Chapter Three

Case Study of the Potential Development of Source Rock in the Monterey Formation

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3.1. Abstract

Recent estimates of vast resources in the Monterey formation have focused attention on Monterey source rock as an untapped oil resource. Historically, most California production has been migrated oil in conventional traps, rather than oil produced directly from source rocks. Here we evaluate Monterey source rock geology and examine prior estimates of its resources. High-volume hydraulic fracturing in conjunction with long-reach horizontal wells is the key technological advance that has allowed source-rock production outside California. However, horizontal drilling and hydraulic fracturing have not yet enabled commercial production of Monterey source rocks. One major barrier is that the Monterey is highly discontinuous – that is, rather than lying flat, it is folded and faulted. As a result, horizontal wells cannot run for great lengths along the Monterey Source Rock, and without a long well bore, it is difficult to conduct massive, multi-stage hydraulic fractures. We conclude that large-scale production from Monterey source rock is unlikely without some as-yet unforeseen technological advance.

In order to fully understand the potential resources in the Monterey source rock, we recommend that the state commission a comprehensive, peer-reviewed probabilistic resource assessment of continuous-type (shale) oil resources in California. We undertake one important initial step in such a resource assessment by mapping the extent of potential Monterey-equivalent source rocks in California. The Monterey formation and its equivalents form a much larger than the area of potential source rock. Potential Monterey source rock is restricted to the same six basins that have hosted the largest proven oil

reserves and production in California. Some, but not all, of the footprint of potential Monterey source rock overlaps with oil fields tapping shallower, migrated deposits. About 8% of the area within the footprint of potential Monterey source rock reservoirs has already been developed for oil and gas production. The remaining 92%, while not presently producing oil, is at most about 20 kilometers (12 miles) from an existing oil field.

We outline how one can use public records to identify exploration of Monterey source rock so the public can be apprised of the leading indications of likely source-rock development. Information collected by the Division of Oil, Gas and Geothermal Resources (DOGGR) would conceivably allow state agencies to identify successful early exploration of Monterey source rocks and conduct a more detailed evaluation of potential impacts at that time. However, data on exploratory wells would most likely be classified as confidential and would not be made publicly available until the confidentiality of the well(s) expired. Therefore, the public would most likely be unaware of the extent of source-rock production until the first stages of non-exploratory, commercial development were already underway.

We evaluate potential environmental impacts of Monterey source rock development by examining the setting of the source rock footprint in terms of water resources, air quality, potential for seismic activity, and sensitive species and habitats. Given the many uncertainties about how source rock would be developed, as well as data gaps about the environmental impacts of well stimulation identified in Volume II, we cannot make detailed predictions about how impacts from source rock production would differ from the effects of current production. The greatest changes we expect from large-scale development of source rock would be an increase in quantity of oil and gas production and its associated impacts, and an expansion of oil and gas activity into new areas near existing oil fields.

3.2. Introduction

In California, most of the oil and gas (referred to in this chapter as petroleum) originated in deep portions of the Monterey formation – the state's most prolific source rock – and yet most petroleum is not produced directly from Monterey source rocks. Rather, California's production consists of petroleum that has migrated away from source rock into conventional traps. Production of migrated petroleum in conventional traps differs from source-rock production in a number of ways, including: (1) Source rock (also known as "shale oil and shale gas") plays generally cover larger geographic areas than do migrated conventional accumulations; (2) Well stimulation and horizontal drilling are necessary for commercially successful production of source rock, and (3) Source rocks are found at greater average depths than conventional reservoirs of migrated oil.

Direct production of oil from source rocks would represent a fundamental shift in the geographic scale, technology employed, and quantity of petroleum production in the state.

Sections 3.3.1. through 3.3.6. describe source rock production, how it has been carried out in other states, and how it differs from current practice in California. Section 3.3.7 describes the geologic conditions that must be met for successful Monterey source rock production to be possible.

Monterey source rock might never be extensively developed in California. The volume of recoverable resources in Monterey source rock remains uncertain, and no rigorous, probabilistic resource assessment of the Monterey has ever been conducted. The U.S. Energy Information Administration (U.S. EIA's) resource projection for the Monterey Formation dropped from 2.4 billion m^3 (15.4 billion barrels) in 2011 to 0.1 billion m^3 (0.6 billion barrels) in 2014 (U.S. EIA, 2011; U.S. EIA, 2014), but we regard both estimates as problematic. To fully understand the range of possible recoverable resources from Monterey source rock, one would need to undertake a probabilistic assessment that takes into account the geological uncertainties of the resources and of the technologies that might be used to produce them. Section 3.3.8 discusses the estimates issued by the U.S. EIA and outlines the steps required for a systematic resource assessment.

While there has been no clear demonstration that Monterey source rock will be a viable commercial play, there has been some exploratory drilling. We describe the publicly available information on exploratory drilling in Monterey source rock in Section 3.3.9, and outline how one can use public records to identify exploration and production of Monterey source rock in Section 3.3.9.1. Such a search could be conducted using well-stimulation disclosures, which include the two key pieces of information: total well depth and the formation stimulated. However, most exploratory wells are likely to be confidential, and so the relevant information would not be released to the public until confidentiality expired.

In Section 3.3.10 we identify the maximum possible surface footprint of Monterey source-rock plays in California. This footprint is the surface projection of where the Monterey Formation is thought to have been buried deeply enough to convert its solid organic matter (kerogen) to petroleum. In this case study we consider the footprint of potential source rocks within the six major oil-producing basins in California. For brevity, we refer to this area as simply as "potential Monterey source rock." We emphasize that the footprint we identify is a maximum estimate. The true extent of a Monterey source rock play will likely be smaller because of a number of other conditions that must be met to produce oil commercially from source rocks, and the end result may be that there is no viable source rock play.

We discuss potential environmental and human health impacts of Monterey source-rock development in Section 3.4. We evaluate the location of potential Monterey source rock with respect to developed oil fields and associated infrastructure, water resources, air quality, potential for seismic activity, and sensitive species and habitats.

We end with a summary of data gaps, recommendations on how to rectify the data gaps, and a summary of findings and conclusions. Though we regard the potential for large-scale development of Monterey source rock with skepticism, there are concrete methods that could reduce the uncertainties about recoverable resources and forewarn the public if and when there was successful source-rock production. It is also important to recognize that the maximum extent of potential Monterey source rock is much smaller than the full extent of the Monterey formation, and is restricted to basins where oil and gas are already being produced.

3.3. Geological Framework for the Source-Rock Case Study

3.3.1. What is a Source Rock?

Petroleum (which we use in this chapter to refer to oil and gas) originates in source rocks from insoluble organic matter (kerogen), which has been deposited along with inorganic materials in sedimentary basins (Hunt, 1995). In petroleum geology, a source rock is an identifiable sedimentary rock unit (typically a formation or member of a formation) having sufficient concentration of kerogen of suitable composition for the chemical or biological generation of petroleum.

The rate at which temperature increases with depth in the earth is the geothermal gradient. When a potential source rock is progressively buried beneath younger sediments, it is increasingly heated until its kerogen begins to thermally degrade in a process called "cracking." During cracking, shorter-chain hydrocarbon molecules are released from the original complex organic compounds of the kerogen. Source rocks that have been heated enough to crack kerogen into hydrocarbons are said to be "thermally mature" with respect to oil and/or natural gas generation (Figure 3.3-1). A thermally mature source rock is a fundamental component of a petroleum system.

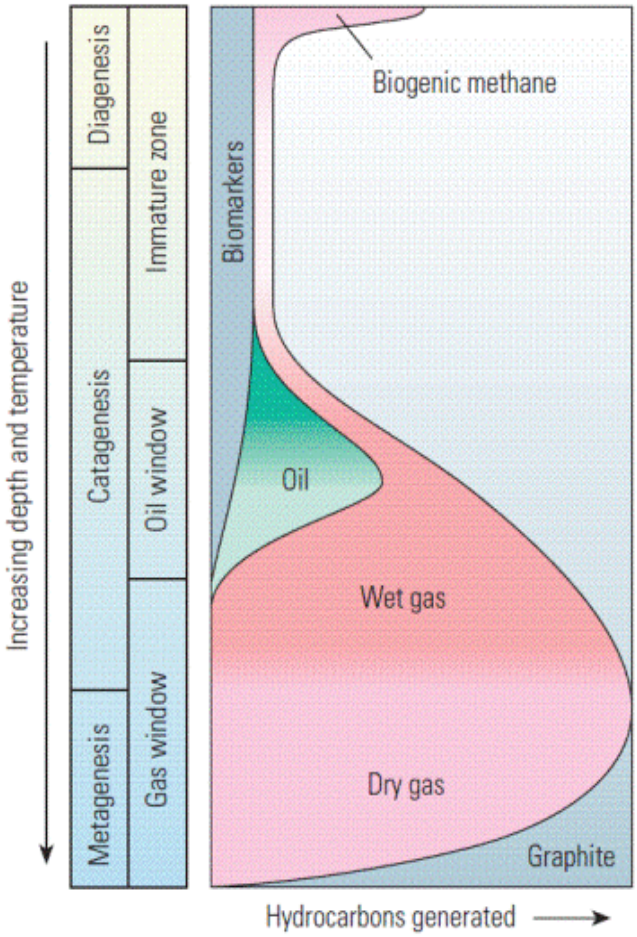


Figure 3.3-1. Thermal transformation of kerogen to oil and gas, depicting the depths of the oil and gas windows (McCarthy et al., 2011). When source rocks are exposed to adequate heat and pressure, they become "thermally mature," generating oil and/or natural gas.

Three broad categories of source rocks are recognized based on the type of kerogen they contain. Monterey Formation has Type II source rocks, which are sedimentary successions with high concentrations of the remains of phytoplankton and bacterial organic matter deposited under oxygen-deficient conditions in marine environments. When heated sufficiently during burial, Type II source rocks generate both oil and natural gas. Worldwide, most known oil has been formed by the thermal alteration of kerogen in Type II source rocks.

Box 3.3-1. What to Call the Monterey?

The Monterey Formation looms large in the public discourse about hydraulic fracturing because a 2011 EIA report estimated 2.4 billion m^3 (15 billion barrels) of oil could be produced from the Monterey Formation using hydraulic fracturing, much like the "shale" oil that is being produced from the Bakken Formation in North Dakota and the Eagle Ford Formation in Texas. The public identifies the idea of having similar developments in California through the use of the term "Monterey Shale."

This report uses more accurate terms than "Monterey Shale" in order to carefully describe the issues and potential of the Monterey. For over a hundred years, geologists have used the term "Monterey Formation" for rocks that were originally deposited off the coast of California between about 17.5 and 6 million years ago (middle to late Miocene Epoch). The Monterey Formation underlies much of California, but varies greatly from place to place in thickness and includes many different rock types, not just shale (for example: diatomite, porcelanite, chert, and siliceous shale, highly organic-rich and phosphatic shale, marlstone, clay shale, sandstone, and volcanic rocks).

Generations of geologists have studied the Monterey and given it different names, leading to much confusion. For example, Antelope Shale, Devilwater Shale, Fruitvale Shale, Gould Shale, McDonald Shale, Modelo Formation, Monterey, Monterey Formation, Monterey Shale, Nodular Shale, Puente Formation, and Stevens Sandstone are just some of the names used to describe strata that could be considered part of the Monterey Formation. For simplicity, this report uses the terms "Monterey Formation" and "Monterey" interchangeably to describe all of these as a single class.

The Monterey source rocks are those parts of the Monterey Formation that are sources of petroleum. Oil forms in those parts of the formation that include concentrated organic material and that have been buried deeply enough so that chemical reactions triggered by heat and pressure transform the organic matter into oil (i.e. the rocks are in the "oil window"). Some of this oil floats upwards (migrates by buoyancy) until it meets a barrier or "trap". The rest of the oil remains behind in the source rock. Nearly all the petroleum so far produced in California has migrated from these prolific Monterey source rocks to the near-surface reservoirs that are now under production. The EIA report was not about this migrated oil. The EIA based their estimate of potential new production on the idea that the oil remaining behind in the source rocks could also be produced. This case study, like the EIA report, focuses on the resources present in the Monterey source rocks themselves.

3.3.2. What is Monterey Source Rock?

In California, the volumetrically most important petroleum source rocks, by far, are found within the Monterey Formation and its stratigraphic equivalents. Stratigraphic equivalent formations share similar physical characteristics, geographic occurrence, and age but have different names. In this case study, we refer to the Monterey Formation and its stratigraphic equivalents simply as the Monterey. The Monterey is a classic petroleum source rock that has been intensively studied for more than 100 years (Tennyson & Isaacs, 2001).

The Monterey originally consisted of marine sediments deposited at mid-bathyal depths (500 to 1,500 meters, or 1,640 to 4,921 ft of water) along the continental margin of California during the latter half of the Miocene Epoch, between about 7 and 18 million years ago (mya). The geologic times referred to in this chapter are shown in Appendix 3.B, “Geologic Time Scale.” The Monterey is known to be present in many of the onshore basins of California, including the Cuyama, La Honda, Los Angeles, Salinas, San Joaquin, Santa Maria, and Santa Barbara-Ventura Basins. It is also known or postulated to be present in the offshore basins from Point Arena on the North to the Oceanside Basin on the south (Figure 3.3-2). The Monterey is believed to be the principal source of oil in the largest oil fields of the Salinas, San Joaquin, Santa Maria, Santa Barbara-Ventura, and Los Angeles Basins.

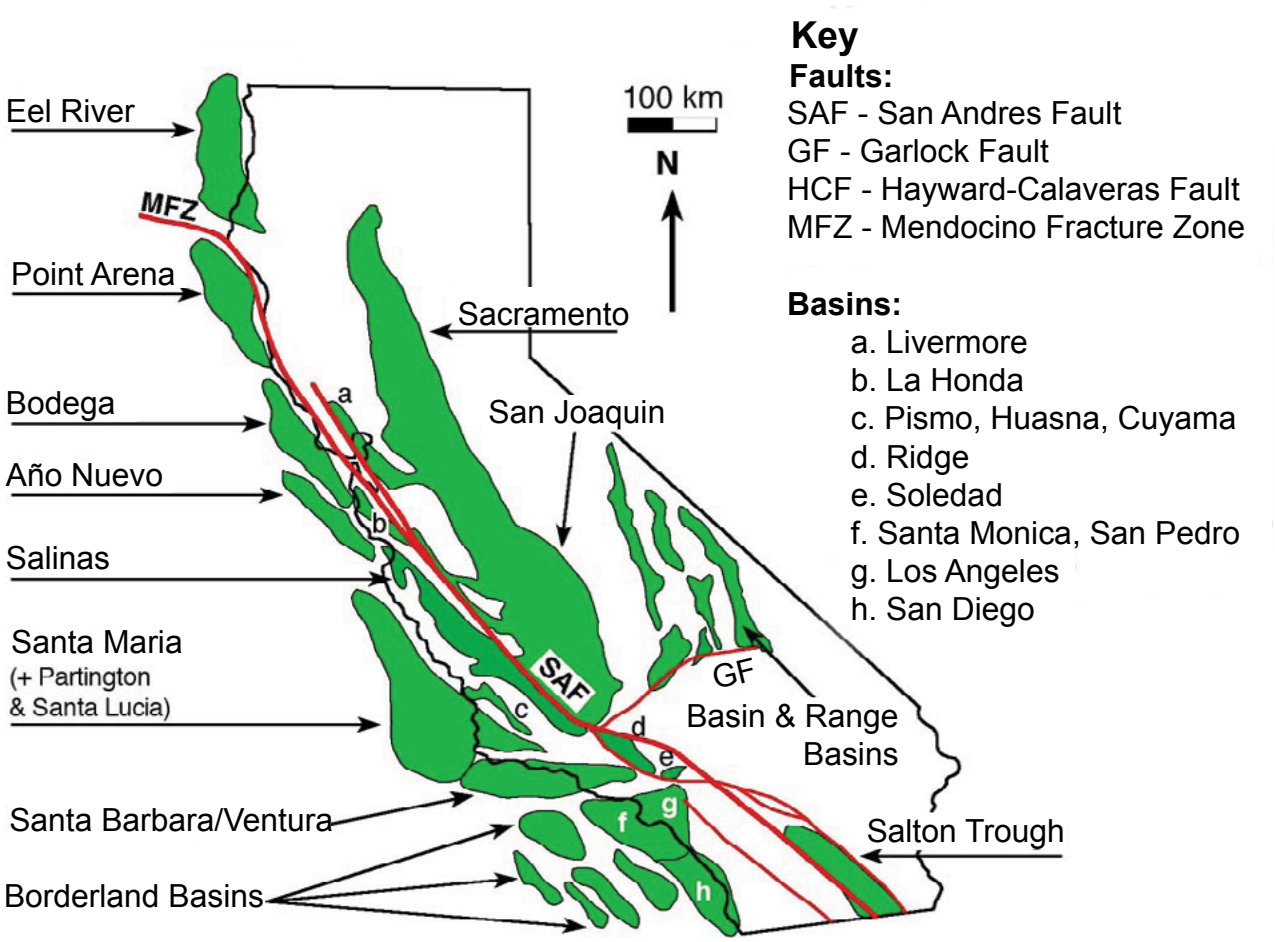


Figure 3.3-2. Neogene sedimentary basins in and along the coastal margins of California, from Behl (1999). The Monterey occurs as thick and extensive deposits within many of the Neogene sedimentary basins in California, including all of the major oil-producing basins. The Monterey Formation or its equivalents are known from most coastal basins from Point Arena southward to the Borderland Basins. The Central Valley, or Great Valley of California comprises the Sacramento Valley in the north and the San Joaquin Valley in the south.

The lithology (physical characteristics) and thickness of the Monterey vary greatly both within and among the basins. This variability makes it challenging to produce oil directly from the source rock, as described in greater detail in Sections 3.3.7 and 3.3.8. For greater detail on the lithology of the Monterey, see Volume I, Chapter 4, Section 4.4.

3.3.3. Non-Monterey Source Rocks in California

In this case study we focus principally on the Monterey because it is the volumetrically dominant source-rock system in the state. However, it is important to recognize that other active source rocks have been identified. Lillis (1994) interpreted the Soda Lake Member of the Vaqueros Formation to be the source of much of the oil that has been produced in the Cuyama Basin. Magoon et al. (2009) interpreted the Late Eocene Tumey Formation to be the source rock for more than 130 million m^3 (800 million barrels) of recoverable oil in fields on the west side of the San Joaquin Basin. The Eocene-age Kreyenhagen Formation is another petroleum source rock in the San Joaquin Basin. At the location of its reference section at Reef Ridge, just south of Coalinga in the San Joaquin Basin, it is a siliceous, shale-rich formation more than 305 m (1,000 ft) thick (Von Estorff, 1930). The Kreyenhagen is interpreted as the source rock for almost 0.32 billion m^3 (2 billion barrels) of oil in accumulations along the northwest side of the San Joaquin Basin, including oil in the Coalinga and Kettleman North Dome oil fields, among others (Magoon et al., 2009). The Moreno Formation is a shale-rich formation of Cretaceous to Paleocene age (McGuire, 1988), which is known to be the source rock for the small quantities of oil produced from the Oil City pool of the Coalinga oil field (Magoon et al., 2009). Locally, other formations may serve as petroleum source rocks as well. For a more detailed discussion of these source rocks and references describing them, please see Volume I, Chapter 4.

3.3.4. What is a Source-Rock System Petroleum Play?

In source-rock plays, hydrocarbons are produced directly from the rock where they were generated. Such plays, also referred to as “continuous accumulations,” tend to cover large areas, have low matrix permeability, and low recovery factors. Low matrix permeability means that hydraulic fracturing is often required to increase hydrocarbon flow rates to an economic level, and low recovery rates mean that only small proportion of the total hydrocarbons in place are produced. In conventional reservoirs, hydrocarbons have migrated out of the source rock and accumulated in a natural trap in a geological layer. Conventional reservoirs cover relatively small areas, have comparatively high matrix permeabilities, and have higher recovery efficiencies than unconventional reservoirs. Figure 3.3-3 shows a stratigraphic section that illustrates the relationship between source rock and conventional plays. Active source rock is at depth in the oil window, while conventional petroleum deposits are petroleum that has migrated out of the active source rock and accumulated under traps.(See Volume I, Section 4.3.1: “Introduction to Unconventional Resources in the United States”)

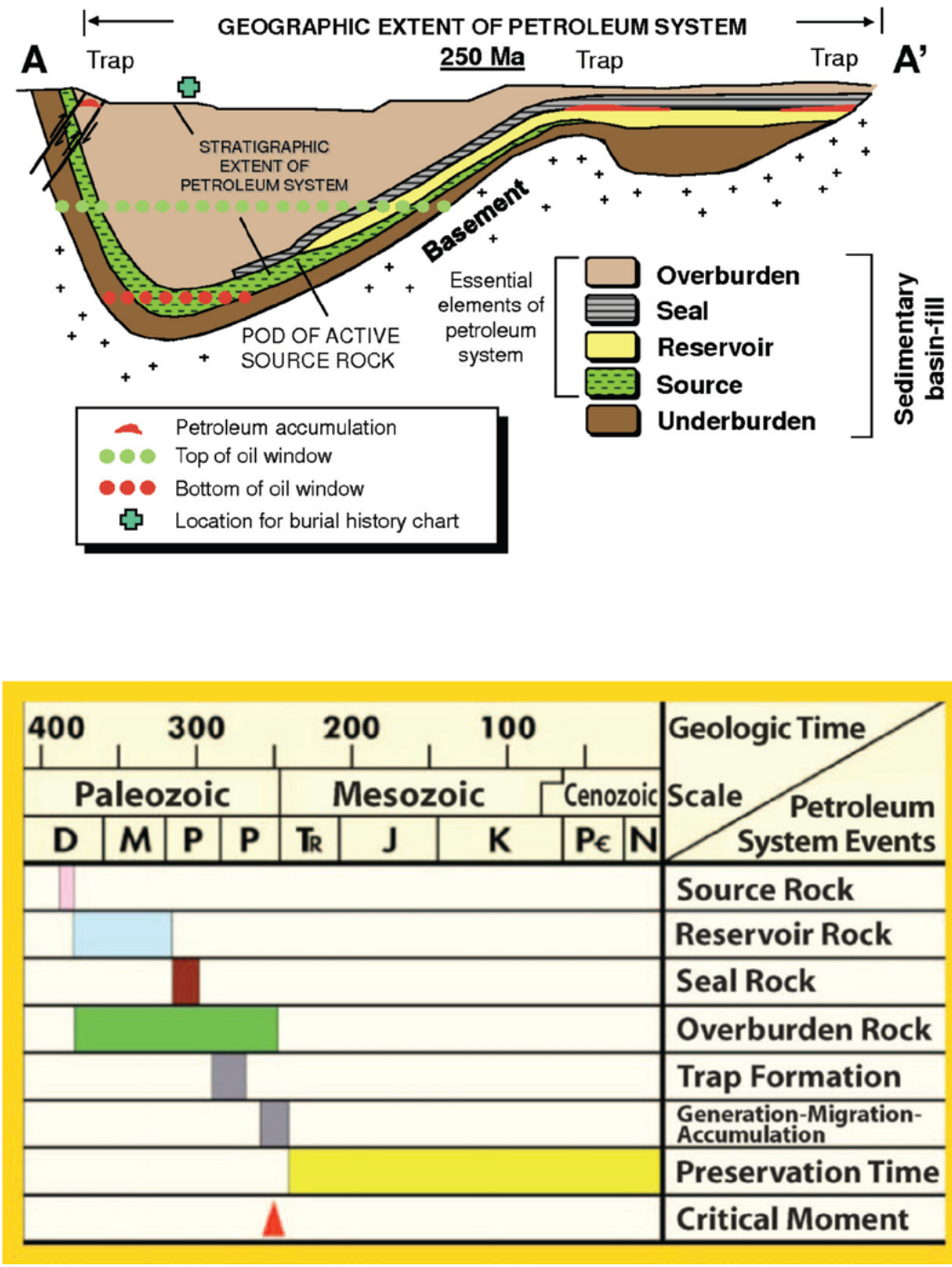


Figure 3.3-3. Example of a hypothetical petroleum system showing, cross section, and timeline for system formation. Figure from Magoon & Dow, 1994.

When potentially productive source rocks are buried and heated to thermal maturity, high pore-fluid pressures resulting from hydrocarbon generation, combined with sediment compaction, cause some of the newly-formed hydrocarbons and other fluids, such as water and non-hydrocarbon gases, to be expelled from the source rocks in a process termed "primary migration." If these fluids are effectively expelled into adjacent formations that are porous and permeable, the hydrocarbon fluids move preferentially upward due to their buoyancy relative to water. The buoyant movement of hydrocarbons is termed "secondary migration." The expelled hydrocarbons migrate upward through the sedimentary basin until they either accumulate at a permeability barrier to migration (a trap) or they seep out at the surface, where bacteria and inorganic oxidation decompose them. Trapped accumulations of migrated hydrocarbons are the traditional target of petroleum exploration. When found and developed such accumulations become conventional oil or gas fields and the rocks containing the entrapped hydrocarbons are conventional reservoirs. Nearly all production in California has been of migrated oil from conventional reservoirs.

Although large amounts of hydrocarbons are expelled during thermal maturation, as long as the source rock remains in the "oil generation window," at least some oil will remain in the source rock, both as free hydrocarbons in pore spaces within the kerogen, and adsorbed on the surfaces of kerogen and other sedimentary particles. Oil producers have long been aware that residual hydrocarbons remain in source rocks during and after oil generation and operators drilling through source-rock intervals have routinely reported oil "shows." However, owing to the extremely low permeability of the source rocks, the residual hydrocarbons were not believed to be commercially producible. This view is now changing.

In recent years, as conventional fields have become depleted, harder to find, and more difficult to access, technological advances in directional drilling, down-hole imaging, and reservoir stimulation have enabled explorationists to commercially produce residual hydrocarbons directly from source rocks or from other low-permeability sedimentary rocks that are intimately associated with the source rocks.

Hydrocarbons produced from source rocks are called shale oil or shale gas. In shale oil and shale gas accumulations, the source rock and the reservoir rock are essentially one and the same.

3.3.5. Source-Rock Plays Versus Current Petroleum Production Practice in California

Most conventional oil accumulations have clearly identifiable and distinctive source rocks, reservoirs, traps, and seals, but in continuous-type shale-oil accumulations, source rocks, reservoir rocks, traps and seals are the selfsame formation. A summary of the major differences between source rock and conventional reservoirs is presented in Table 3.3-1.

