Dunham (ed), Pacific Section, SEPM, Book 53, 1–36.

Durham, D.L. (1974). Geology of the Southern Salinas Valley Area, California. *US Geological Survey Professional Paper,* 819, 111 p.

Durham, L.S. (2010). Monterey Shale Gets New Look. *AAPG Explorer, 31*(11), 10, 12.

Durham, L.S. (2013). Monterey Shale Continues to Tempt and Tease. *AAPG Explorer, 34*(2),10, 12.

Eichhubl, P., and R.J. Behl (1998). Diagenesis, Deformation, and Fluid Flow in the Miocene Monterey Formation. In: *Diagenesis, Deformation, and Fluid Flow in the Miocene Monterey Formation,* P. Eichhubl (ed), Pacific Section SEPM Special Publication, Book 83, 5–13.

El Shaari, N., W.A. Minner, and R.F. Lafollette (2011). Is There a "Silver Bullet Technique" for Stimulating California's Monterey Shale? *SPE Paper 114526. In: SPE Western North American Regional Meeting,* Anchorage, Alaska, pp. 1–10.

Emanuele, M., W.A. Minner, L. Weijers, E.J. Broussard, D.M. Blevens, and B.T.Taylor (1998). A Case History: Completion and Stimulation of Horizontal Wells with Multiple Transverse Hydraulic Fractures in the Lost Hills Diatomite. SPE Paper 39941. In: *SPE Rocky Mountain Regional Conference,* Denver, U.S.A., pp. 335–347.

Finkbeiner, T., C.A. Barton, and M.D. Zoback (1997). Relationships among In-Situ Stress, Fractures and Faults, and Fluid Flow: Monterey Formation, Santa Maria Basin, California. *AAPG Bulletin, 81*(12), 1975–1999.

Fishburn, M. (1990). Results of Deep Drilling, Elk Hills Field Kern County, California, In: *Structure, Stratigraphy and Hydrocarbon Occurrences of the San Joaquin Basin, California,* Pacific Section, SEPM, 157–167.

Ganong, B.L., C. Hansen, P. Connolly, and B. Barree (2003). Rose Field: A McLure Shale, Monterey Formation Development Story. SPE Paper 83501. In: *SPE Western Regional/AAPG Pacific Section Joint Meeting,* Long Beach, California, May 19-24, 2003, pp. 1–9.

Gaswirth, S.B., K.R. Marra, T.A. Cook, R.R. Charpentier, D.L. Gautier, D.K. Higley, T.R. Klett, M.D. Lewan, P.G. Lillis, C.J. Schenk, M.E. Tennyson, and K.J. Whidden (2013). Assessment of Undiscovered Oil Resources in the Bakken and Three Forks Formations, Williston Basin Province, Montana, North Dakota, and South Dakota, *US Geological Survey National Assessment of Oil and Gas Fact Sheet,* 2013-3013, 4 p.

Gautier, D.L. (2014). Potential for Future Petroleum Development in California. CCST presentation, January 23, 2014.

Gautier, D.L., A. Hosford Scheirer, M.E. Tennyson, K.E. Peters, L.B. Magoon, P.G. Lillis, R.R. Charpentier, T.A. Cook, C.D. French, T.R. Klett, R.M. Pollastro, and C.J. Schenk (2003). Chapter 1: Executive Summary—Assessment of Undiscovered Oil and Gas Resources of the San Joaquin Basin Province of California, 2003. In: *Petroleum Systems and Geologic Assessment of Oil and Gas in the San Joaquin Basin Province, California,* A. Hosford Scheirer (ed), US Geological Survey Professional Paper, 1713, 2 p.

Gautier, D.L., M.E. Tennyson, T.A. Cook, R.R. Charpentier, and T.R. Klett (2013). Remaining Recoverable Petroleum in Ten Giant Oil Fields of the Los Angeles Basin, Southern California. *US Geological Survey Fact Sheet,* 2012-3120, 2 p.

Goodman, E.D., and P.E. Malin (1992). Evolution of the Southern San Joaquin Basin and mid-Tertiary "Transitional" Tectonics, Central California. *Tectonics, 11*(3), 478–498.

