An Independent Scientific Assessment of Well Stimulation in California

Volume 1

Well Stimulation Technologies and their Past, Present, and Potential Future Use in California

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Executive Summary

In 2013, the California Legislature passed Senate Bill 4 (SB 4), setting the framework for regulation of well stimulation technologies in California, including hydraulic fracturing. SB 4 also requires the California Natural Resources Agency to conduct an independent scientific study of well stimulation technologies in California to assess current and potential future practices, including the likelihood that well stimulation technologies could enable extensive new petroleum production in the state, evaluate the impacts of well stimulation technologies and the gaps in data that preclude this understanding, identify risks associated with current practices, and identify alternative practices which might limit these risks.

The study is issued in three volumes. This document, Volume I, provides the factual basis describing well stimulation technologies, how and where operators deploy these technologies for oil and gas production in California, and where they might enable production in the future. Volume II discusses how well stimulation affects water, the atmosphere, seismic activity, wildlife and vegetation, traffic, light and noise levels; it will also explore human health hazards, and identify data gaps and alternative practices. Volume III presents case studies to assess environmental issues and qualitative risks for specific geographic regions. Volumes II and III will be released July 2015.

Well stimulation enhances oil and gas production by increasing the permeability of the reservoir rocks. The report discusses three types of well stimulation as defined in SB 4. Hydraulic fracturing uses a high-pressure fluid in a well to create fractures in the rock and then props the fractures open by injecting sand so they remain permeable after the high pressure ceases. Acid fracturing uses a high-pressure acidic fluid to fracture the rock and etch the walls of the fractures, so they remain permeable after they partly close following application of the high pressure. Matrix acidizing does not fracture the rock; instead, low-pressure acid is pumped into the well to dissolve some of the rock and increase the permeability. Acid fracturing and matrix acidizing are referred to collectively as acid stimulation.

This report addresses oil and gas production both on land and offshore in California. Figure ES-1 provides basic statistics about the volume of oil and gas production from California basins between 2002 and 2014. The figure also illustrates how much of the produced volume is associated with hydraulic fracturing. In Northern California, production of natural gas is rarely conducted with the help of well stimulation. In contrast, about 20% of the total oil production in the state is facilitated by hydraulic fracturing, with most of this occurring in the San Joaquin Basin.
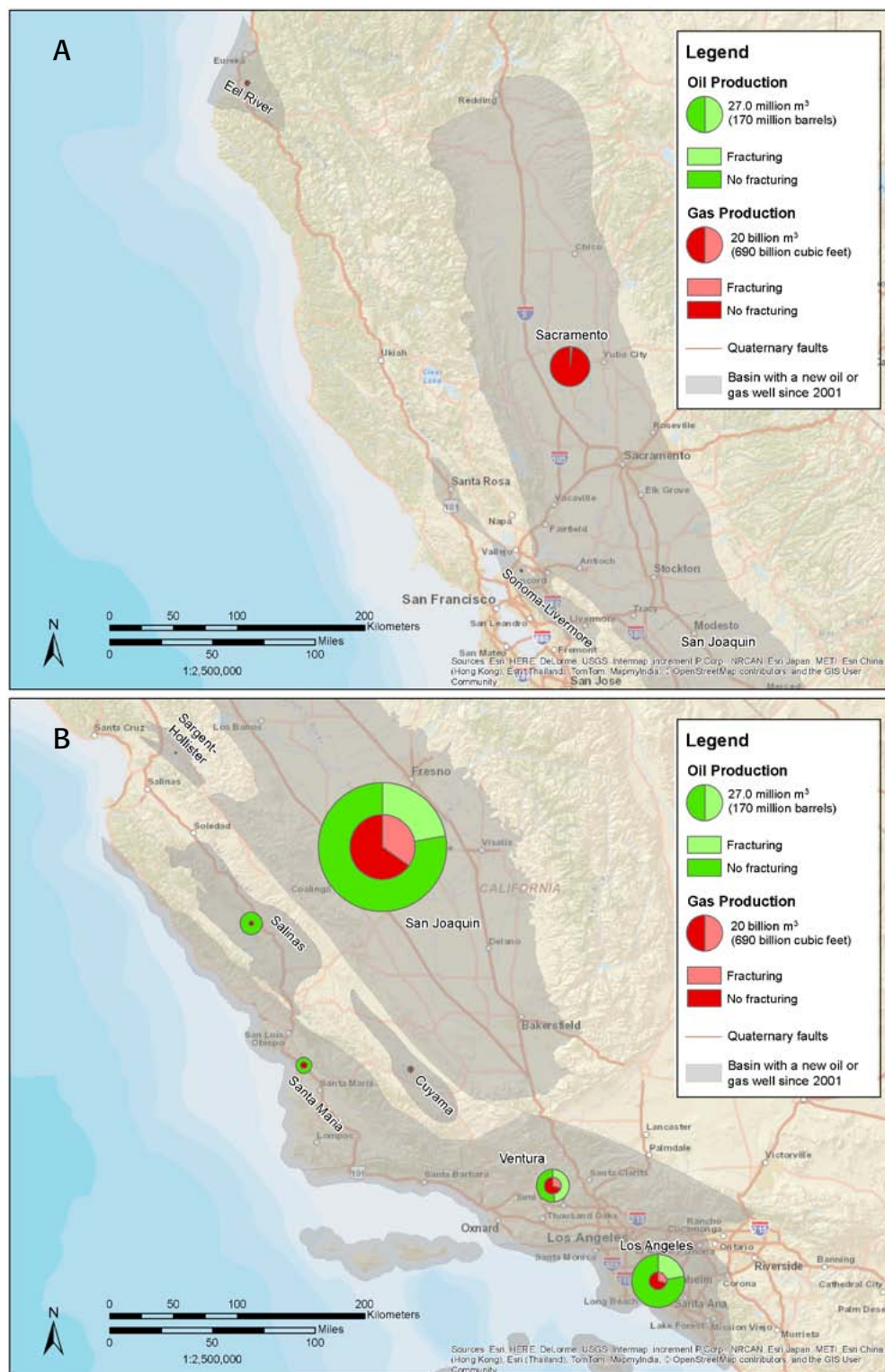
Figure ES-1. *Production of oil and gas with and without hydraulic fracturing in each basin in A) northern and B) southern California from 2002 through May 2014. The area of each circle is proportional to the production volume in each basin.*

Data Availability, Key Findings and Conclusions

- The following findings and conclusions are based on available information. Data on where, when, and how operators conduct well stimulation in the state were not collected thoroughly or consistently across the state prior to 2014. Data submittal on all operations across the state was required starting in 2014; however, the number of reported operations initially decreased as operators adjusted to the new regulations imposed by SB 4. We developed findings and conclusions based on a review of published literature and official and voluntary databases through June 2014. Much of the information prior to the start of mandatory reporting in January 2014 remains incomplete and unverified. We describe the limitations of the data throughout the report in order to transparently qualify the accuracy of the conclusions.

- Due to the timeline of this study relative to the institution of mandatory reporting on January 1, 2014, the analyses conducted in this report assess only six months of well stimulation data resulting from the implementation of SB 4. Even after the start of compulsory reporting, inconsistencies between datasets collected by various state and private institutions suggest that inaccuracies may persist. However, we cross-checked multiple independent data sets and found largely consistent results, indicating that we can have reasonable confidence in the quality and consistency of the data collected before and since mandatory reporting commenced. Comprehensive understanding of well stimulation in the state requires complete and accurate reporting regulations as specified by SB 4 and sufficient time for the number and type of operations to stabilize. In contrast to the well stimulation data, we consider the available information on the geology of developed petroleum resources in California and the potential for future use of well stimulation in similar reservoirs of the state to be of high quality.

- Recognizing these limitations in the data, the report conclusions should be taken as generally accurate, if not precise. The authors have reasonable confidence that additional data becoming available in the future might change some of the quantitative findings in the report, but would not fundamentally alter the report conclusions about well stimulation in California.

Hydraulic fracturing of onshore oil wells: Almost all hydraulic fracturing in California occurs in the San Joaquin Basin in wells that produce primarily oil. We expect this practice to continue as the main use of well stimulation in the state for the foreseeable future.

- Over the last decade, about one fifth of oil production in California came from wells that had been subject to hydraulic fracturing. In this time period, operators fractured about 125 to 175 wells of the approximately 300 wells installed per month in California. Available data indicate that hydraulic fracturing has been the

main type of well stimulation. The number of hydraulic fracturing operations per month in California represents one-tenth of the number of hydraulic fracturing operations reported to FracFocus per month in the entire country in 2012 and 2013. As FracFocus is a voluntary database, the true number of hydraulic fracturing operations conducted in the country is likely higher than reported, and so the fraction of operations in California is probably lower. About 95% of reported hydraulic fractures in California were in the San Joaquin Valley, nearly all in four oil fields in Kern County (Chapter 3).

- Current hydraulic fracturing activities in California are different than in other states, and as such recent experiences with hydraulic fracturing in other states do not necessarily apply to current hydraulic fracturing in California. Available data suggest that present-day hydraulic fracturing practices in California are different from other states such as Texas and North Dakota, primarily because of differences in the geology of the petroleum reservoirs. Generally, current hydraulic fracturing in California tends to be performed in shallower wells that are vertical as opposed to horizontal; and requires much less water per well, but uses fluids with more concentrated chemicals than hydraulic fracturing in other states. For example, in California, a hydraulic fracturing operation consumes on average 530 cubic meters (m^3; 140,000 gallons, gal) of water per well, compared to about 16,000 m^3 (4.3 million gal) per well used in horizontal wells in the Eagle Ford Formation in Texas. Consequently, the practices and impacts of hydraulic fracturing in other states do not directly apply to current hydraulic fracturing in California (Chapter 3).

- The most likely scenario for future oil recovery using hydraulic fracturing is expanded production in and near existing oil fields in the San Joaquin Basin in a manner similar to the production practices of today. The vast majority of hydraulic fracturing in the state takes place in the San Joaquin Basin in reservoirs that depend on this technology for economic production. A significant amount of oil remains in these reservoirs. It is highly likely that continued production in these reservoirs will use hydraulic fracturing (Chapter 4).

- This study's review of the two oil resource projections from deep source rocks in the Monterey Formation developed by the United States Energy Information Administration (US EIA) concluded that both these estimates are highly uncertain. Recent reports from the US EIA have indicated there may be substantial oil resources in deeper source-rock reservoirs, especially in the Monterey Formation. The 2011 US EIA report suggested 2.4 billion m^3 (15 billion barrels) of recoverable oil in these source rocks, but a subsequent 2014 US EIA report using more restrictive assumptions reduced the estimate to 0.095 billion m^3 (0.6 billion barrels). There is little evidence to support either estimate. No reports of significant production from the Monterey or other source rocks have been identified to date in California. If innovations do someday allow recovery

of oil from California's source rocks, the undertaking would likely require well stimulation technology. Future exploration of Monterey source rock could improve our understanding of the potential, challenges, costs, and rewards for production in these reservoirs (Chapter 4).

Stimulation of dry gas wells[1]: Almost all wells that produce primarily gas are located in Northern California. These dry (non-associated) gas wells are rarely stimulated, and we do not expect this to change in the near future.

- Operators rarely stimulate California dry (non-associated) gas wells. Approximately ten dry gas wells per month were installed on average from 2002 through 2011, of which about one was hydraulically fractured. We found no records of hydraulic fracturing of gas wells since 2011 and no records of acid stimulation in these wells. However, most of the gas production in the state is not from dry gas wells, but from wells that primarily produce oil. As such, about a fifth of the gas produced in the state is facilitated by hydraulic fracturing (Chapter 3).

- Geologic assessment indicates that significant unconventional natural gas resources on a basin-wide scale, such as the Marcellus or Barnett shales or in the Piceance basin, probably do not exist in California. Most of the remaining undiscovered non-associated natural gas in California is likely to be similar to reservoirs in production today that currently do not use well stimulation technology. The geologic conditions in California are unlikely to have created large basin-wide gas plays (Chapter 4).

- Operators hydraulically fracture gas storage wells. Hydraulic fracturing facilitates about a third of the subsurface storage of natural gas in the state. We expect this to continue given the importance of these facilities to balance urban natural gas demand from season to season. About two times a year on average, operators of gas storage facilities use hydraulic fracturing to enhance storage, mostly in one facility serving southern California (Aliso Canyon) (Chapter 3).

Hydraulic fracturing offshore: Hydraulic fracturing is used in a small proportion of offshore wells; we expect hydraulic fracturing to continue to play an incidental role in offshore production.

- The majority of offshore production takes place without hydraulic fracturing. Most of this limited hydraulic fracturing activity is conducted on man-made islands

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1. Wells typically produce both oil and gas. The distinction between a dry gas well and an oil well is in the relative amount of oil and gas produced. Dry gas wells produce a large amount of gas compared to oil, sometimes called "non-associated" gas. Oil wells produce a small amount of gas relative to oil, known as "associated" gas.

close to the Los Angeles coastline; little activity is documented on platforms. Operations on close-to-shore, man-made islands resemble onshore oil production activities. Ninety percent of offshore fracturing operations in California waters occurred on man-made islands in the Wilmington field. On these islands, operators conduct about 1-2 hydraulic fracturing operations in the 4-9 wells installed per month. The only available survey of stimulation in federal waters records 22 fracturing stimulations conducted or planned from 1992 through 2013, compared to more than 200 wells installed during that period. All but one of these hydraulically fractured wells were in the Santa Barbara-Ventura Basin. About 10-40% of fracturing operations in wells in state waters and half of operations in federal waters were frac-packs[2] (Chapter 3).

- If expansion of oil production offshore is allowed in the future, production could occur without well stimulation technology. Billions of barrels of potential oil reserves exist off the California coast, but both federal and state laws and policies restrict expansion of production into new areas. Current production from offshore platforms uses some well stimulation to marginally improve productivity, but most production does not require well stimulation. New production, if ever permitted, would likely resemble existing production. The use of well stimulation technologies discussed in this report in the offshore environment would not affect production nearly as much as a change in current policies and regulations that now restrict new production offshore (Chapter 4).

Acid stimulation: Operators report the use of acid for well stimulation much less often than hydraulic fracturing. Of the known operations, most are matrix acidizing treatments conducted in oil wells in the San Joaquin Basin.

- Available data indicate that operators use acid stimulation about 10% as often as hydraulic fracturing in California. In contrast, operators commonly use acid treatments for well maintenance and remediation of damage caused by drilling. In California, the definition of acid stimulation varies from one regulatory agency to another, and the agencies have different record-keeping practices. This makes it difficult to assess the extent of acidizing in the state. Analysis of existing data suggests that acid is widely used for well maintenance in California, whereas about 15–25 acid operations in the approximately 300 wells installed per month in California are reported as stimulation. Nearly all reported cases of acid stimulation take place in the southwestern portion of the San Joaquin Basin. Although acid is commonly used for well maintenance and remediation, acid stimulation does not represent an important well stimulation technology in California compared to hydraulic fracturing (Chapter 3).

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2. As opposed to hydraulic fracturing intended to open permeable fracture pathways in unconventional reservoirs to enable oil or gas production, frac-packs are employed to deal with formation damage around a production well and/or sand production into the well. See Chapter 2 for more details.

- Acid stimulations in California reservoirs are not expected to lead to major future increases in oil and gas development in the state. In general, the geologic conditions in the state's oil reservoirs are not amenable to effective acid stimulation treatment. Acid stimulations can be effective in carbonate reservoirs, but these are rare in California. The underlying geology of California means that acid is not useful now or in the future for creating major increases in the permeability of the formation (Chapters 2 and 3).

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Acronyms and Abbreviations

APCCH	American Petrofina Central Core Hole
API	American Petroleum Institute
ASTM	American Society for Testing and Materials
AU	Assessment Unit
barrels/min	Barrels per Minute
BBO	Billion Barrels of Oil
BCFG	Billion Cubic Feet of Gas
BOEM	Bureau of Ocean Energy Management
BSEE	Bureau of Safety and Environmental Enforcement
CCST	California Council on Science and Technology
cm	Centimeter
CO$_2$	Carbon Dioxide
cP	Centipoise
cp	Commonly Polyacrylamide
CT	Crystobalite-type
CVRWQCB	Central Valley Regional Water Quality Control Board
DOC	Department of Conservation
DOE	Department of Energy
DOGGR	Division of Oil, Gas, and Geothermal Resources
EDTA	Ethylenediaminetetraacetic Acid
EGMBE	Ethylene Glycol Monobutyl Ether
EOR	Enhanced Oil Recovery
EPS	Explosive Propellant Systems
EUR	Estimated Ultimate Recovery
ft	Feet/Foot
ft^3	Cubic Feet
g/cm^3	Grams per Cubic Centimeter
g/l	Grams per Liter
gal	Gallons
gal/ft	Gallons per Foot, (see also gpf)
GIS	Geographic Information System
GPa	Gigapascals
gpf	Gallons per Foot (see also gal/ft)
GTK	Growth-to-Known
HCl	Hydrochloric Acid
HF	Hydrofluoric Acid
HF/HCl	Hydrofluoric/Hydrochloric Acid

IB	Inner Borderland
ICoTA	Intervention & Coiled Tubing Association
in	Inches
km	Kilometers
km²	Square Kilometers
LBNL	Lawrence Berkeley National Laboratory
LPG	Liquid Propane
m	Meters
m²	Square Meters
m³	Cubic Meters
m³/s	Cubic Meters per Second
Ma	Million Years Ago
MAPDIR	Maximum Pressure Differential and Injection Rate
md	Millidarcies
mi²	Square Miles
MMB	Million Barrels
MMBO	Million Barrels of Oil
MMBOE	Million Barrels of Oil Equivalent
MMS	Minerals Management Service
MPT	Mud Pulse Telemetry
MWD	Measurement While Drilling
NGL	Natural Gas Liquids
NH$_4$HF$_2$	Ammonium Bifluoride
NIFZ	Newport Inglewood Fault Zone
NORM	Naturally Occurring Radioactive Materials
NTA	Nitrilotriacetic Acid
NYSDEC	New York State Department of Environmental Conservation
OCS	Outer Continental Shelf
OOIP	Original Oil in Place
ppm	Parts per Million
psi	Pounds per Square Inch
PVFZ	Palos Verdes Fault Zone
PVP	Palos Verdes Peninsula
Remax	Maximum Potential Recovery Efficiency
SB 4	Senate Bill 4
SCAQMD	South Coast Air Quality Management District
scf	Standard Cubic Feet
scf/STB	Standard Cubic Feet of Gas per Stock Tank Barrel of Oil
SMFZ	Santa Monica Fault Zone
STB	Stock Tank Barrel
TCF	Trillion Cubic Feet
TOC	Total Organic Carbon
TSO	Tip Screenout

TVD	True Vertical Depth
US EIA	United States Energy Information Administration
USGS	United States Geological Survey
WFZ	Whittier Fault Zone
WST	Well Stimulation Technologies

Chapter One

Introduction, Overview, and Summary of Findings and Conclusions

In 2013, the California Legislature passed Senate Bill 4 (SB 4; Pavley 2013), setting the framework for regulation of well stimulation technologies in California, including hydraulic fracturing. SB 4 also requires the California Natural Resources Agency to conduct a study of well stimulation technologies in the state to assess current and potential future practices, including the likelihood that well stimulation technologies could enable extensive new petroleum production in the state, evaluate the impacts of well stimulation technologies and the gaps in data that preclude this understanding, identify risks associated with current practices, and identify alternative practices that might limit these risks. The language of SB 4 that mandated the independent scientific study is given in Appendix A.

The study is issued in three volumes plus a Summary Report. This document, Volume I, provides the factual basis describing what well stimulation technologies are, how they are conducted in general and practiced in California, where they have been and are being used for oil and gas production in the state, and the locations where they might enable production in the future. Volume II presents the potential impacts of well stimulation technologies with respect to water, air quality, and greenhouse gas emissions, as well as induced seismicity, ecology, and traffic and noise. Volume II also identifies key data gaps and alternative practices. Volume III examines case studies of well stimulation, its impacts, and qualitative hazards as they pertain to selected locations in California. The Summary Report, Volumes II and III are to be completed by July 1, 2015.

This assessment builds upon a recent report undertaken for the Bureau of Land Management concerning well stimulation in California by the California Council on Science and Technology (CCST), Lawrence Berkeley National Laboratory (LBNL), and Pacific Institute (CCST et al., 2014; available at http://ccst.us/BLMreport). Whereas that report for the Bureau of Land Management exclusively addressed well stimulation for onshore oil production in California, the current analysis has been broadened to include both oil and gas production in California for onshore and offshore environments and incorporates new information derived from newly released data and research. The assessment of environmental impacts in CCST et al. (2014) is incorporated and expanded upon in Volume II, which also includes discussion of alternative practices as well as data gaps. The case studies presented in Volume III go beyond the subjects covered in the previous report.

1.1. Background

Over the last decade, application of horizontal drilling and hydraulic fracturing has allowed a substantial increase in production of oil and gas from low-permeability rocks, such as the Marcellus Shale in Pennsylvania and the Bakken Formation in Montana and North Dakota (Pearson et al., 2013; Hughes, 2013). After drilling vertically to the kickoff point, horizontal drilling then advances a well boring along a geologic layer rather than across it, as is typical for vertical drilling. Consequently, horizontal wells are in contact with a larger volume of the oil- and gas-producing zone than vertical wells, thereby increasing petroleum (oil and gas) production from the well. Hydraulic fracturing is the practice of injecting fluids into a well at a sufficiently high pressure to open existing or create new fractures in the geologic material surrounding the well. These fractures open permeable flow pathways between the target formation and the well, allowing greater petroleum production in a given time period.

In 2011, the United States Energy Information Administration (US EIA) estimated the California Monterey Formation contains 2.45 billion cubic meters (m^3; 15.4 billion barrels) of recoverable tight oil in source-rock shale, approximately 64% of the recoverable oil from low-permeability rocks in the United States (US EIA, 2011). As shown in Figure 1-1, the current production from low-permeability portions of the Monterey Formation in California is modest compared to production from other low-permeability strata in the United States, and has not changed significantly over the past decade. The EIA estimate led to the belief that there was a real possibility of developing vast new oil and gas deposits in the state with the use of well stimulation, which simultaneously raised excitement about economic prospects and concerns about associated environmental and social impacts. However, subsequent revision dramatically lowered the estimated quantity of recoverable oil in the Monterey Formation to about 0.095 billion m^3 (0.6 billion barrels), highlighting the large uncertainty in the estimate (US EIA, 2014).
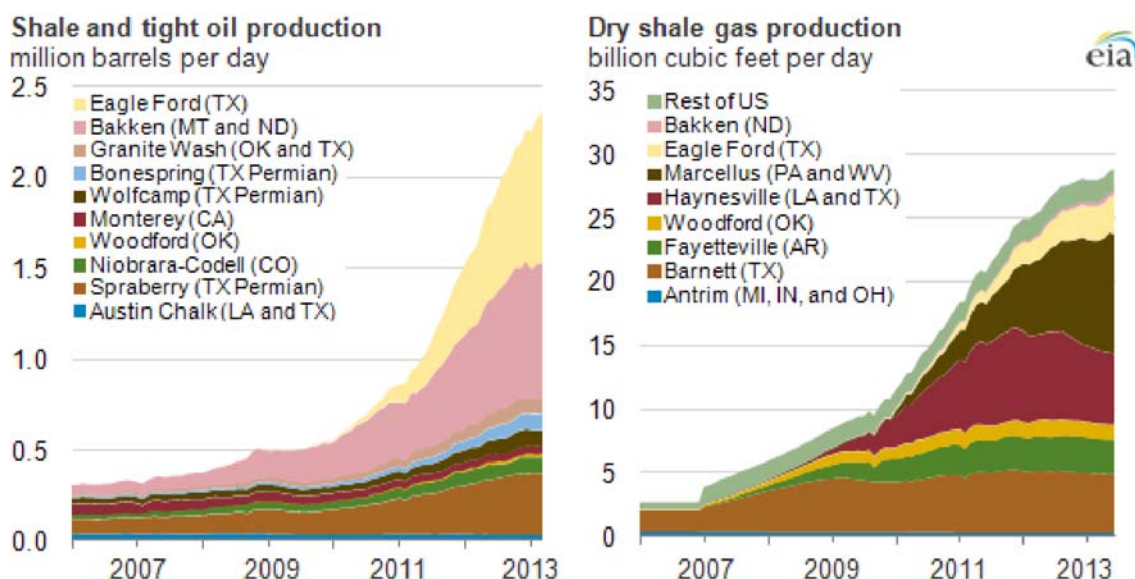
Figure 1-1. *(A) Oil production through time from selected shale and low permeability ("tight") oil plays in the United States. Note that production from the Monterey Formation in California is a small and declining proportion of U.S. shale and tight oil production. (B) Gas production from shale plays in the United States. Note that there is no shale gas produced in California. U.S. EIA (2013).*

Regardless of the extent to which well stimulation may or may not be applied in the Monterey Formation in the future, well stimulation technologies are already an important part of oil and gas production in the state. As described in this report, operators use well stimulation in California routinely to enhance production of what is referred to as "migrated" deposits: oil and gas that has moved out of source rocks such as the Monterey and into other types of geologic structures, usually nearer the surface. Therefore, in contrast to many parts of the country, questions regarding well stimulation in the state are not limited to development of new source-rock shale reservoirs.