Table 3.3-1. Comparison of source rock and conventional reservoirs. The table reflects typical patterns and trends; some formations may be exceptions to the rule.

Characteristic	**Source Rock Reservoirs**	**Conventional Reservoirs**
Permeability	Lower	Higher
Geographic extent	Larger	Smaller
Depth	Deeper	Shallower
Recovery rate	Lower	Higher
Role of hydraulic fracturing	Necessary for economic production	Sometimes necessary for economic production
Role of horizontal drilling	Nearly always necessary for economic production	Sometimes necessary for economic production

From a technical development perspective, perhaps the most important distinction between conventional reservoirs and unconventional shale oil reservoirs is permeability. In contrast to reservoirs in most conventional oil fields, shale oil reservoirs exhibit extremely low permeability. Whereas typical conventional reservoirs are sandstones or limestones with permeabilities measured in hundreds or even thousands of millidarcies (Levorsen, 1967), shale oil reservoirs, such as the Eagle Ford shale, are Total Organic Carbon (TOC)-rich fine-grained rocks having permeabilities measured in tens of nanodarcies (Hentz & Ruppel, 2011). A nanodarcy is a unit of measurement of permeability equivalent to $1x10^{-9}$ Darcy, whereas a millidarcy is a unit of measurement of permeability equivalent to $1x10^{-3}$ Darcy.

Box 3.3-2. Conventional and Unconventional Resources Versus Migrated and Source Rock Resources

In this chapter, we prefer to use the terms source rock and migrated reservoirs to avoid conflicting definitions of the terms “unconventional” and “conventional.” Unconventional versus conventional can differentiate between source rock and migrated resources or between low- and high-permeability formations. Low-permeability formations require well stimulation to produce (Vol. I, Ch. 2). Source rock plays are low-permeability and therefore are unconventional by either definition. However, California has large migrated petroleum resources in low-permeability formations, such as the diatomite in the southwestern San Joaquin, which would be considered conventional by the first definition (they are migrated accumulations), but unconventional by the second (they are in low-permeability rocks). To avoid this confusion we prefer to use the terms source rock and migrated resources. The term source rock resource is synonymous with the term “continuous resources.” Shale gas and oil are one major category of source rock resources, and the type under consideration in this case study.

The development footprint of a source-rock play is typically much larger than that of traditional oil fields. In most migrated oil fields, particularly in California, resources are geographically concentrated, with large volumes of petroleum contained in comparatively small areas. For example, the Long Beach oil field in the Los Angeles Basin originally contained between 18.9 billion and 22.6 billion m^3 (3 billion and 3.6 billion barrels) of oil in place, with recoverable oil volumes (cumulative historical production plus reported remaining reserves) of almost 1 billion barrels, all within a productive area of only 7 square kilometers (~143,000,000 barrels/km^2). In contrast, source-rock accumulations extend across thousands or tens of thousands of square kilometers. For example, in its study of the Bakken Shale/Three Forks oil resources in North Dakota and Montana, the USGS estimated that between 7 and 8 billion barrels of oil is recoverable from a potentially productive area of more than 98,000 square kilometers (~80,000 barrels/km^2) (Gaswirth et al., 2013).

In addition to being highly concentrated, conventional accumulations of migrated oil are typically found at much shallower depths than are source rock plays. This is because the shale oil accumulations can only be developed at depths where source rocks are thermally mature for oil generation, whereas conventional accumulations are found in structures where oil has become trapped after buoyancy-driven secondary migration. For example, at South Belridge oil field, on the west side of the San Joaquin Basin, migrated oil is produced from diatomites at average depths of about 1,000 feet, whereas the source rock for the oil at South Belridge is probably the Monterey-equivalent McLure Shale, which is thermally mature at depths of 13,000 to almost 20,000 feet (Magoon et al., 2009).

Without fracture stimulation and horizontal drilling, economic production is generally not possible from source-rock systems. In Texas, North Dakota, and elsewhere, large-scale commercial production of oil and gas from low-permeability source-rock system reservoirs has been achieved by drilling thousands of “horizontal” wells, coupled with multi-stage massive hydraulic fracturing (e.g., Texas Railroad Commission, 2015). Well known productive source-rock systems include the gas and liquids produced from the Barnett Shale in the Fort Worth Basin of northern Texas (Pollastro et al., 2007), the oil, gas, and natural gas liquids produced from the Eagle Ford Shale in the Gulf Coast Basin of southern Texas (Harbor, 2011; Hentz and Ruppel, 2011), and oil produced from the Bakken Formation in the Williston Basin in Montana and North Dakota (Price & LeFever, 1992; Nordeng, 2009).

For example, in the Eagle Ford shale of south Texas, wells are drilled vertically downward until the shale is encountered, at which point the drilling direction is changed to follow the formation for 1,000 to 2,500 m (3,281 ft to 8,202 ft). Then, 10 to 30 massive hydraulic fracture treatments are conducted, in which the pore fluid pressure inside the target source/reservoir rock is raised until the rock breaks (fractures) and free hydrocarbons flow through the fractures to the wellbore. The fracturing accesses large areas of the source rock, often opening natural fractures, which are common in most shales, and enabling flow through manufactured conduits that are much higher

permeability than the matrix permeability in unfractured shale. In this manner, hydraulic fracturing makes a distinct reservoir within the contacted areas of the source rock.

Production from such source-rock systems has become economically and politically important in the United States, significantly reducing the quantities of oil being imported, (U.S. EIA, 2014), driving down natural gas prices (U.S. EIA, 2014b), and replacing large quantities of coal by natural gas for electricity generation (Macmillan et al., 2013).

3.3.8. Patterns of Development of Source-Rock Plays Outside California

Shales have long been known to contain producible hydrocarbons, but widespread production was not feasible until innovations in technology, coupled with sustained high commodity prices, made commercial production possible. The first large-scale commercially successful source-rock development was in the Barnett Shale in the Fort Worth Basin of northern Texas. Beginning in 1981, persistent efforts by Mitchell Energy and Development Corporation achieved modest production rates from vertical wells. But in the late 1990s Mitchell began testing horizontal drilling, massive hydraulic fracturing, and friction-reducing “slick-water” chemicals. In so doing, Mitchell demonstrated that high-volume shale production could be achieved by the consistent application of advanced technologies. In the 2000s, gas prices rose and costs of horizontal drilling declined to the extent that by 2005 horizontal wells outnumbered vertical wells in the Barnett. At the end of 2012 more than 16,000 wells, the vast majority of them horizontal, were producing hydrocarbons from the Barnett Shale.

The commercial successes in the Barnett attracted numerous other operators, both to the Fort Worth Basin and to potential shale plays elsewhere. In addition to the Barnett, volumetrically large shale gas production has been demonstrated in the Fayetteville Shale in the Arkoma Basin in Arkansas, the Woodford Shale in the Arkoma basin of Oklahoma and Arkansas, the Haynesville Formation in Louisiana and Texas, and the Marcellus Shale in the Appalachian Basin in Pennsylvania and West Virginia, among others.

In recent years shale developments have been victims of their own success, as burgeoning reserves and production have pushed commodity prices down to levels that made many shale gas operations sub-economic. As natural gas prices fell relative to oil operators increasingly focused on producing liquids rather than gas from source rocks. As of this writing, oil prices have also declined to the extent that investments in shale oil developments have also slowed.

Although hundreds of organic-rich shales are known in North America and thousands are recognized worldwide, most shale oil production has come from just two productive intervals: the Bakken/Three Forks strata in the Williston Basin of North Dakota and Montana and from the Eagle Ford Formation in southern Texas. As of 2013 these two “plays” accounted for more than 94% of reserves and slightly less than 94% of production of shale oil in the United States (U.S. EIA, 2015). The Bakken Formation is described and

compared to the Monterey Formation in Volume I, Chapter 4 of this study.

Numerous other source-rock system oil plays have been tested in the U.S. and in Canada, resulting in relatively minor (compared to the Bakken or Eagle Ford) proven reserves and production. The volumetrically most important of these plays are the oil-productive Bone Spring/Wolfcampian strata in the Permian Basin of west Texas and eastern New Mexico, the oil production from the mainly gas-prone Marcellus Shale in the Appalachian Basin of Pennsylvania and West Virginia, oil production from the mainly gas-productive Barnett Shale, and oil from the Niobrara Formation in Colorado, Kansas, Nebraska, and Wyoming.

The Eagle Ford Formation, which is arguably the most commercially successful shale oil development in the world, comprises a succession of fine-grained calcareous strata that underlie much of southern and southeastern Texas. The potentially productive area of the Eagle Ford Formation covers roughly 52,000 km^2 (20,000 mi^2) between the Mexican border and the Sabine uplift in East Texas in a band 80 km (50 mi) wide, 644 km (400 mi) long, and about 75 m (250 ft) thick. Throughout its productive area, the Eagle Ford is largely undeformed, gradually dipping into the subsurface from an arcuate band of outcrops near Del Rio, San Antonio, Austin, and Fort Worth to greater and greater depths. The Eagle Ford produces oil, gas, and natural gas liquids in various combinations, depending upon depth and thermal maturity. The formation probably enters the oil window (the temperature at which oil begins to be generated in significant quantities) at a depth of about 1,800 m (5,906 ft). The Eagle Ford is most oil-productive between about 2,400 and 3,700 m (7,874 and 12,139 ft). At greater depths production becomes increasingly gas-rich. Natural gas has been produced from the Eagle Ford at depths as great as 5,500 m (18,000 ft). Fundamental to the success of large-scale operations in the Eagle Ford is its great lateral continuity. It lies flat enough to run long horizontal well bores (Figure 3.3-4). Over large distances it dips very gradually, allowing for highly consistent well construction across a large area (Figure 3.3-5). Consistent, repeatable well construction, stimulation and production over large areas are key to profitable source rock production.

Figure 3.3-4. Schematic of a horizontal well with multi-stage hydraulic fractures superimposed on a road cut in the Eagle Ford Formation, west Texas (public domain image, courtesy of Halliburton 2013). The curved black line originating at the left represents a well bore turning horizontal. Potential locations for hydraulic fractures are indicated with vertical black lines. The yellow lines indicate depositional layers. The schematic demonstrates the lateral continuity of the Eagle Ford Formation, which lends itself to industrial-scale drilling of extended-reach horizontal production wells with multi-stage hydraulic fractures.

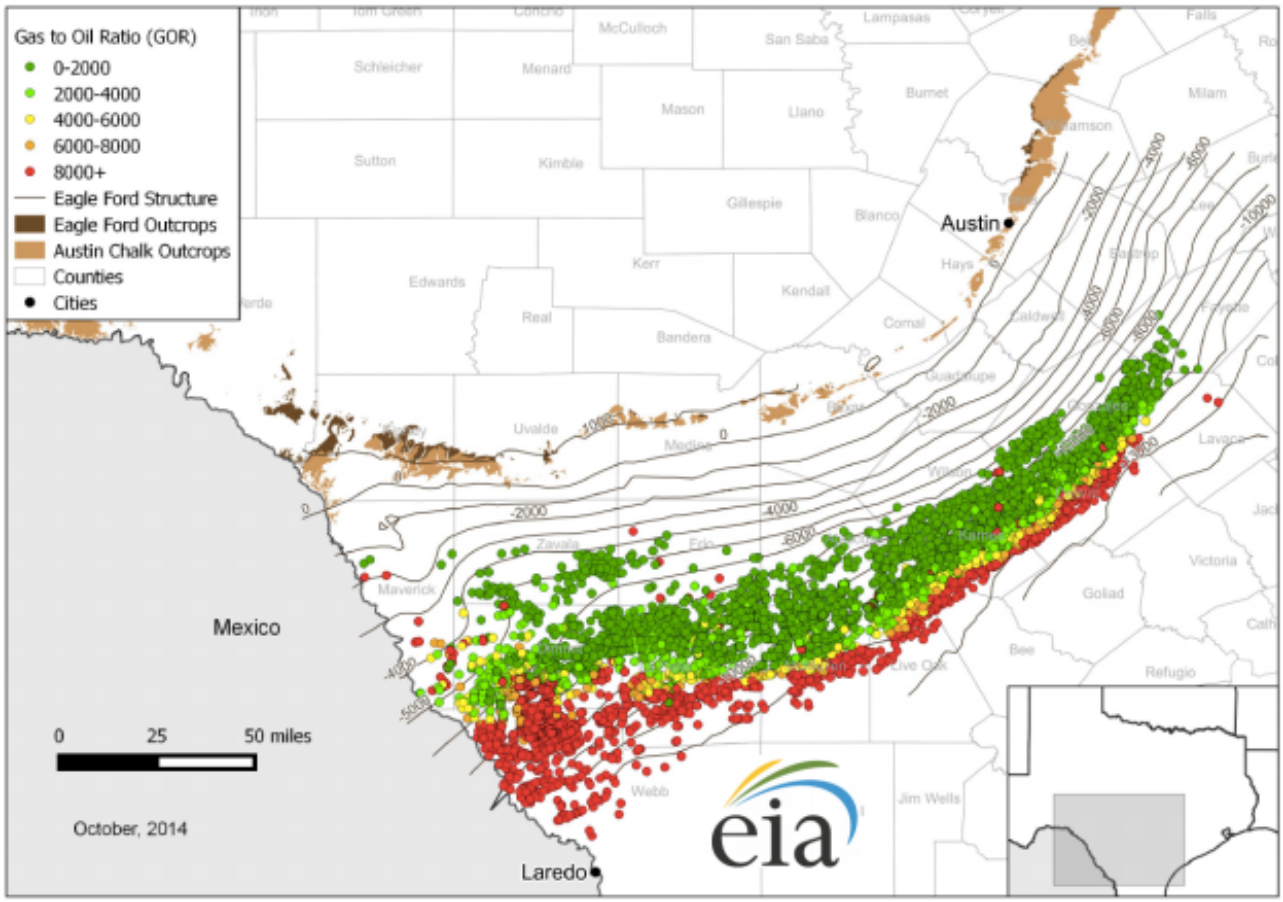


Figure 3.3-5. Structure map showing depth to top and initial gas oil ratio of wells producing from the Eagle Ford Formation as of October 2014. The GOR (gas-oil ratio) values shown are the amount of natural gas produced (standard cubic feet) per barrel of oil. Image from EIA, 2014.

According to the Texas Railroad Commission (TRRC) Petrohawk Energy drilled the first Eagle Ford well in 2008. The discovery well was directionally drilled with approximately 975 m (3,200 ft) of lateral displacement at a total depth of 3,396 m (11,141 ft.). The well initially flowed 215,208 m^3 (7.6 million cubic feet) of gas per day. As of December 4, 2014 the TRRC reported that 7,334 oil wells and 3,786 gas wells were on schedule[1] with a further 6,565 permitted locations representing pending oil or gas wells (Figure 3.3-6). In 2008, Eagle Ford oil production was a mere 56 m^3 (352 barrels) per day, but in

1. "On schedule," or "on proration schedule," is a term the TRRC uses to refer to wells that are in their lists as actively producing or plugged. It excludes wells that are shut in or are not yet producing.

September 2014 the TRRC reported that Eagle Ford oil production exceeded 148,494 m^3 (943,000 barrels) of oil per day during the period of January through September 2014. According to the Oil and Gas Journal, more than $13 billion dollars were invested in Eagle Ford production in 2013, with 260 rigs drilling about 300 wells per month (Oil and Gas Journal, 2015).

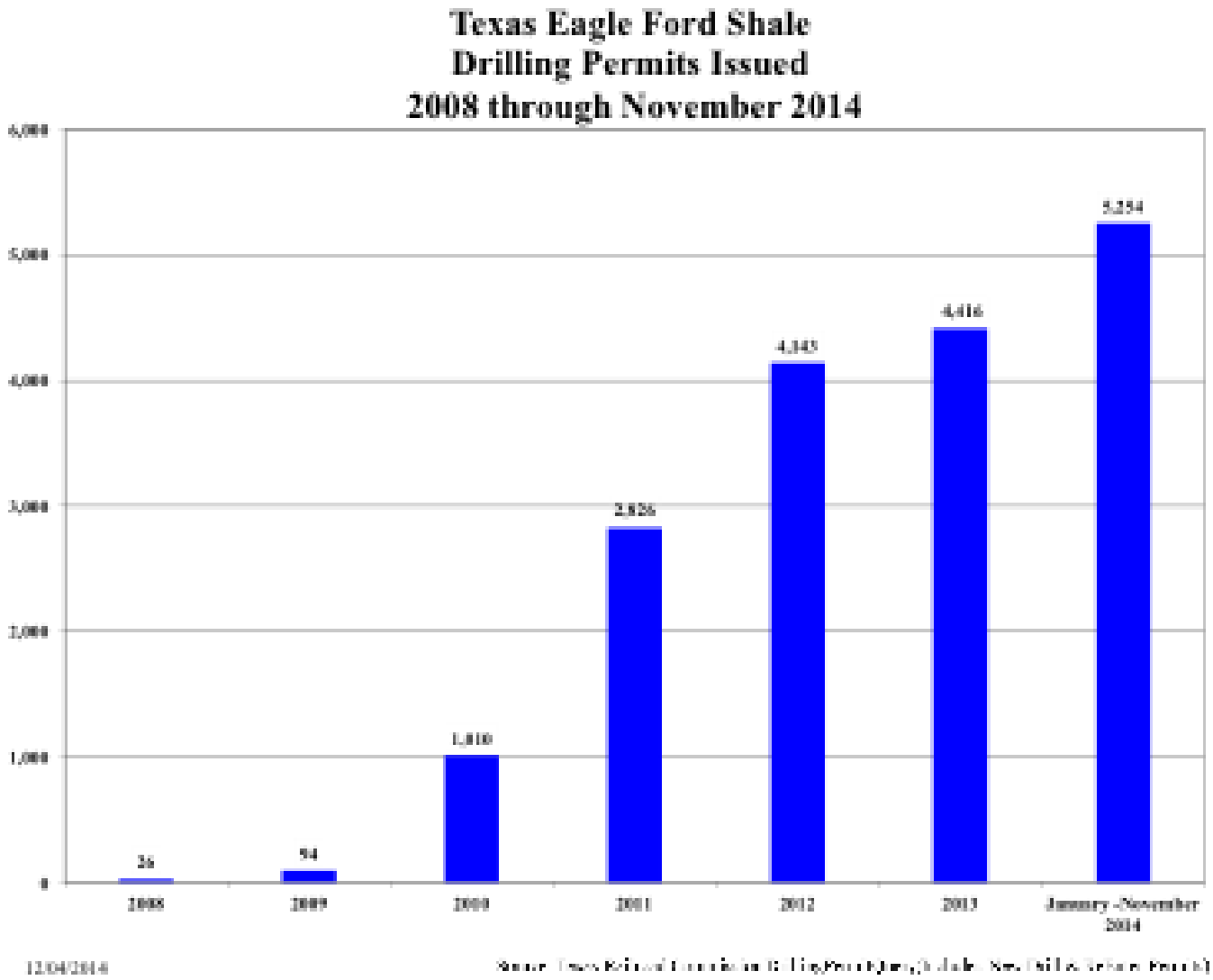


Figure 3.3-6. Texas Eagle Ford drilling permits issued by the Texas Railroad Commission between 2008 and November 2014. Image courtesy of the Texas Railroad Commission (2015).

3.3.7. What is the Potential for Production from Source-Rock (Shale Oil) in California?

The Monterey is present in large portions of many of the Tertiary[2] sedimentary basins of California, but its potential for production as a source-rock system (shale oil) reservoir has not been demonstrated. The basic physical requirements for productive shale oil reservoirs are quite specific; the Monterey may meet these requirements in certain, restricted areas of its geographic distribution, as discussed in Section 3.3.10, "The Geographic Footprint of Thermally Mature Monterey Source Rock in California."

Highly productive source-rock (shale oil) systems share several physical/geological characteristics; some are displayed by Monterey Formation source rocks, as summarized in Table 3.3-2. These characteristics are as follows:

1. High concentration of Type II (marine) kerogen
2. Thickness of highly organic-rich strata in excess of 20 meters.
3. Thermal maturity for oil (%R_o[3] of 0.8 to 1.3)
4. Abnormally high pore-fluid pressures (overpressuring, above a normal water pressure gradient)
5. Brittle[4] lithology capable of sustaining natural or induced fractures
6. Simple tectonic history and minimal structural complexity
7. Retention of producible hydrocarbons

2. Technically, the International Commission on Stratigraphy no longer formally recognizes the term "Tertiary." The time period covered by the Tertiary is now referred to as the Paleogene and Neogeone, but for simplicity, we will refer to this period as the Tertiary. A full geologic timeline is provided in Appendix 3.B.

3. Ro stands for vitrinite reflectance in immersion oil, an optical microscopic measure of thermal maturity first developed by German coal petrographers. Vitrinite is a particular type of organic particle commonly found in coals and shales, which becomes increasingly reflective to incident light with greater temperature exposure. For this reason, vitrinite reflectance, or % Ro, is a commonly used measure of the time-temperature exposure of the organic matter in source-rocks

4. A material is brittle if, when subjected to stress, it breaks rather than deforms. In fine-grained rocks, brittleness is typically imparted by a significant content of silica or carbonate minerals and a relatively low content of clay minerals such as illite or kaolinite, which deform readily under stress and do not, in general, sustain fractures.

Table 3.3-2. Summary of seven characteristics of productive source rocks, the status of data availability on the Monterey Formation, and our evaluation of whether large portions of the Monterey are likely to display this characteristic.

	Data available on Monterey formation?	**Large portions of Monterey display this characteristic?**
High concentration of Type II (marine) kerogen	Yes	Yes
Thickness of highly organic-rich strata in excess of 20 meters.	Yes	Yes
Thermal maturity for oil (%R_o of 0.8 to 1.3)	Yes	Yes
Abnormally high pore-fluid pressures (overpressuring)	Limited	Likely
Brittle lithology capable of sustaining natural or induced fractures	Limited	Likely
Simple tectonic history and minimal structural complexity	Yes	No
Retention of producible hydrocarbons	Limited	Unlikely

3.3.7.1. High Concentration of Type II Kerogen

Parts of the Monterey that are highly enriched in marine kerogen are known to be prolific petroleum source rocks (Isaacs, 1989; Isaacs, 1992; Peters et al., 2013; Peters et al., 2007; Tennyson & Isaacs, 2001). According to Graham and Williams (1985), shales of the Monterey in the San Joaquin Basin have TOC concentrations ranging from 0.40 to 9.16 percent by weight (wt. %), with a mean value of about 3.43 wt. %. Isaacs (1987) reported TOC concentrations ranging from 4 to 8% from Monterey shales collected in the Santa Maria Basin and along the Santa Barbara coast, with highest TOC values in the phosphatic shales of the middle Monterey. In the Los Angeles Basin similar Monterey-equivalent phosphatic shales (locally named the Nodular Shale) have from 2 to 18% TOC, and average about 4% (Jeffrey et al., 1991; Hoots et al., 1935). Many of these measured values are well in excess of the 2 wt. % average TOC believed to be the necessary minimum concentration for a commercially successful source-rock reservoir.

3.3.7.2. Thickness of Organic-Rich Strata

In wells and outcrops along the Santa Barbara coast and in the adjacent Santa Maria and Santa Barbara-Ventura Basins, TOC-rich shales are more than 100 m (328 ft) thick. In the Los Angeles Basin, west of the Central Syncline, the phosphatic Nodular Shale is 50 to 100 m (164 to 328 ft) thick (Isaacs 1980). In the southwestern San Joaquin Basin, where the entire Monterey is more than 1,830 m (6,000 ft) thick, it contains four major shale sequences: the Gould, Devilwater, McDonald, and Antelope shales (Mosher et al. 2013), each of which probably contains net thicknesses of tens of meters of strata having

concentrations of organic matter sufficient for consideration as possible source-rock reservoirs.

3.3.7.3. Thermal Maturity

Two variables determine where, when, and at what depths source rocks become thermally mature: (1) the local geothermal gradient (the rate at which temperature increases with depth) and (2) the reaction kinetics - the rates at which various sedimentary organic compounds crack to release hydrocarbons when heated. The Monterey Formation is known to be in the oil window in the deep parts of most major petroleum basins in California, but the geothermal gradient varies greatly from basin to basin (e.g., Jeffrey et al. 1991). Because the reaction kinetics of Monterey source rocks remains somewhat uncertain, the locations of thermally mature Monterey are also to some degree uncertain (Tennyson & Isaacs, 2001). Nevertheless, much has been learned in recent decades and the depth range of the Monterey oil window is generally known in the most petroliferous basins. In Appendix 3.A, we present maps of the thermally mature sections of the Monterey.

3.3.7.4. Abnormally High Pore-Fluid Pressures

Commercially successful shale oil developments have generally been in areas where the target formations display fluid pressures in excess of the hydrostatic pressure of water (the pressure in a column of water due to the weight of the fluid above it). Both the highly productive areas of Bakken/Three Forks (Sonnenberg et al., 2011) and Eagle Ford Formation (Hentz & Ruppel, 2011) display abnormally high fluid pressures. Most commercially successful shale gas plays, such as the Barnett Shale in the Fort Worth Basin and the Fayetteville Shale in the Arkoma Basin, also exhibit abnormally high fluid pressures.

In California, few wells have penetrated thermally mature source rock intervals, but abnormally high fluid pressures are indicated by certain deeply drilled wells. In the San Joaquin Basin, wells drilled near Lost Hills for deep gas resources, encountered extremely high fluid pressures at the depths where source-rock intervals are believed to be thermally mature. In the Los Angeles Basin, the American Petrofina Central Core Hole No. 1 (Redrill) demonstrated abnormally high pore fluid pressures below about 18,000 feet, presumably related to hydrocarbon generation in Monterey-equivalent source rocks at greater depths (Wright, 1991).

3.3.7.5. Brittle Lithology

The remains of diatoms (silica-rich phytoplankton) are an important component of the Monterey. The physical properties of diatomaceous deposits change systematically during burial as a result of increasing temperature: Non-crystalline “Opal-A” diatom frustules are first transformed into crystobalite-type crystallinity “Opal-CT” and at higher temperatures

to microcrystalline quartz chert (Isaacs, 1981). This temperature-controlled mineralogical transformation is accompanied by significant shifts in porosity, permeability, elasticity, and brittleness. As a result, certain Monterey lithologies, such as chert, porcelanite, and siliceous mudstone, are particularly susceptible to fracturing (Hickman & Dunham, 1992; Isaacs, 1984). Although by no means certain, it seems reasonable to postulate that the highly organic-rich source-rocks of the Monterey in the Los Angeles, San Joaquin, and other basins are interbedded with brittle rocks that could sustain natural or induced fractures and, therefore, might support petroleum production.