Govean, F.M., and R.E. Garrison (1981). Significance of Laminated and Massive Diatomites in the Upper Part of the Monterey Formation, California. In: *The Monterey Formation and Related Siliceous Rocks of California,* R.E. Garrison, R.G. Douglas, K.E. Pisciotto, C.M. Isaacs, J.C. Ingle (eds), Pacific Section, SEPM, 181–198.

Graham, S.A. (1978). Role of Salinian Block in Evolution of San Andreas Fault System, California. *AAPG Bulletin, 62*(11), 2214–2231.

Graham, S.A. (1987). Tectonic Controls on Petroleum Occurrence in Central California. In: *Cenozoic Basin Development of Coastal California,* R.V. Ingersoll and W.G. Ernst (eds), Rubey Volume VI, Prentice Hall, Englewood Cliffs, New Jersey, 47–63.

Graham, S.A., and L.A. Williams (1985). Tectonic, Depositional, and Diagenetic History of Monterey Formation (Miocene), Central San Joaquin Basin, California. *AAPG Bulletin, 69*(3), 385–411.

He, M., S. Graham, A. Hosford Scheirer, and K.E. Peters (2014). A Basin Modeling and Organic Geochemistry Study in the Vallecitos Syncline, San Joaquin Basin, California. *Marine and Petroleum Geology, 49,* 15–34. doi:10.1016/j.marpetgeo.2013.09.001

Hertzog, R., L. Colson, B. Seeman, M. O'Brien, H. Scott, D. McKeon, P. Wraight, J. Grau, D. Ellis, J. Schweltzer, and M. Herron (1989) Geochemical Logging with Spectrometry Tools. *SPE Formation Evaluation,* June 1989, 153-162.

Hickman, R.G., and J.B. Dunham (1992). Controls on the Development of Fractured Reservoirs in the Monterey Formation of Central California. In: *Structural and Tectonic Modelling and Its Application to Petroleum Geology,* R.M. Larsen, H. Brekke, B.T. Larsen, and E. Talleraas (eds), Norwegian Petroleum Society Special Publication 1, 343–353.

Hoots, H.W., A.L. Blount, and P.H. Jones (1935). Marine Oil Shale, Source of Oil in Playa Del Rey Field, California. *AAPG Bulletin, 19*(2), 172–205.

Hosford Scheirer, A. (2013). The Three-Dimensional Geologic Model Used for the 2003 National Oil and Gas Assessment of the San Joaquin Basin Province, California. In: *Petroleum Systems and Geologic Assessment of Oil and Gas in the San Joaquin Basin Province, California,* Chapter 7. A. Hosford Scheirer (ed), US Geological Survey Professional Paper, 1713, 81 p.

Hosford Scheirer, A., and L.B. Magoon (2008). Chapter 5: Age, Distribution, and Stratigraphic Relationship of Rock Units in the San Joaquin Basin Province, California. In: *Petroleum Systems and Geologic Assessment of Oil and Gas in the San Joaquin Basin Province, California,* A. Hosford Scheirer (ed), US Geological Survey Professional Paper, 1713,107 p.

Hughes, J. D. (2013). *Drilling California: a Reality Check on the Monterey Shale.* Post Carbon Institute and Physicians Scientists and Engineers for Healthy Energy, Santa Rosa, CA. 49 pp. Retrieved from http://www.postcarbon.org/reports/Drilling-California_FINAL.pdf

Ingersoll, R.V., and P.E. Rumelhart (1999). Three-stage Evolution of the Los Angeles Basin, Southern California. *Geology, 27,* 593–596.

Ingersoll, R.V. (2008). Restructuring Southern California. In: *Ores and Orogenesis: Circum-Pacific Tectonics, Geologic Evolution, and Ore Deposits,* J.E. Spenser and S.R. Titley (eds), Arizona Geological Society Digest, 22, 409–417.

Isaacs, C.M. (1980). Diagenesis in the Monterey Formation Examined Laterally along the Coast near Santa Barbara, California. *US Geological Survey Open-File Report,* 80-606, 329 p.

Isaacs, C.M (1981a). Field Characterization of Rocks in the Monterey Formation along the Coast near Santa Barbara, California. In: Guide to the Monterey Formation in the California Coastal Areas, Ventura to San Luis Obispo, AAPG Pacific Section, 39–53.