Well Stimulation Technologies Covered in this Report

This report concerns three well stimulation technologies used to open permeable flow paths or increase permeability in hydrocarbon reservoirs: hydraulic fracturing, acid fracturing, and matrix acidizing. In the technical literature, the term "well stimulation" can also refer to technologies used to repair damage in and near the well induced by well drilling and hydrocarbon production. These types of well stimulation are not the focus of this report and are excluded from regulation under SB 4. However, because there is often not a clean separation between these two types of well stimulation, this review does address areas where well stimulation objectives or techniques may overlap with well maintenance.

Box 1.1. The History of Oil Production in California

California has a long history of oil production, from a variety of regions and geological formations. The Midway-Sunset field, which is the largest in California in terms of expected total oil production, was discovered in 1894. The twelve largest onshore or partially onshore oil fields were discovered by 1932 and the 43 largest by 1949. All 45 onshore or partially onshore oil fields containing more than 16 million m^3 (100 million barrels) of expected total oil production each, referred to as "giant" oil fields by California's Division of Oil, Gas and Geothermal Resources (DOGGR), were discovered by 1975 (DOGGR, 2010).

California's oil production has ranked third in the nation from at least the 1980s through 2013, currently behind Texas and North Dakota. The volume of oil produced in California peaked in 1985 and had declined by approximately half as of 2013 (US EIA, 2014). California also generates natural gas, both from gas wells and from wells that mainly produce oil. Wells that produce only gas occur primarily in the Sacramento Basin, but most of the gas in the state is associated with oil production in the San Joaquin Basin. The majority of oil and gas production in the state is onshore, although there are manmade islands and platforms constructed to enable production offshore. DOGGR oversees the state's oil, gas, and geothermal industries onshore and in state waters within 5.6 kilometers (km; three nautical miles) of the coast; federal agencies oversee oil and gas production in waters farther from shore.

Oil production in California has been enhanced by application of several technologies. Wide deployment of water flooding commenced in the mid-1950s. This secondary oil recovery method involves injecting water into the oil reservoir, which causes more oil to flow to the production wells. Two additional methods of enhanced oil recovery, cyclic steaming and steam flooding, were first widely deployed in the mid-1960s (Division of Oil and Gas, 1966). Injection of steam heats highly viscous ("heavy") oil, resulting in more oil flowing to the production well. In cyclic steaming, injection of steam alternates with oil production in the same well. Steam flooding involves continuous steam injection into wells interspersed among the production wells. Intensive deployment of hydraulic fracturing commenced in the 1980s (see Chapter 3).

DOGGR first reported the portion of oil produced by water flooding and steam injection in 1989. It attributed 71% of oil production in that year to these techniques (DOGGR, 1990). A total of 76% of production in 2009, the most recent year with attribution, was due to these techniques (DOGGR, 2010). The portion of production involving hydraulic fracturing was not listed.

In addition to steam injection, fire flooding and downhole heating were tested for heating viscous oil in the subsurface in the early 1960s. Fire flooding involved injecting air into the reservoir to sustain combustion of part of the oil in order to reduce the viscosity of the remaining oil, thereby enhancing production, but was found to be generally uneconomical. Downhole heating resulted in more modest, and less economic, production increases than steam injection (Rintoul, 1990). Additional enhanced oil recovery techniques actively evaluated in the 1980s included polymer flooding, caustic flooding, miscible fluid flooding, and carbon dioxide (CO_2) injection.

Hydraulic fracturing creates conductive fractures in reservoir rocks in order to enhance the flow of fluids, including water, oil, or natural gas to the well. In the hydraulic fracturing process, the operator pumps fluids containing a variety of chemicals into a zone of the well until the fluid pressure is sufficient to fracture the rock. Then, the operator pumps small particles called "proppant" into the fractures to keep them open during subsequent production. The spent hydraulic fracturing fluid, called "flowback" fluid, returns from the well after the fracturing operation. Fluid recovered from the well gradually changes from flowback to "production" fluids (oil, gas, and produced water). The time at which the fluids change from flowback water to production fluids is not precisely defined.

Acid fracturing accomplishes the same goal as hydraulic fracturing by injecting low pH fluids instead of proppant into the fractures created by the elevated pressure. The acid is intended to non-uniformly etch the walls of the fracture, so that some fracture conductivity is maintained after the fracture closes. This type of stimulation is generally only applied to carbonate reservoirs with reservoir rock that has more than 65% hydrochloric acid (HCl) solubility. The typical HCl strength is 15% to 28% by weight (Kalfayan, 2008).

A matrix acidizing process injects diluted acids into the rocks around a well at pressures too low to result in rock fracture. The most commonly used acids are HCl in carbonate formations, and hydrofluoric/hydrochloric acid (HF/HCl) mixtures in sandstone formations. Matrix acidizing in carbonates can create small channels or tubes called wormholes that can propagate as far as 6 meters (m; 20 feet, ft) into the formation. Wormholes stimulate the well similarly to a small hydraulic fracturing treatment. Because of much slower reaction rates in sandstones as compared with carbonates, the acid dissolution in sandstones is limited to a much smaller distance from the well, perhaps two-thirds of a meter (2 ft) or less into the formation. Because of this limited penetration distance, the benefit of matrix acidizing in sandstones comes primarily from removing damaging solids that have reduced the near-well permeability. There are some instances of matrix acidizing using HF/HCl reported in the Monterey Formation in California that may have had greater penetration because of naturally occurring fractures.

1.1.1. Key Questions Addressed in Volume I

Volume I addresses two key questions:

- **Key Question 1**: What are the past and current practices of well stimulation technologies in California, including hydraulic fracturing, acid fracturing, and matrix acidizing?

- **Key Question 2**: Where could well stimulation technologies allow expanded production of oil and gas in California?

1.1.2. Method and Data Sets Available for the Report

This assessment reviews and analyzes both existing data and scientific literature, with preference given to the findings in peer-reviewed scientific literature. Scientific papers published in journals undergo peer review prior to publication to provide quality control on the information. Qualified reviewers not involved in the work assess the thoroughness, accuracy, and relevancy of the work, and provide comments describing any omissions or inaccuracies to the author(s) of the paper and the editor of the journal. For the paper to be published, the author(s) must address omissions or errors to the satisfaction of the editor. If reviewers conclude that a manuscript contains inaccuracies or deficiencies so severe that they cannot be remedied, the work will not be published. Work published under this system of review is referred to as "peer-reviewed scientific literature."

During the conduct of this review and the preparation of the CCST et al. (2014) report, it was found that the body of relevant peer-reviewed literature—the sources that meet the highest standard of scientific quality control—is limited. For instance, there is little information on water demand in California for hydraulic fracturing. Consequently, other relevant, non-peer-reviewed information was considered. These included government data and reports, such as well records collected by DOGGR and recent notices submitted pursuant to SB 4 (Pavley, 2013), as well as non-peer reviewed reports and documents if they were topically relevant and determined to be scientifically credible by the authors and reviewers of this volume. We also accessed and analyzed voluntary web-based databases, such as those provided by FracFocus. Finally, we solicited and reviewed nominations of literature from the public. Criteria for consideration of material are described in Appendix E, "Review of Information Sources."

Data on where, when, and how operators conduct well stimulation in the state were not collected thoroughly or consistently across California prior to 2014. Data submittal on all operations across the state was required starting in 2014; however, the number of reported operations initially decreased as operators adjusted to the new regulations. We developed findings and conclusions based on a review of published literature and official and voluntary databases through June 2014. Much of the information prior to the start of mandatory reporting in January 2014 remains incomplete and unverified. Due to the timeline of this study relative to the institution of mandatory reporting on January 1, 2014, the analyses conducted in this report assess only 6 months of well stimulation data records as required by SB 4. Even after the start of compulsory reporting, inconsistencies between datasets collected by various state and private institutions suggest that inaccuracies may persist. However, we cross-checked multiple independent data sets and found largely consistent results, indicating that we can have reasonable confidence in the quality and consistency of the data collected before and since mandatory reporting commenced. We describe the limitations of the data throughout the report in order to transparently qualify the accuracy of the conclusions. Comprehensive understanding of well stimulation in the state requires complete and accurate reporting regulations as specified by SB 4, and sufficient time for the number and type of operations to stabilize.

In contrast to the well stimulation data, we consider the available information on the geology of developed petroleum resources in California and the potential for future use of well stimulation in similar reservoirs of the state to be of high quality.

Recognizing these limitations in the data, the report conclusions should be taken as generally accurate, if not precise. The authors have reasonable confidence that additional data becoming available in the future might change some of the quantitative findings in the report, but would not fundamentally alter the report conclusions about well stimulation in California.

1.1.3. Organizational Structure and Report Development Process

The California Natural Resources Agency contracted with CCST and LBNL to conduct the independent scientific study of well stimulation. Both CCST and LBNL also participated in the CCST et al. (2014) study undertaken for the Bureau of Land Management, discussed earlier. Report authors at CCST, LBNL, and other research institutions performed research and analysis. CCST appointed a steering committee based on technical expertise in fields relevant to the study to provide a range of technical experience. Under the guidance of the steering committee, report authors developed findings based on a literature review and data analyses that are described in Chapters 2–4 of this report. The steering committee collaborated with report authors to develop consensus conclusions, which are given in the findings and conclusions section of this chapter and are briefly summarized in the executive summary. Appendix B, "CCST Steering Committee Members," provides information about CCST's steering committee, and Appendix C, "Report Author Biosketches," provides information about the authors.

1.2. Volume I Structure and Content Overview

Volume I includes an executive summary and four chapters. The executive summary gives a brief overview of the major findings and conclusions of this study. This chapter gives the motivation, history, and methods employed for the report, and summarizes findings and conclusions. The detailed technical information in the remainder of this report is presented in Chapters 2 through 4. Chapter 5 gives a brief outlook on the two upcoming Volumes II and III.

Chapter 2 presents general information on well stimulation and associated technologies used to enable or improve hydrocarbon flow rates and recovery from reservoir intervals with low permeability or near-wellbore permeability damage. The chapter describes techniques for drilling and constructing the well, and surface facilities and surface operations for both onshore and offshore environments. The chapter defines and presents well stimulation methods, including the typical types of materials and procedures, and how the methods are applied in differing geologic conditions. The stimulation methods described are hydraulic fracturing, acid fracturing, and matrix acidizing as specified by SB 4.

Chapter 3 presents information on the past and current use of well stimulation technologies for onshore and offshore oil and gas production in California. These are discussed in terms of how these technologies have been used in the past along with information about current applications in California. The current level of activity for each well stimulation method is assessed, in total for California as well as basin by basin, and the types and quantities of well stimulation fluids currently in use are discussed.

Chapter 4 presents information on the petroleum geology of California and the potential for future applications of well stimulation both on and offshore in California. The chapter describes the geologic components and processes that affect the development of petroleum systems, the important reservoir rock types currently being produced using well stimulation technologies in California, and the rock properties of these reservoirs compared with the Bakken shale (a shale reservoir found in North Dakota, Montana, and Canada, that has been extensively developed using well stimulation technologies). The chapter then presents the California basins that contain oil and gas reservoirs, including deeper petroleum source rocks that have not to-date been subject to significant petroleum resource development, and evaluates the potential for using advanced well stimulation technologies to produce these source rocks, particularly the Monterey Formation. The chapter closes with an examination of the EIA estimate of the production potential of the Monterey Formation.

This report is written at many levels to suit the needs of many readers. Those wishing a high-level summary of the meaning of the report are directed to the Executive Summary or the remainder of this chapter. The following Chapters 2, 3, and 4 are much more technical and detailed, but each chapter contains an abstract that summarizes the meaning of the chapter and highlights the key points. Finally, the report has many appendices and boxes that contain highly detailed and technical analyses, as well as descriptions of related issues that do not fall neatly within the outline of the report.

1.3. Summary of Findings and Conclusions

This report develops a set of findings and conclusions based on available data. We define a finding as a synoptic statement about the data. A conclusion, on the other hand, involves the interpretation or analysis of the data and the conclusions of this report have been reached in a consensus process with the steering committee. This volume of our report set, Volume I, largely documents the factual basis of our assessment. Consequently, this particular volume contains no recommendations.

Key Question 1: What are the past and current practices in well stimulation technologies, including hydraulic fracturing, acid fracturing, and matrix acidizing in California?

Many of the concerns about oil and gas production enabled by well stimulation (especially hydraulic fracturing) arise because of experiences in other states with these technologies. Over the last decade, application of horizontal drilling and hydraulic fracturing stimulation in other states has allowed a substantial increase in oil production from low-permeability source rocks, such as the Marcellus Shale or the Bakken Formation, often in communities that had no prior experience with petroleum production. This report critically evaluates the past and current well stimulation practices in California and how they compare to hydraulic fracturing-enabled production in other oil and gas basins, and how the use of these technologies might occur in the future in California. Estimated rates of well stimulation operations from 2012 through 2013 are shown in Figure 1-2.
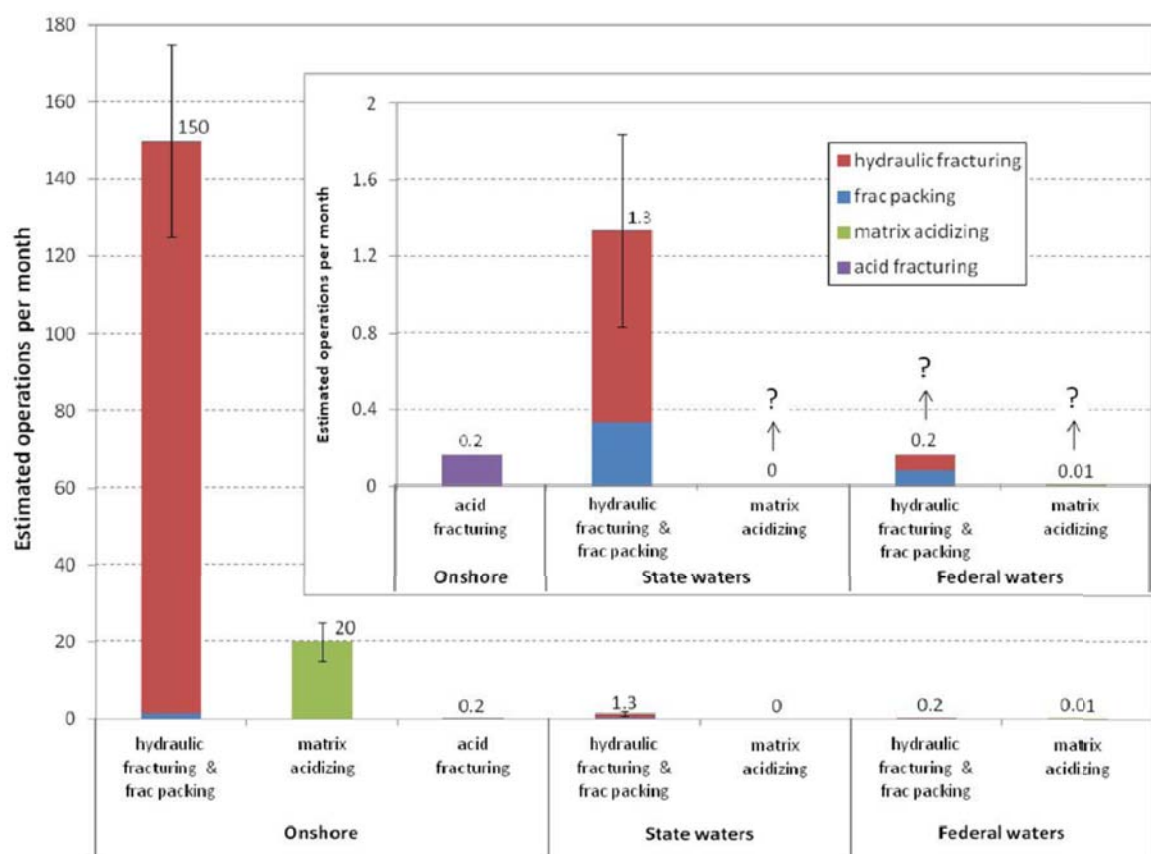
Figure 1-2. *Estimated recent well stimulation activity in California (2012 and 2013). The inset shows the smaller rates on an expanded scale. Arrows marked with question marks indicate rates estimated from one, non-comprehensive data source.*

1. Finding: Over the last decade, about one fifth of oil production in California came from wells that had been subject to hydraulic fracturing.

Operators have applied hydraulic fracturing in a variety of forms over many decades in California, with records of application in at least 96 of California's more than 500 oil fields. About 95% of the hydraulic fractures in the state take place in the San Joaquin Basin, where the majority of the state's oil and gas are produced. Most of the recorded fracturing operations in California occur in diatomite (a type of rock from which oil is produced in the San Joaquin Basin) in the North and South Belridge and Lost Hills fields located in Kern County in the San Joaquin Basin. These fields, plus the nearby Elk Hills field, consistently account for over 85% of hydraulic fracturing operations

In this time period, operators fractured about 40%–60% of the approximately 300 wells installed per month in California. Available data indicate that hydraulic fracturing has been the main type of well stimulation applied in California and is currently performed on an estimated average of 125 to 175 wells per month. This number represents about one-tenth of the number of hydraulic fracturing operations reported to FracFocus per month in the entire country in 2012 and 2013. As FracFocus is a voluntary database, the true number of hydraulic fractures in the country is likely higher than reported, and so the fraction of operations in California is probably lower.

Hydraulic fracturing can usefully increase production in many oil and gas reservoirs, but often the costs do not outweigh the benefits in which case operators do not use the technology extensively. On the other hand, some reservoirs including diatomite reservoirs in the San Joaquin Valley would likely go out of production if operators could not use hydraulic fracturing. Economic production of these reservoirs currently depends on hydraulic fracturing (Chapter 3).

2. Finding: Well stimulation technologies are not currently an important part of production from dry gas wells in California.

The Sacramento Basin, including the Dobbins-Forbes and the Winters-Domingine petroleum systems, contains most of the wells in California meeting the definition for non-associated gas production (wells that produce primarily gas instead of wells that produce gas associated with oil production).[1] In contrast to the conclusions regarding the importance of well stimulation for production from oil wells, operators used hydraulic

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1. Gas wells (non-associated gas) are defined by the Energy Information Administration as producing more than 1,069 m^3 gas per m^3 of liquid hydrocarbon (oil) (m^3/m^3; 6,000 standard cubic feet of gas per stock tank barrel of oil, scf/STB)). Although most of the gas wells are located in the Sacramento Basin, most of the natural gas production in California is actually gas co-produced from oil wells. This gas is either dissolved in the oil at reservoir temperature and pressure, and separates out during production to surface conditions, or exists as a gas in the reservoir, typically overlying the oil due to buoyancy.

fracturing in fewer than one of the ten non-associated gas wells installed per month on average from 2002 through 2011, all in the Sacramento Basin. These operations constitute less than 1% of total hydraulic fracturing conducted in California. The data reported to the state contain no records of hydraulic fracturing of gas wells since 2011 and no records of acid stimulation in gas wells (Chapter 3).

3. Conclusion: Available data suggests that present-day hydraulic fracturing practices in California differ significantly from current practices used for unconventional shale reservoirs in other petroleum basins, such as in North Dakota and Texas. Large-scale high-fluid-volume hydraulic fracturing has not found much application in California, apparently because it has not been successful.

California reservoirs deploying hydraulic fracturing produce oil or gas from traditional migrated oil fields, in contrast to other parts of the country, where hydraulic fracturing is deployed to produce oil and gas from source rock reservoirs. Oil production in the Bakken and the Eagle Ford source-rock formations takes place in thin, laterally extensive, nearly horizontal layers of oil source rock that exhibit very low permeability. The relative geological simplicity allows producers to install long, horizontal wells, and then create permeability in the geological formations surrounding these wells by using hydraulic fracturing to create networks of connected fractures. The majority of California's oil production does not come from the low-permeability shale source-rock, but rather from more permeable reservoir rocks into which oil migrated from the source rocks. Migrated oil reservoirs do not resemble the low-permeability, laterally extensive, and continuous source-rock shale layers that are amenable to production with high volume hydraulic fracturing from long-reach horizontal wells found in other states. As a result, to date, hydraulic fracturing has not been used extensively in the relatively complex California source rocks, which present greater challenges compared to the source rocks in other states.

According to DOGGR well data and SB 4 stimulation notices, most of the hydraulically fractured wells in California are vertical or near vertical, and on average shallower than in other states. Consequently, California wells are not as long and thus have shorter treatment intervals than the long-reach horizontal wells commonly hydraulically fractured in basins in other states.

Operational practices differ from other states in several ways. More than 95% of the hydraulic fracturing events in California employ gel, typically a crosslinked gel, for the stimulation fluid, as opposed to applications of "linear gel" (uncrosslinked gel) or "slickwater" (friction reducer) often used elsewhere in unconventional resource developments. The primary ingredient in slickwater is a friction reducer, which allows for higher injection rates within the pressure limitations of a well or the fracturing equipment. A low-viscosity slickwater also encourages growth of a hydraulic fracture/natural fracture network. This is accomplished by creating new fractures as well as opening existing fractures that were closed. Higher viscosity gel treatments, as used in California, allow

more proppant to be transported into the fracture and result in simpler fractures with wider openings. Gel-based fracturing has utility in relatively malleable and permeable rocks, such as the predominant oil reservoir rocks in California. Hydraulic fracturing operations using gel require less fluid volume per length of treatment, but typically have higher chemical concentrations.

Because of the predominance of stimulation in vertical and near-vertical wells, and the use of gel, operators use much smaller volumes of water in hydraulic fracturing in California than in oil source-rock plays elsewhere. The volume of fracturing fluid divided by the distance along wells where the treatment is applied in California is 2.3 m^3/m (180 gallons per ft, gal/ft) based on FracFocus and notice data. This is much less than the 9.5 m^3/m (770 gal/ft) used in horizontal wells in the Eagle Ford Formation.

The average amount of reported water used in the recent past and currently in California for each hydraulic fracturing operation is 530 m^3 (140,000 gal) per well. For comparison, this volume is similar to the annual water use of 580 m^3 (153,000 gal) in an average household in California over the last decade. The average per-operation volume in California is significantly less than the average 16,100 m^3 of water per well (4.3 million gal) reported for horizontal wells in the Eagle Ford shale tight oil play in Texas.

In California, particularly in some San Joaquin Basin fields, operators increasingly deploy hydraulic fracturing to enhance injection of water and steam into reservoirs to facilitate flow of oil from production wells. Hydraulic fracturing of production wells as a share of all wells installed per year has declined from 25% to 20% over the 2002 to 2012 period. In contrast, fracturing of injection wells for enhanced oil recovery[2] has doubled, from 5 to 10% of all wells. The data indicate hydraulic fracturing has increasingly been a component of enhanced oil recovery projects in migrated oil accumulations. This is in contrast to the increasing use of hydraulic fracturing for primary production from hydrocarbon source rock in other parts of the country.

For all these reasons, the current experience with hydraulic fracturing observed in other states may offer insights for, but does not necessarily imply similar experience in California (Chapter 3).

4. Finding: The majority of offshore production takes place without hydraulic fracturing. The fracturing that does take place is mostly from man-made islands close to the Los Angeles coastline. Available data do not contain many records of hydraulic fracturing from platforms.

The state government has exclusive jurisdiction over offshore oil and gas production within 5.6 km (three nautical miles) of the shore, while the federal government has

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2. Enhanced oil recovery utilizes injection wells to inject water or steam into a reservoir in order to increase production from the production wells.

jurisdiction in waters beyond this limit. The two zones are referred to as state and federal waters. Most offshore oil production in state waters is accomplished from purpose-built artificial islands, chief among them the four islands in the Wilmington Field in the City of Long Beach. Oil produced in federal waters comes exclusively from platforms. In federal waters, the California Coastal Commission has consistency review authority over federal actions. Almost no offshore wells in either area produce only gas.

Operations on man-made islands resemble onshore oil production activities. Operators conducted an average of 16 fracturing operations per year in state waters in the years prior to 2014. Hydraulic fracturing activity declined throughout the state in 2014, likely due at least in part to new regulatory requirements. The 16 operations per year represent about a quarter of the annual number of wells starting production in these areas. Nine out of ten fracturing operations occurred on the islands in the Wilmington Field. The proportion of new wells on the islands that undergo hydraulic fracturing is similar to the proportion in the onshore portion of the Los Angeles Basin. Both onshore and offshore operations used an average of about 550 m³ (150,000 gal) of fracking fluid per operation.

About 10–40% of fracturing operations in both state waters and onshore in the Los Angeles Basin are "frac-packs" rather than hydraulic fracturing. Frac-packs are often employed in formations that are of moderate to high permeability. A frac-pack has the purpose of increasing the connection between the well bore and the formation after drilling. Although a frac-pack may also open permeable flow paths in the reservoir rock near the well, this is not the purpose of the operation. The main functions of a frac-pack are to control sand and bypass near-well formation damage. Like a hydraulic fracturing job, a frac-pack operation injects fluid and proppant under pressure to fracture the formation. However, frac-packs require a relatively small volume of fluid and proppant, because the intention is to repair damage near the wellbore, not open permeable flow paths in the reservoir rocks. Fractures generated with a frac-pack typically extend a relatively modest 3 to 30 m (10 to 98 ft). After the fracture forms, gravel injected around the well casing serves as a filter, reducing the quantity of sand that can enter the well along with the oil.