3.3.7.6. Simple Tectonic History and Minimal Structural Complexity

In comparison to the mid-continent settings where most commercially successful shale plays have been developed, California basins exhibit extreme structural complexity owing to their tectonic setting along the active continental margin of North America. In the Williston Basin where the Bakken/Three Forks production has been developed, and in the Gulf Coast area of southern Texas, where the Eagle Ford shale production has been demonstrated, productive formations are continuous and essentially undeformed for tens or hundreds of kilometers. The petroleum producers exploit this lateral continuity by drilling thousands of similar long-reach horizontal production wells within the target formation. In contrast, the richest petroleum areas of California are located in tectonically active settings and exhibit extremely complex faulting and folding, and highly discontinuous formations, which pose technical challenges to those who would wish to develop continuous-type plays. Whereas operators in southern Texas can dependably predict the depths and thermal maturities of Eagle Ford strata over distances of more than 400 km (49 mi), in California basins it is difficult to predict formation characteristics over distances of even a few hundred meters.

Highly variable lithology, combined with temperature-dependent silica phase transitions (El Shaari et al., 2011), and complex tectonic settings, set the Monterey apart from most other source-rock systems (e.g., Wright, 1991; Ingersoll and Rumelhart, 1999). This inherent stratigraphic, mineralogical, and structural complexity will make it challenging to discover and develop source-rock oil in California, as evidenced by the largely negative results of deep drilling in the San Joaquin Basin (Burzlaff and Brewster, 2014). Closely spaced faults or folds disrupt the reservoir to such an extent that vertical well success would be unlikely. In any event, this development will only be economic with very high oil prices with current technology. Because of its extreme variability, effective hydraulic stimulation methods would need to vary significantly over short distances in various portions of the Monterey (El Shaari et al., 2011). For these reasons, the techniques and technologies successfully employed in Texas, North Dakota, and Pennsylvania where many similar long-reach horizontal wells are drilled over large areas cannot be simply copied for development of the Monterey (e.g., El Shaari et al., 2011).

3.3.7.7. Retention of Producible Hydrocarbons

In the Bakken/Three Forks formations in the Williston Basin, in the most productive areas of the Eagle Ford in south Texas, and in most other highly productive shale plays, significant volumes of oil and gas have been generated and then retained in the source rock over long periods of geological time. In contrast, in highly productive California basins, oil from the Monterey has apparently been effectively expelled to migrate and accumulate in conventional traps of the major oil fields. The complex tectonic history of sedimentary basins in California and the extensive presence of natural fractures in the siliceous Monterey mudstones seem to have facilitated the efficient expulsion and migration of oil generated in the basin depocenters via higher-permeability fracture and fault pathways to the producing conventional fields. Therefore, the amount of free hydrocarbons retained within the thermally mature Monterey source rocks is uncertain, and lack of oil retention is a significant risk to potential Monterey shale oil production.

3.3.8. Uncertainties Surrounding the Monterey Formation as a Petroleum Reservoir

The lithological variability of the Monterey, its diverse rock types, its vertical and lateral heterogeneity, and its mineralogical transformations resulting from silica mineral phase changes during burial make it challenging to predict its reservoir rock properties in advance of drilling. Superimposed on its sedimentological and stratigraphic heterogeneity is the structural complexity of many California basins resulting from their tectonic setting on an active continental plate margin. These complexities, which are inherent to the Monterey, result in uncertainty that is not easily reduced.

In spite of careful geochemical work (Isaacs and Rullkötter, 2001), the rate at which Monterey organic matter is converted to petroleum liquids (reaction kinetics) remain incompletely understood. For this reason, the precise depths and locations where organic-rich Monterey rocks are actively generating oil and gas are still difficult to predict with certainty. Moreover, these depths vary greatly from basin to basin.

The geological complexities of the Monterey and its source rocks are sure to make widespread production technically difficult. The successful shale plays, which have been transforming the physical and economic landscapes of Texas and North Dakota, now depend upon industrial-style drilling programs, in which hundreds or thousands of horizontal wells, each extending laterally for long distances, are efficiently drilled in rapid succession, using similar techniques and yielding comparable volumes of produced hydrocarbons. The lithological, structural and geochemical complexities of the Monterey make the performance of such long-reach horizontal wells difficult or impossible to predict. Closely spaced vertical wells are an alternative, but they, too, suffer from the highly variable rock properties encountered in the Monterey Formation in the subsurface.

Source-rock formations are generally low-permeability, and consequently require stimulation to allow hydrocarbons to flow to the well (King 2012). Successful shale

plays in Texas and North Dakota employ multi-stage hydraulic fracturing in tandem with long-reach horizontal wells (Bazan et al., 2012; Pearson et al., 2013). The stimulation methods that could be used on the Monterey shale are not well understood at this point. Matrix acidizing or hydraulic fracturing could be used depending on the local formation characteristics, in particular, natural fracturing. If there is sufficient permeability from natural fractures, acidizing may be the preferred method, otherwise hydraulic fracturing is more likely to be used (El Shaari et al., 2011). Moreover, the social and economic climate in much of California does not, in general, encourage widespread drilling in previously undeveloped areas.

In the final analysis, only exploratory and development drilling can significantly reduce the range of possible development scenarios. However, at present the quantity, quality, and distribution of potentially recoverable source-rock resources are poorly constrained and it is extremely difficult to set policy or plan for mitigation against possible environmental impacts when we are uncertain if, where, and with what technology source rock would be developed.

3.3.8.1. The EIA Assessment of the Monterey/Santos Shale Oil Play

To our knowledge, no systematic geology- or engineering-based assessment of either in-place or technically recoverable petroleum resources in unconventional, source-rock systems (shale oil) of California has ever been published. However, much of the media focus and public concern about hydraulic fracturing and the potential for widespread development of shale oil resources in California stem from two point estimates of technically recoverable resources released by the DOE Energy Information Administration (EIA). As part of a larger special report entitled “Review of Emerging Resources: U.S. Shale Gas and Shale Oil Plays”, the EIA announced in 2011 that the “Monterey/Santos Play” contains some 2.4 billion m^3 (15.4 billion barrels) of technically recoverable “shale oil.” This estimated recoverable volume, which represented the majority of U.S. shale oil resources reported by EIA, was considerably larger than the reported recoverable resources attributed to two most active and productive shale oil plays in North America: the Bakken/Three Forks formations in the Williston Basin and the Eagle Ford Formation of Texas. Just three years later, in their Annual Energy Outlook for 2014, the EIA reported the technically recoverable oil in the same “Monterey/Santos play” to be 95.4 million m^3 (0.6 billion barrels). Both estimates were supposedly based on a calculation involving the geographic extent of the play, number of producing wells per unit area, and oil production per well (Table 3.3-3). Given the position of authority from which EIA reports energy information and the wildly differing values of these two point estimates, it is not surprising that these estimates have been the source of much confusion and consternation.

Neither the methodology nor the sources of input data were documented in sufficient detail to adequately evaluate these deterministic estimates. However, the reduced estimates of 2014 were explained as follows: “Key factors driving the adjustment included new geology information from a U.S. Geological Survey review of the Monterey shale and a lack of production growth relative to other shale plays like the Bakken and Eagle Ford” (U.S. EIA, 2014b).

Box 3.3-3: Scientific Estimates and the Incorporation of Uncertainty

A “deterministic” or “point” estimate generates a single result. This is in contrast to a probabilistic estimate, which will generate a range of outputs and associated degrees of confidence. An example of a probabilistic resource estimate is the USGS estimate of additional recoverable oil from nine of the largest oil fields in the San Joaquin Basin (Tennyson et al., 2012). The USGS estimated with 95% confidence that at least 572.4 million m^3 (3.6 billion barrels) of additional oil could be recovered, and 50% confidence that 1 billion m^3 (6.3 billion barrels) of additional oil could be recovered. A common-sense example of deterministic estimates versus probabilistic interval estimates would use a six-sided die as an example. An example of a deterministic estimate of the output from rolling a die is to take the mean value of the six sides and estimate the likely result to be 3. A probabilistic interval estimate would say that the result can range from 1 to 6 and we can say with 100% confidence that the value will be at least 1, 83% confidence that the value will be at least 2, and so forth.

Table 3.3-3. Comparison of model parameters for the 2011 U.S. EIA/INTEK and 2014 U.S. EIA estimates of technically recoverable oil from the "Monterey/Santos play."

Model Parameters	US EIA/INTEK (2011)	US EIA (2014)
Areal extent (mi^2)	1,752.0	192.0
Wells/mi^2	16.0	6.4
Production/well (Kbbl[5] oil)	550.0	451.0
Total recoverable oil (Bbbl[6] oil)	15.4	0.6

While the EIA estimates cannot be effectively evaluated on the basis of the information provided, several issues concerning these estimates warrant comment.

1. Given the highly uncertain geological and technical situation surrounding direct recovery of oil from California source rocks, it seems crucial that any credible estimate must define exactly what is being evaluated. In the case of the Monterey Formation, which is both a source rock and, in places, a reservoir for migrated petroleum, it is particularly important that the scope of the assessment be made clear. The EIA routinely reports so-called "tight oil" production from California, but makes no distinction between migrated "tight oil" and source-rock system shale oil. This lack of clarity makes their estimates nearly impossible to interpret unambiguously.

2. The great uncertainty inherent in an unproven play concept such as shale oil production in California makes it imperative that any credible estimate be clearly defined in terms of probability. In other words, is the estimate a mean resource value? Is it a median estimate? If so, what is the uncertainty surrounding the estimate? Or, is it a maximum value? Or something else? From the EIA report it is impossible to tell.

3. The U.S. EIA purports to provide estimates of technically recoverable resources, but technical recoverability can only be meaningfully evaluated in terms of the application of a particular technology. In the case of the Monterey source rocks, no appropriate production technology has yet been identified, so a deterministic estimate of technical recoverability is highly speculative. The 2014 EIA estimate seems to assume development with horizontal wells, but no technology is specified for the 2011 estimate.

4. The confusion surrounding the range of uncertainty in shale oil resources of California could be clarified by a systematic, geology- and engineering-based assessment of in-place and technically recoverable resources in the source-rock systems of each of the principal petroleum basins. Such an assessment should be

5. Kbbl = kilobarrels or a thousand barrels of oil.

6. Bbbl = a billion barrels of oil.

probabilistic rather than deterministic, and include an evaluation of the principal sources of uncertainty, with clearly explained methodology and sources of input data. The USGS is said to be working on such an assessment, but nothing has yet been published.

3.3.8.2. Recommendation: Comprehensive Peer-Reviewed Probabilistic Resource Assessment of Continuous-Type (Shale) Oil Resources in California

As of now, the range of possibilities for development of shale-oil type resources is unconstrained. Consequently the State of California has an insufficient understanding of the resource situation to understand or develop policy for future development of Monterey source rock. Therefore, the immediate need is for a systematic resource assessment. Such an assessment would provide an integrated set of geology- and engineering-based probabilistic estimates of the resource endowment, technical recoverability, and (possibly) unit costs for development of continuous-type source-rock or shale oil resources in California. The assessment of resource endowment gives an understanding of the magnitude of the potential and provides a tool for prioritization of effort. The assessment of technically recoverable resources quantifies the volumes and uncertainties of resources that can be delivered given the application of specific technology and links the estimated resource with the types and intensities of technologies that would be involved possible development. Given that the technology that could be used to successfully develop the Monterey source rock is unknown, the range of possibilities of recoverable resources would cover the use of various technologies. A resource-cost analysis would add a measure of monetary value to the volumetric assessments, extend the geological uncertainty through to its impact on economic measures, and enable the assessment results to be used in economic models.

3.3.8.2.1. Basic Principles of Assessment

The proposed assessment should be designed to both meet the immediate need to constrain the uncertainties surrounding the measurement of the potential for petroleum production from source-rock systems, and be carried out within basic and certain standards of scientific credibility. These standards should include a careful statement of the problem to be addressed; clear specification of the desired deliverable output; peer review; transparent presentation of the exact methodology to be employed; open presentation of the input data, including data, their sources, and limitations; and a presentation of the assessment output, including the full range of probabilistic results. In many cases, the range of values and quantified uncertainty are more important than the estimates of the central tendency (such as the mean value). Finally, the assessment should be reproducible within the specified uncertainties by any qualified scientific group attempting to replicate the study.

3.3.8.2.2. Scope of the Assessment

The study should include all continuous-type source-rock system (shale-oil) resources in the Tertiary Basins of California. This initial step, the geological screening of potentially productive areas within the state, has already been undertaken in Volume I Chapter 4 of this SB4 report, and is reiterated in this Case Study.

The assessment could be completed by organizations with proper staffing and experience. Organizations with a record of producing similar assessments include the U.S. Geological Survey, which has long-experience in such quantitative assessments. An example is the 2013 USGS study of the technically recoverable resources in the Bakken/Three Forks petroleum system of the Williston Basin (Gaswirth et al., 2013). The Texas Bureau of Economic Geology has also completed high-quality resource assessments, as has the Norwegian Petroleum Directorate, and the Geological Survey of Canada, among others.

3.3.8.2.3. Components of the Analysis

The recommended assessment would need to comprise several modules, each of which would have specific deliverables and timeframe, as follows:

1. *Geological Screening:* As discussed above, an initial basin screening is included in Volume I, Chapter 4, and reiterated in this Case Study. The potentially productive basins identified by the screening process are: Cuyama, Los Angeles, Salinas, Santa Barbara-Ventura, San Joaquin, and Santa Maria.

2. *Geological interpretation:* The geological framework of the potentially productive petroleum basins determines the occurrence, distribution, and quality of yet-to-find and yet-to-be-developed continuous-type resources. Therefore, development of a geological model for hydrocarbon occurrence in each basin is the starting point for assessment.

3. *Play and Sub-Play Identification:* Identification, geological description, and specification of each play and sub-play for analysis. This activity would include preparation of narrative summaries, mapping play-concept boundaries, and stratigraphic specifications of play and sub-play extents.

4. *Industry/Public Meeting:* Convene an open forum for description and discussion of assessment strategy, methodology, and play concepts to be evaluated during the assessment project. This would be a solicitation of external comments and recommendations.

5. *Assessment of the State of Nature:* Conduct a probabilistic assessment of the total resource endowment, also known as the original oil in place (OOIP), of each specified play and or sub-plays identified within each of the petroleum basins.

Such an assessment identifies those areas of greatest resource potential and therefore their likely desirability for resource exploitation.

6. *Assessment of Technically Recoverable Resources:* Probabilistic geological and engineering assessment of total recoverable resources of each play and sub-play for specified technical development model(s). Probabilistic estimates of technically recoverable resources are fundamental to further use of the assessments, but must of necessity include an engineering analysis, based upon the geological models of the plays and sub-plays in order to specify technological applications that would be required to develop the plays/sub-plays.

7. *Appraisal of Resource Costs:* The technical model used in the assessment of technically recoverable resources might include an analysis of the types of wells and related infrastructure required for development of the postulated shale oil resources. This technical evaluation is a link between the geological uncertainty and the financial costs and environmental consequences of development of each play and sub-play.

8. *Aggregation and Allocation of Results:* Depending upon the specifications of the study, results would be aggregated to totals for each play or basin, and, if desired, allocated to geographic subsets such as water districts, ecological regions, etc.

9. *Preparation of Final Report:* Final report of methods, input, and results

10. *Further Refinement Using Empirical Data:* At present, any assessment of the potential for development of California source rock reservoirs will be highly uncertain because of the lack of empirical data. If private companies decide to drill wells in California source rock, publicly reported data from those wells could be used to revisit the results and reduce the uncertainties of the resource assessment. See section 3.3.6., "Identifying production from source rock," for further details on how information on production is reported to the state.

3.3.9. Exploratory Drilling in Monterey Source Rock to Date

Production of a new reservoir begins with surveys to identify areas and depths of resource potential, then exploratory drilling, followed by appraisal drilling, then development, and finally, production. Each step must be successful to proceed with the next. Information on exploratory drilling is likely to be held confidential by the operators. Records for exploratory wells are expressly permitted confidential status upon request of the operator, meaning full records are not reported to the state (California Public Resources Code Section 3234). However, there is some publicly available documentation of exploratory drilling from source-rock systems in California. To our knowledge, none of these exploratory activities have achieved levels of production sufficient to justify commercial development.

Quiet exploration for development opportunities in source-rock systems has been underway for years, as various companies have developed land positions and conducted the background geological studies necessary to make exploration and development investments. In its 2011 shale oil report, the U.S. EIA stated that, on the basis of acreage positions, at least five companies (Berry Petroleum (now Linn Energy), National Fuel Gas, Occidental (now California Resources Corporation), Plains Exploration (now Freeport-McMoRan Inc.), and Venoco had active exploration efforts looking for shale oil opportunities in the Monterey. No doubt other companies have been considering Monterey source-rock exploration as well.

Although the companies are understandably quiet about their commercial intentions, the next stage in shale-play evaluation, exploratory drilling, is probably also already underway, as indicated by deep drilling programs in the vicinity of thermally mature source rocks in the San Joaquin and the Los Angeles Basins. Of the two, the San Joaquin has had, by far, the most attention devoted to it.

Venoco drilled a number of San Joaquin Basin wells targeting zones at depths between 1,830 and 4,270 m (6,000 and 14,000 ft), possibly in attempts to test source-rock intervals (Durham 2010). As part of the effort, Venoco drilled several deep wells in Semitropic oilfield that evidently targeted the Monterey. One of them, the Scherr Trust et al. 1-22 (API 03041006), which began drilling in December 2010, went to 4,243 m (13,921 ft) vertical depth in an attempt to test the Monterey, which was perforated and fractured at depths of 3,808-3,813 m (12,495-12,510 ft). Flow tests produced non-commercial amounts of oil (DOGGR, 2015).

Attempts to develop the Eocene Kreyenhagen source rocks have had similar results. Although an industry report by Petzet (2012) concerning testing of hydraulic fracturing and oil production in the Kreyenhagen indicated the presence of mobile oil, no further development or oil production from the Kreyenhagen was indicated.

Burzlaff and Brewster (2014) reported that there were 501 wells drilled between 2009 to 2013 to test unconventional oil reservoirs in the Monterey. However, of the 495 that were identified by field, none had depths in the range of thermally mature source rock for the basin where they were located. Six wells were listed as “any field” and could not be associated with a specific basin. These six were drilled by Venoco and had depths in the 2,734 – 3,048 m (9,000 – 10,000 ft) range, which is potentially deep enough to reach thermally mature source rock in some California basins. The 501 wells had average initial production rates of 12 to 24 m^3 (75-150 barrels) of oil per day, with expected ultimate recoveries of (EUR) of 3,200–4,000 m^3 (20,000–25,000 barrels) for wells in fields on the west side of the San Joaquin Basin and 14,000–16,000 m^3 (90,000–100,000 barrels) for wells in fields on the east side of the Basin. This well performance was evidently considered insufficient for economic production, as no reserves were reported and no production was established from the wells. However, for comparison, Dana van Wagener of DOE-EIA reported that horizontal production wells in the Eagle Ford Formation of

Texas have roughly comparable average EURs, ranging from 12,719 - 53,102 m^3 (80,000 to 334,000 barrels), depending upon the county in Texas (van Wagener, 2014).

Most of the area of thermally mature source rocks lies outside existing oil field boundaries (see Figure 3.3-7). One of several notable exceptions is Elk Hills oil field, where Miocene and older source rocks are thought to be in the oil window at depths of 3,930–5,850 m (12,900–19,200 ft) (Magoon et al., 2009). In order to evaluate the prospects for hydrocarbon production from deep intervals at Elk Hills, the U.S. Department of Energy (DOE) drilled three wells to depths of 5,569–7,455 m (18,270–24,426 ft) (Fishburn, 1990). The wells did not result in commercial production, but they did have shows of oil and gas. Cores of shale recovered from the Eocene Kreyenhagen Formation below 4,785 m (15,700 ft) in the 987-25R well, exuded oil and gas from fine fractures.

Another potential deep San Joaquin Basin target is shale that has been displaced due to deep thrust faulting and folding, such as that described by Wickham (1995) at the Lost Hills field. Based upon a subthrust play developed for the East Lost Hills, several exploratory deep wells were drilled into the footwall (the rocks below the fault). In 1998 the first well drilled encountered high gas pressures at 5,377 m (17,640 ft), well control was lost and the rig was engulfed in flames. It took more than six months to bring the well under control (Schwochow, 1999).

When and if the results of geological investigations and initial exploratory drilling warrant, the most likely next steps in source rock reservoir development would entail demonstrating proof-of-concept with relatively small-scale program of production wells in geographically select areas. Such development would probably begin with the drilling several additional exploratory wells that the potential operators would use to (1) determine the reservoir parameters of the target formations and to (2) prepare a development plan for production.

Commercial production would not begin until successful production had been demonstrated by the exploration wells and by geographically restricted production demonstrations. At that point, if operators had the appropriate permits, they would begin a development program in the area of the target formation found to have potential. This could expand to a large number of wells if (a) there is lateral continuity of an interval with attractive properties, and (b) the production response from initial development wells is economic. A successful beginning of large-scale production would presumably be announced with fanfare at some point, as it would be a boon to the net value of the company. We found no evidence that production in Monterey source rock has moved beyond the exploratory stage.

3.3.9.1. Identifying Production from Source Rock in Public Records

Tracking exploratory activity in source rock would be useful for allowing state agencies and the public to recognize and plan for new oil and gas development. It is not

straightforward to identify a comprehensive list of exploratory wells in source rock from the public records maintained by DOGGR. There are four key characteristics that one would look for to identify an exploratory well in source rock:

1. Completion with well stimulation, either hydraulic fracturing or matrix acidizing;

2. True vertical depth (TVD) great enough to potentially reach thermally mature source rocks;

3. Production from a formation that could potentially generate oil or gas when exposed to sufficient heat and pressure (these formations are listed in Table 3.3-4), and

4. Confidential status (exploratory wells are typically filed under confidential status, as defined in California Public Resources Code Section 3234).

If a well meets all four of these characteristics, it may be exploring source rock; however, one would need information on the precise depth of thermally mature rock at those coordinates to definitely identify a well as producing from source rock.

The only place where information on the four characteristics is systematically compiled in a searchable format is in the Well Stimulation Disclosure Reports database, which compiles information on stimulated wells dating back to January 2014 (15 months before the writing of this case study).[7] Under the proposed final regulations on well stimulation, expected to go into effect July 1, 2015, the first characteristic (completion with stimulation) would be part of the public well stimulation disclosures, even for confidential wells. A well's confidential status would also be part of the public disclosures. However, true vertical depth and productive horizon would be held in confidence by the state until the information becomes public record (DOGGR, 2015b). A state agency with access to confidential information could search in the Well Stimulation Disclosure Reports (DOGGR, 2015c) for wells meeting the four criteria described above to track early evidence of source rock activity. Onshore wells are granted confidentiality for a two-year period, and offshore wells are granted confidentiality for a five-year period, with the possibility of extensions (California Public Resources Code Section 3234).

7. Information on TVD, production horizon/pool, and well completion and confidential status is mostly available in well records. The PDFs of well records are available through DOGGR's online well search database, including those of confidential wells, once confidential status has expired (DOGGR, 2015a). However, it is not possible to systematically perform a search based on the four characteristics of interest in the online database.

We performed a search in this database and found three stimulated wells[8] of sufficient depth and producing from the Monterey or Kreyenhagen, both potential source rocks, but these three wells were not filed as confidential. In fact, no confidential wells have been listed in the database to date. As a result we are skeptical that any well listed thus far in the well stimulation disclosures is an exploratory well. Most likely the three wells we identified, while quite deep, are producing from regions of the Monterey or Kreyenhagen that are shallower than thermally mature rock in that location. Information that would help one understand whether well is exploring a new formation includes (a) the location of the wells with respect to existing oil fields, (b) how close adjacent wells are located, and (c) the depths and intervals adjacent wells (or wells in the area) are completed in. One would expect an exploratory well to be either relatively distant laterally from any neighboring wells, and/or completed at a substantially different depth from nearby wells. The relevant information is available in the DOGGR online well record database (DOGGR, 2015a). Continued monitoring of the records in the stimulation disclosures would show if there is substantial interest and exploration of California source rocks.

Table 3.3-4. Potential source rocks (shales rich in total organic carbon). The pools listed below are those that could be positively identified in DOGGR's 2011-2014 production databases as shales rich in total organic carbon; when found below the top of the oil window, they are expected to generate hydrocarbons. Other pools listed in the database were not potential source rocks, or we had insufficient information to determine their status. Basin abbreviations: SJ = San Joaquin, SM = Santa Maria. Data from DOGGR (2014).

Pool Name	Basin	Field Name(s)
Antelope	SJ	Monument Junction
Antelope Shale	SJ	Asphalto
Antelope Shale/Carneros	SJ	Railroad Gap
Antelope Shale-East Dome	SJ	Buena Vista
Antelope Shale-West Dome	SJ	Buena Vista
Antelope/McDonald	SJ	Lost Hills
Fruitvale	SJ	Tejon, North
Kreyenhagen	SJ	Kettleman Middle Dome
McDonald	SJ	Belridge, South
McDonald-Devilwater	SJ	Cymric
McLure	SJ	Kettleman Middle Dome
Miocene-Oligocene	SJ	Wheeler Ridge
Monterey	SJ	Cymric
Reef Ridge-Antelope	SJ	Cymric
S Margarita-Fruitvale-Rd Mtn	SJ	Tejon

8. API numbers 02957574, 03120504, and 03052679.

Monterey Deep	SM	Orcutt
Monterey North Block	SM	Zaca
Monterey South Block	SM	Zaca
Monterey-Knoxville	SM	Guadalupe (ABD)
Monterey-Lospe	SM	Lompoc
Monterey-Pt. Sal	SM	Casmalia
Sisquoc-Monterey	SM	Barham Ranch

3.3.10. The Geographic Footprint of Thermally Mature Monterey Source Rock in California

Although the Monterey and its equivalents can be found throughout much of California, a potential Monterey source rock play is restricted to just the six basins with the largest proven oil reserves in the state. While the Monterey is a named formation in various Tertiary Basins (Figure 3.3-2), years of geological mapping and exploratory drilling demonstrate that thick successions of highly organic-rich Monterey strata at the appropriate levels of thermal maturation for active petroleum systems are only present in a handful of basins. These are the same basins that contain large conventional oil fields sourced from the Monterey: the Cuyama, Los Angeles, Salinas, San Joaquin, Santa Maria, and Santa Barbara-Ventura Basins (Figure 3.3-7, and for a detailed examination of the geological context of potential source-rock system developments in each of the basins, see Appendix 3.A). Because the Monterey is naturally highly fractured and releases much of the oil it generates, we infer that any basin with a prolific Monterey source rock would also have large pools of oil originating from the Monterey.