Isaacs, C.M. (1981b). Lithostratigraphy of the Monterey Formation, Goleta to Point Conception, Santa Barbara coast, California. In: *Guide to the Monterey Formation in the California Coastal Areas, Ventura to San Luis Obispo,* AAPG Pacific Section, 9–23.

Isaacs, C.M. (1981c). Porosity Reduction during Diagenesis of the Monterey Formation, Santa Barbara Coastal Area, California. In: *The Monterey Formation and Related Siliceous Rocks of California,* R.E. Garrison, R.G. Douglas, K.E. Pisciotto, C.M. Isaacs, J.C. Ingle (eds), Pacific Section, SEPM, 257–271.

Isaacs, C.M. (1982). Influence of Rock Composition on Kinetics of Silica Phase Changes in the Monterey Formation, Santa Barbara Area, California. *Geology, 10,* 304–308. doi:10.1130/0091-7613(1982)10<304

Isaacs, C.M. (1984). Geology and Physical Properties of the Monterey Formation, California. SPE Paper 12733. *SPE California Regional Meeting,* Long Beach, CA, April 11-13, 1984, 84–96.

Isaacs, C.M. (1987). Sources and Deposition of Organic Matter in the Monterey Formation, South-Central Coastal Basins of California. In: *Exploration for Heavy Crude Oil and Natural Bitumen,* R.F. Meyer (ed), AAPG Studies in Geology, 25, 193–205.

Isaacs, C.M. (1989). Marine Petroleum Source Rocks and Reservoir Rocks of the Miocene Monterey Formation, California, USA. In: *Petroleum resources of China and related subjects,* H.C. Wagner, L.C. Wagner, F.F.H Wang, and F.L. Wong (eds), Circum-Pacific Council for Energy and Mineral Resources, Earth Science Series, 10, 825-848.

Isaacs, C.M. (1992a). Petroleum Geology of the Central Coast Basins Assessment Province, California for the 1987 National Assessment of Undiscovered Oil and Gas Resources. *US Geological Survey Open-File Report,* 89-450D, 49 pp.

Isaacs, C.M. (1992b). Petroleum Geology of the Santa Maria Basin Assessment Province, California for the 1987 National Assessment of Undiscovered Oil and Gas Resources. *US Geological Survey Open-File Report,* 89-450C, 43 pp.

Isaacs, C.M., K.A. Pisciotto, and R.E. Garrison (1983). Facies and Diagenesis of the Miocene Monterey Formation, California: A Summary. In: *Siliceous Deposits in the Pacific Region,* A. Iijima, J.R. Hein and R. Siever (eds), Developments in Sedimentology, 36, 247–282.

Isaacson, K.A., and J.R. Blueford (1984). Kreyenhagen Formation and Related Rocks—A history. In: *Kreyenhegen Formation and Related Rocks,* J.R. Blueford (ed), Pacific Section SEPM, 1–7.

Jabbari, H., and Z. Zeng (2012). Hydraulic Fracturing Design for Horizontal Wells in the Bakken Formation. ARMA Paper 12-128. *46th US Rock Mechanics / Geomechanics Symposium, Chicago, IL, June 24-27, 2012,* 11 pp.

Johnson, C.L., and S.A. Graham (2007). Chapter 6: Middle Tertiary Stratigraphic Sequences of the San Joaquin Basin, California. In: *Petroleum Systems and Geologic Assessment of Oil and Gas in the San Joaquin Basin Province, California,* A. Hosford Scheirer (ed), US Geological Survey Professional Paper, 1713, 18 pp.

Keller, M.A. (1995). Ventura Basin Province (013). In: 1*995 National Assessment of United States Oil and Gas Resources; Results, Methodology, and Supporting Data,* D.L Gautier, G.L. Dolton, K.I. Takahashi, and K.L. Varnes (eds), US Geological Survey Data Series 30, 13 pp.

Keller, M.A. (1988). Geologic Basis for the Assessment of Undiscovered Oil and Gas Resources of the Ventura Basin Province, California, 1987 national assessment. *US Geological Survey Open-File Report,* 87-450M, 39 pp.