There are no reports of matrix acidizing for reservoir stimulation in state waters according to DOGGR's databases. However, based on data submitted to the South Coast Air Quality Management District (SCAQMD), a large portion of the wells on the islands in the Wilmington Field are acidized. Requirements for reporting vary currently, making it difficult to determine how many of these operations are matrix acidizing. The DOGGR requirements for reporting acid treatments are currently changing to require all acid use to be reported, and these reports should illuminate the situation in the future.

The only available survey of stimulation in federal waters indicated 17 fracture stimulations occurred or were planned from 1992 through 2003, none from 2004 through 2009, and five more from 2010 through 2013. Half of these were frac-packs, which is a higher proportion than in state waters, which in turn is higher than onshore. One of the

fracturing operations was in the Santa Maria Basin and the rest in the Santa Barbara-Ventura Basin. Three matrix-acidizing operations are listed during the overall period. Over 250 new wells were installed in federal waters from 1992 to 2009, an average of over ten per year. This suggests a considerably smaller proportion of wells are hydraulically fractured or stimulated with acid from offshore platforms than in onshore wells. However, the data are incomplete, so these estimates may be low. Data regarding the volume of water used in these stimulations were not available.

The low proportion of offshore wells that are fractured, and the high proportion of these that use frac-packs, accords with records indicating that offshore platforms target relatively high-permeability formations where production does not require well stimulation. Given that there are abundant conventional resources available offshore, the more-expensive-to-develop low permeability plays requiring well stimulation are less likely, though possible to produce in the future (Chapters 3 and 4).

5. Finding: Acid stimulations as identified in available data are used about a tenth as frequent as hydraulic fracturing in California, but available data indicate acid treatments, which include well maintenance and remediation of damage due to drilling, are common.

There are two uses of acid in "well stimulation": matrix acidizing and acid fracturing. Matrix acidizing involves injecting acid into the existing rock pores around the open portion of the well. Acid fracturing also involves injecting acid, but at a sufficiently high pressure to fracture the rock. The fluid produced back to the surface after these treatments has much lower acid content than the injected fluid, because most of the acid has been neutralized by reaction with the rock. Neither method uses sand or other proppants.

In California, operators use acid in higher permeability formations in the South Coast and in lower permeability formations in the San Joaquin Basin. Acidizing is often used for well maintenance and remediation of damage, essentially restoring the permeability near the well that may have been reduced by drilling and well operation. Matrix acidizing can also be employed to increase the permeability of the rock itself beyond the zone impacted by drilling mud invasion or production activities if larger acid volumes are injected. The treatment generally results in only modest well productivity increases, in part because the types of minerals typically found in California do not dissolve readily in acid, and in part because the acid is neutralized by reactions near the well bore before it can penetrate more deeply. Consequently, the improvements achieved by matrix acidizing usually do not cause oil or gas recovery in a low-permeability reservoir to become viable. By comparison, the large-scale hydraulic-fracturing treatments being applied in shale formations like the Eagle Ford or the Bakken increase well productivity by orders of magnitudes above the productivity of an unstimulated well.

Various California regulations use different definitions and reporting requirements regarding the use of acid in oil and gas wells. The interim regulations on well stimulation

treatments that went into effect on January 1, 2014 (DOGGR, 2014a) defined a cutoff for matrix acidizing in terms of a concentration of acid. The draft proposed regulations, which are expected to go into effect on July 1, 2015 (DOGGR, 2014b), define matrix acidizing as exceeding a certain volume of acid. This definition may significantly change the number of reported operations in the future. The SCAQMD requires all acid use to be reported, regardless of whether it is for stimulation or maintenance, as do the proposed DOGGR regulations.

The proposed regulations will impose more monitoring and reporting requirements when acid is used for matrix acidizing to increase permeability than when acid is used for repairing well damage and restoring permeability. However, as a technical matter, it is hard to distinguish between matrix acidizing to increase permeability and acidizing to restore permeability. Any operation engineered primarily to restore permeability near the well may also increase it farther away from the well. Using the definition in the proposed regulations regarding acid volume and concentration, we have estimated that there are about 15–25 matrix acid stimulations in the approximately 300 wells installed each month in the state. Almost all the acid operations are located in five oil fields in the southwestern portion of the San Joaquin Basin. The notices indicate an average matrix acidizing water volume per well of 160 m^3 (42,000 gal).

Operators used acid fracturing in fewer than 1% of reported well stimulations currently identified and noticed through May 2014 in California, all located in two fields in the southwestern San Joaquin Basin. Acid fracturing generally only works in carbonate reservoirs where the acid can react quickly to dissolve the rock. California has predominantly silica-based reservoirs where the acid-mineral reaction rates are too slow to etch the fracture walls and make acid fracturing successful. No reports of the use of acid fracturing, even in the few carbonate reservoirs that California does have in the Santa Maria and possibly the Los Angeles basins, were identified in the literature (Chapter 3).

Key Question 2: Where will well stimulation technologies allow expanded production of oil and gas in California?

Conjectures about the potential of the Monterey Formation to provide significant new supplies of oil using well stimulation technologies have driven public concern over the use of these technologies. As was shown in Figure 1-1, the current production from low-permeability strata in other parts of the United States vastly exceeds production from low-permeability portions of the Monterey Formation in California. Furthermore, the Monterey production level has remained fairly constant between 2000 and 2012, whereas production from oil shales such as the Eagle Ford and the Bakken formations has increased dramatically. However, in 2011, the US EIA estimated that the Monterey

Formation contains 2.45 billion m³ (15.4 billion barrels) of recoverable tight oil[3] (US EIA, 2011). This estimate of recoverable tight oil in the Monterey Formation gained broad attention and raised the question whether California might experience the same type of rapid increase in oil production and disruptive development of associated infrastructure that occurred elsewhere in the country, such as in Montana and North Dakota (e.g., Garthwaite, 2013). The EIA has subsequently revised their estimate of recoverable oil in the Monterey Formation downward to about 4% of the original estimate (US EIA, 2014). Our review of both EIA estimates indicates that they both have large uncertainties. We do not know much about the distribution and abundance of oil retained in deep Monterey source rocks, or how successful production could occur, which makes determining the potential for Monterey shale oil production using well stimulation highly uncertain. (Chapter 4).

6. Conclusion: The most likely scenario for expanded oil production using well stimulation in California is production in and near reservoirs in the San Joaquin Basin that are already using these technologies.

Existing and likely future production is expected to come from reservoirs containing oil migrated from source rocks. The United States Geological Survey (USGS) estimates that approximately 1.6 billion m³ (10 billion barrels) of additional oil are technically and economically feasible to recover and might be produced near 19 existing giant fields[4]. The San Joaquin Basin accounts for about 0.56–1.6 billion m³ (3.5–10 billion barrels) of this estimate and the Los Angeles Basin accounts for 0.22–0.9 billion m³ (1.4–5.7 billion barrels). Production would require unrestricted application of current technologies, including, but not limited to, well stimulation. Figures 1-3(A), (B), and (C) show existing oil and gas fields in California and locations where expanded production might occur in the San Joaquin and Los Angeles basins, respectively.

Some but not all of this expanded production would require hydraulic fracturing. In California today, production in the diatomite reservoirs of the San Joaquin Basin depends on these technologies. Expanded production in similar reservoirs would likely also require hydraulic fracturing. While the total number of hydraulic fracturing operations is much smaller than in the San Joaquin Basin, about 25% of production in the Los Angeles Basin is associated with hydraulic fracturing. Future production of remaining oil could use similar technology (Chapter 4).

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3. "Tight oil" refers to oil produced from low permeability rocks.

4. A giant field is defined by DOGGR as having greater than or equal to 16 million m³ (100 million barrels) of recoverable oil.
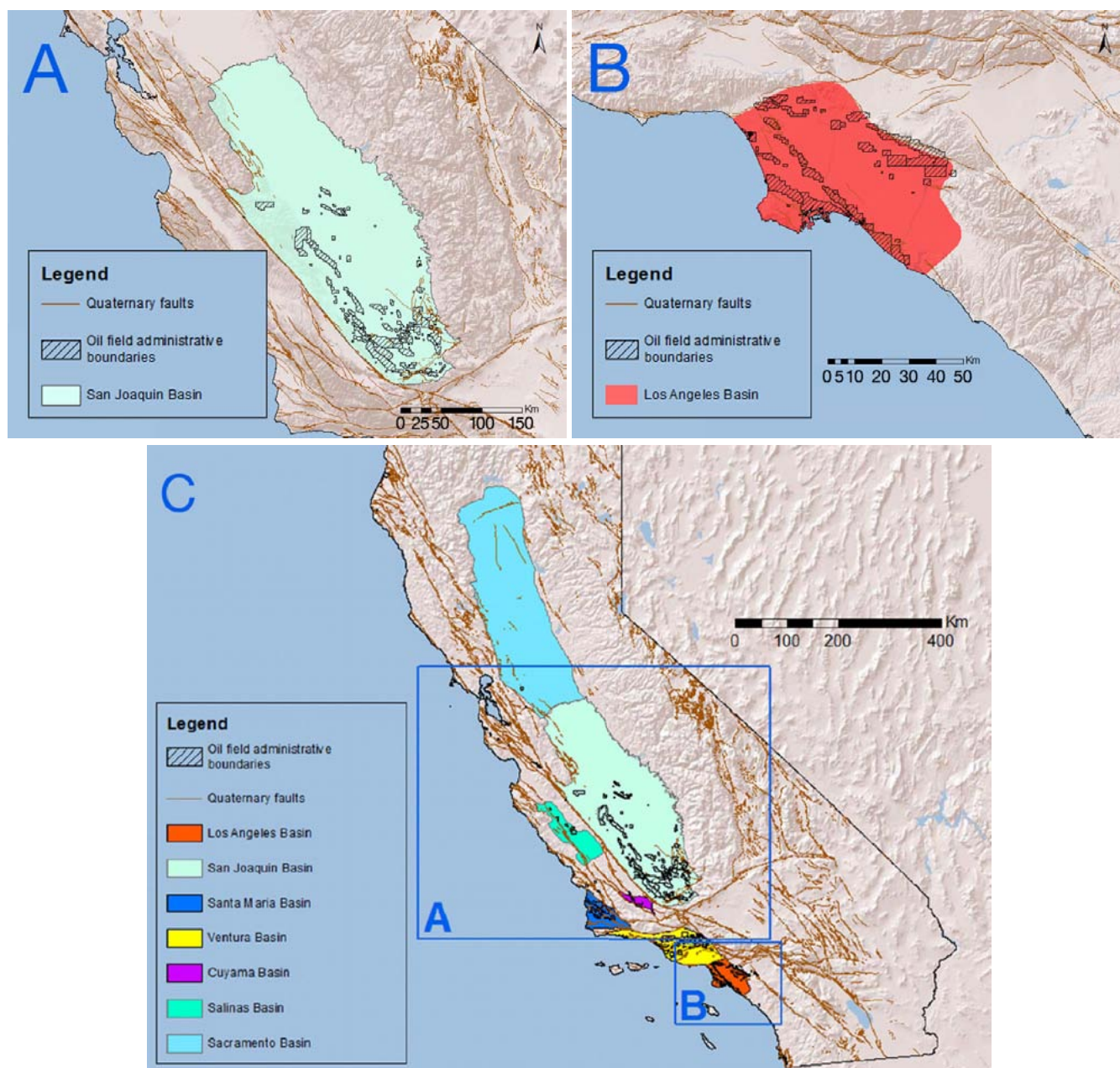
Figure 1-3. *Maps of major sedimentary basins and associated oil fields in California. (A) The San Joaquin Basin with outlines of producing oil fields. USGS estimates an additional 0.56-1.6 billion m³ (3.5-10 billion barrels) of oil could be recovered from existing fields in the San Joaquin Basin. (B) The Los Angeles Basin with outlines of producing oil fields. USGS estimates an additional 0.22-0.9 billion m³ (1.4-5.7 billion barrels) of oil could be recovered from existing fields in the Los Angeles Basin. (C) All major sedimentary basins and associated oil fields in California. Data from DOGGR, Wright (1991), and Gautier (2014).*

7. Conclusion: Estimates of the potential for oil production in the source rocks of the Monterey Formation remain highly uncertain.

New oil and gas production in regions removed from existing fields could occur, but remain more uncertain than increased production in and near existing oil and gas fields. A considerable amount of source rock, including the Monterey Formation and other geologic units within the deeper portions of major basins, could potentially contain oil that has not migrated ("source-rock" oil) and could perhaps be extracted by utilizing well stimulation. The evolution of the Monterey Formation involved complex depositional processes and subsequent deformation by a succession of tectonic events, resulting in highly heterogeneous as well as folded and faulted rocks. Their resource potential is quite difficult to characterize, and little information has been published providing information on these deep sedimentary sections. As a result, the potential recoverable resources associated with these rocks remain difficult to estimate. No reports of significant production of source oil from these rocks have been identified to date (Burzlaff and Brewster, 2014).

The US EIA 2011 INTEK report has garnered considerable attention because of its large estimate of 2.45 billion m^3 (15.4 billion barrels) of technically recoverable oil in Monterey Formation source rock. Little empirical data supports this analysis, and the assumptions used to make this estimate appear consistently on the high side. INTEK estimated that the average well in low-permeability source rock in the Monterey Formation would produce 88 thousand m^3 (550 thousand barrels) of oil. This amount greatly exceeds the average single-well oil production of only 11 and 22 thousand m^3 (67 and 140 thousand barrels) that has occurred to date from low-permeability rocks in the San Joaquin and Santa Maria basins, respectively. Consequently the INTEK estimate requires a four- to five-fold increase in productivity per well from an essentially unproven resource.

INTEK posited production over an area of 4,500 square kilometers (km^2; 1,800 square miles, mi^2), almost the entire source rock area estimated in this report. However, there has not been enough exploration to know what areas of the Monterey source rock had oil to begin with and where it has retained that oil. It is unlikely the entire source rock area will be productive, given the extreme heterogeneity in the Monterey Formation. Finally, even if significant amounts of oil do remain in the Monterey Shale, and wells can successfully reach this oil, the technology to produce the oil (which might include hydraulic fracturing) has to result in economically viable production. For all these reasons, the INTEK estimate of recoverable oil in Monterey Formation source rock warranted skepticism.

The EIA recently issued a revised estimate of 0.1 billion m^3 (0.6 billion barrels) of this unconventional oil resource (US EIA, 2014b). The lower estimate results mainly from a nine-fold reduction in the estimated potential resource area to 500 km^2 (190 mi^2). Few empirical data support either the first or second estimate of recoverable oil. Neither EIA report includes the derivation of the values used in the calculations, nor a description of the uncertainties associated with the input values. The information and understanding

necessary to develop a meaningful forecast, or even a suite of scenarios about possible recoverable unconventional oil in the Monterey shale, are not available.

Even though major production increases from shale oil-source rock are considered highly uncertain, over time they are not impossible. Future exploration could identify new source rock reserves that would likely require hydraulic fracturing for development. High-volume proppant fracturing has enabled development of low permeability source-rock reservoirs elsewhere. If large-scale proppant fracturing indeed works in source rocks in California as it has in other low permeability plays in the United States, this would change the outlook for oil and gas production in the state. The oil and gas industry constantly innovates, and research and development could improve the utility of proppant fracturing in the future. Deep test wells in source rock-shale plays have been drilled in California that with research and development may eventually prove successful. Major California producers still have ongoing Monterey source rock exploration programs, and thus a better understanding of the Monterey source rock potential, challenges, and costs and rewards to the producer and to California may come about as time goes by (Chapter 4).

8. Conclusion: The future development of new large, basin-wide unconventional natural gas resources, such as has occurred in the Marcellus or Barnett shales or in the Piceance Basin, is unlikely in California. Production in existing gas fields may be enhanced with well stimulation in the future, although these technologies are not widely used today.

The USGS estimated undiscovered conventional resources of between 4.0 and 31 billion m^3 (140 and 1,100 billion cubic feet, ft^3) of natural gas, with a mean estimate of 15 billion m^3 (530 billion ft^3) for the Sacramento Basin. The conventional reservoirs of the Sacramento Basin exhibit few of the features of true basin-centered gas accumulations (such as regional water expulsion, abnormal fluid pressures resulting from hydrocarbon generation, and absence of hydrocarbon-water contacts). Geologists do not expect basin-center gas accumulation to exist in the Sacramento Basin. While reservoir stimulation techniques may improve natural gas production from low permeability reservoir rocks sporadically, widespread development of unconventional gas resources in California using well stimulation appears unlikely (Chapter 4).

9. Conclusion: If expansion of offshore oil production along California's coast is allowed in the future, this production would not likely require well stimulation technology.

Billions of barrels of undiscovered and undeveloped recoverable oil exist off the California coast, but both federal and state laws and policies restrict expansion of production into new areas. Most current production offshore proceeds without well stimulation, and it is most likely that new production will resemble existing production. The use of well stimulation technologies discussed in this report in the offshore environment would not affect production nearly as much as a change in current policies and regulations that now restrict new production offshore.

The U.S. Bureau of Ocean Management has estimated potential oil and gas reserves for the offshore basins of California. Most of the existing offshore production occurs in the Santa Maria, Santa Barbara/Ventura, and Los Angeles basins (Fig. 1-4). Large volumes of discovered-but-undeveloped as well as yet-to-find petroleum exist in these basins. The Bureau of Ocean Management and Bureau of Safety and Environmental Enforcement have recently estimated that a mean technically recoverable resource of 176 million m^3 (1.11 billion barrels) of oil and 24 billion m^3 (840 billion ft^3) of gas remain to be found and developed in the federal outer continental shelf (OCS) of the Santa Maria and Partington basins (Piper and Ojukwu, 2014), 213 million m^3 (1.34 billion barrels) of oil and 78 billion m^3 (2,740 billion ft^3) of natural gas for the federal OCS of the Santa Barbara/ Ventura Basin, and around 140 million (0.89 billion) barrels of recoverable oil remaining to be found in the offshore areas of Los Angeles Basin. These resources are likely similar to those that have already been found and developed, which typically occur in sandstone and fractured siliceous quartz-phase Monterey Formation reservoirs, and thus will not require the use of well stimulation. Much less is known about the Point Arena Offshore, Bodega Basin, and Año Nuevo Basins, which are located north of the currently producing offshore fields. The US Minerals Management Service estimated that these three basins contain a mean undiscovered oil resource of about 670 million m^3 (4.2 billion barrels) of oil, and about 130 billion m^3 (4,500 billion ft^3) of natural gas (Dunkel et al., 1997). This 1995 estimate is similar to their 2011 assessment, which reports about 660 million m^3 (4.12 billion barrels) of technically recoverable oil and about 124 billion m^3 (4,370 billion ft^3) of natural gas from these three basins (Piper and Ojukwu, 2014). A large portion of the California offshore basins occurs in the federally defined Cordell Bank, Gulf of the Farallones, Monterey Bay, and Channel Islands National Marine Sanctuaries, where petroleum exploration is forbidden (*Chapter 4*).
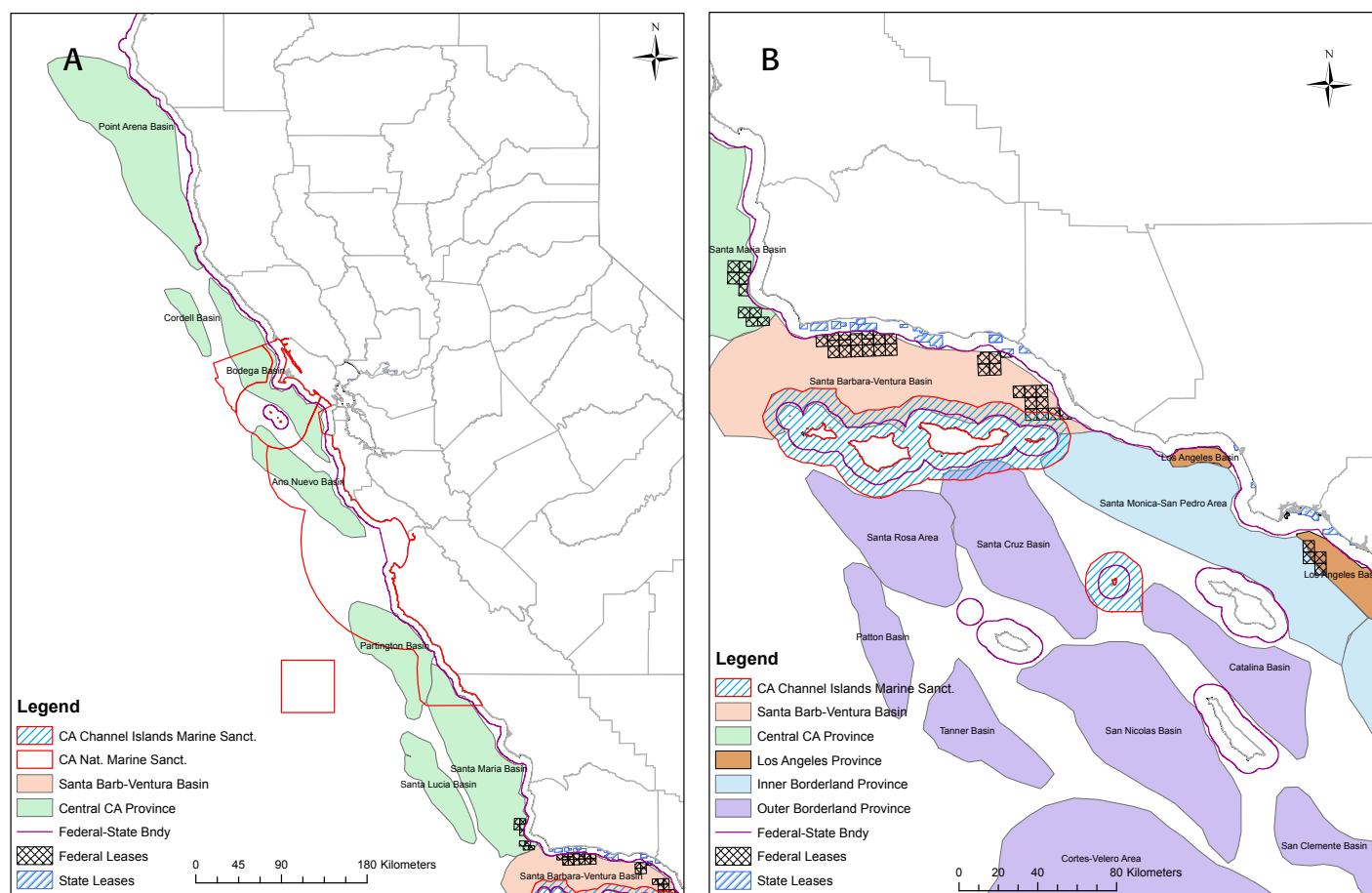
Figure 1-4. *Maps of offshore sedimentary basins in (A) central and (B) southern California, with locations of existing state and federal offshore leases, adapted from Dunkel et al. (1997) and Dunkel and Piper (1997).*

Conclusion 10. Acid stimulations in California reservoirs are not expected to lead to major increases in oil and gas development in the state.

While acidizing technology is used to stimulate wells in California, it is not expected to lead to dramatic increases in oil and gas development as has hydraulic fracturing. Acid stimulations can be effective in carbonate reservoirs, but these are rare in California. A successful matrix acid treatment in the California siliceous environment does not increase formation permeability, but is limited to removing near-wellbore permeability damage. The rate that acid dissolves silica-type rocks would have to increase by a factor of 10,000 to work as well as it does in carbonates. Such large changes in effectiveness seem highly unlikely (Chapters 2 and 3).

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Chapter Two

Advanced Well Stimulation Technologies

Abstract

This chapter provides background information on the materials and methods used to perform the three common well stimulation methods: (1) hydraulic fracturing, (2) acid fracturing, and (3) matrix acidizing. Operators perform a hydraulic fracturing treatment by injecting a fracturing fluid into a well at sufficient pressure to fracture the target formation. Once fractures form, operators inject a granular material (proppant) into the fractures to prop the fractures open after the injection pressure is relieved—otherwise, the fractures would close. Acid fracturing is similar to hydraulic fracturing, except that an acid solution is injected instead of proppant to prevent loss of the fracture openings after the injection pressure is relieved. This is accomplished by the acid etching channels into the fracture surfaces.

Commonly, both fracturing stimulation methods generate deeply penetrating fractures into reservoirs with low permeability (permeability is the ability of the rocks to conduct fluid, including oil, gas, or water), thereby providing relatively conductive flow pathways to the well. The main exception is a smaller-scale variant of hydraulic fracturing known as a "frac-pack," which is commonly used to redirect flow near the well to prevent formation sand and other particulates from entering the well and bypass damaged zones near the well. Matrix acidizing involves the injection of an acid solution into the formation to dissolve formation rock or fine materials that impede fluid flow in a region near the well. Matrix acidizing treatment takes place at lower pressures and does not produce fractures.

The application of well stimulation technologies for petroleum production in California depends on the following:

1. Reservoirs that are relatively more permeable or are relatively weak mechanically (ductile) tend to require less intensive fracturing. Less intensive fracturing requires smaller volumes of fracture fluids. Reservoirs that are less permeable and are relatively strong mechanically (brittle) tend to require more intensive fracturing, and consequently larger volumes of fracture fluids.