For a detailed examination of the geological context of potential source-rock system developments in each of the basins, see Appendix 3.A, “Source Rock Potential of Major Oil-Producing Basins in California.”

The maps of the footprint of potential Monterey source rock in Figure 3.3-7, and the supporting maps in Appendix 3.A, differ slightly from maps of potential source rock in Volume I, Chapter 4 in two ways. First, the maps of source rock in the San Joaquin basin in this chapter show a slightly larger area because they include all areas where the Monterey formation lies below the top of the oil window; the corresponding maps in Volume I, Chapter 4, show only portions in the oil window while excluding the lower regions in the gas window. Second, the maps of potential source rock in the Santa Maria and Cuyama Basins are somewhat larger in this chapter than in Volume I, Chapter 4. In this chapter we used a slightly shallower cut-off for the minimum depth of the oil window than in Volume I, Chapter 4. The cut-off points for the top of the oil window and supporting citations are given in Table 3.3-5. Our rationale was that we wished to evaluate the possible impacts within the largest reasonably defensible estimate of potential Monterey source rock.

Table 3.3-5. Characteristics of Monterey source rock in each of the six major oil-producing basins in California.

	Estimated shallowest depth of thermally mature source rocks			**Estimated surface area of Monterey formation in oil and gas window**			
Basin	**(m)**	**(ft)**	**Reference**	**(km²)**	**(mi²)**	**Reference**	**Counties**
Cuyama	2,500	8,200	Lillis (1994)	150	60	Lillis, 1994; Sweetkind et al., (2013)	San Luis Obispo, Santa Barbara
Los Angeles	2,400	8,000	Pitman (2014)	460	180	Wright, (1991); Gautier, (2014)	Los Angeles, Orange
Salinas	4,000	13,000	Menotti and Graham (2012)	220	80	Durham, (1974); Menotti and Graham, (2012)	Monterey, San Luis Obispo
San Joaquin (Antelope and McClure)	3,000	10,000	Magoon et al. (2009)	3,630	1,400	Magoon et al., (2009)	Fresno, Kern, Kings
Santa Maria	2,000	6,700	Tennyson and Isaacs (2001)	290	110	Tennyson and Isaacs, (2001); Sweetkind et al., (2010)	Santa Barbara
Santa Barbara-Ventura	4,600	15,000	Jeffrey et al. (1991)	1,100	420	Gautier, this chapter	Los Angeles, Santa Barbara, Ventura, Offshore

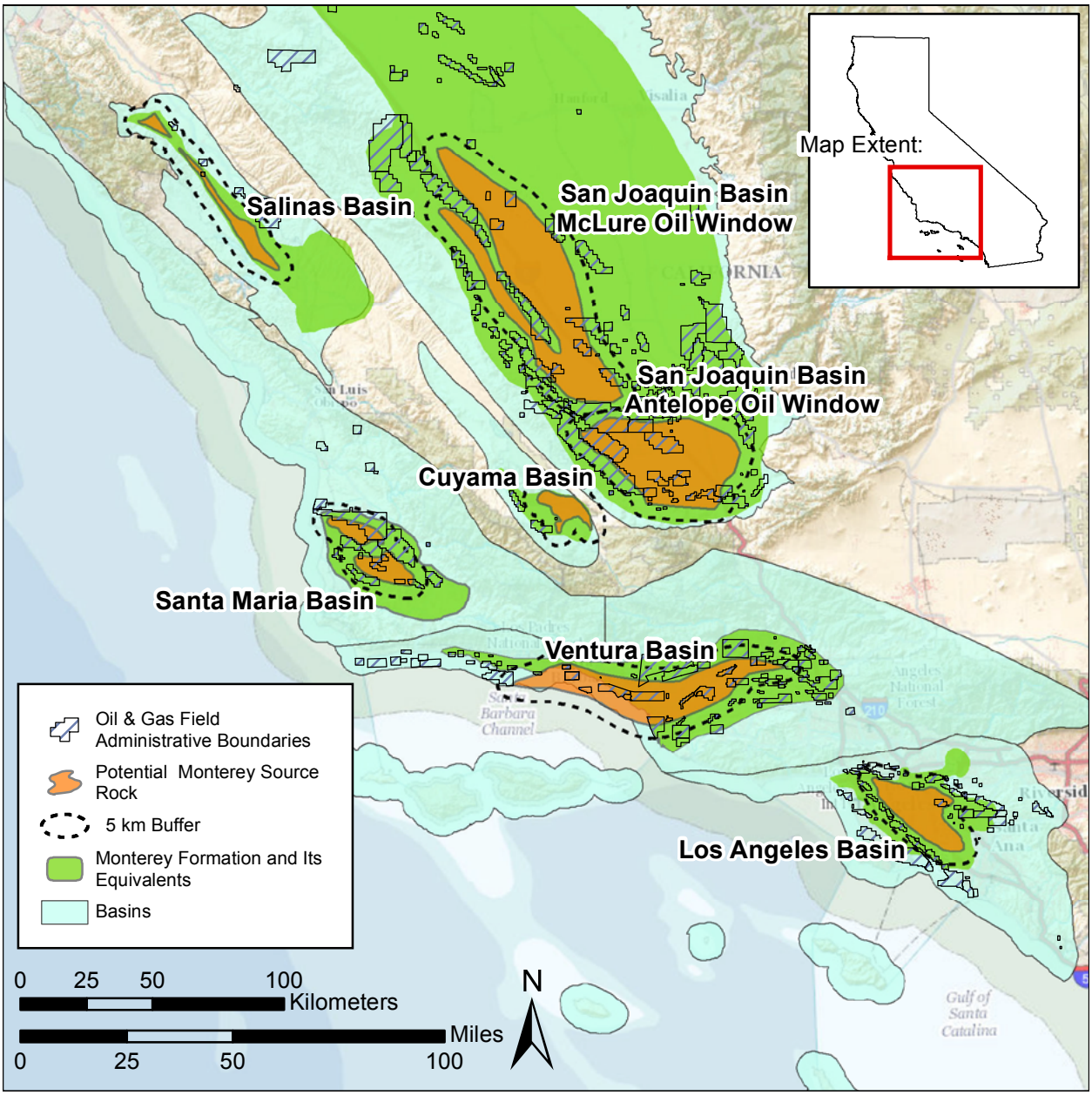


Figure 3.3-7. Extent of potential Monterey source rock in the six major oil-producing basins in California. The regions colored in orange indicate the areas overlying a maximum estimate of the portion of the Monterey that is deep enough to generate oil or gas. We added a five-kilometer buffer when assessing the area of potential environmental impacts to account for uncertainty in the true areal extent and on the assumption that impacts would extend beyond the boundaries of the source rock.

3.4. Potential Environmental Impacts of Well Stimulation in Monterey Source Rock

3.4.1. Overview of Potential Environmental Impacts of Well Stimulation in Monterey Source Rock

Large-scale development of source rock would most likely expand the location and quantity of petroleum production in the state, and make use of hydraulic fracturing and/or matrix acidizing. Consequently, we would expect development of source rock to have both direct and indirect impacts from well stimulation. Direct impacts are caused specifically and uniquely by the act of well stimulation, such as a hydraulic fracture extending into protected groundwater, accidental spills of fluids containing hydraulic fracturing chemicals or acid, or inappropriate disposal or reuse of produced water containing stimulation chemicals. These direct impacts do not occur in oil and gas production unless well stimulation has occurred. Well stimulation can also incur indirect impacts, i.e., those not uniquely attributable to well stimulation itself. A low-permeability reservoir such as Monterey source rock requires stimulation for economic production. Indirect impacts occur in all oil and gas development, whether or not the wells are stimulated. For example, disposal of produced water through underground injection may carry the risk of inducing an earthquake. If this produced water comes from a reservoir that cannot be produced without well stimulation, the injection of produced water (and associated seismic risk) would be an indirect impact of well stimulation. That is, injection of wastewater is not a unique impact of well stimulation, but well stimulation could enable petroleum production from Monterey source rock, and therefore increase the volume of wastewater injection in the state. We would expect development of Monterey source rock to result in an increase in quantity, and expansion in the geographic area, affected by the direct and indirect impacts of well stimulation.

Uncertainties about how Monterey source rock development would transpire, in addition to the data gaps in how current well stimulation affects the environment outlined in Volume II, prevent a thorough assessment of the potential environmental impacts.

Key Uncertainties about Monterey Source Rock Development:

1. What technology would be used (horizontal wells, hydraulic fracturing, and/or new innovations),

2. Density of wells and volumes of hydrocarbons produced per well,

3. Location and timeline of development,

4. How regulations, environment and demographics will have changed,

5. Probability of chance events (i.e. accidents).

Even with the availability of more comprehensive data on how Monterey source rock would be developed, it is not possible predict how the system is going to function in the future, considering the uncertainties around environmental impacts of well stimulation, and oil and gas in general, that were identified in Volume II. Accurate prediction of impacts would require adequately validated and calibrated models. Constructing such models is not possible with the current state of knowledge.

Although many factors about source rock development and its potential impacts are uncertain, it is still possible to identify the known environmental and demographic conditions in the vicinity of source rock, and impacts from source rock production that would differ from migrated oil production. Our intention in our survey of potential environmental impacts of Monterey source rock development is not to make detailed predictions about future impacts, nor to reiterate the generalities about potential impacts made in Volume II; rather, we focus on the environmental resources in the footprint of Monterey source rock to better understand the resources that could be impacted by development of the area.

3.4.2. Land Use and Infrastructure Development

Potential Monterey source rock can be found near areas already producing petroleum as of 2014 (Figure 3.4-1) – unsurprising, given that Monterey source rock is the origin of most of the oil found in California's migrated reserves. The footprint of potential Monterey source rocks can be divided into two categories: "brownfield," defined as having a well density of at least one well per square kilometer; and "greenfield," defined as areas with fewer than one well per square kilometer.

The categories of brownfield and greenfield can be further subdivided according to whether or not they are within current administrative field boundaries as defined by DOGGR. The vast majority of brownfield areas are within field boundaries, but some there are some areas with wells that fall outside administrative boundaries. Quite a bit of land within administrative boundaries is technically greenfield – that is, has less than 1 well per square kilometer.

Only 9% of the potential Monterey source rock footprint is brownfield – that is, has at least one well in a one-kilometer radius (Table 3.4-1). The area that falls within the administrative boundaries of an oil field is only somewhat larger – 16% of the potential Monterey source rock footprint.

Table 3.4-1. Percentage of potential Monterey source rock footprint; rows show portion in the brownfield category (defined as at least one well per square kilometer), and greenfield category (defined as fewer than one well per square kilometer). Columns show areas inside or outside currently designated administrative field boundaries. Total MSR = total Monterey Source Rock.

Designation	Well Density	Area Total (km²)	Area Total (%)	Area Inside Bounds (km²)	Area Inside Bounds (%)	Area Outside Bounds (km²)	Area Outside Bounds (%)
Brownfield	≥ 1	503	9	459	8	44	<1
Greenfield	< 1	5,364	91	495	8	4,869	83
Total MSR	all	5,867	100	954	16	4,913	84

However, even the portions of the footprint that are outside field boundaries are located near current oil fields: all of the footprint falls within 20 kilometers (12 miles) of the boundary of a currently designated oil field (Figure 3.4-1).

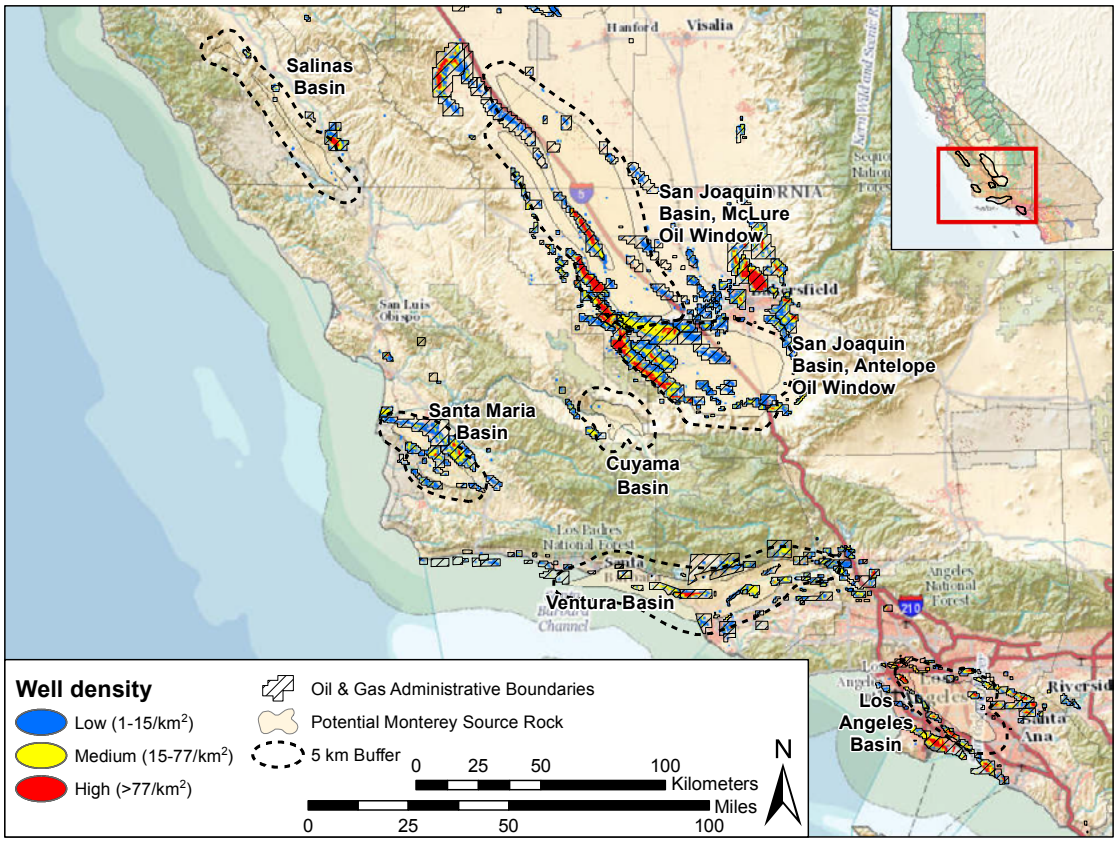


Figure 3.4-1. Oil fields, well density as of 2014, and potential Monterey source rock in California. While most area developed for oil and gas production is within administrative boundaries, some is not. Conversely, not all areas within field boundaries are developed for oil and gas and may be used for cities, farms, or open land.

The footprint of potential Monterey source rock plays is distributed over ten counties; eleven including the five-kilometer buffer. Table 3.4-2 shows the square kilometers of footprint in each county and, for comparison, the number of new and active wells identified in DOGGR's All Wells database as of March 2014. All counties with potential Monterey source rock have at least some new and active wells within their boundaries. The county with the greatest proportion of Monterey source rock is Kern County; it also is the county with 80% of new and active wells in the state.

Table 3.4-2. Area of potential Monterey source rock footprint by county. New and active wells from DOGGR All Wells database as of March 2014 (DOGGR, 2014a).

County	Over source rock		In 5 km buffer		Total Area	New & Active Wells	
	km²	%	km²	%	km²	wells	%
Fresno	78	1	177	3	255	3,356	3.8
Kern	2,629	45	1,723	28	4,351	70,615	79.3
Kings	927	16	647	10	1,575	222	0.2
Los Angeles	393	7	501	8	894	4,303	4.8
Monterey	218	4	822	13	1,041	1,100	1.2
Orange	62	1	142	2	204	1,161	1.3
San Luis Obispo	124	2	286	5	410	312	0.4
Santa Barbara	515	9	1,009	16	1,524	1,312	1.5
Tulare	0	0	3	0	3	91	0.1
Ventura	898	15	937	15	1,835	2,524	2.8
Other Counties	0	0	0	0	0	89,039	4.5
Grand Total	5,845	100	6,247	100	12,092	84,996	100.0

The proximity of potential new Monterey source rock development to existing production is important because it will affect the amount of new infrastructure that would be needed to support new production. One important piece of infrastructure for which we have spatial data is the network of oil and gas pipelines in the state; these pipelines transport petroleum from where it is produced to refineries and to its final point of use. As shown in Figure 3.4-2, oil and gas pipelines already exist in the basins where there is potential Monterey source rock, although the network varies in density across the basins, with the Salinas Basin in particular having a relatively sparse network of pipelines. Another important piece of infrastructure that would need to be developed in and around new oil fields is a means for wastewater disposal. Locations of existing Class II disposal wells are shown in Figure 3.4-11 through 3.4-15, and the current locations of evaporation-percolation ponds are shown in Figure 3.4-3. Class II disposal wells and evaporation-percolation ponds both have highly clustered distributions in and around existing oil fields. It is likely that if new areas were to be developed to produce Monterey source rock, more such features would need to be installed.

Figure 3.4-2. Pipelines for transport of oil and gas in California overlaid with potential Monterey source rock. Pipeline data from Zucca (2000).

3.4.3. Potential Impacts to Water Resources

The major potential impacts to water resources discussed in Volume II, Chapter 2 were associated with water use for well stimulation and the possibility of water contamination by stimulation fluids (and comingled produced water). In this case study, we present information on the location of potential Monterey source rock in relation to existing wastewater disposal infrastructure, surface water bodies, groundwater aquifers, water wells, and water supply systems. Because the extent of source rock is larger and differs from the current brownfield area, there is potential for new and different water resources to be affected by source rock production.

There are a few predictable differences in how impacts of source rock production would likely differ from those of current production in California. First, most of the source rock footprint is not in the immediate vicinity of existing oil and gas wells, and therefore the risk of hydraulic fractures intercepting a nearby improperly plugged, abandoned, or deteriorated well is diminished. Second, source-rock production will be on average much deeper than migrated oil production. Consequently, there will be a greater margin of safety between hydraulic fractures and shallow groundwater. Third, water produced from deeper formations in the San Joaquin Basin tends to be higher in Total Dissolved Solids (TDS); one study found that produced water in the San Joaquin Basin from depths shallower than 1,500 m (4,900 ft) had less than 4,000 mg/L TDS (and typically less than 2,000 mg/L), whereas waters from depths greater than 1,500 m typically had more than 25,000 mg/L TDS (Fisher and Boles, 1980), likely due to the transition from non-marine strata at shallow depths to marine strata at greater depths.

Below we show the geographic overlap between key water resources and the areas that could be developed as a source-rock play, and discuss possible impacts to water resources.

3.4.3.1. Wastewater Management

The main documented methods used for disposal of wastewater from stimulated wells in California are: (1) evaporation-percolation ponds (57% of total produced water volume in the first full month after stimulation), followed by (2) subsurface injection (26%), (3) “other” (14%), (4) not reported (3%), and (5) surface body of water (0.2%) (Volume II, Chapter 2). Discharge of oil field wastewater to evaporation-percolation ponds, also known as “percolation pits,” is regulated by the Regional Water Boards under their Waste Discharge Requirements (WDR). In this section we examine where percolation pits have been used in the past several years within the footprint of Monterey source rock, on the assumption that, unless regulations change, this practice will continue in the future.

As shown in Figure 3.4-3, percolation pits are presently used in at least four of the six basins with potential Monterey source rock: the Salinas, Santa Maria, San Joaquin and Cuyama Basins. The status of percolation pits in the Los Angeles and Ventura Basins is ambiguous: records in DOGGR’s production database report that wastewater is disposed

of via “evaporation/percolation” in these areas, albeit a small volume compared to the San Joaquin Basin. However, state water quality regulators have no records of active ponds in the vicinity of the two basins.

Information on oil and gas wastewater disposal reported by operators to DOGGR is inconsistent with the reported pond locations. For example, the production database reports 41,000 m^3 (33 acre-feet) and 47,000 m^3 (38 acre-feet) of produced water disposed to ponds in Los Angeles and Ventura Counties, respectively, though no sump locations were reported for either county. Conversely, there was no disposal to ponds reported in Santa Barbara County, yet there were active ponds in the county. This mismatch indicates that either the records of pond locations are incomplete, wastewater disposal volumes and located reported in the production database are inaccurate, or both.

In addition to unlined sumps, Class II wells are also a likely disposal method, using either existing wells or constructing new Class II wells to handle additional wastewater flows. Wastewater can be injected into Class II wells for the purpose of enhanced oil recovery (though not in source-rock formations) or simply disposed of underground. Similar to unlined sumps, Class II wells are generally located within the perimeter of existing oil and gas fields (Figures 3.4-11 to 3.4-15).

At present, the main infrastructure for wastewater disposal (evaporation-percolation ponds and Class II wells) is located in and around existing oil fields. Development of greenfield portions of the Monterey source rock footprint would require operators to develop new wastewater disposal infrastructure. Possible strategies would be: 1) construction of new sumps and/or Class II wells in greenfield areas, 2) transport of wastewater to current sumps and/or Class II wells, or 3) increased reliance on other avenues of wastewater disposal, such as beneficial reuse at the surface (such as treatment followed by use for irrigation) or disposal to publicly-owned treatment works.

Since it is likely that produced water from Monterey source rock would be from deeper formations and have higher TDS values on average than water currently produced in the state, the options for its disposal (at least without prior treatment) may be affected. For example, it is possible that it will exceed the TDS limits set by the Central Valley Regional Water Quality Control Board for disposal in pits overlying groundwater with existing and future beneficial uses. High TDS may also compromise its usefulness for irrigation or other beneficial reuse, or as a base fluid for stimulation fluids.

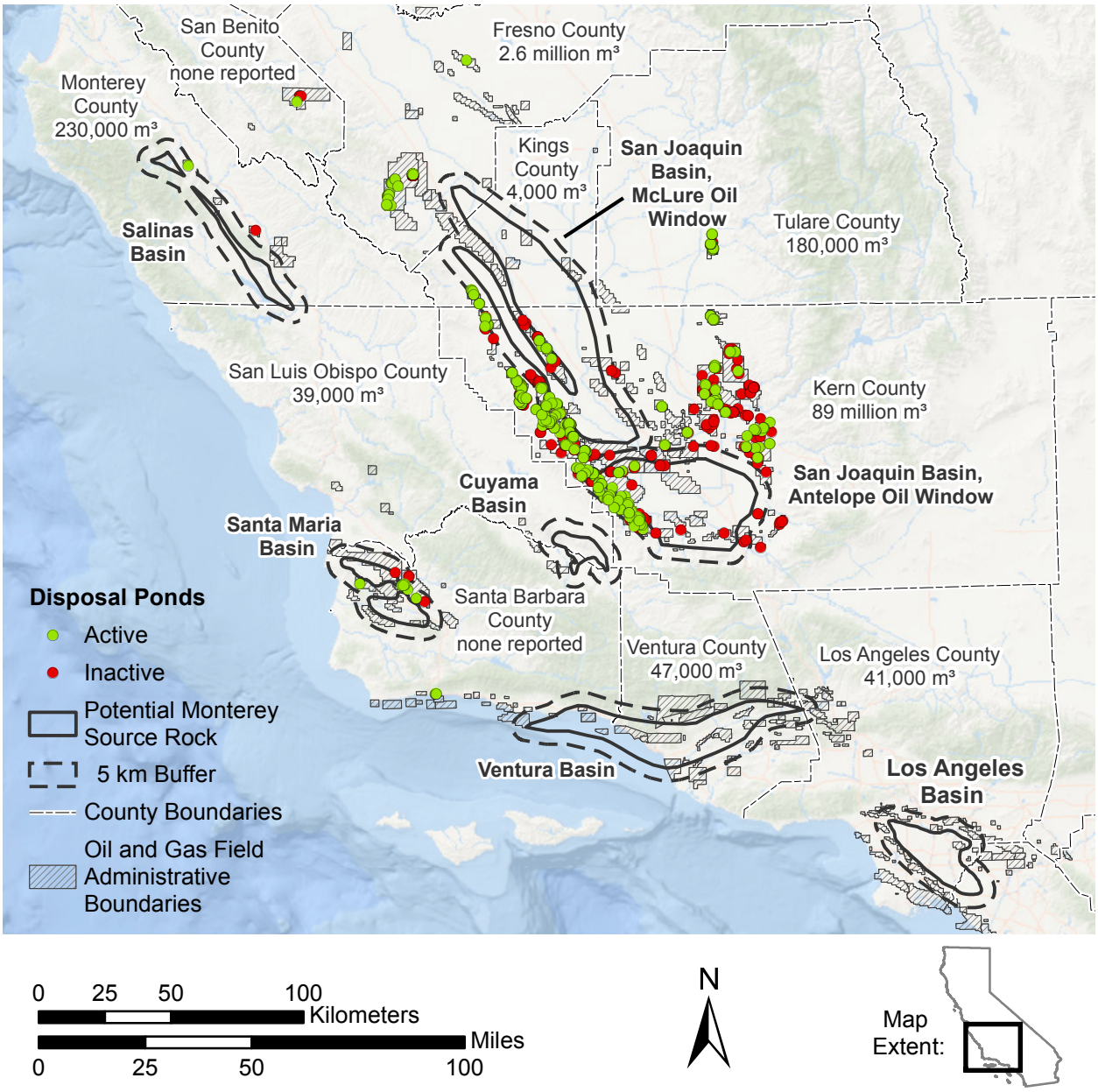


Figure 3.4-3. Potential Monterey source rock overlaid with known locations of oil and gas wastewater evaporation-percolation ponds in the state, and oil and gas field administrative boundaries. County labels indicate volume of wastewater sent to evaporation-percolation ponds by county in 2013. Data on Central Valley sump locations from the Central Valley Regional Water Quality Control Board (Holcomb, pers. comm, 2015); data on other sump locations from the California State Water Resources Control Board (Borkovich, pers. comm., 2015). DOGGR administrative boundaries from DOGGR (2014b). Volumes of wastewater calculated from DOGGR production database (DOGGR, 2014c).

3.4.4. Potential Impacts to Surface and Groundwater Quality

Below, we discuss surface water and groundwater resources that are in close proximity to the Monterey source rock and could be affected by increased oil and gas development in these areas. This includes the groundwater basins that lie immediately above or adjacent to source rock, as well as nearby surface water bodies, such as rivers, lakes, and streams. We then identify water-related infrastructure that could be impacted if these resources are contaminated. These include water wells, water supply for domestic and municipal uses, and irrigated agricultural lands.