Keller, M.A., and C.M. Isaacs (1985). An Evaluation of Temperature Scales for Silica Diagenesis in Diatomaceous Sequences Including a New Approach Based on the Miocene Monterey Formation, California. *Geo-Marine Letters, 5,* 31–35.

Kruge, M.A. (1986). Biomarker Geochemistry of the Miocene Monterey Formation, West San Joaquin Basin, California: Implications for Petroleum Generation. *Organic Geochemistry, 10,* 517–530.

Lagoe, M.B. (1982). *Stratigraphy and Paleoenvironments of the Monterey Formation and Associated Rocks, Cuyama Basin, California.* Ph.D. dissertation, Stanford University, Stanford, CA, 216 pp.

Lagoe, M.B. (1984). Paleogeography of Monterey Formation, Cuyama Basin, California. *AAPG Bulletin, 68*(5), 610–627.

Lagoe, M.B. (1985). Depositional Environments in the Monterey Formation, Cuyama Basin, California. *Geological Society of America Bulletin, 96*(10), 1296–1312.

Lanners, R.K. (2013). *Chemostratigraphy of Hemipelagic Facies of the Monterey Formation and Equivalent Sedimentary Rocks, Los Angeles Basin, California.* M.S. thesis, California State University, Long Beach, 119 pp.

Lefever, J.A. (2008). Isopach of the Bakken Formation. *North Dakota Geological Survey Geologic Investigations, 59, Bakken Formation Map Series,* Sheet 1, 2008.

LeFever, J.A., R.D. LeFever, and S.H. Nordeng (2011). Revised Nomenclature for the Bakken Formation (Mississippian-Devonian), North Dakota. In: *The Bakken-Three Forks Petroleum System in the Williston Basin,* J.W. Robinson, J.A. LeFever, S.B. Gaswirth (eds), Rocky Mountain Association of Geologists, 11–26.

Lillis, P.G. (1994). Soda Lake-Painted Rock (!) Petroleum System in the Cuyama Basin, California, U.S.A. In: *The Petroleum System—From Source to Trap,* L.B. Magoon and W.G. Dow (eds), AAPG Memoir, 60, 437–451.

Lillis, P.G., and L.B. Magoon (2007). Petroleum Systems of the San Joaquin Basin Province, California — Geochemical characteristics of oil types. In: *Petroleum Systems and Geologic Assessment of Oil and Gas in the San Joaquin Basin Province, California,* Chapter 9, A. Hosford Scheirer (ed), US Geological Survey Professional Paper 1713, 52 pp.

Link, M.H., and B.R. Hall (1990). Architecture and Sedimentology of the Miocene Moco T and Webster Turbidite Reservoirs, Midway-Sunset Field, California. In: *Structure, Stratigraphy and Hydrocarbon Occurrences of the San Joaquin Basin, California,* Pacific Section, SEPM, 115–129.

Liu, X. (1994). *Nonlinear Elasticity, Seismic Anisotropy, and Petrophysical Properties of Reservoir Rocks.* Ph.D. dissertation, Stanford University, Stanford, CA, 149 pp.

Liu, X., Vernik, L., and Skopec, R.A. (1997) Core Elastic Properties of the Monterey Formation, Santa Maria Basin, California. Society of Core Analysts paper SCA-9735, 11 p.

MacKinnon, T.C. (1989). Petroleum Geology of the Monterey Formation in the Santa Maria and Santa Barbara Coastal and Offshore Areas. In: *Oil in the California Monterey Formation Los Angeles to Santa Maria, California July 20-24, 1989,* Field Trip Guidebook T311, T. MacKinnon, J.W. Randall, and R.E. Garrison (eds), American Geophysical Union, Washington, D.C., 11–27.

Magoon, L.B., and W.G. Dow (1994). *The Petroleum System. In: The Petroleum System—from Source to Trap,* L.B. Magoon and W.G. Dow (eds), AAPG Memoir, 60, 3–24.

Magoon, L.B., P.G. Lillis, and K.E. Peters (2009). Chapter 8: Petroleum Systems Used to Determine the Assessment Units in the San Joaquin Basin Province, California. In: *Petroleum Systems and Geologic Assessment of Oil and Gas in the San Joaquin Basin Province, California,* A. Hosford Scheirer (ed), US Geological Survey Professional Paper 1713, 65 pp.