2. Acid fracturing can work well in carbonate reservoirs, i.e., those rich in limestone and dolomite. California's oil and gas resources are primarily found in silicate-rich rock rather than carbonate rock.

3. The principal use of matrix acidizing in silicate-rich rock is to remove near-wellbore permeability damage, and the technique has a limited effect on larger-scale reservoir flow characteristics. A possible exception would be reservoirs in which acidizing may open up natural fractures by dissolving plugging material.

4. Offshore fields tend to have moderate-to-high permeability, so operators commonly use frac-packs to bypass formation damage and control sand production rather than fracturing to open permeable flow pathways.

2.1. Introduction

The term *stimulation* with respect to petroleum production refers to a range of activities used to increase the petroleum production from reservoirs (rocks containing oil and gas in pore spaces or in natural fractures) by increasing reservoir permeability. There are two distinct situations that lead to the use of stimulation technologies. The first is damage induced by well drilling and construction and through oil and gas production operations (Economides et al., 2013). Damage may occur in the form of blocked perforations in the well casing through which oil and gas flows, e.g., by scale formation (mineral precipitation) or sand production from the reservoir into the well (Ghalambor and Economides, 2002). Damage can also occur to the rock in the immediate vicinity of the well as a result of mechanical disturbances and chemical interaction with the fluids (drilling mud) used during drilling. For example, pores may be plugged by drilling mud, particulates or swelling clays, or fine particles in the rock may migrate into the well (Ghalambor and Economides, 2002). Mechanical damage in the form of crushing and compaction of the rock may occur as a result of creating the perforations (holes) through the casing. The perforation process is carried out by shooting a high-velocity jet produced by a shaped charge through the steel casing and cement and penetrate a short distance into the rock. The perforations connect the well to the reservoir (Ghalambor and Economides, 2002). Techniques to correct these adverse impacts of well construction by clearing blockages in the well, or restoring the permeability of the rock, are termed *well stimulation*. These forms of well stimulation are considered maintenance activities that are directed at the well or the immediate vicinity of the well affected by drilling or well construction.

The term *stimulation* also refers to the use of techniques to open permeable flow paths between the undisturbed reservoir rock and the well or increase reservoir permeability, such that it can provide economic rates of hydrocarbon production (permeability is the ability of the rocks to conduct fluid including oil, gas, or water). This stimulation is also on occasion termed *well stimulation*, but is perhaps more precisely called *reservoir stimulation* (Economides et al., 2013). The focus of this report will be on stimulation technologies whose purpose is to open permeable flow paths in the reservoir or increase reservoir permeability and these technologies will be referred to by the term *well stimulation*, or simply *stimulation*. This is in accord with the definition of well stimulation in Section 3157 of Division 3, Chapter 1 of the California Public Resources Code.

2.2. The Purpose of Stimulation Technologies

As described above, the production of oil and gas from a reservoir depends on reservoir permeability, but it is also a function of reservoir thickness, the viscosity of the fossil fuels produced, well radius, and other factors. Because of the complexity of the problem, an exact permeability threshold for the use of well stimulation technologies does not exist (Holditch, 2006). However, the likelihood that well stimulation is needed to economically produce oil and gas increases as the reservoir permeability falls below about 10^{-15} square meters (m²; about 1 millidarcy, md) (e.g., King, 2012).

A hydrocarbon reservoir is typically classified as *unconventional* if well stimulation is required for economical production. Guidelines concerning the classification of petroleum resources (World Petroleum Council, 2011) categorize a reservoir as unconventional if it is spatially extensive and yet not significantly affected by natural flow processes. The oil in the Bakken play in North Dakota is an example of such an accumulation. A different and quantitative definition proposed by Cander (2012) is shown in Figure 2-1, in which the permeability of the reservoir and viscosity of the oil or gas are used to define conventional and unconventional. This definition is an alternative guide to the conditions amenable to well stimulation.
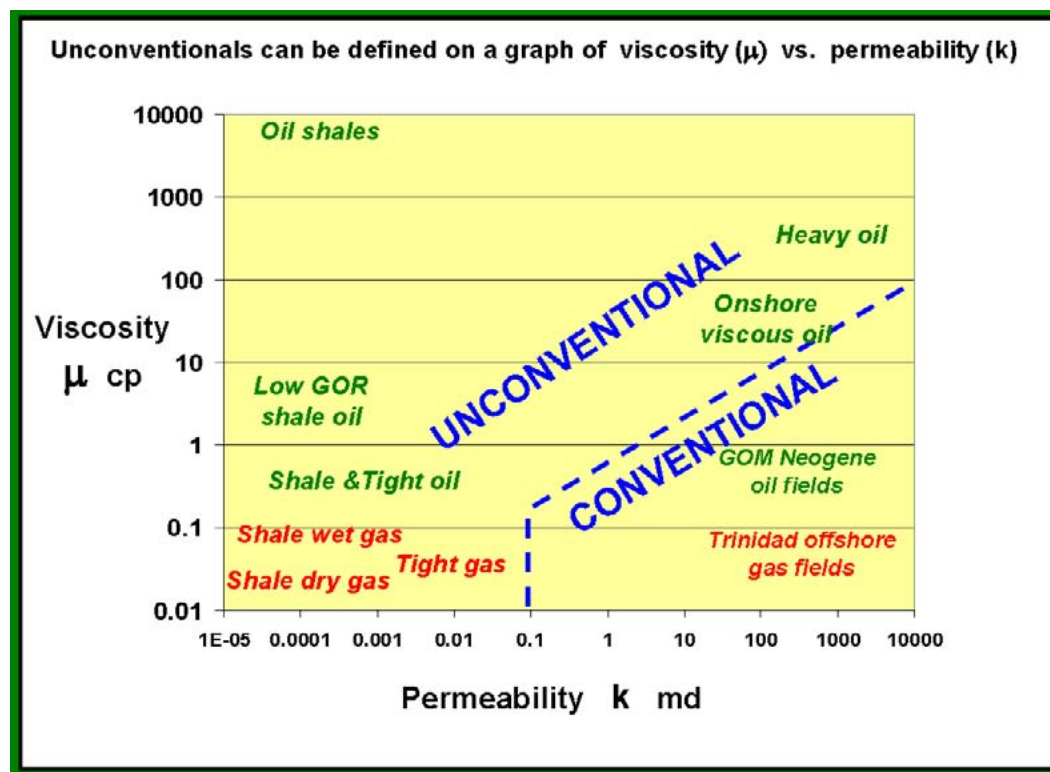
Figure 2-1. *Definition of unconventional hydrocarbon resource (Cander, 2012)*

The threshold between conventional and unconventional is defined by practical considerations. Unconventional resources require the use of technology to increase hydrocarbon flow rate or the fluid viscosity to produce the oil and gas at commercially economic rates, although stimulation can increase rates even in otherwise commercial wells. Conversely, conventional resources can be produced commercially without altering permeability or viscosity (Cander, 2012). This report focuses on well stimulation technologies for reservoirs that are unconventional because of small permeability. Enhanced oil recovery methods for reservoirs that contain viscous oils are not treated in this report.

There are three main well stimulation technologies: hydraulic fracturing either using proppant (traditional hydraulic fracturing) or acid (also known as acid fracturing) and matrix acidizing. (Economides and Nolte, 2000). Hydraulic fracturing is a stimulation technique that uses high pressure fluid injection to create fractures in the rock and then fill the fractures with a granular material called proppant to retain the fracture openings after the fluid pressure is relieved. The large -permeability fractures then act as pathways for hydrocarbon to flow through to the well. Acid fracturing is similar in that fluid is injected under pressure to create fractures, but then acid is injected to etch channels into the fracture walls to retain fracture permeability instead of injecting proppant. Matrix acidizing is a stimulation method in which acid is injected below the pressure necessary to create fractures. The acid dissolves plugging materials and/or the reservoir rock near the well primarily to mitigate permeability damage caused by drilling, well construction and operations. In carbonate reservoirs, matrix acidizing can result in limited stimulation of reservoir permeability beyond the near-well region. Because these methods do not reduce viscosity, they are primarily targeted at rock formations containing gas or lower-viscosity oil, although they may be used with thermal stimulation for heavy oil.

The main technologies currently used for the production of most unconventional reservoirs are horizontal drilling combined with some form of hydraulic fracturing (McDaniel and Rispler, 2009). Because of this close association, horizontal wells are also discussed in this report. Relatively simple geologic systems have nearly horizontal deposition and layer boundaries, and typically have much longer dimensions along the horizontal directions compared with the (usually) vertical dimension perpendicular to bedding. Horizontal drilling allows a well to access the reservoir over a longer distance than could be achieved with a traditional vertical well. An example of horizontal and vertical wells is in Figure 2-2 for the Eagle Ford play in Texas, which consists of a calcium-carbonate rich mudstone called marl. Some regions of the Eagle Ford produce non-associated gas, which are considered unconventional shale gas resources, and some produce oil, which are considered unconventional shale oil resources. "Shale oil" discussed here differs from "oil shale," which is a rock that contains a solid organic compound known as kerogen. When exposed to a certain range of temperatures, kerogen decomposes into crude oil. In this case, the horizontal well intercepts about 1,500 meters (m; 4,900 feet, ft) of reservoir as compared with about 80 m (262 ft) by the vertical well.
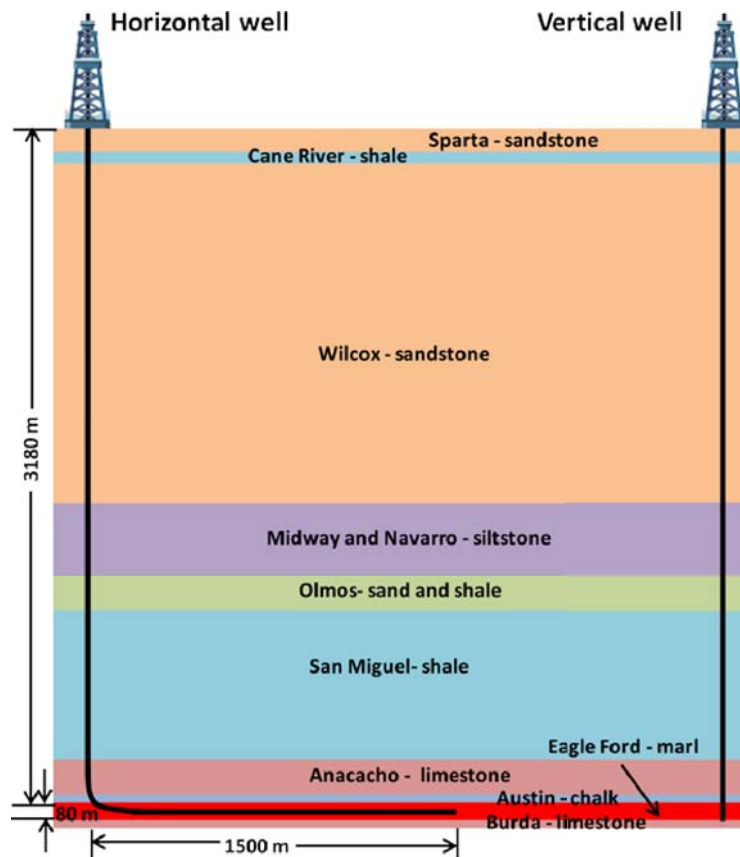
Figure 2-2. *Example of horizontal and vertical wells in the Eagle Ford play (stratigraphy from Cardneaux, 2012)*

Hydraulic fracturing induces fractures by injecting fluid into the well until the pressure exceeds the threshold for fracturing. The induced fractures emanate from the well into the reservoir and provide a high-permeability pathway from the formation to the well, as shown on Figure 2-3. One of the goals of the fracturing operation is to only fracture rock within the target reservoir; if the hydraulic fracturing strays out of the low-permeability target zone, there will be a "short-circuiting" effect, as more permeable units will contribute production fluids. During portions of a hydraulic fracture treatment, "proppant" (natural sand or man-made ceramic grains) is generally pumped in the frac fluid to prop the fracture(s) open, to maintain fracture conductivity after the treatment is completed and the well is put on production. The effective stress imposed on a fracture plane and the proppant within the fracture is the total stress perpendicular to the fracture plane minus the pore pressure within the fracture. The use of proppant becomes particularly important for maintaining fracture permeability as formation fluids, a load-supporting element of formation strength, are removed by production. The creation of a highly permeable fracture network allows for the effective drainage of a much larger volume of

low-permeability rock, and thus increases the hydrocarbon flow rates and total recovery. Another variation of hydraulic fracturing is called acid fracturing, where acid is injected instead of proppant. The acid etches channels into the fracture surfaces, which then prevent the natural overburden stress from closing the fractures and allows fluid-flow pathways to remain along the fractures even after the injection pressure is removed. Industry comparisons of stability of propped fractures to that of acid fractures indicate that propped fractures are usually more stable over time, especially in sandstones and soft carbonates (Abass et al., 2006).
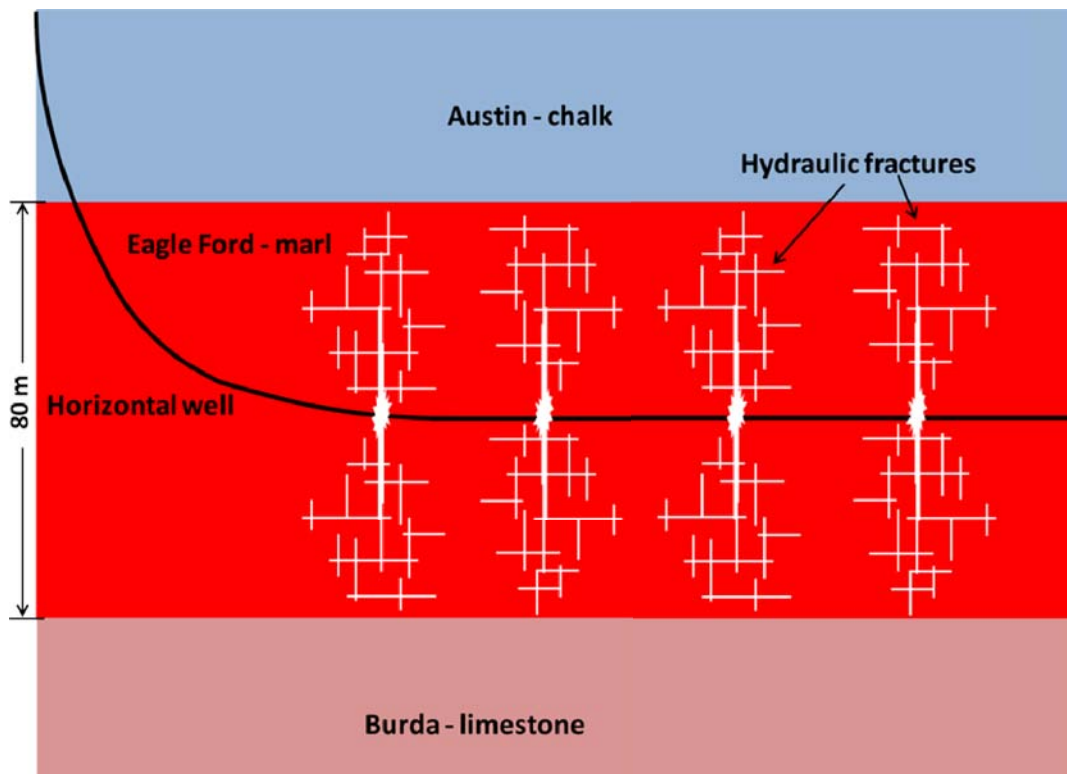
Figure 2-3. *Hydraulic fractures initiated from a series of locations along a cased and perforated horizontal well.*

Matrix acidizing is injecting acidics at pressures less than the fracture pressure, such that the acid dissolves acid-soluble minerals in the rock matrix or the acid soluble plugging components in the pores. The end result is enhanced flow pathways through the rock matrix. By comparison, however, the penetration into the formation of enhanced permeability caused by matrix acidizing is not typically as extensive as it is after hydraulic fracturing with proppant or acid. The two important exceptions in carbonate reservoirs are the creation of more deeply penetrating channels, known as wormholes, and deeper acid penetration into more permeable fractures of naturally fractured reservoirs (Economides et al., 2013).

Well drilling and construction, hydraulic fracturing, and matrix acidizing are discussed in more detail below.

2.3. Well Drilling, Construction, and Completion

Well drilling, construction, and completion are necessary steps for conducting production operations from the vast majority of hydrocarbon reservoirs. (Some shallow hydrocarbon deposits, such as oil sands, can be mined from the surface.) Well construction is the installation of well casing and cement that seals the annular space between the casing and the formation as drilling proceeds. Well casing and cement provide the main barriers against contamination of groundwater in upper formations by native (e.g., deeper and more saline groundwater), injected, or produced fluids during well operation.

Well completion is a separate step following drilling and construction of the well. Well completion can be done to configure and optimize the well for hydrocarbon production, or well completion techniques such as hydraulic fracturing and acid fracturing can optimize the formation for hydrocarbon production. Types of well stimulation described are those required for well completion. Completion includes (as needed) sand control (gravel packing and frac-packs), perforation of the production casing, installation of production tubing, matrix acidizing, hydraulic fracturing, and acid fracturing. Sections 2.3.1- 2.3.3 covers onshore well drilling and construction; offshore well drilling and construction are covered in Section 2.3.4.

2.3.1. Well Pads

Wells on land (onshore) are drilled on a prepared surface known as a well pad. The well pad is the area of land used for the drilling rig, equipment and for the facilities for holding and processing drilling muds. After well drilling is complete, the pad is used to hold all of the equipment and facilities used for well stimulation treatments, such as water tanks, gel storage unit trucks, chemical storage trucks, transfer pumps, proppant storage trucks or bins, blender units, and pumps to inject the fracturing fluids into the well.

Once the well pad location and size has been determined, the area is cleared of vegetation and leveled. The topsoil is excavated and stored near the pad for subsequent site restoration (US Fish and Wildlife Service, 2014). Well pads are usually covered with gravel that is compacted to a flat surface. The flat surface is particularly important for multi-well pads so that the drilling rig on the pad can be moved to different locations on the pad without having to disassemble and reassemble the rig. A geotextile is sometimes placed under the gravel for mechanical support of the gravel and can also act as a spill-protection barrier (Pennsylvania Department of Conservation and Natural Resources Bureau of Forestry, 2011). (A geotextile is a synthetic permeable textile material used to permit water movement, retard soil movement, add reinforcement, and provide separation between overlying and underlying soils or rock.) The preparation of a well pad also usually includes storm water and sediment (erosion) control and drilling fluid pits

or tanks. Drill pad sizes generally range from about 4000 to 8000 m² (44,000 to 130,000 square feet, ft²) for vertical wells and 8000 to 24,000 m² (44,000 to 260,000 ft²) for horizontal wells (Smrecak, 2012; US Department of the Interior, 2011; US Department of the Interior and US Department of Agriculture, 2013) but may be smaller in urban environments. High-volume hydraulic fracturing can require a larger well pad because of the amount of water and proppant that needs to be stored on the pad and made readily available for injection.

2.3.2. Vertical Wells Onshore

Until the 1980s, the vast majority of petroleum production wells worldwide were vertical wells (US EIA, 1993). Although the use of horizontal-well technology has steadily increased since that time, vertical wells are still being drilled for petroleum production. (Horizontal wells, discussed in Section 2.3.3, are an important technological development for production from source-rock shale reservoirs.) This fact means that older wells tend to be vertical.

Nearly all oil or gas wells (vertical or horizontal) are drilled using the rotary drilling method (Culver, 1998; Macini, 2005a). The first major oil discovery using rotary drilling was made at Spindletop near Beaumont, Texas, in 1901 (Geehan and McKee, 1989). There are a several methods used to drill wells, but most of these alternative methods are used for wells less than 600 m (1,970 ft) deep (ASTM, 2014) and therefore are not suitable for most oil or gas wells, which average over 1,500 m (4,920 ft) deep in the US (US EIA, 2014). Even in California, where there are significant oil resources developed at shallow subsurface depths (< 600 m (1,970 ft) in depth, see Chapter 3), rotary drilling is the main method used for oil and gas wells (Jenkins, 1943).

2.3.2.1. Rotary Drilling Process and Drilling Muds for Onshore Wells

The rotary drilling process is conducted from a drilling rig at the ground surface. The drill bit and other components, such as weights called drill collars, make up the bottom-hole assembly that is connected to the first section of drill pipe, and then is put in place below the drilling rig floor to begin. The drill pipe is connected to a square or hexagonal pipe called the "kelly." The kelly is turned by a motor via the rotary table in the floor of the drilling rig and a kelly bushing that connects to the kelly. Alternatively, a newer system known as "top drive" can be mounted to the rig derrick that turns the drill pipe (Macini, 2005a). In either case, the rotational coupling with the drill string (collectively the drill pipe and bit) permits vertical movements such that the desired downward force can be applied to the drill bit while it is rotating. (More recent technology has led to the development of downhole motors that drive rotation of the drill bit; therefore, rotation of the drill pipe is not required. This technology is particularly important for directional drilling and will be discussed further in Section 2.3.3.) When the hole has been drilled deep enough to hold the bottom-hole assembly and drill pipe, another section of pipe is added and the process is repeated.

As drilling proceeds, the bit is supplied with drilling mud, which is denser and more viscous than water, through a nonrotating hose that connects to the top of the kelly through a connection called a swivel. Drilling mud flows down the drill string and exits through ports on the face of the drill bit. This action flushes drill cuttings away from the drilling face and up the annulus between the drill pipe and the borehole wall or casing pipe, and the mud holds the boring open against formation pressures. The circulating mud exits the annulus and is recycled back to the well after the cuttings have been separated from the mud (Varhaug, 2011). Figure 2-4 shows the components of the drilling mud circulation system.
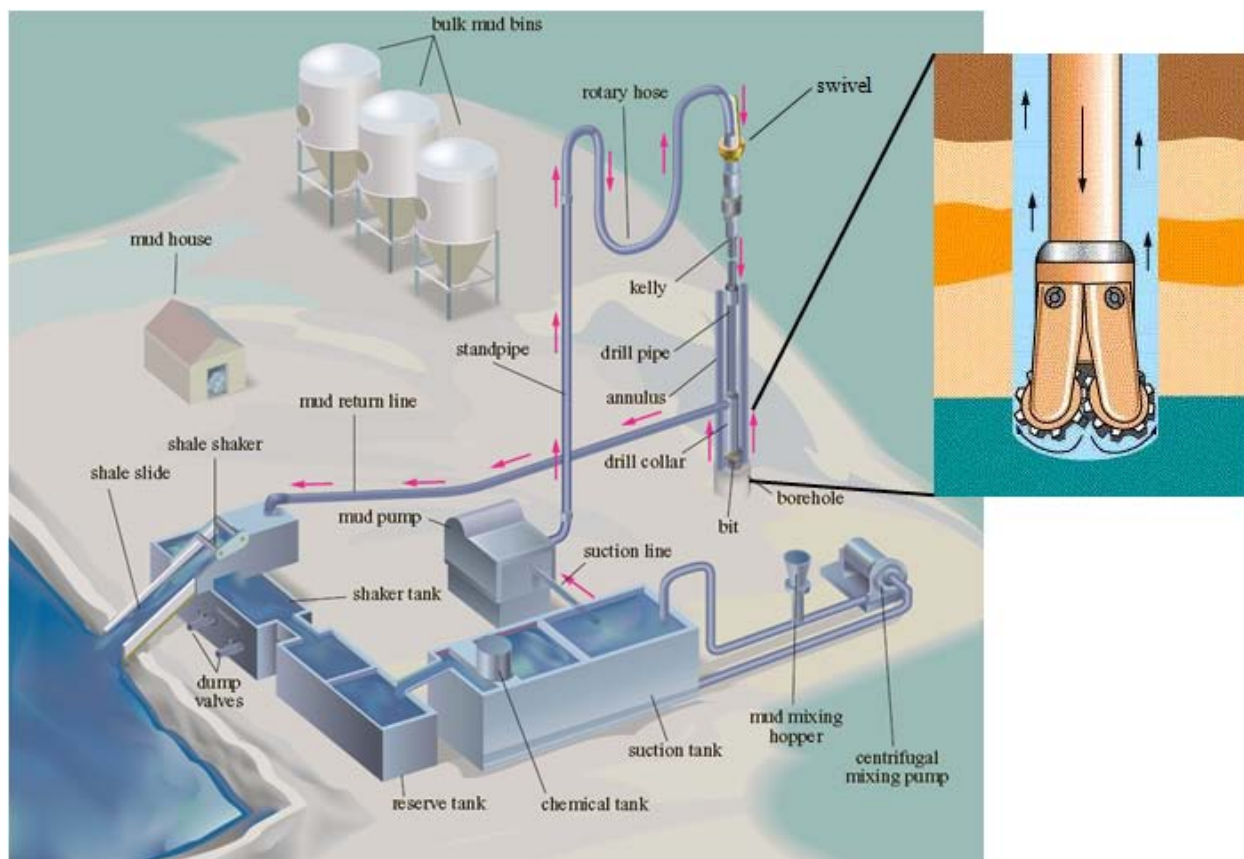
Figure 2-4. *Drilling mud circulation system. Arrows indicate mud flow direction (modified from Macini (2005a) and Oil Spill Solutions (2014))*

Drilling fluids have several important functions. As mentioned previously, the mud continuously cleans the cuttings off the bit face and transports them out of the hole. The mud also limits the rate at which cuttings settle in the borehole annulus, so that the drill bit is not quickly buried by cuttings whenever the mud flow is temporarily stopped. The mud also serves to lubricate and cool the drill bit. Finally, the mud provides hydraulic

pressure to help stabilize the borehole walls and control native fluid pressures in the rock, to prevent an uncontrolled release (blowout) of these fluids through the borehole. When a downhole motor is used, the energy of the flowing drilling mud also drives the bit rotation.