3.4.4.1. Surface Water Bodies

Surface water bodies, such as rivers, lakes, streams, and wetlands, can be located in close proximity to oil and gas activities. For example, the Salinas River is close to the San Ardo oil field (Figure 3.4-4). Because of this proximity, oil and gas activity could release contaminants into these water bodies through a variety of pathways. One possible pathway is spills or accidental releases directly into a waterway, or on the land surface, where contaminants could run off into surface water bodies. In addition, polluted groundwater can discharge to the surface via springs or subsurface discharge to streams (via baseflow) or other surface water bodies. Pollutants released to surface water bodies have the potential of being transported with water flows, affecting downstream water bodies. In coastal watersheds, pollutants that enter the environment could be transported downstream to the ocean and coast. We inventoried the surface water bodies that overlie the Monterey source rock or that fall within 5 kilometers of this area using geographic data from the U.S. Geological Survey (USGS 2014). Figure 3.4-5 shows the surface water features that overlie the Monterey source rock.[9] A more detailed view of each source rock area is shown in Appendix 3.D (Figure 3.D-1). There are more than 4,000 km (2,485 mi) of rivers and streams overlying the Monterey source rock, and another 7,000 km (4,350 mi) above the 5 km (3 mi) buffer, for a total of over 11,000 km (6,835 mi) of rivers and streams (Table 3.4-3). In addition, there are 2,800 km (1,740 mi) of man-made canals and ditches above the Monterey source rock and its 5 km (3 mi) buffer. The San Joaquin and Los Angeles Basins have a relatively low density of surface water features compared to the other four basins.

9. Note that some of the rivers and streams shown are ephemeral, and may flow rarely or intermittently.

Table 3.4-3. Length of streams, rivers, and canals overlying the Monterey source rock, by oil basin.

	River/Stream (length in km)		Canal/Ditch (length in km)	
	Over source rock	+5 km Buffer	Over source rock	+5 km Buffer
Cuyama Basin	240	1,000	-	-
Los Angeles Basin	37	190	43	87
Salinas Basin	440	2,000	-	16
San Joaquin Basin	1,400	3,500	1,899	2,600
Santa Maria Basin	280	770	-	10
Ventura Basin	1,800	3,800	78	180
Total	**4,200**	**11,000**	**2,000**	**2,800**

Data from the National Hydrography Dataset, version 2.2 (USGS 2014).

Note: the length of river and stream miles in the second column is cumulative; in other words, it is the sum of features that above the source rock and within the 5 km (3 mi) buffer. All figures rounded to two significant digits. Figures may not sum to total due to rounding.

There are other water bodies in the study area, such as lakes, ponds, reservoirs, and other impoundments (not including the evaporation-percolation ponds identified earlier). We found 122 such features overlying the Monterey source rock, and another 79 in the 5 km (3 mi) buffer area (Table 3.4-4). These water bodies have a total surface area of 94 km² or 23,000 acres. Some water bodies shown are farm ponds or wetlands, and may only be wet at certain times, depending on the weather and how they are managed.

Table 3.4-4. Surface water bodies (lakes, ponds, and reservoirs) that overlie the Monterey source rock.

	Over source rock			In 5 km buffer		
Oil Basin	Number of Water Bodies	Surface Area		Number of Water Bodies	Surface Area	
		km²	acres		km²	acres
Cuyama Basin	2	0.03	8	2	0.0	8
Los Angeles Basin	6	0.2	45	13	2.7	660
Salinas Basin	1	22	5,400	9	42	10,200
San Joaquin Basin, Antelope Oil Window	36	5.9	1,500	45	6.5	1,600
San Joaquin Basin, McLure Oil Window	45	18	4,600	75	25	6,200
Santa Maria Basin	13	4.0	990	18	4.2	1,000
Ventura Basin	19	8.3	2,100	39	13	3,300
Total	**122**	**59**	**14,500**	**201**	**94**	**23,000**

Figure 3.4-4. A view of the Salinas River near San Ardo, with the San Ardo oilfield in the background. Photo by Wikipedia user Antandrus.

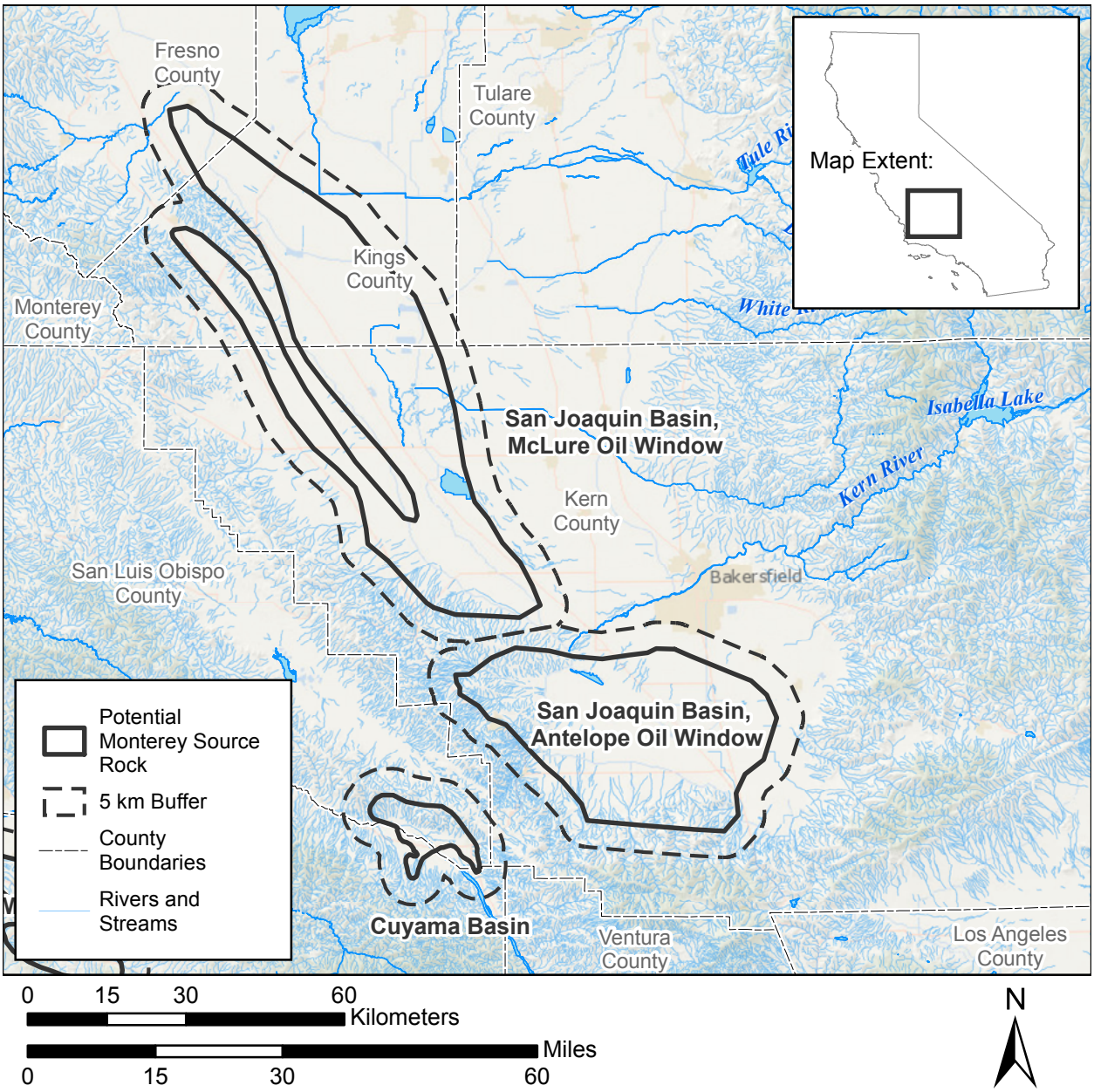


Figure 3.4-5. Surface water features overlying the Monterey source rock. A series of close-up maps for each basin is shown in Appendix 3.D. Data from U.S. Geological Survey (2014). Note that the in order to make the smallest streams visible at this scale, they are depicted larger than they are and so form an almost continuous field of blue on the map. Also, many of these rivers and streams are ephemeral, meaning they do not flow continuously or year-round.

3.4.4.2. Groundwater Aquifers

In California, groundwater is an important source of water for households, municipalities, industry, and agriculture. Groundwater also helps sustain rivers and streams, providing critical ecosystem flows. The Monterey source rock lies thousands of feet underground, below groundwater basins that provide water for human and environmental uses. Wells for oil and gas exploration, production, and waste disposal pass through groundwater basins, and above-ground activities disturb the land surface over these groundwater basins. There are several possible pathways by which contamination could occur, as discussed in Volume II, Chapter 2. Based on data from the Department of Water Resources (DWR), we identified 16 groundwater basins[10] that overlie the Monterey source rock, as shown in Figure 3.4-6 (a) through (d). Four additional groundwater basins are not located immediately above the source rock but fall within the 5-kilometer buffer zone used for this study. The San Joaquin Basin contains the largest area where groundwater overlies source rock, followed by the Los Angeles Basin and the Santa Maria Basin (Table 3.4-5). The groundwater basins which overlap the Monterey source rock are listed in Table 3.C-1. One of the potentially affected basins, the San Joaquin Valley Groundwater Basin, covers a vast area spanning the width of the Central Valley from the Tehachapi Mountains in the South to the San-Joaquin-Sacramento River Delta in the north, and spans approximately 36,000 km^2 (14,000 square miles).

The movement of groundwater is complex and, in many parts of California, poorly understood. Arguably, hydraulic fracturing in the very deep Monterey source rock is safer than operations in shallower wells, because one would expect to often find aquitards between deep hydraulically fractured zones and usable groundwater. A confining layer (aquitard) could slow flow of groundwater and contaminants. However, relying on an aquitard to keep pollutants from migrating is inherently risky; the integrity of an aquitard cannot be assumed unless it has been observed as maintaining separation between aquifers, based on observations of either pressure or water chemistry.

The groundwater basins shown in Figure 3.4-6 have been identified by DWR as areas underlain by permeable materials capable of storing or providing a significant supply of groundwater. In some areas, groundwater is salty or otherwise of low quality, such that it could not be used for public supply without costly treatment measures. In some of these areas, regulators allow the disposal of oilfield wastes into subsurface aquifers via Class II wells. Beginning in 2014, following the enactment of SB 4, state law requires operators to monitor groundwater in the vicinity of production wells that have been stimulated.[11] Regulators (the State Water Resources Control Board and the Regional Water Quality Control Boards) allow exemption to the monitoring requirement where the operator

10. The Department of Water Resources defines a groundwater basin as an alluvial aquifer or a stacked series of alluvial aquifers with reasonably well-defined boundaries in a lateral direction and a definable bottom (DWR 2003, page 88).

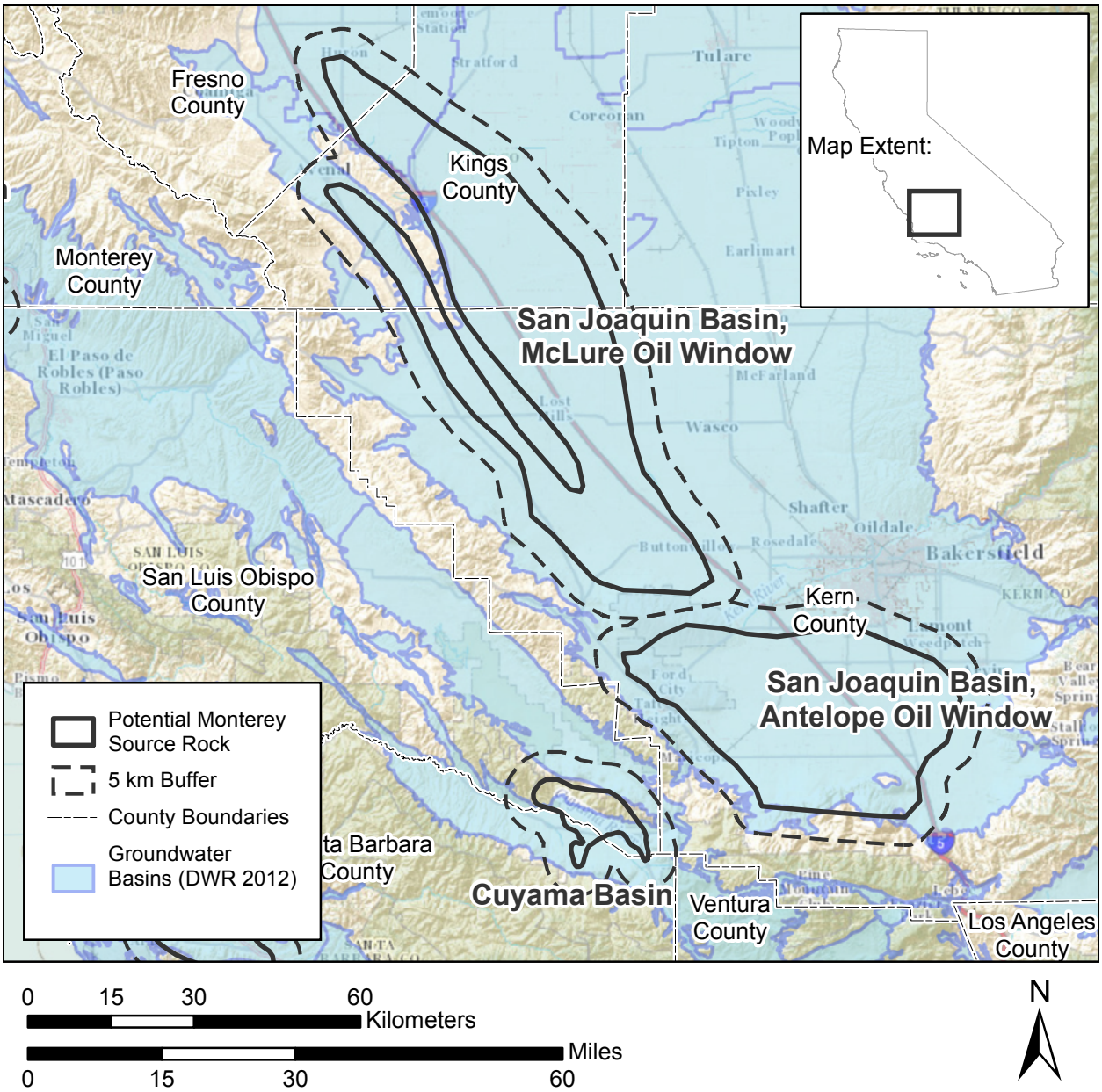
11. Public Resource Code section 3160, subdivision (d)(1)(F)(iii)

demonstrates that there are no "protected waters," meaning that water contains high levels of salt (exceeds 10,000 mg/L total dissolved solids) or traces of oil (occurs inside of a hydrocarbon-bearing zone). As of April 1, 2015, a total of 18 exemptions have been granted, generally covering 1-square mile sections or smaller areas, and all inside of four fields: North and South Belridge, Elk Hills, and Seneca-Coalinga (California State Water Resources Control Board, 2015).

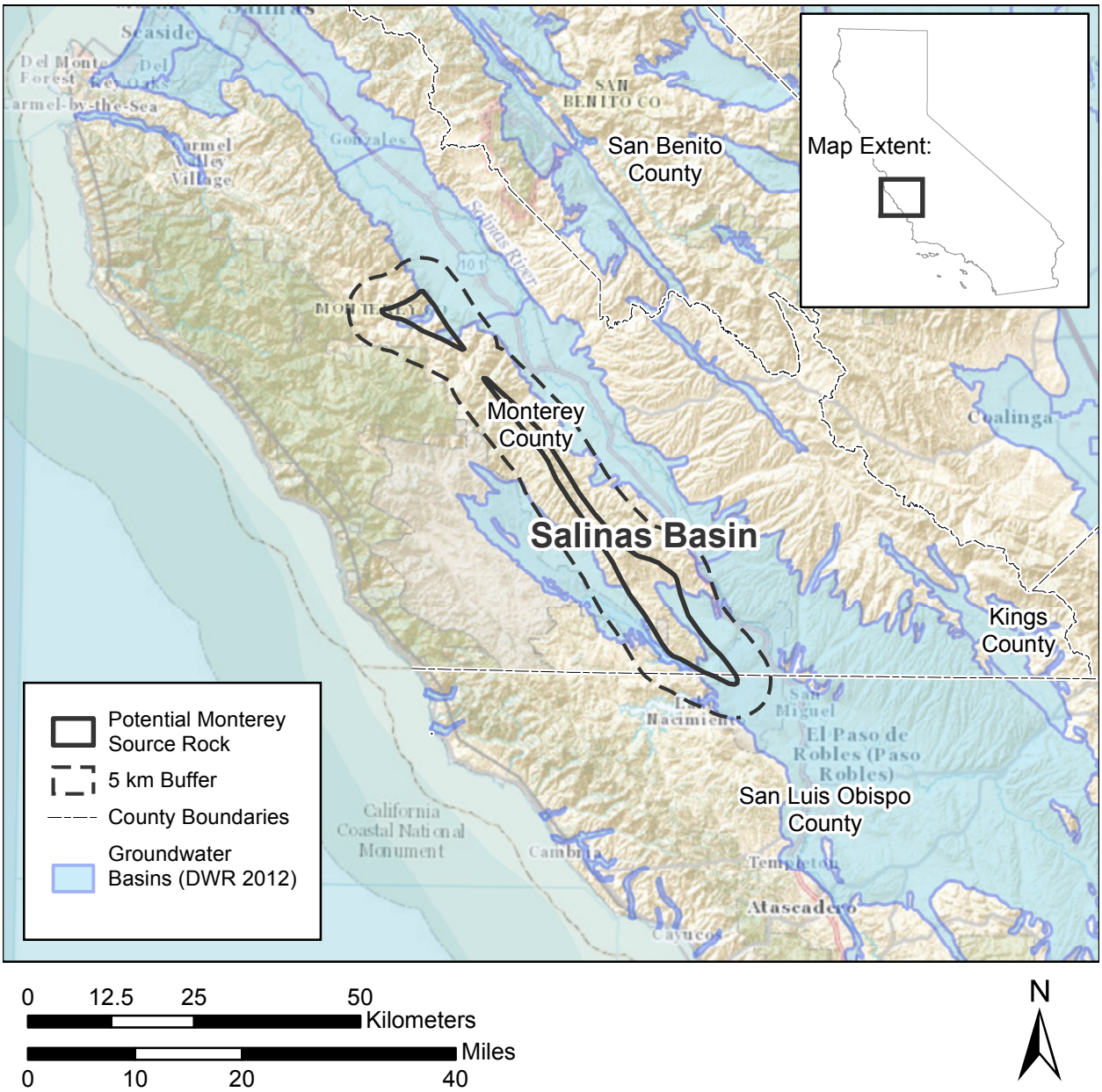
Subsurface injection was the second most common disposal method for produced water from stimulated wells, as discussed in more detail in Volume II, Chapter 2. However, there are significant concerns about whether California's Underground Injection Control (UIC) program is adequately protective of underground sources of drinking water (USDWs) – defined as groundwater aquifers that are used for water supply or could one day supply water for human consumption (Kell 2011; Walker, 2011). Currently, the State Water Board is reviewing injection wells that may be disposing of oilfield wastes in aquifers that lack hydrocarbons and contain water with less than 10,000 mg/L total dissolved solids. These wells are being reviewed for "proximity to water supply wells or any other indication of risk of impact to drinking water and other beneficial uses" (Bohlen & Bishop, 2015). We discuss this issue in more detail in Volume II, Chapter 2.

Table 3.4-5. Area of groundwater basins overlapping with Monterey source rock oil windows and their 5 km (3 mi) buffer, in square kilometers.

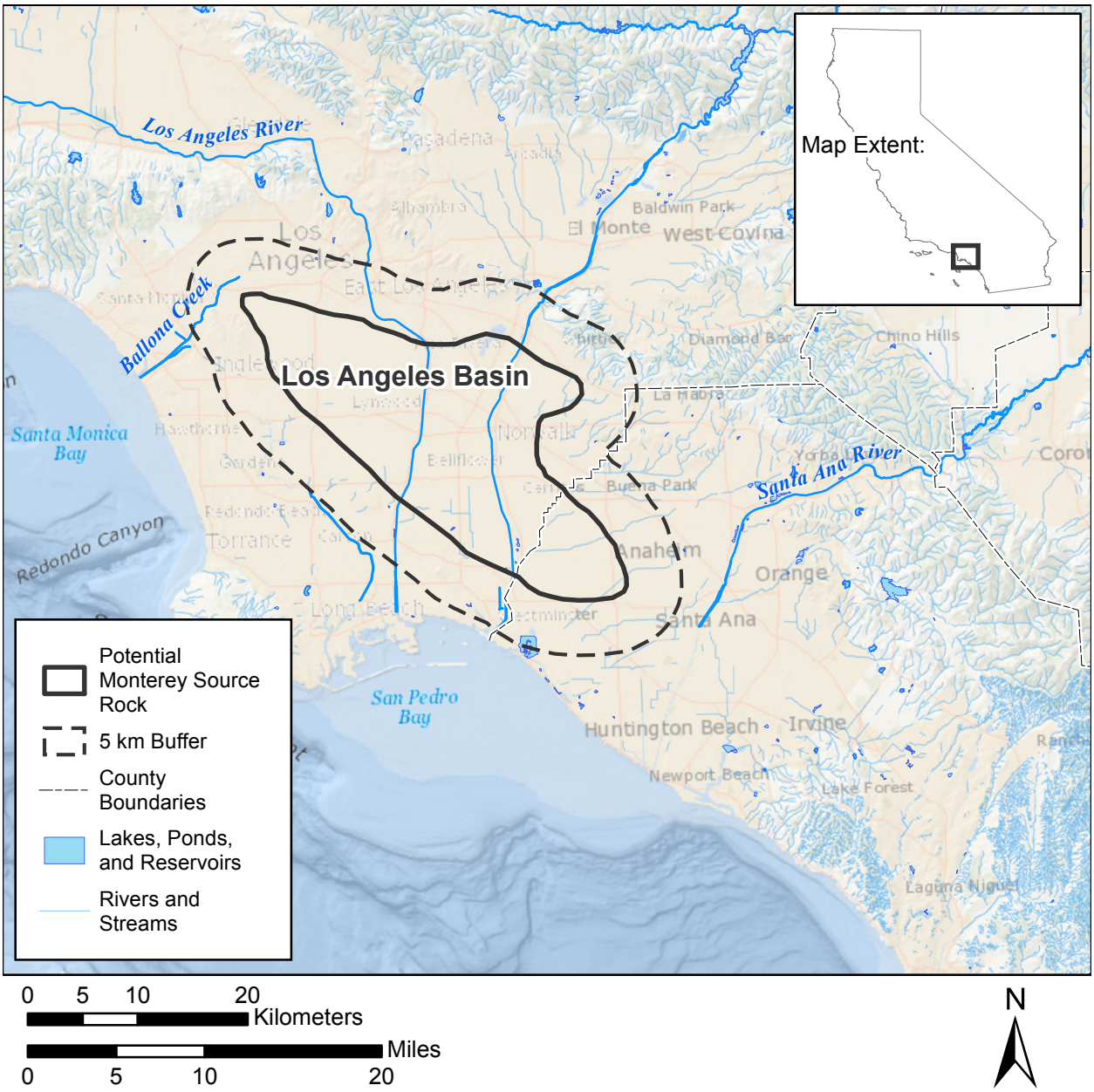
Basin	Source Rock Area (km²)	Area of Groundwater Basin that Overlies source Rock	
		Over source rock	In 5 km Buffer
Cuyama Basin	147	82	600
Los Angeles Basin	455	455	1,492
Salinas Basin	222	48	565
San Joaquin Basin	3,634	3,584	8,703
Santa Maria Basin	290	259	1,021
Ventura Basin	1,097	388	986
Total	**5,845**	**4,817**	**13,367**


Fresno County
Kings County
Monterey County
San Joaquin Basin, McLure Oil Window
San Luis Obispo County
Kern County
San Joaquin Basin, Antelope Oil Window
Cuyama Basin
Ventura County
Los Angeles County
Map Extent:
Potential Monterey Source Rock
5 km Buffer
County Boundaries
Groundwater Basins (DWR 2012)
0 15 30 60 Kilometers
0 15 30 60 Miles
N

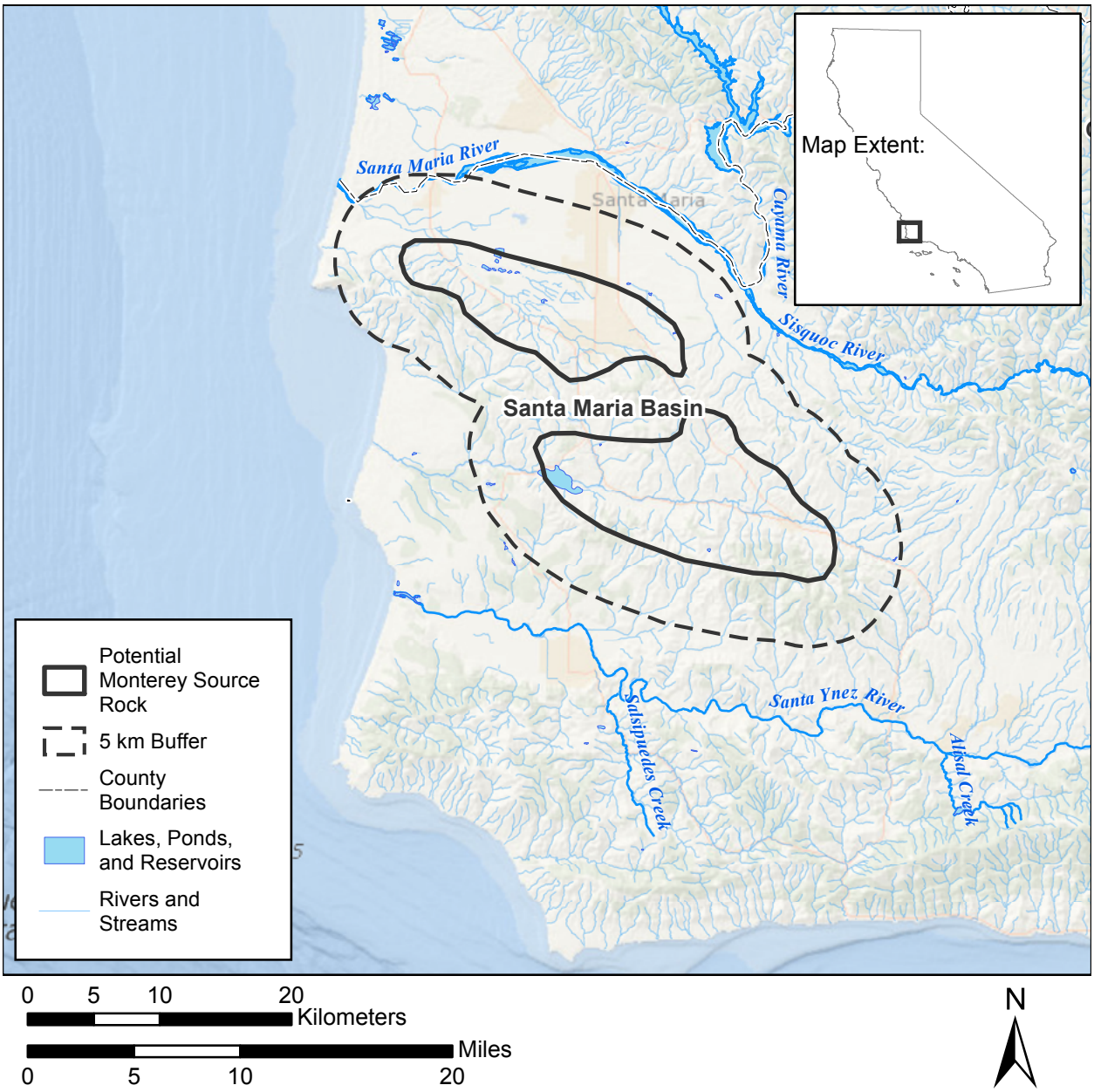
a)


Map Extent:
San Benito County
Monterey County
Salinas Basin
Kings County
San Luis Obispo County
Potential Monterey Source Rock
5 km Buffer
County Boundaries
Groundwater Basins (DWR 2012)
0 12.5 25 50 Kilometers
0 10 20 40 Miles
N

b)


Map Extent:
Los Angeles Basin
Los Angeles River
Ballona Creek
Santa Monica Bay
Redondo Canyon
San Pedro Bay
Santa Ana River
Pasadena
Los Angeles
East Los Angeles
Baldwin Park
El Monte
West Covina
Diamond Bar
Chino Hills
La Habra
Norwalk
Buena Park
Anaheim
Orange
Santa Ana
Torrance
Long Beach
Huntington Beach
Irvine
Newport Beach
Lake Forest
Potential Monterey Source Rock
5 km Buffer
County Boundaries
Lakes, Ponds, and Reservoirs
Rivers and Streams
0 5 10 20 Kilometers
0 5 10 20 Miles
N

c)



d)

Figure 3.4-6. Maps of groundwater basins (or alluvial aquifers) overlying the Monterey source rock in (a) San Joaquin and Cuyama Basins, (b) Salinas Basin, (c) Ventura and Los Angeles Basins, and (d) Santa Maria Basin. Data on groundwater basins from California Department of Water Resources (2003); further details on data in Appendix 3.C.