Martinez, A.D., M.R. Marquez, M.E. Knauss, and K.D. Shotts, (1994). Southeast Lost Hills Hydraulic Fracturing Stimulation of the McDonald Shale Zone: Case History. SPE Paper 27900. In: *Proceedings, SPE Western Regional Meeting, Long Beach, CA, March 23-25, 1994.* 521–529.

Mayuga, M. (1970). Geology and Development of California's Giant—Wilmington Oil Field. In: *Geology of Giant Petroleum Fields,* M.T. Halbouty (ed), AAPG Memoir 14, 158–184.

McCarthy, K., K. Rojas, M. Niemann, D. Palmowski, K. Peters, and A. Stankiewicz (2011). Basic Petroleum Geochemistry for Source Rock Evaluation. *Oilfield Review, 23*(2), 32–43.

McCrory, P.A., D.S. Wilson, J.C. Ingle Jr., and R.G. Stanley (1995). Neogene Geohistory Analysis of Santa Maria Basin, California, and Its Relationship to Transfer of Central California to the Pacific Plate. *US Geological Survey Bulletin, 1995*(J). J1–J38.

McGuire, D.J. (1988). Depositional Framework of the Upper Cretaceous-Lower Tertiary Moreno Formation, Central San Joaquin Basin, California, In: *Studies of the Geology of the San Joaquin Basin,* S.A. Graham (ed), Pacific Section SEPM, 173–188.

Menotti, T., and S.A. Graham (2012). The Salinas Basin Petroleum System and Its Outcrop Expression, Central California. In: *Guidebook for Fall Field Trip 1,* M.V. Caputo (ed), Pacific Section SEPM, Book 114, 29 pp.

Menotti, T., K. Meisling, and S.A. Graham (2013). Sedimentary and Structural Evolution of the Neogene Salinas Basin, California: Implications for Burial History Modeling of a Strike-Slip Basin. *AAPG Search and Discovery Article #90162,* Pacific Section AAPG, SPE and SEPM Joint Technical Conference, Monterey, California, April 19-25, 2013.

Mercer, M. (1996). Miocene Monterey Shale Units in Midway-Sunset Field. In: *Geology of the Midway-Sunset Oil Field and Adjacent Temblor Range, San Joaquin Basin, California,* T.H. Nilsen, A.S. Wylie Jr., and G.J. Gregory (eds), AAPG Field Trip Guidebook, 97–110.

Mertz, K.A. (1989). Origin of Hemipelagic Source Rocks during Early and Middle Miocene, Monterey Formation, Salinas Basin, California. *AAPG Bulletin, 73*(4), 510–524.

Milam, R.W. (1985). *Biostratigraphy and Sedimentation of the Eocene and Oligocene Kreyenhagen Formation, Central California.* Ph.D dissertation, Stanford University, Stanford, CA, 240 pp.

Minner, W.A., J. Du, B.L. Ganong, C.B. Lackey, S.L. Demetrius, and C.A. Wright (2003). Rose Field: Surface Tilt Mapping Shows Complex Fracture Growth in 2500' Laterals Completed with Uncemented Liners. SPE Paper 83503. In: *Proceedings, SPE Western Regional/AAPG Pacific Section Joint Meeting,* Long Beach, California, May 19-24, 2003, 1–7.

Montgomery, S.L. (1998). Increasing Reserves in a Mature Giant: Wilmington Field, Los Angeles Basin, Part 1: Reservoir Characterization to Identify Bypassed Oil. *AAPG Bulletin, 82*(3), 367–385.

Montgomery, S.L., and M.F. Morea (2001). Antelope Shale (Monterey Formation), Buena Vista Hills Field: Advanced Reservoir Characterization to Evaluate CO_2 Injection for Enhanced Oil Recovery. *AAPG Bulletin, 85(*4), 561–585.

Morea, M.F. (ed) (1998). Advanced Reservoir Characterization in the Antelope Shale to Establish the Viability of CO_2 Enhanced Oil Recovery in California's Monterey Formation Siliceous Shales. *Annual Technical Progress Report,* February 7, 1997–February 6, 1998, Project DE-FC22-95BC14938, National Petroleum Technology Office, US Department of Energy, 167 pp.