There are three basic types of drilling fluids: (1) aqueous-based mud; (2) hydrocarbon-based mud; and (3) gas, aerated, or foam muds (Khodja et al., 2013), in which the classification is based on the predominant fluid in the mud. One of the critical factors that influences the choice of mud used is the clay content of shale encountered by the borehole. Shales make up about 75% of drilled formations, and about 70% of borehole problems can be associated with shale instability (Lal, 1999). (Note—there is a distinct difference between unstable shales (e.g., gumbo) which have a large clay content, and shale source rocks which often have modulus of elasticity numbers comparable to very fine grain, low-clay-content sandstones.) Clay hydration caused by water-based muds often lead to reduced rock strength and instability in the borehole. This can result in a variety of problems, including borehole collapse, tight borehole, stuck pipe, poor borehole cleaning, borehole washout, plastic flow, fracturing, and lost circulation and well control (Lal, 1999). Furthermore, borehole wash-out in the shale sections can result in problems for cementing the casing in these sections and thus impede the ability to isolate zones and control leakage along the well outside the casing (Brufatto et al., 2003; Chemerinski and Robinson, 1995). Because of these issues surrounding interaction of water with shale, oil-based muds are considered more suitable for drilling through some shale formations. However, because of environmental issues associated with the use and disposal of drilling muds, more suitable water-based muds for drilling through shale continue to be developed (Deville et al., 2011). Another strategy used to minimize the environmental effects of drilling muds is to use water initially to penetrate the freshwater aquifer zone, then progress to more complex, water-based inhibitive muds, and then to oil-based muds at greater depth (Williamson, 2013).

2.3.2.2. Well Casing and Cementing

Wells are secured at discrete intervals as the borehole is being drilled by installing a steel pipe with diameter slightly smaller than the borehole diameter. This pipe, termed casing, is then fixed in place by filling the annulus between the pipe and the borehole wall with cement. After installing the casing, the pathway for fluid movement along the borehole is restricted to the circular interior of the casing. The casing provides mechanical support to prevent borehole collapse and hydraulically isolates flow inside the casing from the rock formations around the well. Furthermore, the casing, in combination with the cement, impedes fluid movement along the borehole outside the casing between the different formations encountered, and to the ground surface as well. This function is referred to as "zonal isolation" (Nelson, 2012; Bellabarba et al., 2008).

Zonal isolation is accomplished by filling the annulus between the casing and the formation with cement, which bonds the casing to the formation. Different types of cements are used depending on conditions of depth, temperature, pressure, and chemical

environment (Lyons and Plisga, 2005). Cement placement and curing processes have to address numerous factors for the cement to be an effective barrier to fluid movement behind the casing (API, 2010). After placement and curing of the cement, American Petroleum Institute (API) guidelines recommend that each section of cemented casing be pressure tested to ensure that the cement is capable of withstanding the pressures to be used during well operations (API, 2009; 2010). Furthermore, wireline logging tools are recommended after the cement job to verify that the well is correctly cemented and there are no hydraulic leakage paths. This is accomplished using acoustic tools (sonic and ultrasonic) that can determine the quality of the cement bond and can detect channels (API, 2009; Griffith et al., 1992).

The first casing to be installed is called the conductor casing (essentially a pipe with diameter larger than any of the other casings in the well), shown in Figure 2-5. This casing prevents the typically weak surficial materials from collapsing into the drill hole. The conductor casing is either driven into the ground by a pile driver or placed in the hole after drilling (API, 2009). The length of the conductor casing is normally 30–50 m (98.4–164 ft) (Macini, 2005a), but generally less than 91 m (229 ft) in length (Burdylo and Birch, 1990). If the conductor pipe is not cemented, it is not strictly considered as part of the well casing (Macini, 2005a).
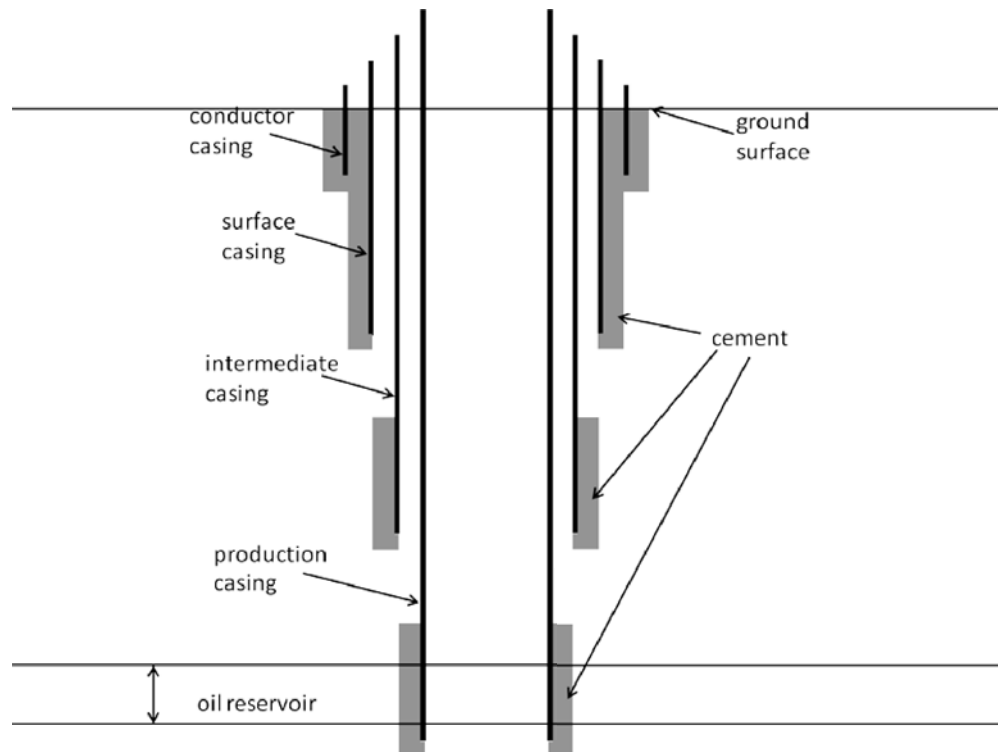
Figure 2-5. *Schematic cross section of well casing and cement configuration. Casing extends above ground surface for connection to wellhead. (redrawn and modified from API, 2009)*

The next casing installed is called the surface casing. The purpose of the surface casing is to protect freshwater aquifers from drilling mud and fluids produced during the life of the well, and to isolate these zones from overlying and underlying strata. The surface casing is necessarily smaller in diameter than the conductor casing and is typically about 91 m (299 ft), but can extend farther up to about 305 m (1,000 ft) in depth (King, 2012). Once the target depth for the surface casing is reached, the surface casing is inserted into the borehole and the annulus between the casing and the borehole wall and conductor casing are cemented. The casing extends from the bottom of the hole to the ground surface. Cement must extend from the bottom of the surface string to the surface, and the ability of the pipe and cement to seal pressure is typically evaluated by test.

The surface casing (or conductor casing if it is cemented) is used to anchor the wellhead, which provides the interface between the well and equipment attached to the wellhead above the ground surface. During drilling operations, an operational and safety valve system called a blowout preventer is attached to the wellhead. After drilling is complete, the blowout preventer is replaced by a different system of pipe hangers, valves, and flow-directing outlets called a Christmas tree, which is used for production operations (Macini, 2005a).

Drilling then proceeds until the next casing, which could be the production casing or an intermediate casing (needed for deeper wells). In either situation, the next section of casing is assembled and inserted into the borehole, and the annulus is cemented to a point where all gas-charged or salt water-charged zones are covered and sealed. Production casing extends through at least part of the surface casing (on shallow wells) or the intermediate casing (on deeper wells) and extends to the top of the producing interval in an open-hole completion or to the bottom of the drilled hole in a cased-hole completion. The production casing is the last section of casing that either enters the reservoir (if the production is to be done through an open hole) or extends throughout the production interval of the borehole. In some instances, a production liner is used that does not extend the full length of the hole. Instead, the liner hangs off the base of and is sealed to the intermediate casing and is not always cemented. The production liner is suspended by use of a liner hanger packer set within a cemented section of the intermediate casing, allowing an overlap section between the production liner and the intermediate casing that can be filled with cement with a bonding area of a hundred meters or more.

The casing is subject to hydraulic and mechanical stress, including axial tension caused by its own weight as well as dynamic stresses caused by installation and operational activities, external fluid pressures from the formation during cementing operations, and internal fluid pressure during drilling and operations. Thermal stresses are also present, and formation induced stresses of creep and seismic movement must be accounted for in the design. These stresses need to be taken into account when selecting casing type and size (Lyons and Plisga, 2005). For systems that will be used for hydraulic fracturing, the high levels of fluid pressure imposed also need to be taken into account for casing and cement selection (API, 2009).

Cementing the annulus of the casing is essential for control of leakage along the well outside the casing. After a casing segment has been put into the borehole, a set of cementing activities that clear the mud from the path of the cement, and remove excess dehydrated mud from the wall of the formation, are performed to increase the bonding of the cement to the formation and the pipe, and develop a cement sheath that acts as a barrier to flow between the non-producing formations and the wellbore. Oilfield cements are usually calcium silicate type (Portland) cements containing additives depending on well depth, temperature, and pressure conditions, borehole rock characteristics, and chemical environment (Economides et al., 1998).

Additives are used for a variety of reasons. Many of these same additives are used in hydraulic fracturing, with the same objective. Cement additives perform several actions, including altering the curing time, controlling water loss and solids/water separation, preventing damage from heat or CO_2, and preventing gas migration—among other things. Water loss and curing reactions that result in shrinkage cracking have been identified as significant factors leading to leakage behind the casing (Dusseault et al., 2000). Various polymers are typically used to prevent water loss (Economides et al., 1998), and magnesium oxide is used to cause an expansion of the cement upon curing (Joy, 2011). The ability of the cement to withstand stresses and borehole flexure without fracturing is increased by the addition of elastomeric fibers such as polypropylene (Sounthararajan et al., 2013; Shahriar, 2011).

After the required volume of mud pre-flushes, dispersants and spacers are pumped down the casing and, once the fluids reach the bottom of the well, the materials turn and are displaced up the annulus to prepare the formation and pipe for cement bonding, A volume of cement is pumped that will displace the other materials up the annulus and allow a strong bond to be formed that will complete the seal and effectively isolate the well. When the cement reaches the bottom of the hole, the cement continues to displace the resident fluids ahead of it upward along the outside annulus of the casing. The injection ends when the cement fills the annulus to the designed top of cement point. Deep intermediate or production casings may not be cemented to the top of the casing. This is because the high fluid pressure associated with the dense cement slurry over these longer intervals can fracture the formation (King, 2012). Once the cement sets, the residual cement and any remaining items from the cement operation that are at the bottom of the hole are drilled out to continue deepening the borehole. A simple schematic of the casing and cement configuration is shown in Figure 2-5.

A number of problems can occur that lead to incomplete cementing around the casing. These include mixing of the cement and the drilling mud, poor displacement of the drilling mud by the cement, off-center casing that contacts the borehole wall, excessive water loss from the cement, and gas migration through the cement prior to setting (API, 2010; King, 2012). Any of these could lead to incomplete cement behind the casing and the potential for leakage along the casing. Because these issues are well known, several methods are available to optimize cementing and make these issues unusual. For example,

to avoid mixing between the cement and the drilling mud, a chemical washer is injected ahead of the cement to help clean out the drilling mud and provide a fluid gap between the cement and the drilling mud. Wiper plugs that are placed just in front of and behind the cement slug that is injected into the casing also prevent cement contamination by the drilling mud (Nelson, 2012). Casing centralizers are used to position the casing in the middle of the borehole to avoid trapping mud between the casing and the borehole wall (leading to mud channels in the cement). Additives are used to reduce cement shrinkage and permeability during setting, and to accelerate setting times, to avoid gas migration problems in the cement (Bonett and Pafitis, 1996).

Although unlikely, leakage along wells is considered the most likely route for injected fracturing fluids or reservoir fluids to migrate into overlying strata (King, 2012). Both casing and cement design need to account for any operational pressures and chemical environments that may occur during well stimulation. If the design is not adequate, leakage can result.

2.3.3. Directional Drilling and Horizontal Wells Onshore

Directional drilling was initially developed in the late 1920s and 1930s (Gleason, 1934; Kashikar, 2005). Directional drilling refers to well construction with at least one section that has a curved axis. A horizontal well is a special case of a directional well in which the well axis is curved along an arc to approximately 90 degrees from the vertical, followed by a straight horizontal section, also referred to as a lateral. The technology required several improvements before it started to be used the 1970s; its application became widespread by the 1990s (Williams, 2004). By the end of 2012, 63% of wells drilled in the US were horizontal, 11% were directional, and only 26% were vertical (Amer et al., 2013). The preponderance of new horizontal wells results from the growth of shale gas and shale oil development.

2.3.3.1. Drilling Process and Drilling Muds

The operations discussed for vertical wells generally apply to the initial phases of drilling a well that will include intentionally curved deeper sections. Directional drilling begins at a kick-off point after the initial vertical section is drilled. One of the first methods developed for establishing a deviation in direction used a mechanical device known as a whipstock, which is a wedge-shaped tool placed in the bottom of the hole that forces the drill to deviate from the vertical direction (Giacca, 2005). A major improvement in directional drilling was the development of steerable systems that use a downhole motor, in which the energy of the drilling fluid can be used to drive bit rotation. The steerable system eliminates the need for a whipstock for directional or horizontal wells. In this system, the direction of the drill bit is bent slightly relative to the drill string axis. Drilling by rotating the drill string causes the bit to drill in a straight line aligned with the drill string. By setting the drill string at a fixed angle and turning the bit through the energy of the drilling mud flow, the angle between the bit and the drill pipe can be maintained. The bit

is rotated using the positive-displacement motor and drills ahead at the angle set by the position of the drill string, which does not rotate, and slides behind the bit. This method creates a somewhat tortuous borehole when drilling curved sections, making drilling more difficult, as well as greater difficulty in formation evaluation and running casing (Williams, 2004).

The latest technology, called rotary steerable drilling, allows for continuous drill-string rotation in curving and straight sections. Changes in direction are imposed by either a point-the-bit system similar to the bent steerable system just discussed, or a push-the-bit system in which pressure is applied by pushing against the borehole wall (Downton et al., 2000). The key difference is that the rotary steerable system mechanics allow continuous rotation of the drill string and produces much smoother and less tortuous curved boreholes. The greatest advantage of a rotary steerable system is that continuous rotation reduces the friction between the drill string and the formation, allowing better transfer of weight to the bit and enhanced cleaning of the cutting from the hole. Sliding (i.e., no rotation) results in less weight on bit and much slower drilling. Control of the drilling direction is done from the surface by sending signals to steering actuators at the drill bit through a series of pressure pulses in the drilling mud (Giacca, 2005), a process referred to as mud pulse telemetry (MPT) (Downton et al., 2000).

In addition to development of improved directional control (inclination and azimuth) and borehole quality, there has been the development of methods to measure the local temperature and pressure conditions, as well as the orientation and motion of the drill bit. This measurement technique is referred to as "measurement while drilling" (MWD), and the information is transmitted to the surface using MPT (Downton et al., 2000; Amer et al., 2013). Thus, the conditions and path of the drill bit is known in real time to help control the drilling process. More recently, sophisticated technology to perform formation evaluation measurements, such as resistivity, gamma ray, sonic, and magnetic resonance measurements, have been integrated into the drilling process and may also be received in real time through MPT (Amer et al., 2013). For drilling in shales, the inclination, azimuth, and gamma ray activity are the most critical data. The information on borehole trajectory and changes in the formation allow for "geosteering," in which directional drilling is actively controlled using real-time data to properly position the borehole relative to the target formation.

The various drilling muds discussed for drilling of vertical wells are also used for directional drilling. Oil-based muds have an advantage for drilling systems in which the drill string does not rotate because the oil-based mud provides better lubrication of the long horizontal well lateral – i.e., sliding pipe along the lateral. The demands of high-angle and horizontal drilling, and extensive drilling path lengths through shales for unconventional reservoirs, result in greater use of oil-based drilling muds. However, alternative water-based muds for these conditions are being developed because of the greater environmental risks and costs associated with oil-based muds. Success using water-based muds requires development of custom formulations based on the specific reservoir rock and conditions to be encountered (Deville et al., 2011).

Directional wells can be drilled with long, medium, or short radius curves. The longer-radius wells are typically used when the objective is extended horizontal reach (thousands of meters), while medium and short radius wells are used when a shorter horizontal leg (~1,000 m (3,280 ft) for medium radius and up to 300 m (984 ft) for short radius) is needed, and/or when highly accurate placement is necessary (Giacca, 2005). Directional drilling also allows for the construction of multilateral wells where a single vertical bore is used to kick off one or more lateral legs from a cased hole (Fraija et al., 2002; Bosworth et al., 1998). The lateral leg is initiated using a whipstock and a milling assembly to cut a well lateral from a cased hole (Fraija et al., 2002; Bosworth et al., 1998). The advances in directional drilling technology discussed here have also led to greater capabilities in terms of well depth and lateral drilling distances. Horizontal wells have been drilled to lateral distances in excess of 10,000 m (32,800 ft) (Sonowal et al., 2009). True vertical well depths up to about 7,010 m (23,000 ft) have been achieved for horizontal wells with lateral reach up to about 3,000 m (9,840 ft) (Agbaji, 2009; Bakke, 2012).

2.3.3.2. Well Casing and Cement

The casing and cementing of the vertical section of a directional well are the same as described in Section 2.3.1.2. There is, however, greater variation in the casing and cementing configurations used for horizontal wells. This variation is in part driven by the hydraulic fracturing approach utilized, so the description of horizontal well completions is given in the next section.

2.3.4. Drilling and Well Construction Offshore

Offshore drilling and well construction are similar in many respects to onshore well drilling and construction. The same rotary drilling process is used along with well casing and cementing. One of the major differences is the offshore platform itself that serves as the well pad in the offshore environment. For offshore production activities, directional drilling is critical for accessing conventional reservoirs because of the difficulty and expense of locating additional platforms. Directional and horizontal drilling is used so that the reservoir can be accessed from limited well spud locations (Inglis, 1987). Furthermore, the operational area on the platform is typically much more limited than on well pads for onshore operations.

There are two basic types of offshore platforms from the perspective of drilling operations: those with surface wellheads and those with subsurface wellheads (Macini, 2005b). Standing platforms have surface wellheads and come in two varieties, fixed and mobile. Fixed platforms are permanent offshore structures used for the production of hydrocarbons. These are typically used for water depths less than 200 m (656 ft) but have been used in water depths up to 500 m (1,640 ft) (US EIA, 1999).

All of California's offshore platforms are fixed (Schroeder and Love, 2004), with water depths up to 365 m (1,200 ft) (Bureau of Ocean Energy Management (BOEM), 2014).

Another type of standing structure is the jack-up platform, which is a mobile and temporary structure used for drilling and stimulation operations in water depths of 100 m (328 ft) or less. The jack-up has a floating vessel hull fitted with long legs at the corners of the hull. Once it arrives at the location where it is to be used, legs are lowered onto the seafloor that lift the hull out of the water to the appropriate height for performing drilling or other operations (Macini, 2005b; Pallavicini, 2005). The methods for drilling and well construction from standing platforms are nearly the same as for onshore (Macini, 2005b). The conductor pipe and other casing pipes extend from their intended position in the borehole, through the ocean water column, all the way above the water surface to the platform. The wellhead and blowout preventer are attached at the top of the casing at or near the platform deck. Each platform is generally used for drilling multiple wells. For example, the California offshore platforms in federal waters have a range of 15 to 96 "slots" per platform for drilling multiple wells (BOEM, 2014).

Deeper water leads to the use of a variety of floating platforms (US EIA, 1999). Depending on the type of floating platform, the wellhead and blow-out preventer may be located at the seabed rather than at the platform. The submarine blowout preventer is controlled remotely from the surface and is connected to a pipe called a marine riser for circulation of the drilling fluid. However, control lines for the blowout preventer are separate lines that are situated external to the marine riser. The marine riser utilizes special connections at the base and at the floating platform to accommodate motion of the platform. The riser itself is similar to casing and serves to contain and direct tools and casing through the water column into the subseabed borehole, and is a conduit for fluids moving into and out of the well (Macini, 2005b). The long vertical section through the water column and cold deep-sea temperatures reduces the temperature of fluids moving through the riser and needs to be considered in the selection of the drilling mud composition (Bennetzen et al., 2010). The borehole for the first casing is usually drilled without the riser, resulting in fluid and cuttings being discharged directly to the seafloor. The first casing string needs to be deep enough so that the mechanical strength of the formation is adequate to hold up against pressures in the next section to be drilled (National Petroleum Council, 2011). After installing the conductor casing, wellhead, and blowout preventer, the construction of the well as it is drilled is similar to onshore well construction as described in Sections 2.3.2 and 2.3.3.

2.4. Hydraulic Fracturing

Hydraulic fracturing is a relatively old technology for improving gas and oil field production rates. However, there has been a significant evolution of this technology in recent years.

Hydraulic fracturing is a well completion technique used after drilling and before production. It is designed to open permeable fracture pathways in the producing formation that connect to the well. It was first implemented in 1949; since this time, use of this stimulation method has grown substantially (Montgomery and Smith, 2010).

Originally, hydraulic fracturing was used exclusively as a well stimulation method, applied in cases where the natural reservoir permeability was too low for economic petroleum recovery. But in the 1990s, hydraulic fracturing started to be used for higher-permeability reservoirs as a method to remediate formation damage around wells (Ghalambor and Economides, 2002). The general permeability levels used to distinguish high and low permeability reservoirs, which is also influenced by the viscosity of the oil, is shown in Figure 2-1.

Unlike California (Chapter 3), the main classes of reservoirs where hydraulic fracturing has been used intensively in other areas of the United States include very-low-permeability unconventional shale reservoirs and tight-gas sand reservoirs, accounting for over 73% of the hydraulic fracturing activity (Beckwith, 2010). Most of the unconventional shale reservoirs contain natural gas, with the exceptions of the Eagle Ford, which produces oil in the shallower portion of the formation, and the Bakken and Niobrara plays, which mainly contain oil.

The typical hydraulic fracture operation involves four process steps to produce the fractures (Arthur et al., 2008). The long production intervals present in most horizontal wells lead to a staged approach to hydraulic fracturing. For the staged approach, a portion of the well is hydraulically isolated in order to concentrate the injected fracture fluid pressure on an isolated interval, which is called a "stage." After isolating the stage, the first phase of the fracturing process is the "pad," in which fracture fluid is injected without proppant to initiate and propagate the fracture from the well. The second phase adds proppant to the injection fluid; the proppant is needed to keep the fractures open after the fluid pressure dissipates. This phase is also used to further open the hydraulic fractures. The third phase, termed the "flush," entails injection of fluid without proppant to push the remaining proppant in the well into the fractures. The fourth phase is the "flowback," in which the hydraulic fracture fluids are removed from the formation, and fluid pressure dissipates. Examples of the stages of hydraulic fracturing, including the time spent for each phase, is given in Section 2.4.7.

An acid preflush is sometimes used prior to injection of the pad. For instance, Halliburton's (2014a) fracture-fluid-composition disclosure indicates it is used in about half of their specific formulations (US DOE, 2009). The acid preflush may be needed to remove pipe mill scale, help clean drilling mud and casing cement from perforations, and to weaken the rock to help initiate a fracture (King, 2010; Halliburton, 2014a; US DOE, 2009). Prior to injecting the acid, corrosion inhibitor, at a level of 0.2 to 0.5% by mass, is added to the fluid to prevent acid corrosion of steel components, such as the casing (US DOE, 2009; King, 2010). The pre-flush acid concentrations range from 7.5 to 15% HCl, and volumes range from 0.946 to 26.5 cubic meters (m^3; 250 to 7,000 gallons, gal) per stage (Halliburton, 2014a) injected at a relatively low rate below the fracture pressure.

Box 2.1. Other Uses of Hydraulic Fracturing

Senate Bill 4 and this scientific study focus on hydraulic fracturing used to enhance oil and gas production or recovery. The definition of a well stimulation treatment in the legislation is:

"For purposes of this article, "well stimulation treatment" means any treatment of a well designed to enhance oil and gas production or recovery by increasing the permeability of the formation."

However, in addition to petroleum production, hydraulic fracturing is used in other areas engaged in subsurface operations (Bierman et al., 2011). These include environmental remediation, geothermal energy, storage of natural gas, waste disposal, and geologic CO_2 sequestration.