3.4.4.3. Water Wells

The risk of contamination from a hydraulic fracture intercepting a usable aquifer is minimal when fracturing source rock, as the depth of Monterey source rock is on the order of 3,000 m (9,843 ft),[12] while aquifers used for drinking, irrigation and domestic purposes are at much shallower depths: as deep as 1,200 m (4,000 ft) in the Los Angeles Basin, 1,000 m (3,500 ft) in the San Joaquin Basin, and 300 m (1,000 ft) in the Salinas Basin (Planert and Williams 1995). However, the other pathways for potential contamination of groundwater are still plausible; these pathways are described in Volume II, Chapter 2. This is of particular concern where water wells are in close proximity to potentially contaminated aquifers, as there is an increased likelihood of human exposure. There is no reliable information on the number and location of water wells in California. Data from water well completion reports filed with DWR, however, gives some indication of the number of water wells within a given area.[13] We note, however, that these data are incomplete and are missing at least 50,000 wells drilled over the past 65 years plus wells drilled prior 1949 (Senter, 2015, pers. comm.). The wells data file reports the approximate location for 648,514 wells in the state. Information on the type of well was not available. An unknown number of these wells are for domestic or municipal use.

There were over 14,000 documented water wells in the area overlying the Monterey source rock. Within 5 km (3 mi) of the source rock, there are an additional 14,000 wells, for a total of about 28,000 wells. The largest number of wells overlying source rock is in the San Joaquin Basin (13,000 wells), followed by the Los Angeles Basin (10,000 wells) (Table 3.4-6). Far fewer wells are located near source rock in the Ventura, Santa Maria, Salinas and Cuyama Basins (140 - 1,800 wells per basin). Figure 3.4-7 shows the density of water wells throughout most of the footprint of potential Monterey Source Rock, apart from the Los Angeles Basin, which is depicted in Figure 3.4-8. Groundwater is an important water source for residents of the study area. For example, groundwater makes up one-third of the water supply for the 4 million residents of the Los Angeles coastal plain (Hillhouse et al., 2002).

Table 3.4-7 summarizes the number of documented wells overlying Monterey source rock by county and basin. In total, nine counties have wells that directly overlie source rock. There are a total of 10 counties in this area; however, the number of wells in San Luis Obispo is unknown due to missing data. Most wells above the Monterey source rock are

12. Monterey source rock is much deeper than most formations already developed in California. As shown in in Volume I Figure 3.15a, about 90% of hydraulically fractured wells in California reported true vertical depths shallower than 900 meters, or less than a third as deep as Monterey source rock. These relatively shallow hydraulic fractures are much closer to aquifers tapped for water use at the surface and thus the potential for contamination from them is higher than when fracturing deeper formations.

13. Since 1949, California law has required that landowners submit well completion reports to DWR, containing information on newly constructed, modified, or destroyed wells.

in Kern County, where there are 12,236 wells within the 5 km buffer. The fewest wells overlying the Monterey source rock are in Tulare County; the 5 km (3 mi) buffer zone of the San Joaquin Basin, McLure Oil Window overlaps only about 1 square mile of the southwest corner of Tulare County.

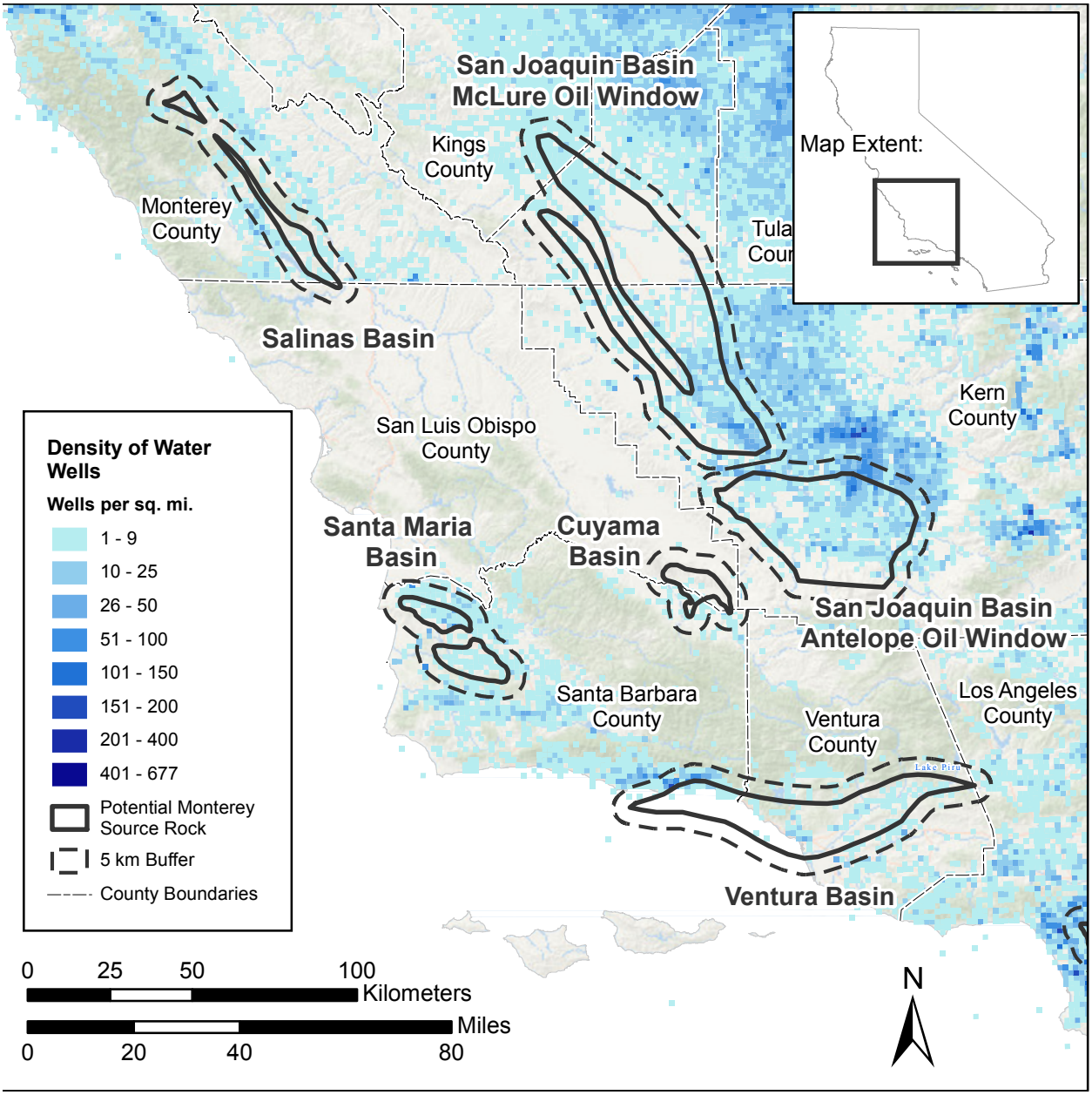


Figure 3.4-7. Density of water wells in Ventura, Santa Maria, Cuyama, San Joaquin and Salinas Basins, and footprint of potential Monterey source rock with 5 km (3 mi) buffer. Information on data source given in Appendix 3.C.

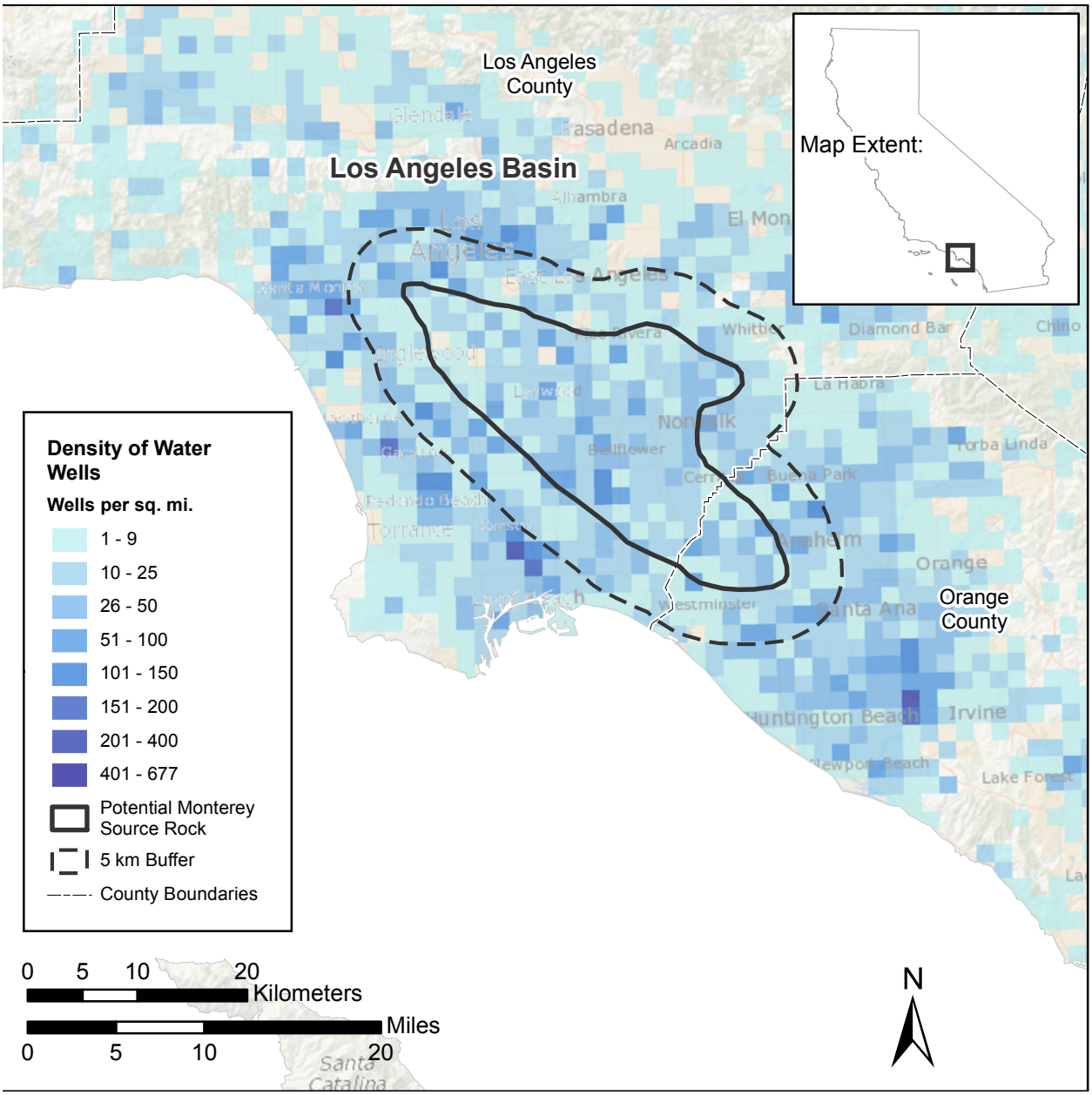


Figure 3.4-8. Density of water wells in the Los Angeles Basin and footprint of potential Monterey source rock with 5 km (3 mi) buffer. Data as in Figure 3.4-7.

Table 3.4-6. Approximate number of water wells overlying the Monterey source rock and 5 km (3 mi) buffer zone, by oil basin.

Basin	Over source rock	In 5 km Buffer	Total
Cuyama Basin	30	109	139
Los Angeles Basin	4,757	5,628	10,385
Salinas Basin	216	635	851
San Joaquin Basin, Antelope Oil Window	4,444	3,006	7,450
San Joaquin Basin, McLure Oil Window	3,575	2,081	5,656
Santa Maria Basin	559	1,224	1,783
Ventura Basin	832	958	1,790
Total	**14,413**	**13,641**	**28,054**

Table 3.4-7. Approximate number of water wells overlying the Monterey source rock and 5 km (3 mi) buffer zone, by county.

	Number of Water Wells			
County	Over source rock	In 5 km Buffer	Source Rock + Buffer	In County
Fresno	155	180	335	44,679
Kern	7,468	4,768	12,236	38,388
Kings	399	184	583	7,534
Los Angeles	3,933	3,873	7,806	20,589
Monterey	217	642	859	12,124
Orange	823	1,792	2,615	8,921
San Luis Obispo*	?	?	?	?
Santa Barbara	1,066	1,983	3,049	5,475
Tulare	0	4	4	23,717
Ventura	351	216	567	1,025
Total	**14,413**	**13,641**	**28,054**	**162,452**

** Well data was not available for San Luis Obispo County. It is highly probable that there are some wells over the Cuyama Basin, and within 5 km (3 mi) of the Santa Maria Basin, but the numbers are unknown.*

3.4.4.4. Water Supply Systems

In this section, we consider the spatial relationship between Monterey source rock and local water suppliers given the possibility of a major increase in water use to develop source rock reservoirs, and potential risks for contamination of nearby water sources. In this section, we overlay the boundaries of source rock with the boundaries of water supplier service areas to better understand the overlap and potential concerns for water supply. Local waters suppliers obtain water from a mix of sources including ground water wells, surface water withdrawals, and water imported from other areas via canals and

pipelines. There is no definitive map or data source that shows the location of wells or surface water intakes for municipal water systems. Where water supplier service areas are in close proximity to well stimulation, it raises concerns, but does not mean that contamination will occur or is even likely. However, a proximity analysis can help identify those areas that are of concern.

The major source of stimulation water in recent reports has been water suppliers (a category which includes both irrigation districts and municipal water suppliers. In 2014, operators obtained water needed for well stimulation from nearby irrigation districts (68%), produced water (13%), operators' own wells (13%), a nearby municipal water supplier (4%), or a private landowner (1%). These statistics are based on 495 completion reports filed by operators and published by DOGGR between January 1 and December 10, 2014 (DOGGR, 2015c).

To begin to understand areas of potential concern, we mapped where water suppliers' service areas overlap with Monterey source rock. Using data and maps of water suppliers' service areas obtained from the California Department of Public Health (DPH), we identified 148 water systems, both public and privately owned, that overlie or are within 5 km (3 mi) of the Monterey source rock (Table 3.4-8 and Figure 3.4-9). These systems currently serve more than 10.3 million Californians. Water systems that rely on local groundwater or surface water may be more vulnerable to pollution or groundwater depletion. Some water suppliers exclusively use groundwater, while many others use a combination of local groundwater wells and imported water delivered by canal or pipeline from watersheds often hundreds of miles away. Among the 84 water suppliers with a population of over 3,000, 78 use some groundwater, four do not use groundwater, and for two others it is unknown if they use groundwater.

Table 3.4-8. Water suppliers that directly overlie or are within 5 km (3 mi) of the Monterey source rock and their population served.

Basin	Number of Water Suppliers	Population served
Cuyama Basin	2	17,600
Los Angeles Basin	72	8,555,731
Salinas Basin	12	21,996
San Joaquin Basin, Antelope Oil Window	13	443,763
San Joaquin Basin, McLure Oil Window	9	42,926
Santa Maria Basin	9	162,838
Ventura Basin	31	1,097,763
Total	**148**	**10,342,617**

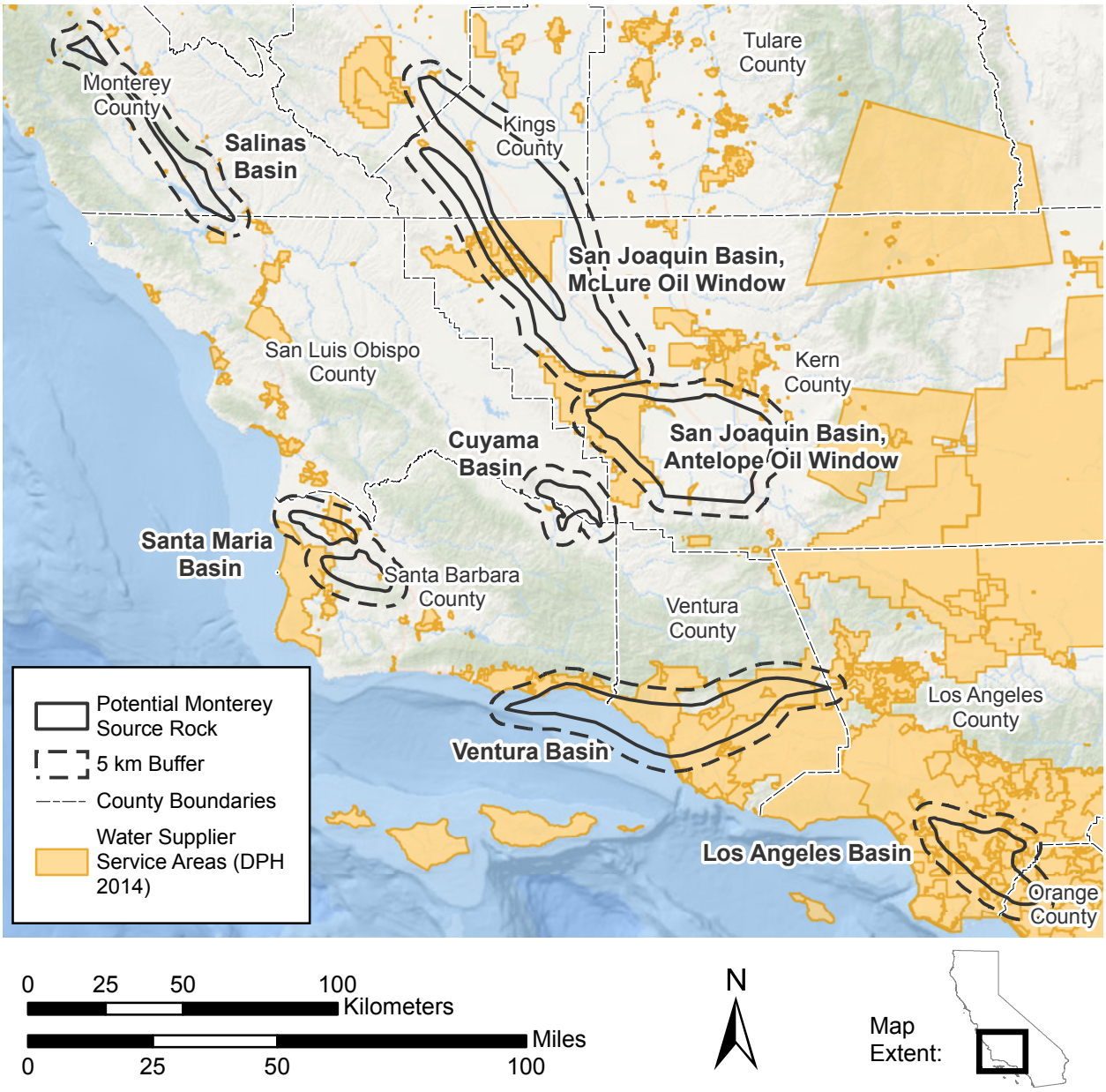


Figure 3.4-9. Water supplier service areas that directly overlie or are within 5 km of the Monterey source rock. Data from California Department of Public Health (2014); details on data in Appendix 3.C.

3.4.5. Potential Impacts to the Atmosphere

If a Monterey Shale source rock play were developed, it could occur in various densities and configurations. It is unclear what the air quality impacts of this play would be, due to the unknown nature of the technology that would be required to access and economically extract the oil.

A first approximation is that development in this play would result in air quality impacts per unit of oil production that are similar in magnitude to current California oil production. The plausibility of this assumption is supported by the following reasons:

1. Oil production from this hypothetical play would be subject to similar air quality rules as development in other California oilfields.

2. Hydrocarbon production from other source rock plays (e.g., Bakken and Eagle Ford liquids plays, Barnett gas play) has not been found to have unavoidably larger impacts per unit of production than conventional oil production. High air emissions from the Bakken play are largely due to associated gas management schemes that would not be acceptable under California regulation (e.g., flaring).

While fracturing consumes energy and results in short-term air emissions, these emissions can be expected to be small compared to emissions associated with decades of lifting, processing, injecting and transporting reservoir fluids. For example, Allen et al. (2013) found green completions technologies effective at reducing emissions from fracturing flowback to very low levels (reductions of 99% of total gas).

The air quality impacts of developing these shales could be problematic due to the general alignment between areas of mature Monterey Shale and areas with already poor air quality. For example, Figure 3.4-10 shows the spatial overlap of mature Monterey Shale source rock and California air districts that are in non-attainment status for Particulate Matter (PM2.5) and ozone. For example, as of January 2015, the San Joaquin Valley region is in “extreme” nonattainment with respect to 2008 8-hour ozone standards and in moderate nonattainment of 2006 PM-2.5 standards (U.S. EPA, 2015). Significant overlap is found between the San Joaquin Valley Unified Air Pollution Control District (SJVUAPCD) and the largest area of mature Monterey Shale source rock. Other major areas of mature source rock coincide with the South Coast Air Quality Management District (SCAQMD) and the Ventura County Air Pollution Control District (VCAPCD). Development in these areas could exacerbate already problematic air quality.

Other regions of mature source rock occur in California’s central coast, under largely agricultural regions of the Santa Barbara, San Luis Obispo and Monterey Bay Unified air districts. While there are active oil fields in all of these areas with source rock, these tend to be smaller in well counts and volumes of production than fields in the San Joaquin Valley and South Coast air districts. Significant development of a source rock play in these regions could impact air quality in areas with relatively good air quality.

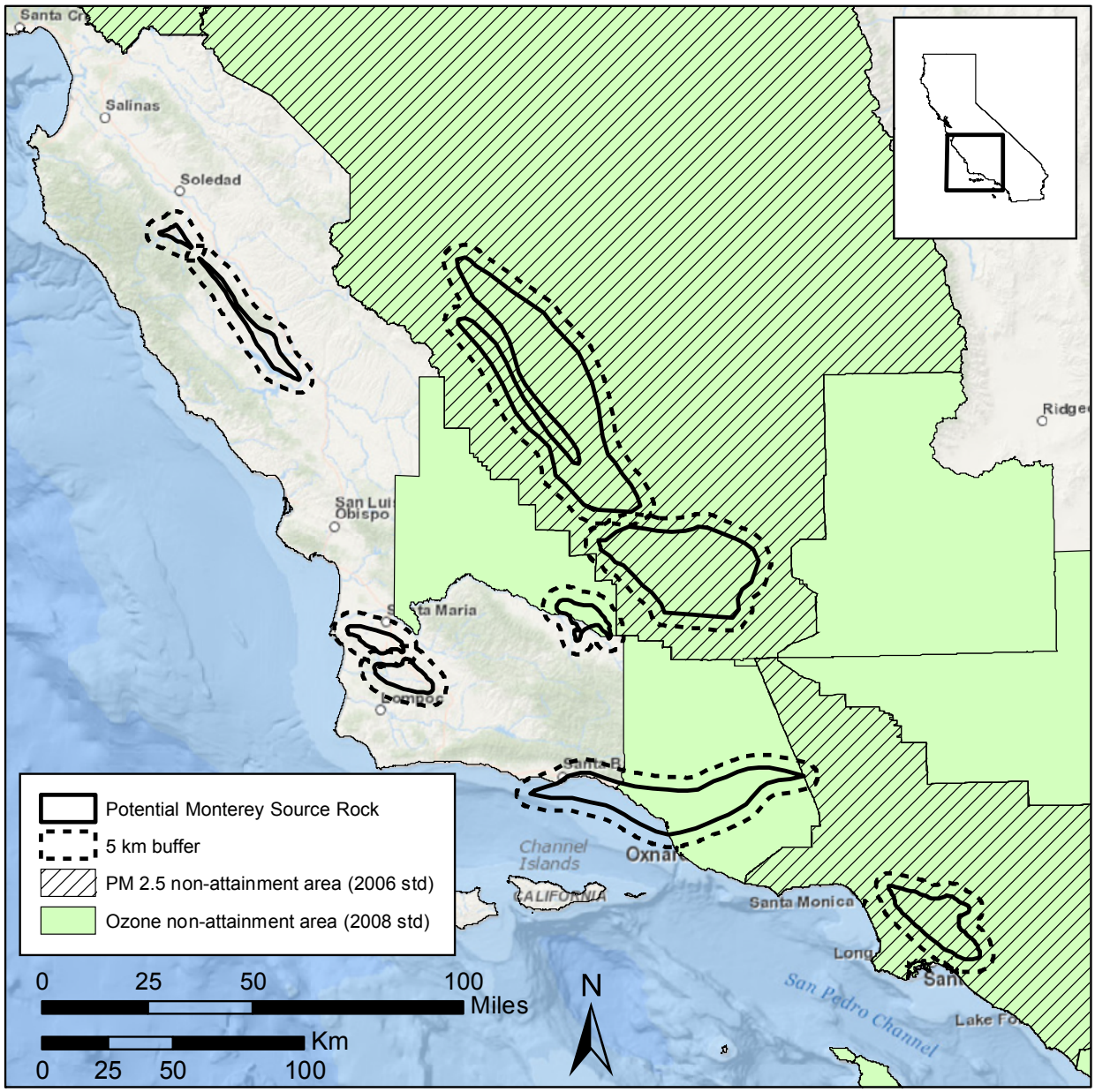


Figure 3.4-10. Spatial alignment between mature Monterey source rock (red) and air districts with PM 2.5 and ozone non-attainment.