Mosher, A., J. Guillaume, and R. Behl (2013). Detailed Lithostratigraphic Characterization of the Monterey Formation at Chico Martinez Creek, California. Search and Discovery Article #50801, *Pacific Section AAPG, SEG and SEPM Joint Technical Conference.* Monterey, CA.

Nagle, H.E., and E.S. Parker (1971). Future Oil and Gas Potential of Onshore Ventura Basin, California. In: *Future Petroleum Provinces of the United States—Their Geology and Potential, Volume 1,* I.H. Cram (ed), AAPG Memoir 15, 254–297.

Nordeng, S.H. (2009) The Bakken Petroleum System: An Example of a Continuous Petroleum Accumulation. *North Dakota Department of Mineral Resources Newsletter, 36*(1), 21–24.

Peters, K.E., D. Coutrot, X. Nouvelle, L.S. Ramos, B.G. Rohrback, L.B. Magoon, and J.E.Zumberge (2013). Chemometric Differentiation of Crude Oil Families in the San Joaquin Basin, California. *AAPG Bulletin, 97*(1), 103–143.

Peters, K.E., L.B. Magoon, Z.C. Valin, and P.G. Lillis (2007). Source Rock Geochemistry of the San Joaquin Basin Province, California. In: *Petroleum Systems and Geologic Assessment of Oil and Gas in the San Joaquin Basin Province, California,* Chapter 11, A. Hosford Scheirer (ed), US Geological Survey Professional Paper 1713, 102 pp.

Peters, K.E., M.H. Pytte, T.D. Elam, and P. Sundararaman (1994). Identification of Petroleum Systems Adjacent to the San Andreas Fault, California, U.S.A. In: *The Petroleum System—From Source to Trap,* L.B. Magoon and W.G. Dow (eds), AAPG Memoir, 60, 423–436.

Petersen, N.F, and P.J. Hickey (1987) California Plio-Miocene Oils: Evidence of Early Generation. In: *Exploration for Heavy Crude Oil and Natural Bitumen,* R.F. Meyer (ed), AAPG Studies in Geology, 25, 351–359.

Petzet, A. (2012). Zodiac Praises Kreyenhagen Formation Characteristics, *Oil and Gas Journal, 110*(2a).

Pisciotto, K. (1981). Diagenetic Trends in the Siliceous Facies of the Monterey Shale in the Santa Maria Region, California. *Sedimentology, 28*(4), 574–571.

Pitman, J.K., L.C. Price, and J.A. LeFever (2001). Diagenesis and Fracture Development in the Bakken Formation, Williston Basin: Implications for Reservoir Quality in the Middle Member. *US Geological Survey Professional Paper,* 1653, 19 pp.

Price, L.C., and J. A. LeFever (1992). Does Bakken Horizontal Drilling Imply a Huge Oil-Resource Base in Fractured Shales? In: *Geological Studies Relevant to Horizontal Drilling: Examples from Western North America,* J.W. Schmoker, E.B. Coalson, C.A. Brown (eds), Rocky Mountian Association of Geologists, 199–214.

Ramakrishna, S., R. Balliet, D. Miller, S. Sarvotham, D. Merkel (2010). Formation Evaluation in the Bakken Complex Using Laboratory Core Data and Advanced Logging Techniques. *SPWLA 51st Annual Logging Symposium,* Perth, Australia, June 19-23, 2010, 16 pp.

Redden, J. (2012). Unlocking the Secrets of the US' Largest Onshore Oil Reserves Monterey/Santos. *World Oil, 233*(11), 88–96.

Redin, T. (1991). Oil and Gas Production from Submarine Fans of the Los Angeles Basin. In: *Active Margin Basins,* K.T. Biddle (ed), AAPG Memoir 52, 239–259.

Reid, S.A., and J.L. McIntyre (2001). Monterey Formation Porcelanite Reservoirs of the Elk Hills Field, Kern County, California. *AAPG Bulletin, 85*(1), 169–189.

Roehl, P.O., and R.M. Weinbrandt (1985). Geology and Production Characteristics of Fractured Reservoirs in the Miocene Monterey Formation, West Cat Canyon Oilfield, Santa Maria Valley, California. In: *Carbonate Petroleum Reservoirs,* P.O. Roehl and P.W. Choquette (eds), Springer-Verlag, New York, NY, 527–545.