It is not surprising that hydraulic fracturing has been used for environmental remediation of subsurface contamination. This is because both environmental remediation and petroleum production have a common goal—to extract fluids from the subsurface environment. For example, hydraulic and pneumatic fracturing have been used for remediation of volatile hydrocarbons (Frank and Barkley, 1995; Marcus and Bonds, 1999). Hydraulic fracturing has been combined with thermal extraction methods for removal of less volatile contaminants (Nilsson et al., 2011).

Geothermal energy involves the extraction of heat instead of fluids from the subsurface. However, it still requires fluid flow as an efficient means to transport heat. Hydraulic fracturing is used to enable fluid flow in some geothermal reservoirs that have low permeability (Craig et al., 2014; Fomin et al., 2003). Geothermal fracturing has the goal of stimulating the entire reservoir volume through the opening of existing natural fractures by shear (Fu et al., 2011). Geothermal systems are typically fractured using water without additives or proppant.

Underground storage of natural gas in depleted oil reservoirs has been used worldwide as a practical method to store the large volumes involved (Hoagie et al., 2013; Wang and Economides, 2012). This type of application is unique in that natural gas is both injected and withdrawn. The use of fracturing in this case is to enable high injection and withdrawal rates.

Hydraulic fracturing for subsurface waste disposal is not standard, but is being tested. The city of Los Angeles has been injecting various municipal wastewater residual streams (brine, digested sludge, and wetcake) into the deep subsurface (depth of 2300 m (7500 ft)) (City of Los Angeles, Bureau of Sanitation and GeoMechanics Technologies, USA, 2014). In this process, waste fluids and solids are injected above the fracture pressure for permanent disposal and methane generation.

Finally, research into geologic CO_2 sequestration has considered the use of hydraulic fracturing to facilitate injection of large quantities of supercritical CO_2 into lower-permeability storage formations. Lucier and Zoback (2008) found that injectivity enhancement techniques such as hydraulic fracturing will be required for practical CO_2 sequestration in saline aquifers.

In the following sections, aspects of hydraulic fracture geomechanics and the attributes of hydraulic fracture fluids and proppants are presented. In addition, the alternative to proppant use for carbonate reservoirs, called "acid fracturing," is discussed further. Following these discussions of the physical mechanisms and materials involved, various engineering alternatives for completion and isolation of the stages and information on the phases of the fracturing process are presented. Another application of hydraulic fracturing, discussed in Chapter 3 but not in this chapter, is fracturing of injection wells using water (without any additives) as the fracturing fluid and no proppant. This technique (called a breakdown step and often used in gas wells) does not appear to have as much documentation in the literature. It was identified as being used in California through inspection of hydraulic fracturing records from the California Department of Conservation, Division of Oil, Gas, and Geothermal Energy.

2.4.1. Hydraulic Fracture Geomechanics, Fracture Geometry, and the Role of Natural Fractures and Faults

Fluid pumped into deep underground rocks at sufficient pressure will cause the rock to break or "fracture." Fractures are formed when fluid pressure exceeds the existing minimum rock compressive stress by an amount that exceeds the tensile strength of the rock (Thiercelin and Roegiers, 2000). The operator cannot control the orientation of the hydraulic fractures. Rather, stress conditions in the rock determine the fracture orientation. Rocks at depth experience different amounts of compression in different directions. The hydraulic fracture will preferentially push open against the least compressive stress for a rock with the same strength in all directions (Economides et al., 2013). Therefore, the fracture plane develops in the direction perpendicular to the minimum compressive stress, as shown on Figure 2-6. Stress field orientation, however, can and does vary with time in producing oilfields as a result of fluid injections and withdrawals (Minner et al., 2002).

If the compressive stress in the rock were the same in all directions (or nearly so), then the orientation of the fracture would tend to be spherical. In addition to stress orientation, rock strength varies, and fracture geometry also depends on the variation in rock strength in different directions.
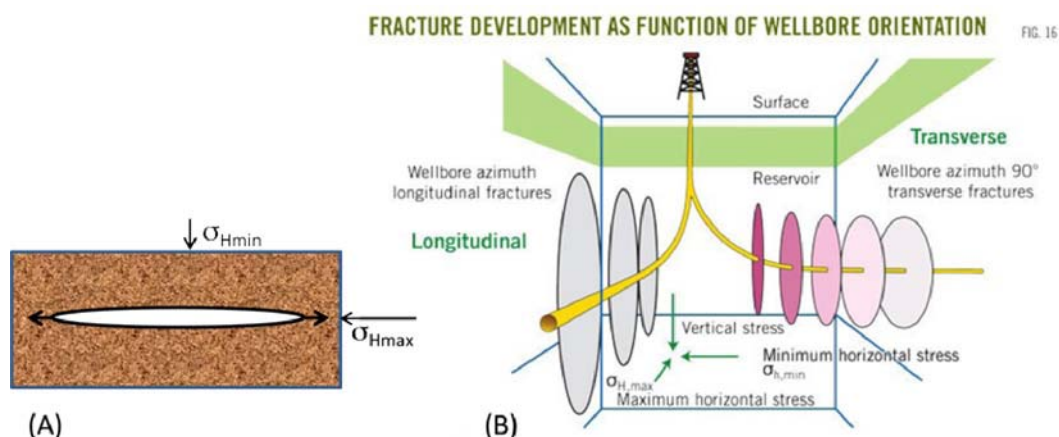
Figure 2-6. *Fracture patterns for different orientations of the borehole relative to principal compressive stresses: (A) fractures open in the direction of the minimum principal stress, (B) effects of horizontal well alignment with maximum and minimum horizontal principal stresses (Rahim et al., 2012)*

Natural fractures are generally present to some degree in natural rock and affect the formation of hydraulic fractures. In fact, natural fractures and other geologic complexities such as stratigraphic limitations on fracture height growth can often result in fracture lengths that are greater than fracture heights (Fisher and Warpinski, 2012; Weijers et al., 2005), unlike those shown in Figure 2-6. Natural fracture features of the rock are often the flow pathways from the reservoir to the hydraulic fractures (Weijermars, 2011). The contact area developed by opening natural fractures is considerably larger than can be achieved by planar fractures. Gale and Holder (2010) found that fractures filled with secondary calcite in siliceous mudrocks are generally weaker than the surrounding rock and may be susceptible to reopening during hydraulic fracturing. However, fractures filled with secondary quartz may be stronger than the surrounding rock and hinder the development of hydraulic fractures. Williams-Stroud, Barker, and Smith (2012) found that shearing of existing fractures played a significant role in hydraulic fracturing, based on discrete fracture network modeling and microseismic measurements from a hydraulic fracturing field test.

Typically, conditions underground favor hydraulic fractures that are vertical. (Vertical fractures result because most rocks at depth experience greater vertical stress than horizontal stress.) Consequently, the question of the vertical fracture height growth is important when considering the potential migration of fracture fluid or other reservoir fluids out of the typically very low-permeability target oil reservoir. Thousands of microseismic measurements have been conducted in the Barnett, Woodford, Marcelllus, and Eagle Ford shales to characterize hydraulic fractures. Fracture heights have been investigated over a range of reservoir depths from 1,220 to 4,270 m (4,000 to 14,000

ft) deep, and found that the tallest fractures formed in deeper sections. However, typical fracture heights are in the range of tens to hundreds of feet (Fisher and Warpinski, 2012). The maximum recorded fracture height from these reservoirs and the Niobrara shale was found to be 588 m (1,930 ft) (Davies et al., 2012). The statistics of fracture height from these measurements show that the probability of exceeding 350 m (1,150 ft) is about 1%, and that of exceeding 130 m (427 ft) is about 50% (Davies et al., 2012). Fracture height is limited by a number of mechanisms, including variability of *in situ* stress, material property contrasts across layered interfaces, weak interfaces between layers, leakoff of fracturing fluid into formations, and the volume of fracture fluid required to generate extremely large fracture heights (Fisher and Warpinski, 2012). Finally, the minimum stress at shallow depths (305–610 m or 1,000–2,000 ft) is typically in the vertical direction, which contrasts with the typical minimum stress being horizontal at greater depth. This stress condition favors a horizontal fracture orientation, which tends to prevent vertical fracture growth from deeper into shallower depths (Fisher and Warpinski, 2012). However, this general trend in stress directions does not always hold true (Wright et al., 1997).

Interaction of hydraulic fracture fluids with faults may also affect fracture height growth. Simulations of hydraulic-fracturing-induced fault reactivation were conducted by Rutqvist et al. (2013), who found fault rupture lengths to be less than 100 m (328 ft). Consequently, in general fault reactivation does not create permeable pathways far beyond the target reservoir (Flewelling et al., 2013). A fracture design that incorporates these factors into the selection of operational variables (pressure, injection rate, fluid type, etc.) for the hydraulic fracture means that fracture height is controllable to a reasonable degree.

Hydraulic fracture development is also affected by neighboring wells, which may undergo hydraulic fracture treatment at the same or at different times. This typically involves multiple parallel horizontal wells that are separated by 457 m (1,500 ft) or less (King, 2010). The fracturing can be carried out simultaneously or in sequence. The idea is to use the change in stress created by neighboring wells and stimulation treatments to alter fracturing directions and increase complexity in the fractures created. Differences in the resulting fractures created using simultaneous or sequential fracturing are not large (King, 2010).

Fracture geometry also depends on other factors not related to rock mechanics per se, in particular on the magnitude of the stimulation pressure and the fracturing fluid viscosity. These are discussed in Section 2.4.2, where fracture fluids and operations are presented.

2.4.2. Hydraulic Fracture Fluids

The design of a hydraulic fracture requires specification of the type of hydraulic fracture fluid. While there are many additives used in hydraulic fracture fluids, most of these are used to mitigate adverse chemical and biological processes, and are the same as those used in drilling. The main property of hydraulic fracturing fluids that influence the

mechanics of fracture generation is the viscosity.[1] Both laboratory and field data indicate that low viscosity fracture fluids tend to create complex fractures with large fracture-matrix area and narrow fracture apertures—as compared with higher viscosity fracture fluids, which tend to create simpler planar-style fractures with low fracture-matrix area and wide fracture apertures (Cipolla et al., 2010).

The lowest viscosity fracturing fluid is slickwater, which contains a friction-reducing additive (commonly polyacrylamide) and has a viscosity on the order of 4 centipoise (cP) (about 4 times that of pure water) (Kostenuk and Browne, 2010). Gelled fracture fluids generally use guar gum or cellulose polymers to increase viscosity (King, 2012). Further increases in viscosity in a guar gelled fluid can be achieved by adding a cross-linking agent to the gel that is typically a metal ion, such as in boric acid or zirconium chelates (Lei and Clark, 2004). The cross-linking binds the gel's polymer molecules into larger molecules, causing an increase in the solution viscosity. Linear gels have viscosities about 10 times that of slickwater, and cross-linked gels have viscosities that are on the order of 100 to 1000 times larger (Montgomery, 2013). Fracture fluids energized using nitrogen and surfactant with linear gels (to create foams) lead to increased viscosity of the energized fluid over the linear gel, and the viscosity of energized cross-linked gels increase by factors of 3 to 10 over those not using a cross-linking agent (Ribeiro and Sharma, 2012; Harris and Heath, 1996). The type of fracture fluid also affects the ability to emplace proppant (see Section 2.4.3). In particular, cross-linked gels are better for transporting proppant than slickwater (Lebas et al., 2013). The effective viscosity is also influenced by the proppant concentration (Montgomery, 2013).

2.4.2.1. Hydraulic Fracture Fluids: Effects on Fracture Geometry

In general, fracture length and fracture-network complexity decrease as the viscosity of the fracturing fluid increases, as illustrated in Figure 2-7 (Cipolla, et al., 2010; Rickman, et al., 2008). Fracture lengths also increase with the volume of injected fracture fluid. Flewelling et al. (2013) found that fracture length could be represented as approximately proportional to fracture height with a proportionality factor that ranged from 0.5 to 1. However, stratigraphic limitations on fracture height growth can often result in fracture lengths that are greater than fracture heights (Fisher and Warpinski, 2012; Weijers et al., 2005). Fracture apertures (or widths) are on the order of a few tenths of an inch (Barree et al., 2005; Shapiro et al., 2006; Bazan, et al., 2012) and tend to increase with viscosity, rate, and volume of the fluid injected (Economides et al., 2013).

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1. Viscosity is a fluid property that quantifies resistance to fluid flow. It takes little effort to stir a cup of water (viscosity ~ 1 centipoise (cP)), noticeably more effort to stir a cup of olive oil (viscosity ~ 100 cP), and significantly more effort to stir a cup of honey (viscosity ~ 10,000 cP).
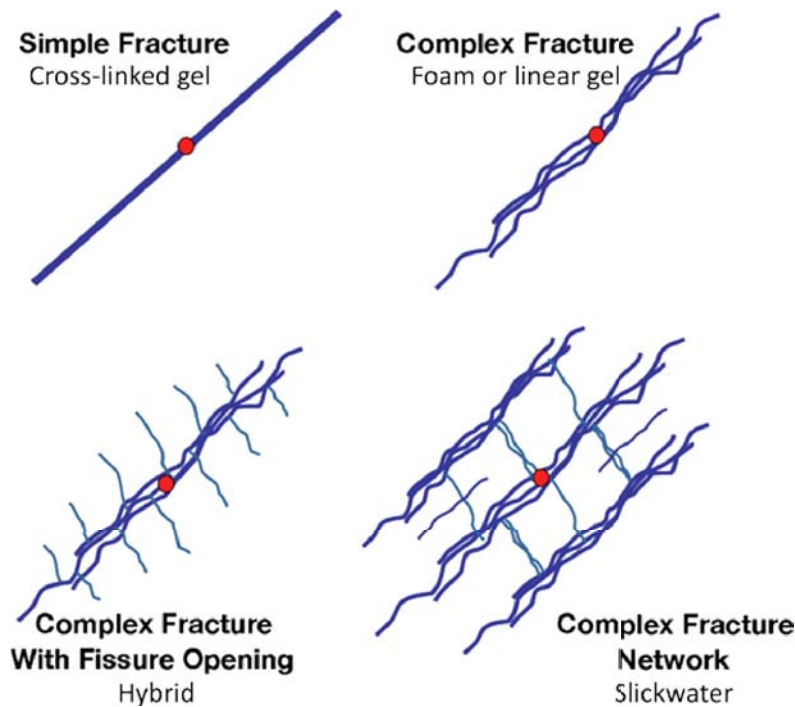
Figure 2-7. *Effects of fracture fluid viscosity on fracture complexity. (modified from Warpinski et al., (2009))*

The type of fluid used depends on the properties of the reservoir rock, specifically the rock permeability and brittleness (Cipolla et al., 2010; Rickman et al., 2008). Formations with higher intrinsic permeability (but still low enough to warrant hydraulic fracturing) are generally stimulated using a higher-viscosity fracture fluid to create a simpler and wider fracture (Cipolla et al., 2010). The rationale for this selection is that the fracture is needed both to increase contact area with the formation and to provide a high conductivity flow path towards the wellbore. As reservoir permeability decreases, the resistance to fluid movement through the unfractured portion of the formation increases. Therefore, a denser fracture pattern (narrower spacing between the fractures) is needed to minimize the distance that reservoir fluids must flow in the rock matrix to enter the hydraulically induced fractures (Economides et al., 2013). This leads to the use of lower-viscosity fracturing fluids to create more dense (and complex) fracture networks.

The choice of fracture fluid also depends on rock brittleness (Rickman et al., 2008). Wider fracture apertures are needed as rock brittleness decreases (or as ductility increases) because of the greater difficulty maintaining fracture permeability after pressure is withdrawn (Rickman et al., 2008). Therefore, rock permeability and brittleness both influence the choice of fracturing fluid. Stimulation of natural fractures is also thought to be critical for effective hydraulic fracture treatment in very low permeability shales (Warpinski, et al., 2009; Cramer, 2008; Fisher et al., 2005). Although these characteristics

may lead to conflicting requirements for the fracturing fluid, permeability is often found to be lower in brittle rocks and higher in ductile rocks (Economides et al., 2013), and natural fractures are usually more prevalent in brittle rock as compared to ductile rock. Natural fractures in shales can be sealed by secondary minerals. Such fractures do not have much influence on the natural permeability, although in some cases they can preferentially reactivate during hydraulic fracturing (Gale and Holder, 2010).

The general trends in fracture fluid types, fluid volumes used, and fracture complexity as a function of rock properties are shown in Figure 2-8. This figure shows that hydraulic fracturing in ductile, relatively higher permeability reservoir rock having low natural fracture density tends to receive a hydraulic fracture treatment using a viscous cross-linked gel, with a relatively low volume of fluid injected but a large concentration and total mass of proppant. The fracture response in this case tends to produce a simple single fracture from the well into the rock that has a relatively large aperture filled with proppant. As rock brittleness and degree of natural fracturing increase, and as permeability decreases, hydraulic fracturing treatments tend to use a higher volume, lower viscosity fracture fluid that carries less proppant. The response of the rock to this fracture treatment is to create more complex fracture networks, in which the fractures have relatively narrower apertures and a more asymmetric cross-section in the vertical direction as a result of limited proppant penetration. In short, ductile and more permeable rocks usually receive gel fracture treatments, while more brittle, lower permeability rocks with existing fractures are more amenable to slickwater fracturing.

Figure 2-8. *General trends in rock characteristics, hydraulic fracture treatment applied, and hydraulic fracture response (modified from Rickman et al. (2008)).*

2.4.2.2. Hydraulic Fracture Fluids: Differences for Gas and Oil Wells

Different hydrocarbon reservoirs can produce a variety of hydrocarbon molecules, ranging from the smallest and lightest (methane) that exist at normal temperatures and pressures in the gas phase, to quite large and heavy molecules associated with heavy oils that are liquids. McCain (1994) identified five classifications of petroleum reservoir fluid types as shown in Table 2-1.

Table 2-1. *Classification of reservoir types (McCain, 1994).*

	Upper Limits for Gas/Oil Ratios for Reservoir Fluid Types				
Units	Black Oil	Volatile Oil	Retrograde Gas	Wet Gas	Dry Gas
Std. m³ gas/std. m³ oil	312	570	2,672	17,811	infinite
scf gas/STB oil	1,750	3,200	15,000	100,000	infinite

scf = standard cubic feet; STB = stock tank barrel

Although there is a (nearly) continuous spectrum of hydrocarbon resource types that lead to these differences in hydrocarbon production, a well is classified as a gas well by the US EIA (2010) if the hydrocarbon production (at standard conditions) is greater than or equal to 1069 m³ gas per m³ of liquid hydrocarbon (oil) (6,000 standard cubic feet of gas per stock tank barrel oil, scf/STB oil) and is classified as an oil well otherwise. This is seen to fall within the retrograde gas category by McCain's (1994) reservoir fluid type classification scheme.

The significant physical differences between gas and oil are that gas is less dense and less viscous than oil. These differences do not affect appreciably the initiation or propagation of hydraulic fractures or the placement of proppant, processes dominated by rock mechanical properties and properties of the hydraulic fracturing fluid and proppant. However, during the flowback stage, fluid pressures in the well are reduced. This initiates flow towards the well in which the resident fluids in the reservoir and injected fracturing fluids flow toward the well. Fracturing fluids, in or near the induced hydraulic fractures, are displaced by the resident gas, oil, and reservoir brine, with the proppant ideally held in place by the fracture closure stress. Displacement of the fracturing fluid and removal of the gelling agents are important, because the effective permeability to gas and/or oil in the fracture is reduced, perhaps significantly, if the fracturing fluid is not efficiently displaced. This tends to defeat the purpose of hydraulic fracturing, namely, to open permeable fracture pathways to gas and/or oil. On the other hand, if fracturing fluid is imbibed from the fracture into the matrix, it is not likely to be recovered. This imbibitions process displaces oil or gas from the matrix into the fracture, which is beneficial to hydrocarbon production. Therefore, the effect of reduced recovery of fracturing fluids on hydrocarbon recovery is complex.

Fluid displacement efficiency is affected by the viscosity and density ratios of the fluids (Muggerridge et al., 2013). High density ratios tend to reduce displacement efficiency unless the higher density fluid is displacing the lower density fluid in a direction upwards (against gravity). Also, the displacement efficiency in a porous media is poorer if the fluid being displaced is being "pushed" with an immiscible fluid of lower viscosity—for example, using natural gas to displace fracturing fluid out of the matrix or a low conductivity natural fracture system. The reason for using a chemical breaker additive in fracturing fluid is to reduce the viscosity of cross-linked gel fracturing fluids for more efficient displacement out of the fracture. Poor displacement of cross-linked gel fracturing fluids often used in tight gas sands can be caused by ineffective breaking of the polymer (Holditch and Tschirhart, 2005).

Furthermore, if the fluid pressure loss during flow from the reservoir to the well is dominated by losses in flowing through the fractures, the higher viscosity of oil will lead to the need for higher conductivity fractures in the case of shale oil as compared with shale gas.

These factors result in a tendency to use lower viscosity fracturing fluids for gas as compared with oil. This is not a clear distinction, however, because other factors play into the choice of fracturing fluid, in particular, the rock characteristics as discussed in Section 2.4.2.1. Nevertheless, analyses of US shale oil and gas production have shown distinct trends in the types of hydraulic fracturing fluids being used. Land rig counts show that the number of gas wells being developed has dropped from 54% of the total in the first quarter of 2011 to 24% in the third quarter of 2012 (Robart et al., 2013). Over the same time period, the number of slickwater fracture treatments has gone from 46% to 24% of the total hydraulic fracture treatments performed, while conventional (gelled) fracs and hybrid fracs have increased from 52% to 74% of the total (Robart et al., 2013). Data also indicates that in the Bakken and the Denver-Julesburg (DJ) Basin, both shale oil resources, hydraulic fracturing has been predominantly done with cross-link gels or cross-link/slickwater hybrid fluid systems (Patel et al., 2014). In contrast, in the Marcellus, a shale gas resource, fracturing fluids are predominantly slickwater and linear gel/slickwater hybrids (Patel et al., 2014). These results are consistent with the trend that lower viscosity fracturing fluids are used for shale gas as compared with shale oil.

2.4.2.3. Hydraulic Fracture Fluids: Other Additives and Alternative Fluids

Fracture fluids may contain several additives in addition to those discussed above. These include biocides, corrosion inhibitors (both used in drilling), clay stabilizers, polymer breakers, and stabilizing formation fines (Kaufman et al., 2008; El Shaari et al., 2008). Example concentrations for slickwater and gelled fracture fluids are given in Figure 2-9.

A summary of the various types of additives is given in Table 2-2. In some cases, acids are injected as a separate pre-flush before injection of the hydraulic fracture pad in order to clean out the casing perforations, help clean out the pores near the well, and dissolve minerals, to aid in initiating fractures in the rock (US DOE, 2009).