Despite the above concerns with additional air quality impacts in non-attainment basins, the level of impact from oil and gas development from a source rock play should be expected to be minor unless development of source rock reached levels of production many times higher than current production in the state. As shown in Volume II, Chapter 3, oil and gas production is the cause of only a small fraction of most criteria air pollutants, dust, and greenhouse gas emissions in California, when measured at the scale of managed air districts (nearly always <10%, and often <1%, per air district). One exception is the emissions of HAPs in the San Joaquin Valley region, where the oil and gas sector is responsible for large fractions of emissions of some HAPs that are commonly associated with hydrocarbon production. Also, note that local impacts of oil and gas development at the county, municipality, or neighborhood scale can be significantly larger than the share of impacts across managed air districts. These local effects are discussed in Volume II, Chapter 3, Volume II, Chapter 6, and Volume III [LA and SJV case study]. Volume II, Chapter 6 describes the public health implications of local concentrations of pollutants in detail.

3.4.6. Potential Impacts to Seismicity

In rare cases, earthquakes of concern can result from well stimulation and the production it enables either through injection of wastewater into Class II wells, or hydraulic fracturing. Both activities inject fluid underground, which causes an increase in underground pressure that can lower the effective confining stress on a fault, hence allowing the fault to slip in an earthquake.

All wells generate wastewater that can be disposed of in a Class II well, not just those that are stimulated. If an earthquake of concern were to be induced by injection of wastewater, it would be considered an indirect impact of well stimulation; an earthquake related to hydraulic fracturing would be a direct impact. Wastewater disposal is associated with a larger potential hazard of induced seismicity than hydraulic fracturing operations because wastewater disposal injects greater volumes of fluid over a longer period of time. Injecting larger volumes than have been used for well stimulation in California to date at the greater depths of the Monterey source rock could increase the direct seismic impact from hydraulic fracturing to some extent; however, the indirect seismic hazard from wastewater disposal would likely still be significantly higher. While shifting to Monterey source rock targets would necessarily increase the depth of well stimulation, the depth of wastewater disposal would not necessarily change. However, production in new places as well as large increases in wastewater could necessitate finding new target horizons for wastewater disposal; we cannot predict at this time whether those horizons would be deeper or shallower as it depends on local geology.

The probability and size of an induced seismic event depends on the volumes of fluids injected, the pressure of injection, the lithology of the injection horizon, and the position of wells in relation to faults and past seismicity. The effect of the event on people depends on its size, proximity to human populations and infrastructure, as well as earthquake

preparedness. Volume II, Chapter 4 discusses seismic hazard in detail. Below we present information on the footprint of the potential Monterey source rock and where it overlaps with faults, historic seismicity, and human populations to provide a brief, qualitative overview of the seismic risk that may be associated with developing Monterey source rock.

Figures 3.4-11 through 3.4-15 include faults active during the Quaternary period (last 1.6 million years) from the U.S. Quaternary Fault and Fold (USQFF) database (http://earthquake.usgs.gov/hazards/qfaults). The earthquake locations shown in the maps were determined by applying high-precision analysis techniques (waveform cross-correlation and clustering) to seismic records from the Southern California Seismic Network for the period 1981 – June 2011 (Hauksson et al. 2012). We include active and plugged UIC Class II wastewater disposal well locations from the Division of Oil Gas and Geothermal Resources (DOGGR) well database to understand where wastewater disposal has been occurring over the last few decades (1977 – 2014) (DOGGR, 2014a). If there were to be development of source rock some distance from present-day wastewater disposal wells, most likely new wells would be drilled.

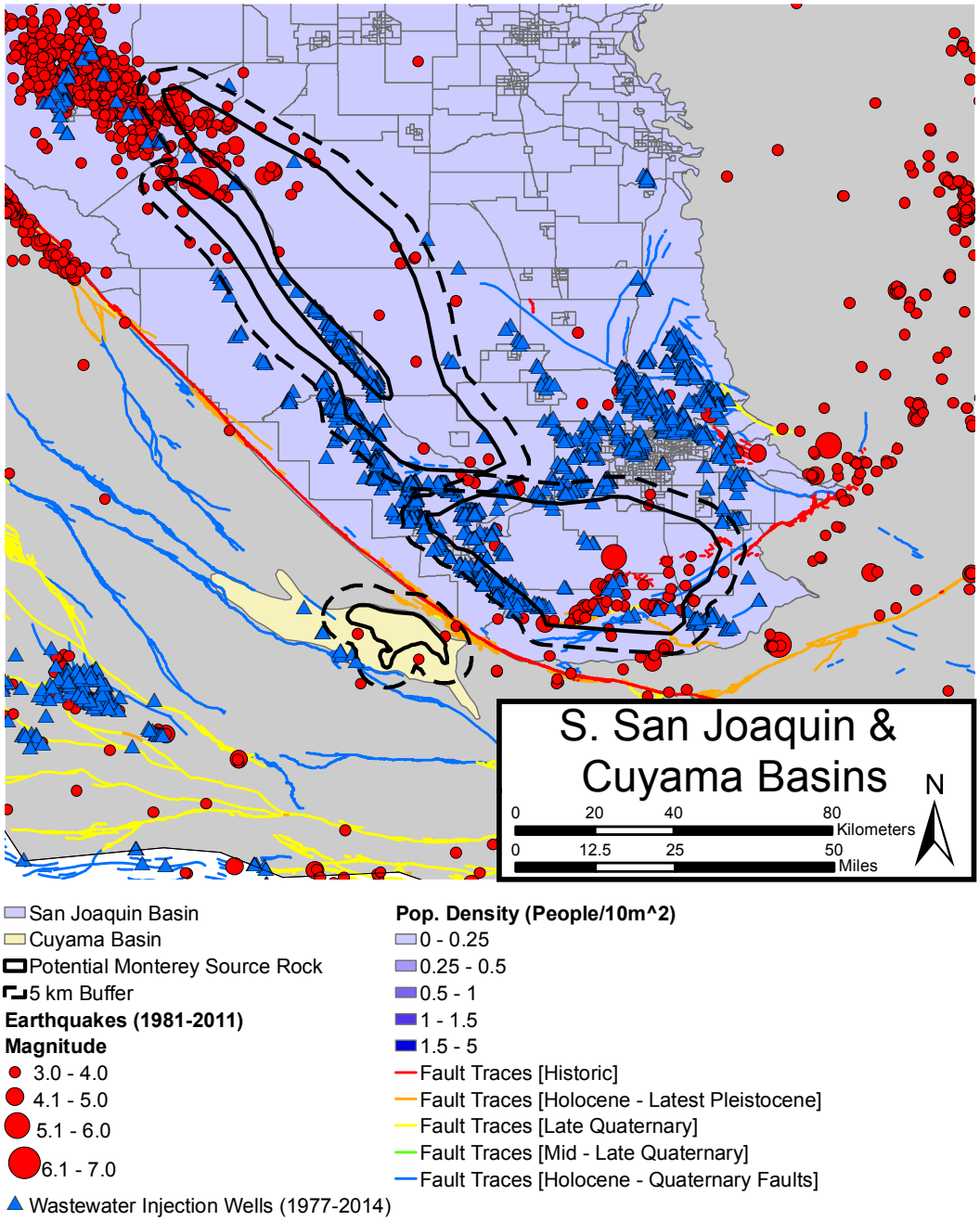


Figure 3.4-11. Factors influencing the potential for induced seismicity in the vicinity of Monterey source rock in the San Joaquin and Cuyama Basins. The maps show potential source rock, the 5 km buffer zone, seismic activity magnitude ≥ 3.0, wastewater injection wells, faults, and population density. Wastewater disposal well locations (1977-2014) from DOGGR injection database; seismic events (1981-2011) from SCEDC catalog. Traces of active faults from USQFF are color-coded by age of most recent activity.

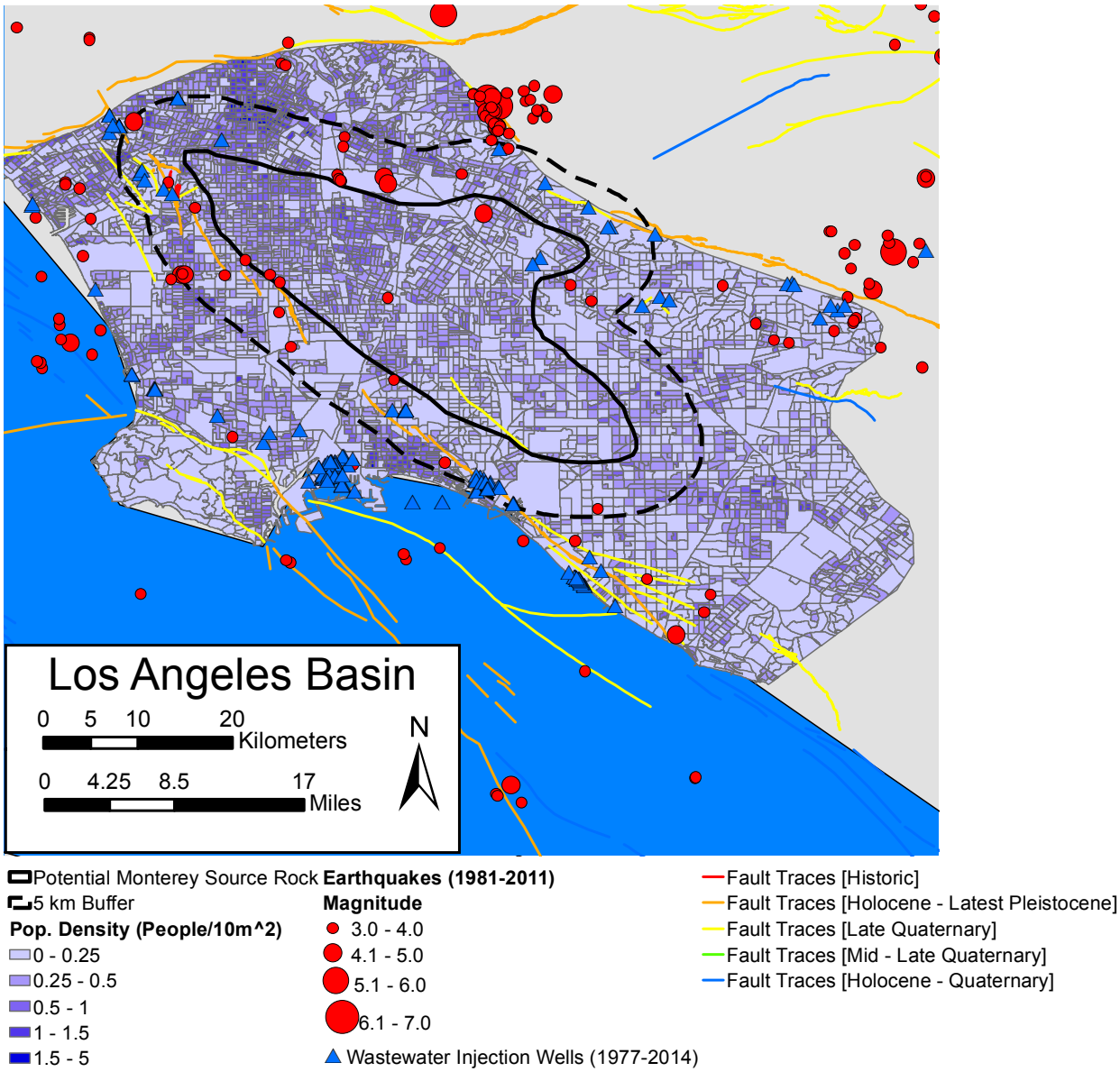


Figure 3.4-12. Factors influencing the potential for induced seismicity in the vicinity of Monterey source rock in the Los Angeles Basin. Explanation as in Figure 3.4-11.

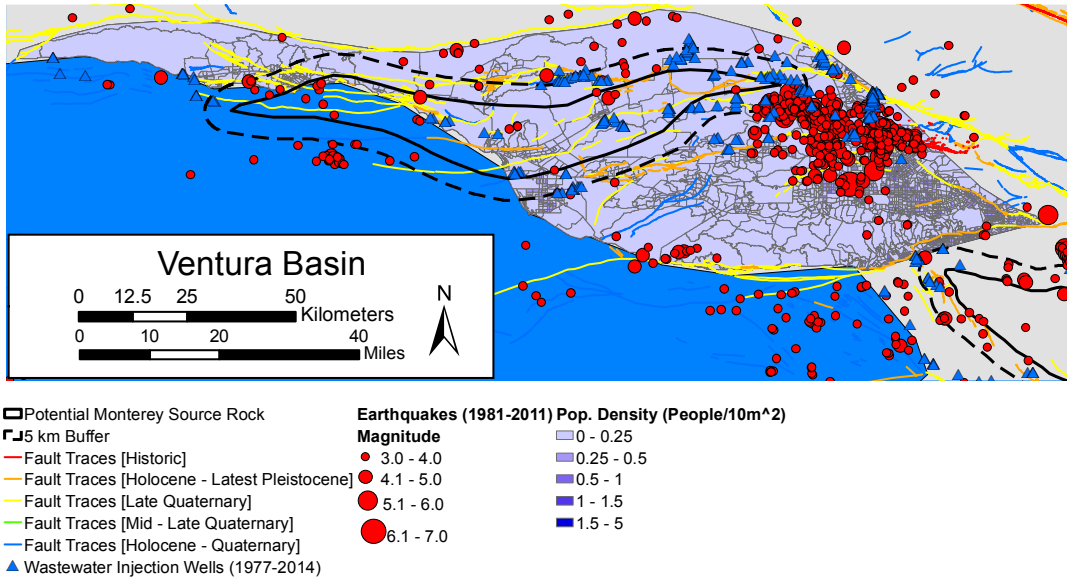


Figure 3.4-13. Factors influencing the potential for induced seismicity in the vicinity of Monterey source rock in the Santa Barbara-Ventura Basin. Explanation as in Figure 3.4-11.

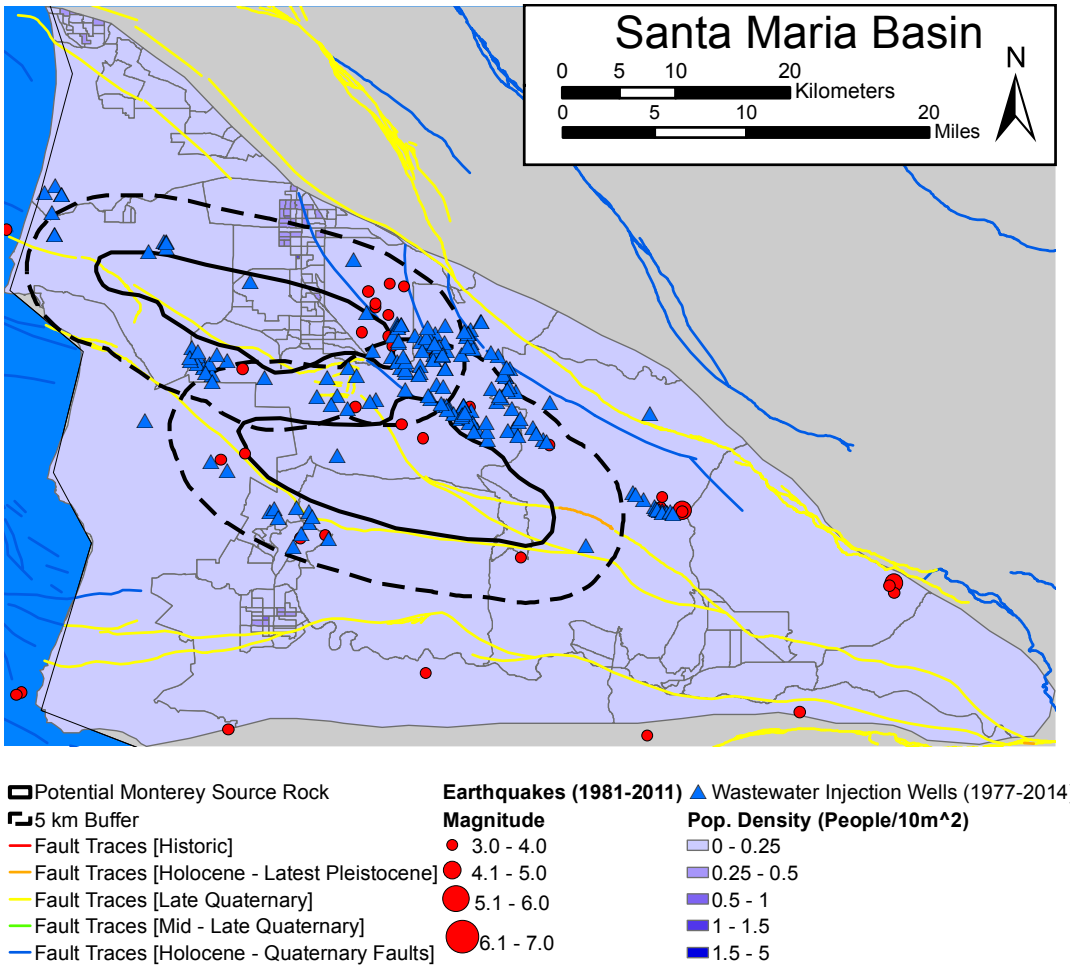


Figure 3.4-14. Factors influencing the potential for induced seismicity in the vicinity of Monterey source rock in the Santa Maria Basin. Explanation as in Figure 3.4-11.

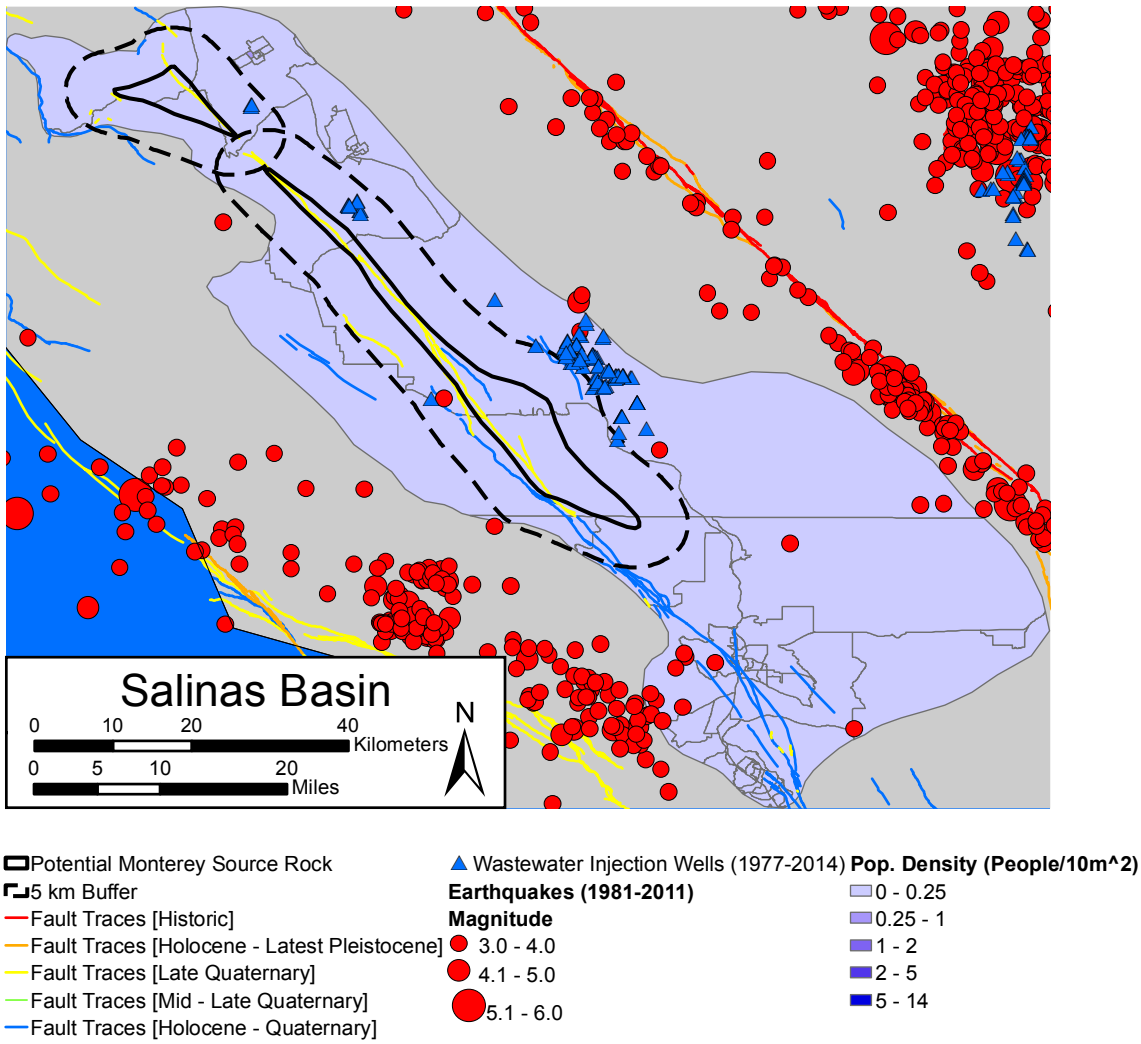


Figure 3.4-15. Factors influencing the potential for induced seismicity in the vicinity of Monterey source rock in the Salinas Basin. Explanation as in Figure 3.4-11.

Within the San Joaquin Basin (Figure 3.4-11), there are clusters of seismic events and large active faults in the southernmost portion of the Monterey source rock footprint (the events in the dense cluster to the northwest are mostly aftershocks of M6+ earthquakes that occurred on deeply buried (blind) faults in 1983 and 1985). Very few earthquakes have been recorded and no faults have been mapped in the central portion of the Monterey source rock zone within the San Joaquin Basin, suggesting a low seismic hazard there. When estimating seismic risk it is necessary to also consider population and infrastructure density. Most areas of the San Joaquin Basin have lower population and infrastructure densities than urban centers like Los Angeles, implying relatively low overall risk throughout the basin. However, large-scale development of Monterey source rock could increase both population density and the scale of infrastructure to some degree.

In the Santa Barbara-Ventura and Salinas Basins (Figure 3.4-13 and 3.4-15), Monterey source rock zones are nearly directly coincident with large active faults having relatively high slip rates slip rates (greater than 1 mm/year). Even though few earthquakes larger than m^3.0 have been recorded near these faults, there is a possibility of elevated potential seismic hazard if future large-volume wastewater disposal occurred within the Monterey footprint in these basins because fluid injection would be occurring near large active faults capable of generating larger magnitude earthquakes. For seismic risk assessment, this observation is especially relevant in more populated areas.

The faults within the Monterey footprint in the Santa Maria Basin have low slip rates (less than 1 mm/year) and there is only sparse, low-magnitude seismicity (Figure 3.4-14). Only one relatively short fault having uncertain activity has been mapped within the Monterey zone of the Los Angeles Basins (Figure 3.4-12), and the seismicity is similarly sparse. Thus, these Monterey source rock zones appear to have lower potential seismic hazard compared to those in the Salinas and Ventura Basins. However, the very large population density in Los Angeles results in a high potential seismic risk despite the relatively low potential incremental seismic hazard. As discussed in Volume II, Chapter 4, Section 4.4.2., microseismic monitoring has been used to monitor hydraulic fracturing in the Inglewood oilfield in the Los Angeles Basin (e.g., Cardno ENTRIX, 2012).

There is a large degree of uncertainty in the preliminary appraisal of seismic risk described above. First, it is generally understood that California has many unmapped faults, which can only be imaged with 3-D seismic reflection surveying, or inferred through analysis of earthquake patterns. Secondly, at present, records of fluid injection in the DOGGR database are likely inadequate to carry out a comprehensive assessment of the potential for induced seismicity in the state. In particular, the monthly averages of injection volume and pressure data currently reported, are too coarse to be useful in many cases. There is also a lack of readily available information on injection depth for most wastewater disposal wells. Improving the quality of these data could inform future induced seismic hazard assessments. At a more fundamental level, there is a lack of understanding of the potential for subsurface fluid injection to cause earthquakes in an active tectonic margin like California, compared with regions in the continental interior where recent cases of induced seismicity related to wastewater injection have occurred. How differences in the geology, tectonic stressing rate and seismicity between California and the continental interior influence the potential for induced seismic hazard has yet to be studied. For more discussion on this uncertainty and additional data gaps, see Chapter 4 of Volume II.

We have outlined some of the factors relevant to assessing seismic risk in the footprint of the Monterey source rock. If large-scale development of Monterey source rock were to commence, it would be important to consider not just the locations of faults, historic seismic activity, and human populations, as discussed here, but also factors such as the local lithology of the injection horizon, pressure and volume of fluid injection, and proximity to human infrastructure to evaluate seismic risk. There also are important data gaps in our understanding of seismicity induced by underground injection in

California that would need to be addressed to conduct thorough risk assessments, as described in Volume II, Chapter 4, Section 4.6. In addition, it would be useful to consider implementing practices to mitigate seismic risk as described in Volume II, Chapter 4, Section 4.5.

3.4.7. Potential Impacts to Wildlife and Vegetation

In this section we examine how the footprint of potential Monterey source rock intersects habitat for wildlife and vegetation. There are a number of ways in which new development of source rock could impact wildlife and vegetation. Construction of well pads and other oil and gas production infrastructure in areas that support native species causes habitat loss and fragmentation. Increased disturbance and traffic can promote invasive species. Increased noise, light, traffic, water contamination, and water use can adversely affect populations of organisms. We do not have enough information about future Monterey source rock development to quantify these impacts in detail, but we look at the footprint of potential source rock to understand the types of habitats and native species that could be impacted by development.