Rowe, G., R. Hurkmans, and N. Jones (2004). Unlocking the Monterey Shale Potential at Elk Hills: A Case Study. SPE Paper 86993. In: *Proceedings, SPE International Thermal Operations and Heavy Oil Symposium and Western Regional Meeting, Bakersfield, CA, USA, March 16-18, 2004,* 6 pp.

Schwartz, D.E. (1988). Characterizing the Lithology, Petrophysical Properties, and Depositional Setting of the Belridge Diatomite, South Belridge Field, Kern County, California. In: *Studies of the Geology of the San Joaquin Basin,* S.A. Graham (ed), Pacific Section SEPM, v. 60, 281–301.

Schwochow, S. (1999). Deep-Gas Prospects of the Southern San Joaquin Valley, California. In: *Petroleum Frontiers,* IHS Energy Group, 16(4) 124 pp.

Shemeta, J.E., W.B. Minner, R.G. Hickman, P.A. Johnston, C.A. Wright, and N.Watchi (1994). Geophysical Monitoring during a Hydraulic Fracture in a Fractured Reservoir: Tiltmeter and Passive Seismic Results. In: *Eurock '94, Delft, Netherlands,* Balkema, Rotterdam, 929–944.

Simenson, A.L, S.A. Sonnenberg, and R.M. Cluff (2011). Depositional Facies and Petrophysical Analysis of the Bakken Formation, Parshall Field and Surrounding Area, Mountrail County, North Dakota. In: *The Bakken-Three Forks Petroleum System in the Williston Basin,* J.W. Robinson, J.A. LeFever, S.B. Gaswirth (eds), Rocky Mountain Association of Geologists, 48–101.

Sloss, L.L. (1987). The Williston Basin in the Family of Cratonic Basins. In: *Williston Basin: Anatomy of a Cratonic Oil Province,* 1987 Symposium, Rocky Mountain Association of Geologists, 1–8.

Sonnenberg, S.A., J.A. Lefever, and R.J. Hill (2011). Fracturing in the Bakken Petroleum System, Williston Basin. In: *The Bakken-Three Forks Petroleum System in the Williston Basin,* J.W. Robinson, J.A. LeFever, S.B. Gaswirth (eds), Rocky Mountain Association of Geologists, 393–417.

Strubhar, M., W. Medlin, S. Nabi, and F. Andreani (1984). Fracturing Results in Diatomaceous Earth Formations, South Belridge Field, California. *Journal of Petroleum Technology, 36*(3), 495–502. doi:10.2118/10966-PA

Sweetkind, D.S., S.C. Bova, V.E. Langenheim, L.E. Schumaker, and D.S. Scheirer (2013). Digital Tabulation of Stratigraphic Data from Oil and Gas Wells in Cuyama Valley and Surrounding Areas, Central California. *US Geological Survey Open-File Report,* 2013-1084, 44 pp.

Sweetkind, D.S., M.E. Tennyson, V.E. Langenheim, and L.E. Schumaker, (2010). Digital Tabulation of Stratigraphic Data from Oil and Gas Wells in the Santa Maria Basin and Surrounding Areas, Central California Coast. *US Geological Survey Open-File Report,* 2010-1129, 11 pp.

Tennyson, M.E. (1995). Santa Maria Basin Province (012). In: *1995 National Assessment of United States Oil and Gas Resources; Results, Methodology, and Supporting Data,* D.L Gautier, G.L. Dolton, K.I. Takahashi, and K.L. Varnes (eds), US Geological Survey Data Series 30, 11 pp.

Tennyson, M.E., T.A. Cook, R.R. Charpentier, D.L. Gautier, T.R. Klett, M.K. Verma, R.T. Ryder, E.D. Attanasi, P.A. Freeman, and P.A. Le (2012). Assessment of Remaining Recoverable Oil in Selected Major Oil Fields of the San Joaquin Basin, California, *US Geological Survey Reserve Growth Fact Sheet,* 2012-3050, 2 pp.

Tennyson, M.E., and C.M. Isaacs (2001). Geologic Setting and Petroleum Geology of Santa Maria and Santa Barbara Basins, Coastal California. In: *The Monterey Formation: From Rocks to Molecules,* C.M. Isaacs and J. Rullkötter (eds), Columbia University Press, New York, 206–229.