Recycling of fracture fluid is one way to reduce the amount of water required for hydraulic fracturing. The principal issue involved is that recycled fracturing fluid develops high concentrations of dissolved salts that become highly saline brines. One approach has been the development of more salt-tolerant additives, such as polymers used for slickwater friction reducers (Paktinat et al., 2011). Other processes are also being developed to aid in the reuse of fracturing fluids (Ely et al., 2011).
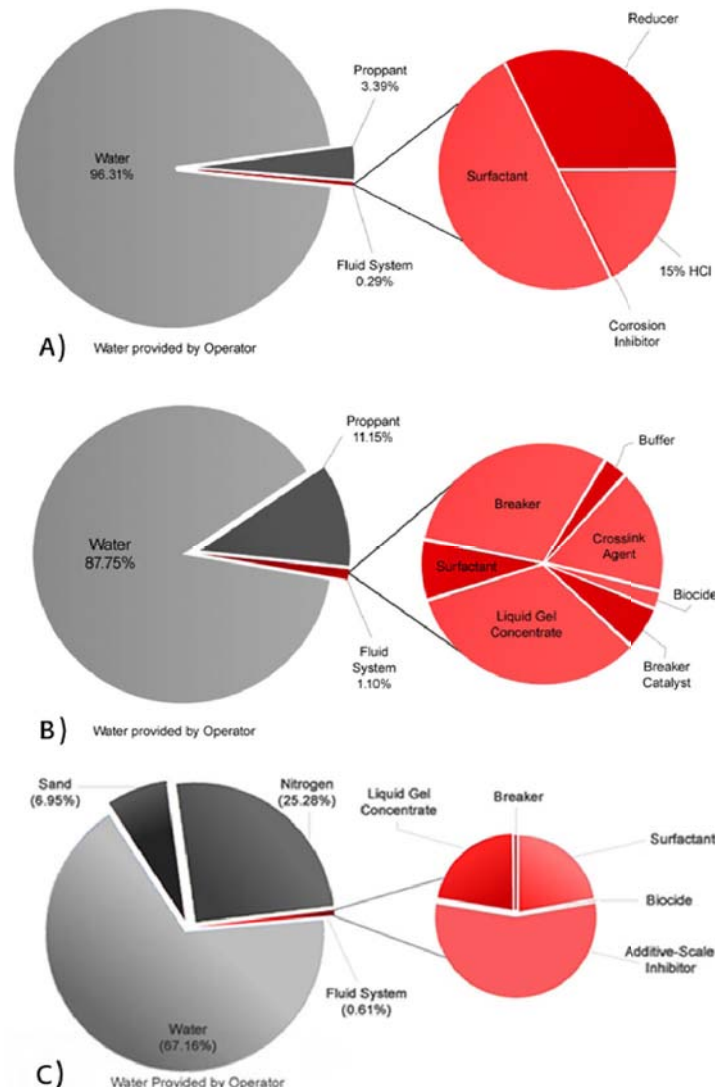
Figure 2-9. *Example compositions of fracture fluids A) Colorado DJ Basin WaterFrac Formulation – a slickwater fracturing fluid; B) Utah Vertical Gel Frac Formulation – a cross-linked gel fracturing fluid; C) Pennsylvania FoamFrac Formulation – a gelled nitrogen foam fracturing fluid (source: Halliburton, 2014a). Note: although not stated on the website, comparisons of these compositions with information on fracture fluid compositions given on the FracFocus (2014) website indicate these values are percent by mass.*

Table 2-2. *Additives to aqueous fracture fluids (NYSDEC, 2011)*

Additive Type	Description of Purpose	Examples of Chemicals
Proppant	"Props" open fractures and allows gas / fuids to fow more freely to the well bore.	Sand [Sintered bauxite; zirconium oxide; ceramic beads]
Acid	Removes cement and drilling mud from casing perforations prior to fracturing fuid injection	Hydrochloric acid (HCl, 3% to 28%) or muriatic acid
Breaker	Reduces the viscosity of the fuid in order to release proppant into fractures and enhance the recovery of the fracturing fuid.	Peroxydisulfates
Bactericide / Biocide / Antibacterial Agent	Inhibits growth of organisms that could produce gases (particularly hydrogen sulfide) that could contaminate methane gas. Also prevents the growth of bacteria which can reduce the ability of the fuid to carry proppant into the fractures.	Gluteraldehyde; 2,2-dibromo-3-ni-trilopropionamide
Buffer / pH Adjusting Agent	Adjusts and controls the pH of the fuid in order to maximize the effectiveness of other additives such as crosslinkers	Sodium or potassium carbonate; acetic acid
Clay Stabilizer / Control /KCl	Prevents swelling and migration of formation clays which could block pore spaces thereby reducing permeability.	Salts (e.g., tetramethyl ammonium chloride Potassium chloride (KCl)
Corrosion Inhibitor (including Oxygen Scavengers)	Reduces rust formation on steel tubing, well casings, tools, and tanks (used only in fracturing fuids that contain acid).	Methanol; ammonium bisulfate for Oxygen Scavengers
Crosslinker	Increases fuid viscosity using phosphate esters combined with metals. The metals are referred to as crosslinking agents. The increased fracturing fuid viscosity allows the fuid to carry more proppant into the fractures.	Potassium hydroxide; borate Salts
Friction Reducer	Allows fracture fuids to be injected at optimum rates and pressures by minimizing friction.	Sodium acrylate-acrylamide copolymer; polyacrylamide (PAM); petroleum distillates
Gelling Agent	Increases fracturing fuid viscosity, allowing the fuid to carry more proppant into the fractures.	Guar gum; petroleum distillates
Iron Control	Prevents the precipitation of metal oxides which could plug off the formation.	Citric acid
Scale Inhibitor	Prevents the precipitation of carbonates and sulfates (calcium carbonate, calcium sulfate, barium sulfate) which could plug off the formation.	Ammonium chloride; ethylene Glycol
Solvent	Additive which is soluble in oil, water and acid-based treatment fuids which is used to control the wettability of contact surfaces or to prevent or break emulsions	Various aromatic hydrocarbons
Surfactant	Reduces fracturing fuid surface tension thereby aiding fuid recovery.	Methanol; isopropanol; ethoxylated alcohol

Alternative fracture fluids are also under investigation. Some of the purposes of alternative fluids are to reduce water use and to reduce formation-damage effects sometimes caused by aqueous fracture fluids and by additives such as gels. These alternatives include supercritical[2] CO_2 and supercritical CO_2-nitrogen mixtures, CO_2 foam, nitrogen, explosive

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2. Supercritical CO_2 exists when the temperature and pressure are above the critical temperature (31° C, 88° F) and critical pressure (7.4 megapascals (MPa; 1070 pounds per square inch, psi)). Supercritical CO_2 is a fluid that has properties between those of a gas and a liquid.

propellant systems (EPS) liquid propane (LPG) (Rogala et al., 2013), and other oil-based fluids including crude oil (Montgomery, 2013). These systems generally eliminate or greatly reduce the amount of water involved in fracturing, with attendant benefits according to Rogala et al. (2013) of elimination or reduction of:

- Formation-damage effects associated with water sensitivity,

- Formation damage associated with water and chemical (particularly gels) remaining in the reservoir,

- Chemical additives and their environmental effects, and

- Flowback waste water disposal.

Despite the advantages from a water perspective, there are several disadvantages according to Rogala et al. (2013), including,

- Transport and handling of pressurized CO_2 with potential for leakage into the atmosphere,

- Relative difficulty to transport proppant in the fracture, particularly for nitrogen,

- Added problems working with surface pressures/increased injection pressures for CO_2, nitrogen, foams, and LPG,

- Risk of explosion with LPG,

- Greater cost except for EPS, and

- Lower fracture lengths for EPS (10–50 m (33–164 ft)).

2.4.3. Proppants

After injecting the hydraulic fracture pad, proppant is injected with the hydraulic fracture fluid. As described earlier, proppants are a solid granular material such as sand that acts to keep fractures from closing after hydraulic fracture fluid pressure is released. Proppant size and size distribution are key factors affecting the permeability of proppant-filled fractures. Larger, more uniformly sized proppants result in the greatest permeability. Proppant grain sizes generally lie in the range of 10^{-4}–2×10^{-3} m (3.28×10^{-4}–6.56×10^{-3} ft) in diameter (Horiba Scientific, 2014).

In addition to these characteristics, the transportability and strength of the proppant also affect the ultimate fracture permeability. The ability of the proppant to be transported by a given fracture fluid depends in part on the proppant size and density. Greater

transportability is desirable because it allows for delivery of proppant deep into the formation fractures. Proppants that are smaller and have a lower density are more easily transported (Economides et al., 2013).

Proppant strength is also important. As the effective stress imposed on a proppant pack increases (with effective stress = closure stress minus pore pressure within the fracture), the proppant permeability and propped fracture conductivity will decrease. As a key end product of a fracturing treatment is fracture conductivity, it is important to consider the effective stress that will be imposed on the proppant under well production conditions during the fracture treatment design process.

The most common proppant is natural sand that has been sieved to a uniform size class (Beckwith, 2011). A number of alternative synthetic proppants have been used as well, including sintered ceramics, with densities ranging from 2.7 (close to sand) to 3.5–3.6 grams per cubic centimeter (g/cm^3) (bauxite). Ceramic and bauxite proppants can be manufactured to have different mass densities and compressive strengths, and the size and shape can be tightly controlled to produce highly uniform grains (Lyle, 2011). Various types of resin coatings have also been used with all types of proppants, including sand (Beckwith, 2011). Resin coatings can be pre-cured or curable on the fly. Pre-cured resin coatings are used to improve proppant strength and to prevent movement of broken proppant fines. Curable resin coatings are intended to bond proppant together after placement to help prevent proppant flowback during the flowback phase of the fracturing process and during hydrocarbon production (Beckwith, 2011).

The transport of proppant also affects the choice of hydraulic fracture fluids. Lower-viscosity fluids are not as capable of delivering proppants and generally are used with lower proppant concentrations during the proppant-injection phase of the operations. Higher proppant settling in lower viscosity fluids will tend to deposit proppant in the lower parts of the fracture as compared with higher viscosity fluids (Cipolla et al., 2010). This is indicated schematically on the right-hand side of Figure 2-8. Furthermore, proppant delivery is more problematic in the more complex fracture networks created by lower-viscosity fracture fluids. Therefore, lower-viscosity fracture fluids are sometimes replaced after injection of the pad with high-viscosity fluids to more effectively deliver proppant. The use of two or more different fracture fluids during the same fracturing event is called a hybrid treatment. Slickwater fracture treatments may only deliver a sparse amount of proppant, resulting in conductivity dominated by the unpropped fracture conductivity (Cipolla et al., 2010). The success of such a treatment may hinge on other factors such as the rock compressive stress varying with direction, and the presence of natural fractures being "self-propped" as a result of shearing of the fracture surfaces (Cipolla et al., 2010).

2.4.4. Acid Fracturing

An alternative to the use of proppant to maintain fracture conductivity is to inject hydrochloric acid under fracture pressures. The only known successful applications of acid fracturing stimulation have been in strongly reactive carbonate reservoirs, although experimental laboratory work concerning acid fracturing in siliceous rock has been reported (Kalfayan, 2007). Acid fracturing typically uses HCl, formic acid, acetic acid, or blends thereof, which etches the faces of the fracture surfaces (Kalfayan, 2008). The presence of the etched channels allows fractures to remain permeable even after the fracture-fluid pressure is removed and compressive rock stress causes the fractures to close (Economides et al., 2013). Acid fracturing is sometimes preferred in carbonate reservoirs because of the relatively high degree of natural fractures generally present and the difficulties of placing proppant because of fluid leak-off into the natural fracture system. Acid fractures generally result in relatively short fractures as compared with fractures secured with proppant; therefore, it is generally more successful in higher-permeability formations (Economides et al., 2013).

2.4.5. Other Uses of Hydraulic Fracturing—Frac-Packs

The hydraulic fracturing described to this point is intended to open permeable fracture pathways in unconventional reservoirs to enable oil or gas production. However, hydraulic fracturing technology has been expanded to deal with other oil production issues that occur in moderate-to higher-permeability conventional reservoirs. These other issues are formation damage around the well and sand production into the well. The hydraulic fracturing technology used for these purposes is called "frac and pack" or just "frac-pack" (Sanchez and Tibbles, 2007) and may also be referred to as a "high-rate gravel pack" (Cardno ENTRIX, 2012). The API notes that frac-packs are a common well stimulation method used for offshore oil and gas production that often have moderate to high permeability and sand control problems (API, 2013).

Traditional hydraulic fracturing for reservoir stimulation is not needed when reservoir permeability is sufficient for economic rates of oil and gas production. However, the formation close to the well can be damaged (i.e., permeability is severely reduced) by many factors relating to the drilling and construction of the well and production operations. These factors include fines migration, swelling clays, plugging by drilling mud solids, and iron precipitation, among other things (Economides and Nolte, 2000). Often, formation damage is addressed using a matrix acidizing treatment. However, some situations are not amenable to treatment by matrix acidizing—for example, if formation damage has occurred deep in the reservoir, the reservoir rock has some mineral sensitivity (e.g., high clay content) that reacts adversely to acid treatments, or particularly severe permeability loss in the damage zone (Guo et al., 2001). In such cases, frac-packs are an alternative treatment, which place a propped fracture across the damage zone to bypass the damage. The other main reason for performing a frac-pack is to control the movement of formation sand into the well, also called sand production, which is a problem that

commonly occurs in unconsolidated reservoirs. Sand production refers to any particulate material that is mobile and capable of moving into the well.

A frac-pack combines a hydraulic fracture with another completion technology called a gravel pack, which is a method for controlling sand production. A gravel pack usually consists of a cylindrical metal screen installed in the production zone of the well in which the annulus between the screen and the casing (or formation if not cased) is filled with gravel (Economides et al., 2013). The gravel is installed as a fluid slurry in which the fluid pressure during gravel placement is kept below fracture pressure. The gravel acts as a filter bed to allow fluid flow but stop the movement of particulates. The gravel is sized to be as large as possible, to minimize flow restrictions for fluid movement through the gravel and yet be small enough to filter out the mobile particulates and also fill the casing perforations.

In contrast, a frac-pack treatment is pumped at pressures above the fracture pressure to induce a hydraulic fracture using a similar hydraulic fracturing process as described in Sections 2.4.1 through 2.4.3. The frac-pack may be considered a fracturing treatment at the high-permeability end of the range shown in Figure 2-8. As expected for a higher-permeability formation, the fracturing fluid is viscosified using a linear or more likely a cross-linked gel (Mathis and Saucier, 1997). Typically, a hydraulic fracture for a frac-pack is relatively short, often 3–30 m (10–98 ft) in length, which is much shorter than fractures in unconventional reservoirs that often extend 150 m (492 ft) or more from the well (Sanchez and Tibbles, 2007; Guo et al., 2001). The fracture length is sized to ensure that the fracture extends beyond any formation damage that may exist near the well. In addition to creating a fracture that propagates out into the formation, proppant is often packed between the well cement and the formation, creating a proppant "halo" around the well (Economides et al., 2013). This occurs because of the much wider fractures produced for a frac- pack treatment compared with other forms of hydraulic fracturing. The gravel pack may be installed in one, continuous treatment following placement of fracture proppant (Hannah et al., 1994) or as a separate gravel pack installation (Monus et al., 1992). A screenless frac-pack is also possible by using a resin-coated proppant or proppant with carbon or nanocomposite fibers to control proppant back-production into the well (Acock et al., 2003; Guo et al., 2012).

The generation of short, wide fractures for a frac-pack relies on a fracturing technique known as a "tip screenout" or TSO. The TSO is generated by injecting a sufficiently small pad such that the pad depletes (i.e., is lost to the surrounding formation) at the desired fracture length (Economides and Nolte, 2000). At this point the proppant is at the fracture tip and tends to bridge across the narrow fracture tip opening, which blocks proppant movement (screen out) and stops fracture propagation. Also, fluid loss from the slurry carrying the proppant to the formation contributes to proppant screen out, terminating fracture propagation. Even though the fracture stops propagating, continued pumping of the proppant slurry causes the fracture to widen. Fracture widths can increase to more than 0.05 m (0.16 ft) (Wong et al., 1993). A wide fracture is needed

for higher-permeability formations that are capable of being produced at higher flow rates. Furthermore, a wide fracture is needed when the formation is particularly soft, and embedment of the proppant under fracture closure pressure can lead to a serious reduction in the fracture width unless a wider fracture is packed with proppant. Similar but smaller-scale treatments than frac-packs are called "high-rate water packs," in which water instead of a gelled fracturing fluid is used above the fracture pressure. High-rate water packs create shorter and thinner fractures than frac-packs (Sanchez and Tibbles, 2007).

An example of a frac-pack treatment is given in Moodie et al. (2004) for the Inglewood field in the Los Angeles Basin. This is a relatively high permeability reservoir in the 4.94×10^{-14} to 9.87×10^{-14} m^2 (50 to 100 md) range, which required frac-pack treatment to mitigate formation damage and control sand production, among other issues. The treatment involved injecting about 115 m^3 (30,000 gallons) of frac fluid with a sand proppant for each 61 m (200 ft) interval, which is about 1.9 m^3/m (150 gal/ft).This is about five times less fluid per unit length than slickwater treatments in the Bakken and Eagle Ford (see Section 2.4.7). The reservoir crude oil was used as the fracturing fluid instead of the more commonly used polymer-based fluid (Ali et al., 2002) because of cost considerations and the need to minimize formation damage caused by the fracturing fluid. The treatment was estimated to create a fracture about 15 m (50 ft) in length.

2.4.6. Hydraulic Fracture Staging in Unconventional Resource Horizontal Well Completions

As mentioned, multistage hydraulic fracturing refers to the application of the hydraulic fracturing process to multiple, hydraulically isolated intervals along the production interval of the well. Fracturing of a well's entire production interval at once can result in an uneven distribution of fractures. Slight variations in rock strength result in the fracturing fluid flow focused on the weakest rock along the well. The multistage fracturing process allows for greater control over where fractures are generated and produces a more uniform distribution of fractures along the production interval.

The conduct of multistage hydraulic fracturing requires that the completion used in the production interval is capable of stage isolation. The two most common completions used for multistage hydraulic fracturing are cemented liner and uncemented liner (Snyder and Seale, 2011). The cemented liner involves installation of the liner and cementing the annulus following the process discussed in Section 2.3.1.2. For the cemented liner, the cement isolates the annulus between the liner and the rock for multistage hydraulic fracturing. An uncemented liner is called an open-hole completion because of the open annulus outside the liner. However, isolation along the annulus for multi-stage fracturing can still be obtained through the use of a series of packers attached to the outside of the tubing or liner. The packers may be hydraulically set mechanical packers, packers that automatically swell in oil or water, or inflatable packers (Snyder and Seale, 2011). McDaniel and Rispler (2009) present a discussion of a wider array of completion configurations for horizontal wells stimulated by hydraulic fracturing.

Multistage stimulation starts at the far end of the production interval first (normally called the toe of the well). For blank (unperforated) liners, openings in the liner for communication with the rock are generated using a perforating gun. This device sets off a set of shaped charges. Each shaped charge shoots a fast-moving jet of metal particles that makes a hole (perforation) that penetrates the casing, casing cement, and a short distance (~0.4–0.9 m (1.31 – 2.95 ft)) into the rock formation (Bell and Cuthill, 2008; Brady and Grace, 2013; Renpu, 2008). The process of multistage hydraulic fracturing using a perforating gun, called "plug and perf," provides the greatest control on placement of fractures. Beginning at the far end of the production interval where a set of perforations are opened, the fracture fluid (pad and fracturing fluid/proppant mixture) is injected and fractures the rock. Then, a bridge plug is set that seals off the perforated and fractured segment from the remainder of the production interval. The next set of perforations is then opened and fractured. This is repeated along the entire production interval (Snyder and Seale, 2011). After all stages have been fractured, the bridge plugs are drilled out to conduct flowback and oil production.

Perforation patterns are typically shot in clusters separated by 10.7–22.9 m (35–75 ft) or more (King, 2010). Each cluster is 0.305–0.71 m (1–2 ft) in length with about 20 perforations per meter (6 perforations per foot). The idea of a cluster is to initiate one main fracture from each cluster, while the multiple perforations within a cluster help to find the easiest fracture initiation point. Hydraulic diversion is often used by limiting the number of perforations so that at the design rate, sufficient friction is established such that all the perforated clusters may be opened. With the narrow spacing between perforations in a cluster, only one fracture will grow, because of the effects of the fracture on the local stress field tend to suppress any other fractures trying to emerge from the cluster (King, 2010). For a typical stage interval of 61 or 91.4 m (200 or 300 ft), this results in about 4 to 7 clusters per stage. The plug and perf and sliding sleeve completions for a horizontal lateral are shown in Figure 2-10.

Open-hole completions can also be accomplished using a sliding-sleeve liner which has pre-set ports that can be opened by size-specific actuator balls (Snyder and Seale, 2011). Multistage fracturing is conducted by dropping a series of actuator balls for each fracturing stage that simultaneously opens the pre-set ports in the uncemented liner and also seals off the far end of the production interval. After performing the fracturing operation, the next actuator ball is dropped and the next section is fractured. This is repeated along the entire production interval (Snyder and Seale, 2011). The actuator balls, which act like check valves, are recovered during the flowback phase after all stages have been fractured. Even more complex sliding sleeve liners can be used in which each sliding sleeve can be individually opened or closed from the surface through remote hydraulic actuators.
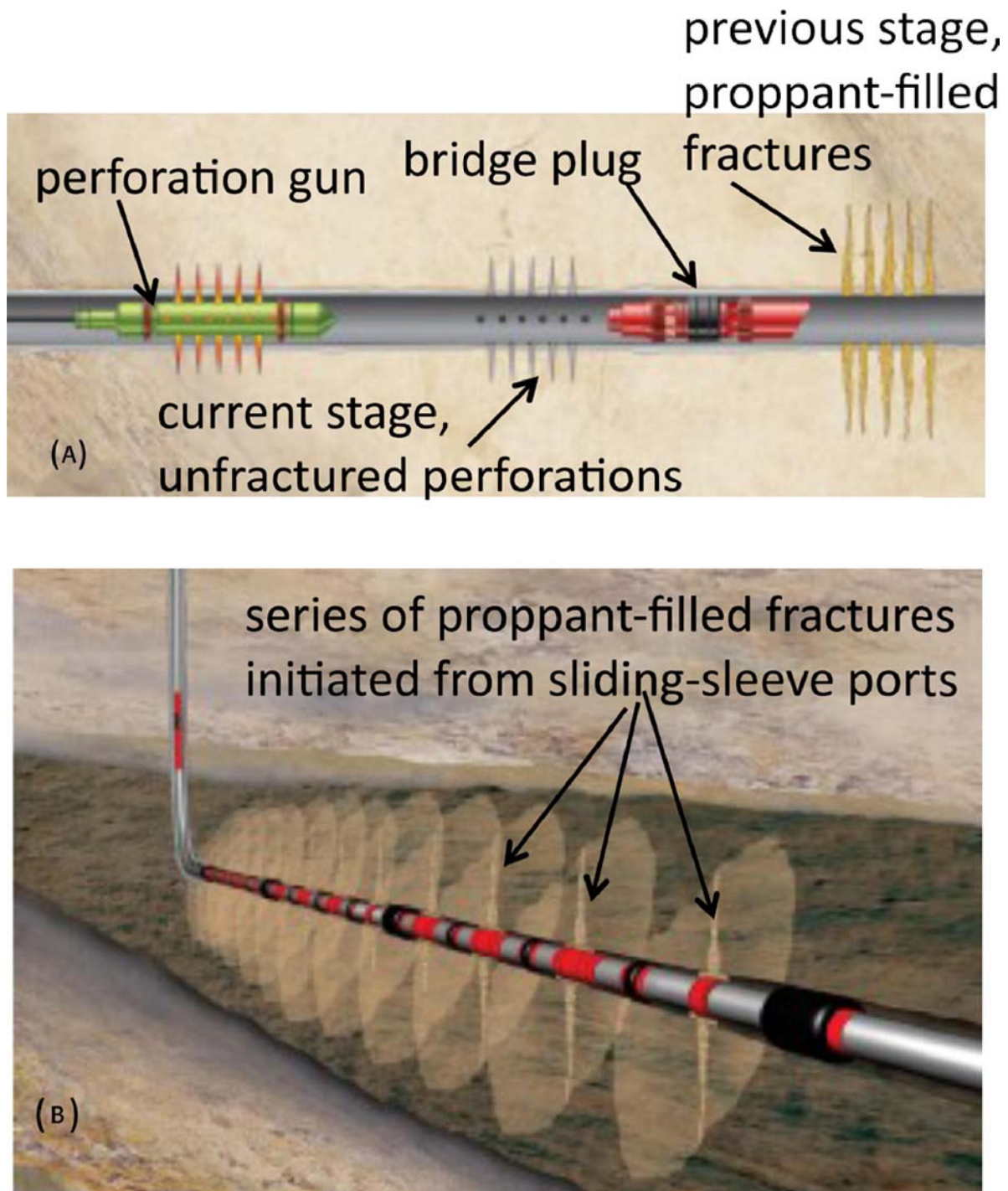
Figure 2-10. *Horizontal well completion. (A) plug and perf; (B) sliding sleeve (source: Allison (2012))*

2.4.7. Fracturing Fluid Flowback

As mentioned, flowback is the fourth phase of a hydraulic fracturing operation. The liquid flowback rates are typically high, ranging from 0.00795 to 0.0159 m^3 per second (m^3/s), equivalent to 3 to 6 oil barrels per minute (barrels/min) initially because of the high-pressure charge just delivered to the reservoir. However, these rates typically decrease quickly to less than 0.00265 m^3/s (1 barrel/min) after 24 hours, and to 0.0002 to 0.002 m^3/s (0.07 to 0.70 barrels/min) after 2 or 3 weeks (King, 2012). Alternate methods of backflow control include limiting the flow by a choke on the flowline.

Natural formation brines get mixed with the recovered fracturing fluid and affect the composition of the flowback fluid. The natural formation waters of petroleum reservoirs can contain high levels of dissolved solids, organic components from contact with *in situ* hydrocarbons, and naturally occurring radioactive materials (NORM) that are consistent with the activity of the formation connate fluids. The concentrations of these materials can be high, because of mixing of the fracture water with connate waters and (to a limited extent) because of dissolution of these constituents into the formation water during prolonged contact with rock and hydrocarbons (Guerra, et al, 2011; Zielinski and Otton, 1999).

Very few well-documented cases of detailed flowback rates and composition have been found. One of the more detailed analyses of flowback rates and composition that has been identified is for the Marcellus Shale in Pennsylvania, an unconventional gas resource (Hayes, 2009). The flowback rate and total dissolved solids concentration for a particular case are shown in Figure 2-11. The input fracturing-fluid total-dissolved-solids composition ranges from 221 to 27,800 parts per million (ppm), where higher levels may be because of recycling of fracturing fluid. The rapid increase in total dissolved solids during flowback indicates that a substantial amount of formation brine is mixing with fracturing fluid in the flowback stream after a few days of flowback (Haluszczak et al., 2013). Another mechanism that can increase the salinity of the flowback is the dissolution of salt or other minerals from the formation into the fracturing fluid (Blauch, et al., 2009).