Figure 3.4-16 shows the spatial alignment of source rock with the land cover categories in the National Vegetation Classification system. As indicated in Table 3.4-9, the two biggest land cover categories are agricultural vegetation and human land use, mainly driven by the dominant land uses in the San Joaquin and Los Angeles Basins. There is also some area that is shrubland and grassland in all basins outside of Los Angeles, a small amount of water mainly because of the portion of source rock that is offshore in the Ventura Basin, and a very small amount of forested land.

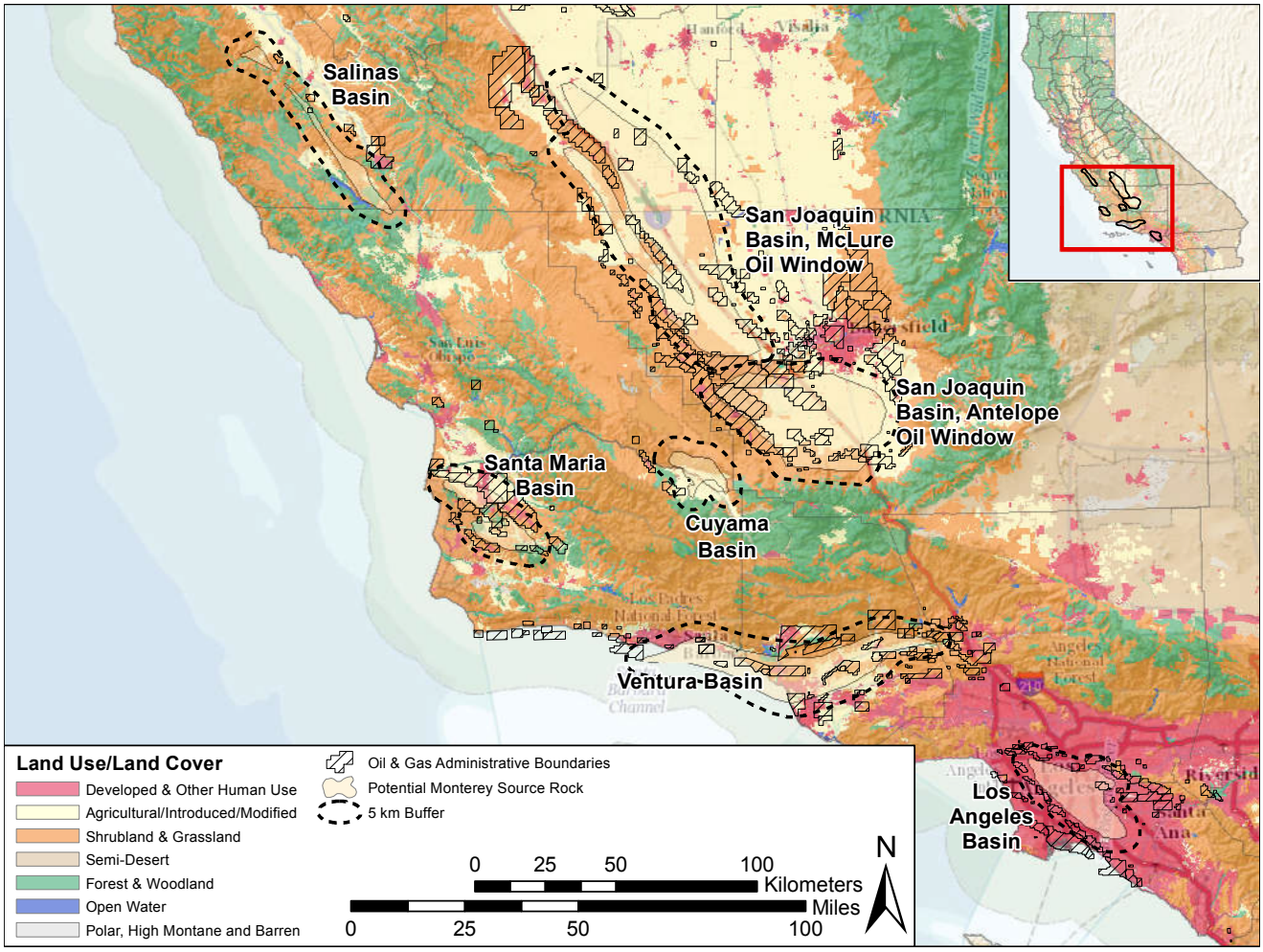


Figure 3.4-16. Overlay of potential Monterey source rock and land use. Land use data from Department of Conservation (2012) and U.C. Santa Barbara Biogeography Lab (1998).

Table 3.4-9. National Vegetation Classification category overlapping with potential Monterey source rock. For a more detailed table broken out by county, see Appendix 3.E.

	Over Source Rock (km²)	In 5 km Buffer (km²)	Over Source Rock + Buffer (km²)	Over Source Rock + Buffer (% of Total)	Outside source rock (km²)	Total (km²)
Agricultural Vegetation	2,900	1,800	4,700	8.9%	48,400	53,100
Developed & Other Human Use	700	900	1,600	7.2%	20,500	22,100
Forest & Woodland	200	400	600	0.4%	144,000	144,600
Open Water	400	400	700	3.4%	19,700	20,500
Shrubland & Grassland	1,700	2,800	4,400	6.4%	63,900	68,300

Publicly owned property, conservation lands and easements often provide important open space for native species. As shown in Figure 3.4-17 and Table 3.4-10, a relatively small proportion (13%) of the potential source rock area falls into these categories. Some of these areas are set aside expressly for conservation, such as the Wind Wolves preserve in the southern San Joaquin, and would be unlikely sites for any oil and gas development. Others, however, U.S. Bureau of Land Management and Forest Service land, are intended to serve multiple purposes and could be leased for petroleum production.

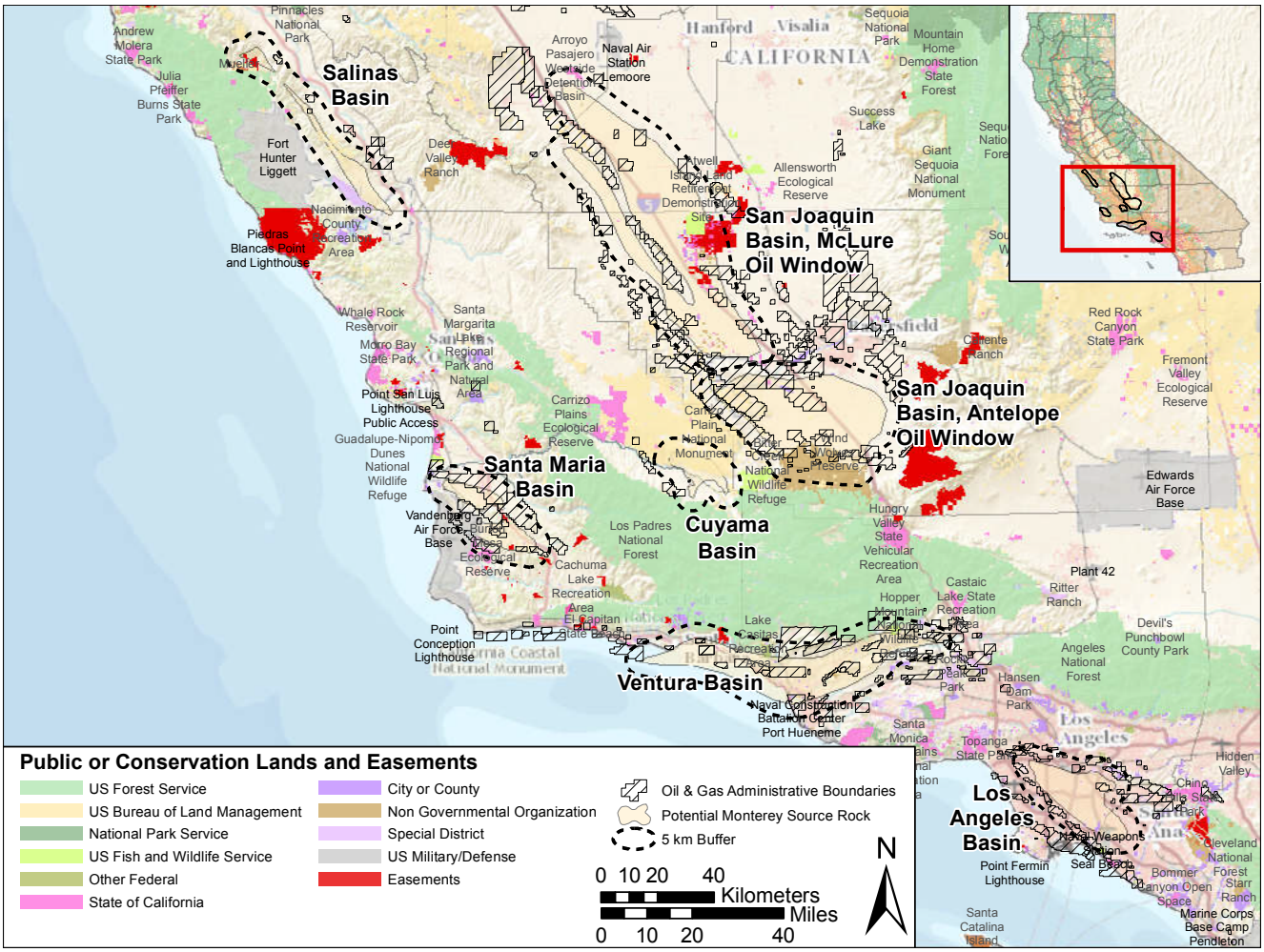


Figure 3.4-17. Overlay of potential Monterey source rock with public lands, conservation lands and easements.

Table 3.4-10. Proportion of potential Monterey Source Rock that is public land or conservation land and easements compared with other ownership types.

	Over Source Rock (km^2)	In 5 km Buffer (km^2)	Over Source Rock + Buffer (km^2)	Over Source Rock + Buffer (% of Total)	Outside Source Rock + Buffer
Public Land or Conservation Lands and Easements	600	1,000	1,600	13%	219,800
Other Ownership	5,300	5,200	10,500	87%	193,300
Total	5,900	6,300	12,100	100%	413,100

The United States Fish and Wildlife Service can designate lands essential for the survival of a threatened or endangered species as critical habitat. Shown in Figure 3.4-18 are the areas of critical habitat that overlap with potential source rock. As indicated by Table 3.4-11, there are a few cases in which much or even all of a species' critical habitat is within the footprint of potential Monterey source rock, such as the Buena Vista Lake Shrew, which has a very small amount of critical habitat in the San Joaquin Basin, and the Ventura marsh milk-vetch. Others, such as the California condor, have a substantial amount of critical habitat in the vicinity of potential source rock.

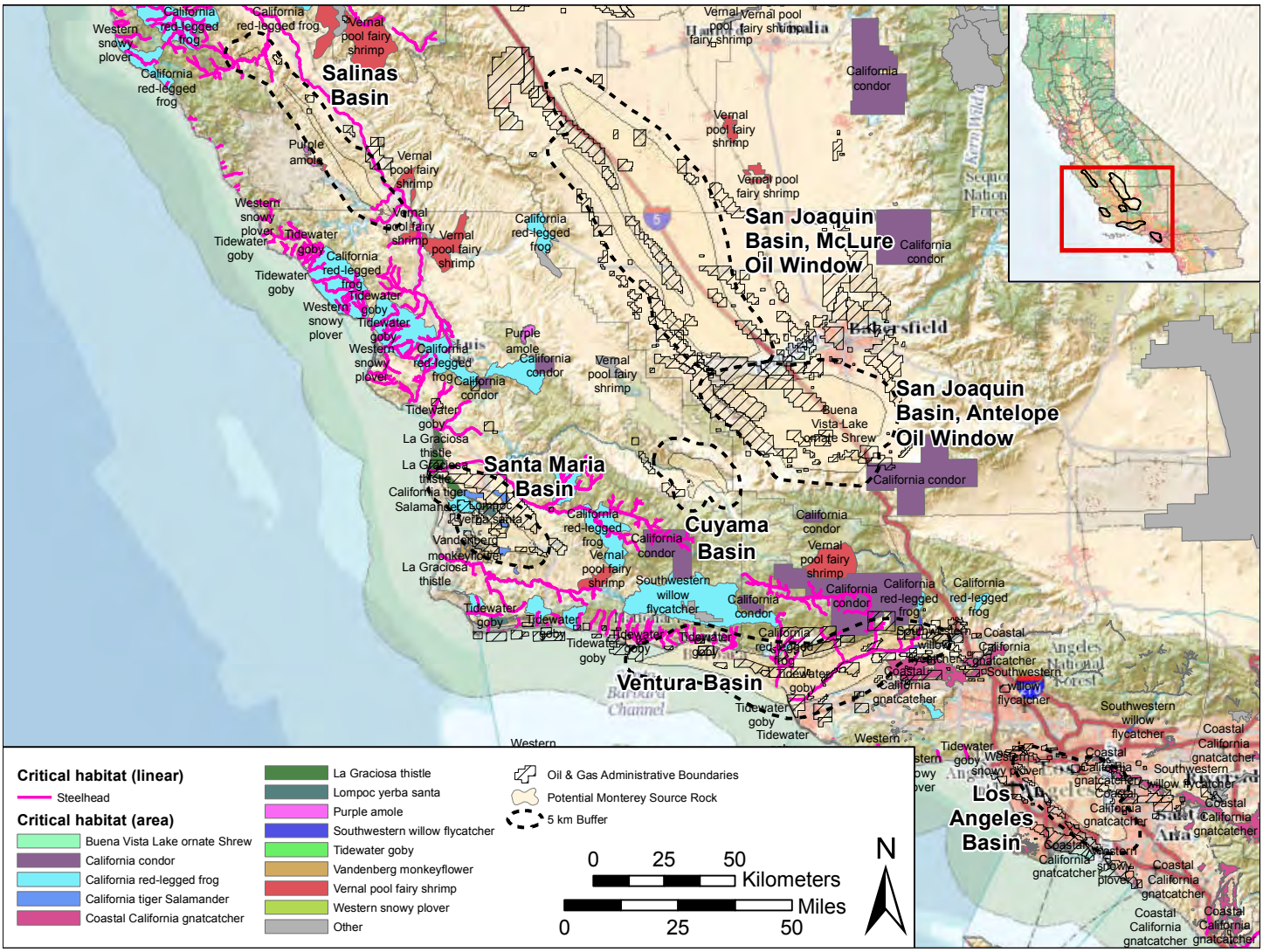


Figure 3-4-18. Overlay of potential Monterey source rock and federally-designated critical habitat. Land use data from U.S. Fish and Wildlife Service (2014).

Table 3.4-11. Overlap of potential Monterey source rock with U.S. Fish and Wildlife Service designated critical habitat for threatened and endangered species. Only those with at least 1% of their critical habitat overlying the potential source rock + 5 km (3 mi) buffer are listed.

	Over Source Rock (km^2)	In 5 km Buffer (km^2)	Over Source Rock + Buffer (km^2)	Over Source Rock + Buffer (% of Total)	Outside potential source rock (km^2)	Total (km^2)
Buena Vista Lake ornate shrew	.3	0	.3	100	0	.3
California condor		76	76	3	2,374	2,449
California red-legged frog	15	45	60	1	6,580	6,640
California tiger salamander	24	19	43	5	810	853
Coastal California gnatcatcher		37	37	2	1,471	1,508
La graciosa thistle	39	17	56	57	42	98
Least bell's vireo	0	12	13	9	137	150
Lompoc yerba santa		9	9	35	17	26
Southwestern willow flycatcher	28	13	41	26	118	159
Tidewater goby	2	0	2	5	38	41
Vandenberg monkeyflower		15	15	37	25	40
Ventura marsh milk-vetch	1	1	2	100		2
Western snowy plover	2	1	3	4	64	67

Critical habitat is not designated for all threatened and endangered species. In particular, despite a large number of threatened and endangered species in the San Joaquin Basin, very little critical habitat has been designated. To show lands that tend to be of high value for native species in the San Joaquin, we show San Joaquin kit fox habitat suitability. Kit foxes tend to co-occur with other native species in the region, although they are more tolerant of human disturbance than most of the native plants and animals in the local species assemblage. As a result the map of their habitat (Figure 3.4-19) likely reflects a slight overestimate of habitat that supports high densities of native species in the area. As indicated by Table 3.4-12, approximately 44% of the area of high suitability for San Joaquin kit fox is within the footprint of potential Monterey source rock or in the 5 km buffer. If development were to occur in Monterey source rock, it would be likely to disproportionately affect native species in the San Joaquin Basin, given the large extent of source rock in that region, the high density of endangered species, and the fact that this region most likely has the greatest potential to be developed as a shale oil play (see the section on the San Joaquin Basin in Appendix 3.A).

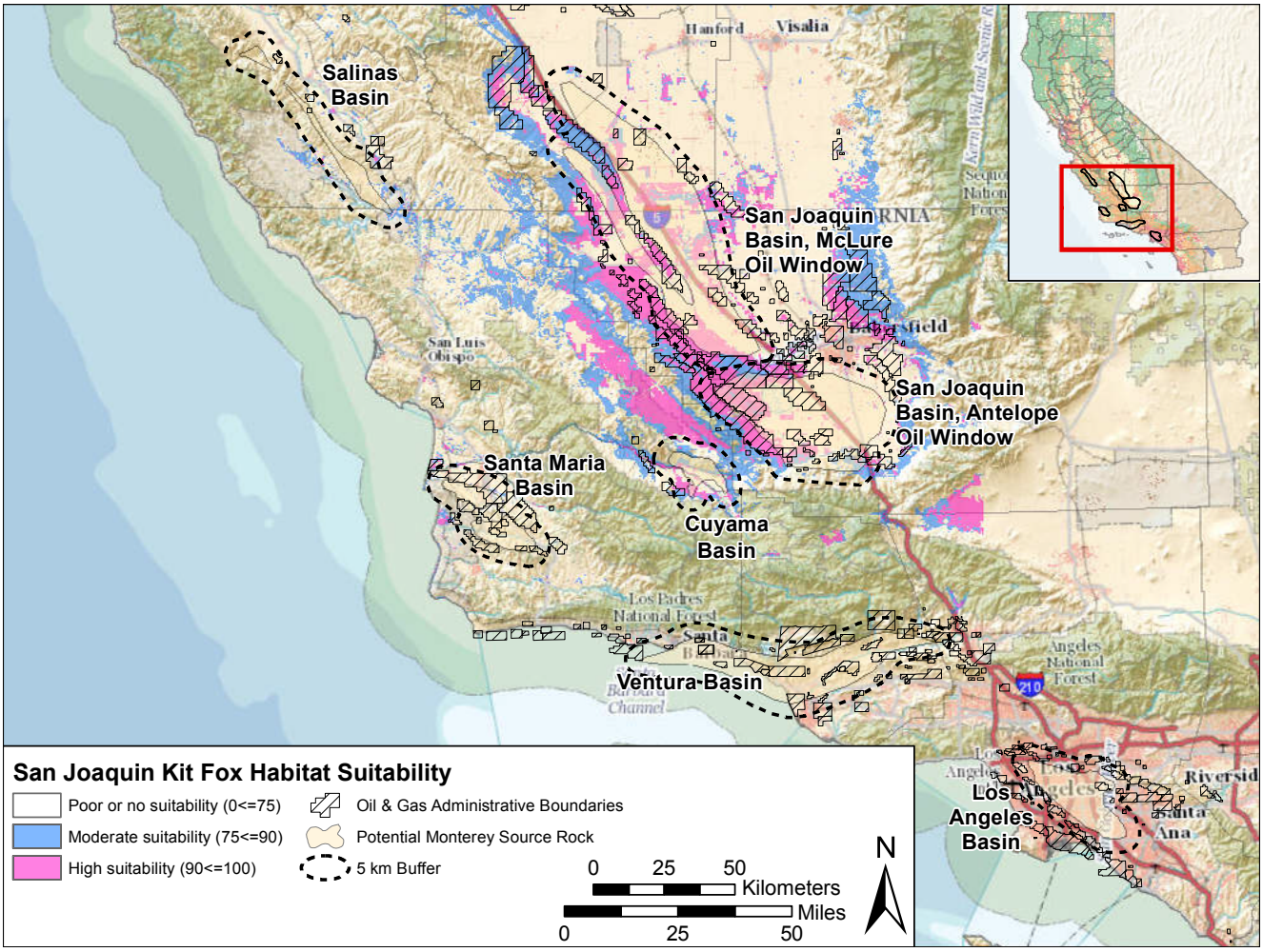


Figure 3.4-19. Overlay of potential Monterey source rock and San Joaquin kit fox habitat suitability.

Table 3.4-12. Overlap of San Joaquin kit fox habitat suitability with potential Monterey source rock.

	Over Source Rock (km²)	In 5 km Buffer (km²)	Over Source Rock + Buffer (km²)	Over Source Rock + Buffer (% of Total)	Outside (km²)	Total (km²)
High	881	863	1,743	44%	2,224	3,968
Moderate	279	563	841	13%	5,888	6,729
Unsuitable	4,686	4,822	9,508	2%	404,068	413,575

3.5. Data Gaps in Understanding the Future of Monterey Source Rock Development and its Impacts

Despite the attention and speculation about the possible resources in Monterey source rock, there is still tremendous uncertainty about its potential resources and indeed whether it will ever be commercially developed. If it were developed, we do not know what technology would be used or the precise locations and density of the activity. As a result we cannot yet predict the environmental and public health consequences of Monterey source rock development. Indeed, as noted throughout Volume II, there are many aspects for which we lack the data necessary to fully evaluate even the past and present impacts of well stimulation in the state. We recommend four studies or groups of studies that would need to be undertaken at the appropriate stage of Monterey source rock development.

Present:

1. Conduct a comprehensive, peer-reviewed, probabilistic resource assessment of Monterey source rock, as described in Section .

2. Fill data gaps described for the environmental impacts of well stimulation described in this report. Here we present a summary of the data gaps described in more detail in Volume II.

    a. Water quality impacts

    b. Water supply impacts

    c. Atmospheric impacts

    d. Seismic impacts

        i. California has many unmapped faults.

        ii. Records of fluid injection in the DOGGR database are likely inadequate to carry out a comprehensive assessment of the potential for induced seismicity in the state. Need to collect more detailed information on injection volume, pressure data, and injection depth for wastewater disposal wells.

        iii. We do not fully understand the potential for subsurface fluid injection to cause earthquakes in an active tectonic margin like California. Most recent cases of induced seismicity related to wastewater injection have occurred in the continental interior.

iv. For more discussion on data gaps for seismic impacts, see Chapter 4 of Volume II.

e. Wildlife and vegetation impacts

Ongoing:

3. Monitor for experimental wells and early stages of commercial development in Monterey source rock, as described in Section .

If commercial-scale development commences,

4. Re-evaluate resource assessment in (1) – does it need to be updated to account for new technology and/or production data from wells?

5. Conduct a rigorous risk assessment of source rock development, using input from Volumes II and III of this report.

3.6. Findings and Conclusions

3.6.1. Findings Concerning Source-Rock Development in California

3.6.1.1. Geologic Basis

A source-rock is a sedimentary formation containing a sufficient concentration of organic matter for the generation of petroleum. The Monterey Formation includes active source rocks from which most California petroleum was generated. Other active petroleum source rocks are also present in certain California basins.

In continuous shale-oil reservoirs, the source rock and the reservoir rock are one and the same. Instead of the geographically concentrated oil in conventional oil fields, low-permeability shale reservoirs extend over vast areas. Technological advances now enable oil and/or gas to be produced directly from source rocks in certain places, particularly from the Bakken and Three Forks formations in the Williston Basin and from the Eagle Ford Formation in Texas. Large-scale shale oil production is enabled by hundreds or thousands of long-reach directional wells, each having been developed with multi-stage massive hydraulic fractures. This approach is not easily transferable to the highly discontinuous and heterogeneous Monterey formation.

Parts of several sedimentary basins in California, which are underlain by thermally mature petroleum source rocks, may have potential for source-rock reservoir production. Potentially productive areas occur in the Cuyama, Los Angeles, Salinas, Santa Barbara-Ventura, Santa Maria, and San Joaquin Basins.

Published EIA estimates of Monterey shale oil do not provide sufficient information for scientific evaluation. We recommend a systematic, probabilistic assessment of California source-rock resources be undertaken to quantify the uncertainty in shale-oil resource potential. Ultimately, the uncertainty can be efficiently reduced or eliminated by drilling exploration and production wells.

3.6.1.2. Exploration of Monterey Source Rock

Impending shale oil development would be signaled by land acquisition, exploratory drilling, and then small-scale production, most likely in the San Joaquin Valley. Identification of likely exploratory wells is possible with information on well depth and target productive horizon. However, exploratory wells are likely to be confidential and the relevant data would not be available outside of state agencies until confidentiality on the well expired.

3.6.1.3. Potential Environmental Impacts

Much of what we can predict about potential future impacts of Monterey Source Rock hinges on the maximum footprint of source rock, and its greater depth relative to current production.

a. Footprint: While the Monterey Formation and its equivalents extend over much of California, only a fraction of it has the potential to be developed as a source-rock play. The total area of estimated Monterey source rock is about 5,900 km^2 (2,300 mi^2). 92% of that area is already developed for oil and gas production (that is, has at least one well per km^2). The remaining 8% is not developed for oil and gas (that is, has less than 1 well per square kilometer). However, the entire extent of potential Monterey source rock is within the six basins with the greatest proven oil reserves in the state; no point of the footprint is more than 20 kilometers (12 miles) from the nearest oil field. Potential Monterey source rock underlies significant water resources, including groundwater basins used by municipal, domestic, and agricultural users. Increased oil exploration in the Monterey source rock could increase the potential for water contamination by stimulation fluids (and comingled produced water).

b. Depth: Thermally mature source rocks are deeper on average than the currently producing formations in California. This means the stimulated interval tends to be far below usable groundwater, reducing the risk of an accidental intersection of a fracture with a usable aquifer. Deeper formations also tend to produce saltier formation water. Development far away from existing wells – both horizontally and vertically – reduces the probability of leakage via an improperly sealed nearby well. However, these formations are overlain by significant water resources, including groundwater basins used by municipal, domestic, and agricultural users. Increased oil exploration in the Monterey source rock increases the potential for water contamination by stimulation fluids (and comingled produced water).

3.7. Acknowledgments

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