Titus, S.J., B. Housen, and B. Tikoff (2007). A Kinematic Model for the Rinconada Fault System in Central California Based on Structural Analysis of En Echelon Folds and Paleomagnetism. *Journal of Structural Geology, 29*(6), 961–982. doi:10.1016/j.jsg.2007.02.004

Underwood, P.J., and L.A. Kerley (1998). Evaluation of Selective vs. Point-Source Perforating for Hydraulic Fracturing. *SPE Drilling and Completion, 13*(3), 151–156.

US Energy Information Administration (EIA) (2011). Review of Emerging Resources: US Shale Gas and Shale Oil Plays. 82 p.

US Energy Information Administration (EIA) (2014a). Drilling Productivity Report for Key Tight Oil and Shale Gas Regions. March 2014, 10 p.

US Energy Information Administration (EIA) (2014b). Assumptions to the Annual Energy Outlook 2014. June
2014, 209 p.

Vasudevan, S., D.M. Willberg, J.A. Wise, T.L. Gorham, R.C. Dacar, P.F. Sullivan, C.L. Boney, F. Mueller (2001) Field Test of a Novel Low Viscosity Fracturing Fluid in the Lost Hills Field, California. SPE Paper 68854-MS, In: *Proceedings, SPE Western Regional Meeting, Bakersfield, California,* March 26-30, 2001.

Von Estorff, F.E. (1930). Kreyenhagen Shale at Type Locality, Fresno County, California. *AAPG Bulletin, 14*(10), 1321–1336.

Walker, A.L., T.H. McCulloh, N.F. Petersen, and R.J. Stewart (1983). Anomalously Low Reflectance of Vitrinite, in Comparison with Other Petroleum Source-Rock Maturation Indices, from the Miocene Modelo Formation in the Los Angeles Basin, California, In: *Petroleum Generation and Occurrence in the Miocene Monterey Formation, California,* C.M. Isaacs, R.E. Garrison, S.A. Graham, and W.A. Jensky II (eds), Pacific Section SEPM, 185–190.

Webster, R.L. (1984). Petroleum Source Rocks and Stratigraphy of Bakken Formation in North Dakota. In: *Hydrocarbon Source Rocks of the Greater Rocky Mountain Region,* Rocky Mountain Association of Geologists, 57–81.

Wickham, J. (1995). Fault Displacement-Gradient Folds and the Structure at Lost Hills, California (U.S.A.). *Journal of Structural Geology, 17*(9), 1293–1302.

Witter, G., R. Knoll, W. Rehm, and T. Williams, (2005). Use of Cutting-Edge Horizontal and Underbalanced Drilling Technologies and Subsurface Seismic Techniques to Explore, Drill and Produce Reservoired Oil and Gas from the Fractured Monterey below 10,000 ft in the Santa Maria Basin of California. *Technical Progress Report, September 30, 2003 to September 29, 2004, DE-FC26-03NT15426,* Temblor Petroleum Company, LLC and Maurer Technology Inc.

Wright, C.A., R.A. Conant, G.M. Golich, P.L. Bondor, A.S. Murer, and C.A. Dobie, (1995). Hydraulic Fracture Orientation and Production/Injection Induced Reservoir Stress Changes in Diatomite Waterfloods. SPE Paper 29625. In: *Proceedings, SPE Western Regional Meeting, Bakersfield, CA, U.S.A., March 8-10, 1995,* 139–152.

Wright, T.L. (1991). Structural Geology and Tectonic Evolution of the Los Angeles Basin, California. In: *Active Margin Basins,* K.T. Biddle (ed), AAPG Memoir 52, 35–134.

Zalan, T.A., M.F. Morea, D.R. Julander, and S.A. Denoo (1988) Applying Integrated Formation Evaluation to Advanced Reservoir Characterization in California's Monterey Formation Siliceous Shales. SPWLA 39th Annual Logging Symposium, May 26-29, 1998, 13 p.

Zieglar, D.L., and J.H. Spotts (1978). Reservoir and Source-bed History of Great Valley, California. *AAPG Bulletin, 62*(5), 813–826.