The recovery of guar polymer in flowback was measured for the Point of Rocks formation at the McKittrick Field in the San Joaquin Valley, California (El Shaari et al., 2005). This is a moderately low permeability (4.9 × 10^{-17} to 2 × 10^{-14} m^2 (0.05 to 20 md)) turbiditic sandstone reservoir that has been hydraulically fractured using a cross-linked guar polymer fracturing fluid. The recovery of guar in the flowback was measured for five separate hydraulic fracture treatments in three wells. The volume of flowback monitored ranged from 170% to 270% of the fracturing fluid injected, and the fraction of guar recovered ranged from 48% to 67% of the mass injected.
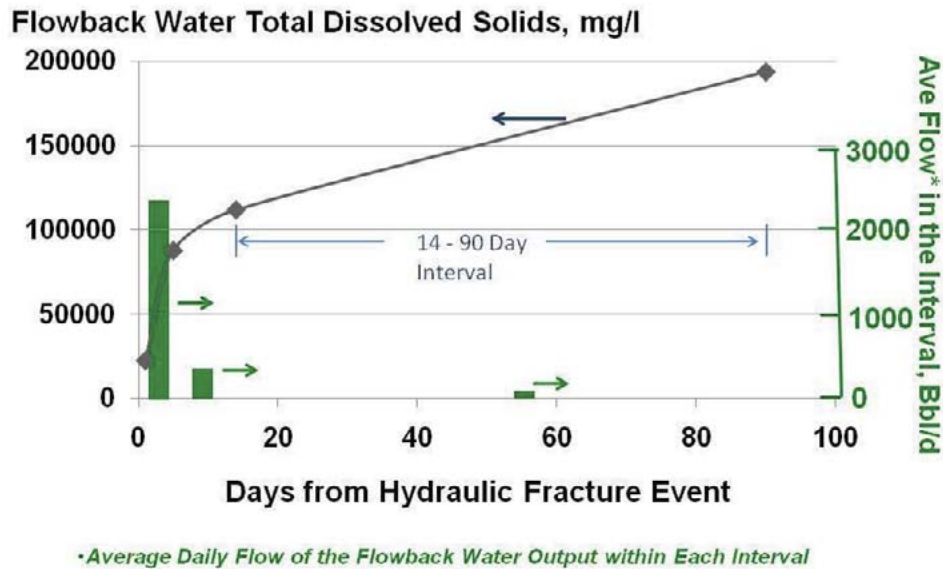
Figure 2-11. *Example of flowback rates and totals dissolved solids composition from the Marcellus shale (source: Hayes, 2009).*

2.4.8. Hydraulic Fracturing Process: Examples from the Bakken and Eagle Ford Plays

This discussion of the different phases of the hydraulic fracturing process will include examples of fracturing conducted in the Bakken and Eagle Ford plays. These unconventional reservoirs are considered analogous to shale reservoirs in California's Monterey Formation (described in detail in Chapter 4), because they compare favorably in terms of total organic content, depth, porosity, and permeability. However, there are significant differences in terms of depositional age, extent of natural fracturing, tendency towards great thickness, multiple lithofacies, tectonic activity, and folding (Beckwith, 2013). Chapter 3 discusses differences between hydraulic fracturing operations as currently implemented in California with hydraulic fracturing for unconventional shale reservoirs such as the Bakken and Eagle Ford.

The Bakken play is located in the Williston Basin in North Dakota, Montana, and Canada (Pearson et al., 2013). The upper and lower members of the Bakken are shales that are source rocks for oil. The middle member is the most frequent production target: It is a silty sandstone to silty dolomite, with permeability in the range of 9.87×10^{-17} m² (0.1 md), and in North Dakota is found at depths of about 3,050 m (10,000 ft) (Pearson et al., 2013; Wiley, Barree, Eberhard, and Lantz, 2004). Production wells in the Bakken shale are typically horizontal wells with long laterals ranging from 2,290 to 2,900 m (7,500 to 9,500 ft) and use open-hole (uncemented) blank or sliding sleeve liners in the production

interval (Pearson et al., 2013). A comparison of fracture fluid volumes used within the middle Bakken member, shown in Table 2-3, found that slickwater fracture operations used about three times more fluid per length of lateral than wells using a hybrid method, and about four times more than wells employing a cross-linked gel (Pearson et al., 2013). This is in accord with the relationship between fracturing fluid type and volume shown on Figure 2-8.

Table 2-3. *Variations in fluid volume and proppant use with treatment type (Pearson et al., 2013)*

Treatment type	Average number of stages	Average stage spacing (m (ft))	Average fluid volume per lateral foot (m³/m (gal/ft))	Average proppant weight per lateral length (kg/m (lbs/ft))
Slickwater	35	84.4 (277)	13.2 (1060)	613 (412)
Hybrid	26	112.2 (368)	3.91 (310)	420 (282)
Cross-linked gel	29	103.3 (339)	3.44 (280)	570 (383)

The Eagle Ford play is composed of interbedded calcareous shale and calcisiltite (a rock consisting of fine-grained calcareous detritus), and massive calcareous shale or mudstone (Smith, 1981). The Eagle Ford play ranges in depth from 762,500 to 4,270 m (2,500 to 14,000 ft). Different parts of the play produce either oil and liquid-rich hydrocarbons or mainly gas (Stegent et al., 2010). The permeability of the Eagle Ford ranges from 0.001 to 0.8 md (or 9.87×10^{-19} m² to 7.90×10^{-16} m²). Production wells in the Eagle Ford more commonly used cemented blank liners with plug and perf completions (Greenberg, 2012). In the example discussed below, the horizontal well has a true vertical depth of 4,040 m (13,250 ft) with a lateral length of 1,160 m (3,800 ft), and produces at a high liquid/gas ratio (Stegent et al., 2010).

While acid preflush treatments have not been identified in examples from the Bakken play, Stegent et al. (2010) reported the use of 19.1 m³ (5,040 gal) of 15% HCl for several Eagle Ford play horizontal wells prior to injecting fracture fluids for each stage. Examples from the Bakken and Eagle Ford use pad volumes that are about 20% to 30% of the total fluid injected (Wiley et al., 2004; Stegent et al., 2010). In the case of the Eagle Ford example, a hybrid fracture fluid scheme is used in which a linear gel alternating with a cross-linked gel is used as the pad and a cross-linked gel is used to carry proppant (Stegent et al., 2010). Furthermore, alternating injections of proppant-laden fluid with the pad fluids are used to transition to a final period of extended proppant injection. Pearson et al. (2013) report on the use of slickwater, cross-linked gel, and hybrid fracturing fluids for the Bakken shale. Hlidek and Rieb (2011) indicate an increase in the use of linear gel pad and a cross-linked gel for proppant injection.
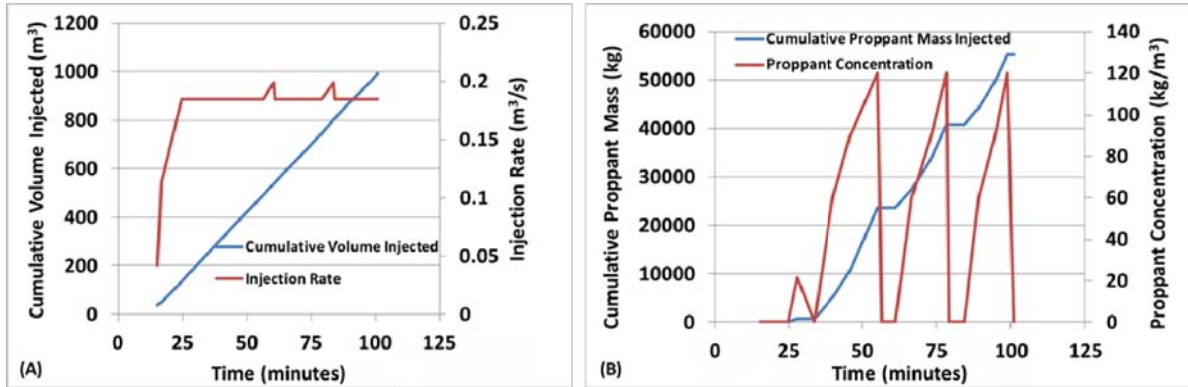
Figure 2-12. *Slickwater fluid and ceramic proppant injection profile for the Bakken Shale example (A) Cumulative fluid injection and injection rate; (B) Cumulative proppant injected and proppant concentration (taken from Pearson et al., 2013, Figure 14)*
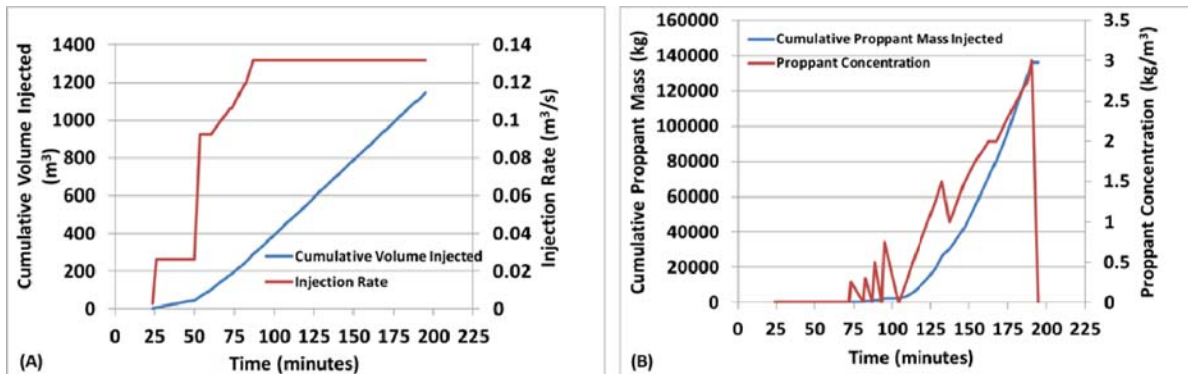
Figure 2-13. *Hybrid fluid and sand proppant injection profile for the Eagle Ford Shale example (A) Cumulative fluid injection and injection rate (fluid type initially a linear gel followed by 15% HCl and then by alternating pulses of x-link gel and linear gel, x-link used exclusively from 95 minutes to the end); (B) Cumulative proppant injected and proppant concentration, (proppant mesh size 30/50 initially until 124 minutes and then 20/40 until the end) (Stegent et al., 2010). Note: about 60% of the 20/40 sand was a resin-coated proppant (Stegent et al., 2010).*

The proppant injection stage constitutes the bulk of the remaining fluid injected for hydraulic fracturing. The final stage ends with a 37.9 m^3 (10,000 gal) or less overflush of fracture fluid without proppant to clear proppant from the well and perforations. The entire injection profiles for the example cases from the Bakken and Eagle Ford plays are shown in Figures 2-12 and 2-13, respectively.

In the case of the Bakken example, there were up to 30 stages per well for a 2,900 m (9,500 ft) lateral. For the Eagle Ford example, a 1,160 m (3,800 ft) lateral was treated with 11 stages. Therefore, the total fluid usage per well for the Bakken in this example is about 29,900 m³ (7.9 million gal), as compared to about 12,500 m³ (3.3 million gal) for the Eagle Ford case.

Based on the number of stages and lateral lengths, the average stage lengths in the two examples were about the same, with a length of 97 m (318 ft) for the Bakken and 105 m (344 ft) for the Eagle Ford. So the volume of fracturing fluid per well length is a bit higher in the Eagle Ford example (10.9 m³/m (881 gal/ft)) than the Bakken example (10.2 m³/m or 824 gal/ft). Treatment, well and formation parameters for the Bakken and Eagle Ford stimulation examples are summarized in Table 2-4. The higher fluid volume for the Eagle Ford as compared with the Bakken is consistent with the trend in Figure 2-8, given the lower permeability in the Eagle Ford. However, the much higher permeability in the Bakken than the Eagle Ford suggests there should be a larger difference in fracturing fluid volume. The small difference in fluid volume may result from the choice of fracture fluid not following the trend for permeability in Figure 2-8. The lower permeability of the Eagle Ford suggests that slickwater would be more likely to be used in that play and a gelled fracture fluid in the Bakken instead of the reverse, as was actually done. It may be that the difference in brittleness between the Bakken and Eagle Ford is a more important control on fluid selection than is permeability. These examples suggest the trends in Figure 2-8 may only be true on average, and that individual cases may deviate substantially.

Table 2-4. *Treatment, well, and formation parameters for the Bakken and Eagle Ford stimulation examples.*

Parameters	Bakken	Eagle Ford
Depth, m (ft)	3050 (10,000)	4040 (13,250)
Lateral length, m (ft)	2900 (9500)	1160 (3800)
Number of stages	30	11
Permeability, md (m²)	0.001 to 0.8 (9.87×10^{-19} to 7.90×10^{-16})	0.1 (9.87×10^{-17})
Fracture fluid volume, m³ (gal)	29,900 (7,900,000)	12,500 (3,300,000)
Fracturing fluid volume/lateral length, m³/m (gal/ft)	10.9 (881)	10.2 (824)

After fracture fluid injection, the well is produced to remove the fracture fluids (but not the proppant). The flowback fluids are initially similar to the injected fracture fluids but gradually are displaced until aqueous-phase fluid compositions are controlled by the aqueous phase present in the reservoir, typically a higher-salinity fluid. The amount of fracture-fluid recovery varies considerably for different reservoirs and generally ranges between 5% and 50% of the injected volume (King, 2012). However, many of the fracture-fluid additives are not recovered because of sorption, or are perhaps recovered as products of chemical reactions that occur in the reservoir. Polymers, biocides, and acids react and degrade under *in situ* reservoir conditions, and surfactants are adsorbed on rock surfaces.

2.4.9. Refracturing

Refracturing is the application of more than one hydraulic fracturing treatment to a well. Repeated hydraulic fracturing is done to boost the performance of a well after the production from an initial fracturing treatment has declined. In general, the low ultimate recovery estimated for most unconventional reservoirs and the rapid production decline found for these types of reservoirs may lead to additional well stimulations. Refracturing is often considered as an alternative to drilling infill wells that also require hydraulic fracturing. Therefore, refracturing may not actually represent additional hydraulic fracture treatments for a given reservoir if the alternative is the addition of infill wells that are also stimulated. Vincent (2010; 2011) has documented numerous cases of refracturing in which successful candidates appear to be related to the following factors:

- Inadequate initial fracture design

- Flawed execution of initial treatment

- Improved fracturing technology and materials

- Improved reservoir knowledge

- Increase in hydrocarbon price

- Changes in reservoir stress

Refracturing may be effective where the original treatment failed to contact regions containing hydrocarbon resources that can be improved through additional perforations, improved treatment diversion, or fracture reorientation. Refracturing may also be successful for cases in which proppant strength or injection were inadequate and resulted in poor fracture conductivity, or where fracturing fluids were used that were not compatible with the reservoir. Vincent (2010) reports that refracturing surveys show about one-third of the refracturing treatments are not successful; however, the current methodology for evaluating and designing effective refracturing treatments for many of these cases were found to be lacking.

Refracturing appears to be used sparingly. The EPA estimates about 10% of unconventional gas wells are refractured (Advanced Resources International, 2012) and an industry survey (Shires and Lev-On, 2012) indicates that the refracturing rate is even more limited, with about 2 percent of the current unconventional wells undergoing refracturing treatments. In the survey, most of the regions showed very low rates of refracturing, with a much higher rate (15%) within the DJ Basin. The difference for the DJ Basin was attributed to the specific geologic factors that did not seem to be present or likely to be present for other unconventional reservoirs. Nevertheless, given the relatively recent use of hydraulic fracturing to produce unconventional oil and gas reservoirs and the currently low ultimate recovery (about 1 to 10%) from such reservoirs (Sandrea,

2012), it can be expected that changes in treatment technologies and strategies will likely lead to an evolving approach to refracturing and/or infill drilling to recover a greater fraction of the hydrocarbon resources present.

2.4.10. Surface Operations Associated with Hydraulic Fracturing

The previous sections have described what occurs during hydraulic fracturing in terms of fluids and materials injected and withdrawn, and their effects on the underground environment. In this section, the surface operations required to conduct hydraulic fracturing are described.

After planning and designing a hydraulic fracture stimulation, the identified materials and equipment need to be brought to the well pad. In terms of bulk, the main materials are the base fracture fluid (usually water) and proppant. As shown in the examples in Section 2.4.7, the amount of water used to hydraulically fracture one well can be as high as tens of thousands of cubic meters (millions of gallons), but can also be significantly less depending on the length of the interval to be stimulated and the characteristics of the rock. The water is transported to the well by truck or pipeline and then stored onsite in tanks or ponds. In addition to water, a large volume of proppant is typically needed, which is transported to the well by truck and contained at the well pad in sand storage units, which may need to hold in excess of a million kilograms (about one thousand tons) of proppant. Water storage tanks are also required for the flowback, which can vary widely in amount from 5 to 50% of the injected volume, with the remainder remaining in the reservoir (King, 2012).

As discussed in Section 2.4.2.4, other chemical additives are commonly used, but the quantities of these additives are always much less (approximately 1 percent) than the base fracture fluid and proppant. Some chemicals are brought to the well pad by special trucks, such as for acid or a gel slurry. Other chemicals are usually delivered on flatbed trucks (Arthur et al., 2008).

In addition to storage equipment, the operation requires other equipment, including frac pumps, blending units, and piping to connect to the source materials and to the well, as shown in Figure 2-14. The piping that connects the blenders on the low pressure side of the frac pumps to the wellhead on the high pressure side is called the *manifold*.
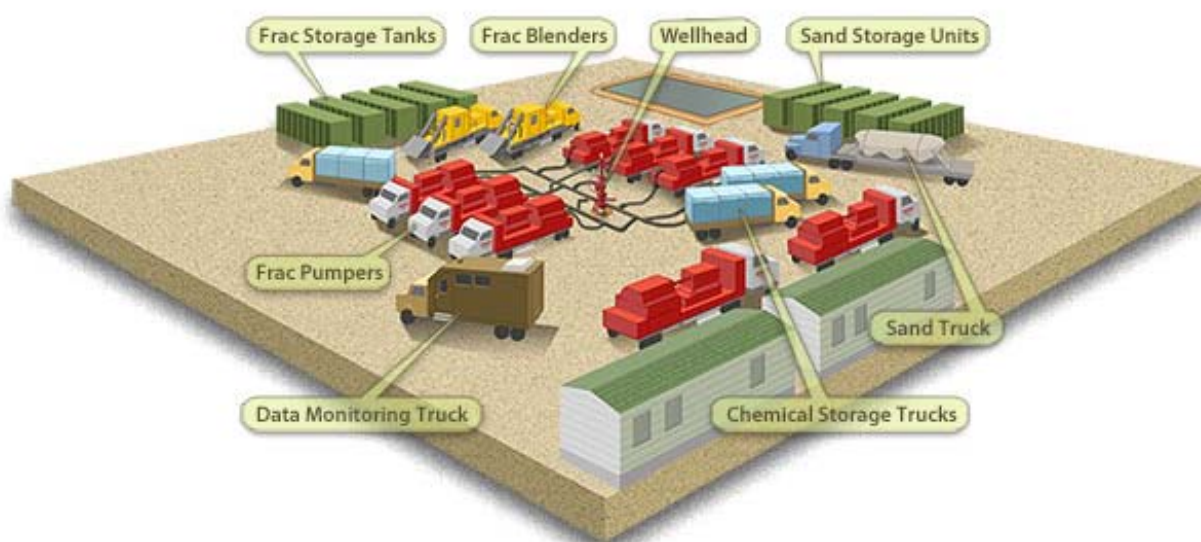
Figure 2-14. *Diagram of hydraulic fracture surface equipment (*http://fracfocus.ca/hydraulic-fracturing-how-it-works/hydraulic-fracturing-process*).*

For offshore operations, hydraulic fracturing materials and equipment are transported to the well by boat instead of truck, and the water is typically seawater. The types of equipment for a hydraulic fracture treatment is similar for an offshore fracturing treatment, but usually involves smaller volumes of base fluid, proppant, and chemical additives and also less equipment, e.g., fewer injection pumps. The largest material component of a hydraulic fracture treatment is the water to be injected. Freshwater is commonly used onshore, but becomes more of a logistical problem offshore. One option that has been implemented for offshore hydraulic fracturing is to use seawater instead of freshwater (Harris and van Batenburg, 1998; Bukovac et al., 2009; API, 2013; Xiao et al., 2014). Offshore operations are limited by space in comparison with well pads that are sized to accommodate the well stimulation equipment and materials. The equipment for a hydraulic fracture treatment can be either based on the platform itself or in conjunction with a jack-up rig and/or a support vessel (Robertson et al., 2010; Abdelaziz et al., 2014; Edwards and Pongratz, 1995). However, there are several physical limitations for offshore hydraulic fracturing that impact the surface configuration of the treatment system (Casero et al., 2008):

- Space limitations

- Weight/area restrictions

- Sea conditions

- Availability of marine and stimulation equipment resources

- Mobilization expense for all rig and stimulation equipment

Because of these limitations, offshore hydraulic fracture treatments often are conducted using a dedicated stimulation vessel or other types of support vessels that hold the stimulation equipment alongside the platform.

2.5. Matrix Acidizing

Matrix acidizing has been used for more than 100 years; the first treatment was performed on carbonate formations near Lima, Ohio in 1895 (Kalfayan, 2008). Matrix acidizing is different from acid fracturing discussed in Section 2.4.4, in that the acid solution is injected below the parting pressure of the formation; therefore, hydraulic fractures are not created by matrix acidizing (Kalfayan, 2008).

The modern application of matrix acidizing is split into two broad categories: carbonate acidizing and sandstone acidizing. Hydrochloric acid (HCl) is very effective at dissolving carbonate minerals. The high reaction rates between HCl and carbonate minerals means that mass transfer of HCl limits the overall rock dissolution rate. The result is that HCl treatments in carbonate rock generate highly nonuniform dissolution patterns called wormholes (Economides et al., 2013). For that reason, carbonate acidizing utilizes HCl injected into the formation to create wormholes that bypass formation damage around the well. However, because wormholes can penetrate up to 6.1 m (20 ft) from the wellbore, carbonate acidizing may also be used to stimulate carbonate formations that do not have significant formation damage around the well (Economides et al., 2013).

Sandstone acidizing uses alternating treatments of concentrated HCl and concentrated mixtures of HCl and hydrofluoric acid (HF), which are effective at dissolving silicate minerals. Sandstone acidizing differs from carbonate acidizing in that the reaction rates are four orders of magnitude (or more) lower, such that the rock dissolution rate is controlled by the chemical kinetics of the process, not the mass transfer of acid into the system (Economides et al., 2013). The result is relatively uniform rock dissolution as compared with carbonates. This type of acidizing treatment dissolves materials (such as drilling mud) that clog the casing perforations and pore networks of the near-wellbore formation. Sandstone acidizing is nearly always limited to treatment of formation damage within 0.3–0.6 m (1–2 ft) of the well. The main exception to the limited range of treatment for sandstone acidizing is for naturally fractured siliceous formations, including shales and cherts (Kalfayan, 2008).

Matrix acidizing is not commonly used for stimulation of unconventional reservoirs. This is because these low-permeability reservoirs require the more deeply penetrating and

intensive stimulation available from hydraulic fracturing to effectively produce oil or gas. Most shales also lack sufficient acid solubility. A unique exception that has been identified is the use of sandstone acidizing stimulation to enhance oil production from a producing field in the Monterey Formation in California (Rowe et al., 2004; Trehan et al., 2012a; El Shaari et al., 2011).

As discussed in Chapters 3 and 4, California's oil and gas resources are primarily found in silicate-rich rock rather than carbonate rock. Therefore, the remainder of this section will focus on sandstone acidizing.

2.5.1. Sandstone Acidizing

Sandstone acidizing typically consists of three injection phases, (1) an initial injection of HCl preflush; (2) injection of an HCl/HF mixture; and (3) a post-flush of diesel, brine, or HCl. After the injection phases, the well is flowed back (Economides et al., 2013). The injection phases are conducted below the fracture pressure. Acid concentrations are dependent on formation mineralogy and permeability. The preflush HCl concentrations typically vary from 5% to 15%, while the HCl/HF mixture may have HCl concentrations from about 13.5% down to 3% and HF from 3% down to 0.5% in various combinations (Kalfayan, 2008). In general, higher permeability formations with lower clay and silt content are treated with higher acid concentrations (Economides et al., 2013).

The purpose of the HCl preflush is to dissolve carbonate minerals and displace formation water. Carbonate minerals react with HF to form insoluble precipitates that can cause formation damage. Organic acids, such as formic-acetic acid blends, are sometimes used alone or in combination with HCl for the preflush (Kalfayan, 2008). The preflush volumes are generally equal to 50 to 100% of the subsequent HCl/HF treatment volume.

The HCl/HF acid treatment is the main acid stage for sandstone acidizing. This acid targets siliceous minerals that are blocking flow paths to the well. These minerals may be siliceous particles from drilling mud, such as bentonite, that have invaded and blocked pores and fractures, or naturally occurring fine-grained sediments in the reservoir. The contact time should be limited to 2 to 4 hours per stage to avoid mineral precipitation damage caused by precipitation of HF reaction products.

Volumes injected generally range from 0.124 to 3.1 m^3/m (10 to 250 gal/ft) of treated interval (Kalfayan, 2008). Injection rates are also important because of the reaction-rate kinetics, both for mineral dissolution and precipitation, the transport times for the acid to penetrate the formation, and because the injection pressure needs to remain below the fracture pressure (Economides et al., 2013). High-volume, high-rate treatments are typically limited to high-permeability, high-quartz content sands and fractured rock, including shales.

Sandstone acidizing is normally used only when formation damage near the well is impeding flow into the well. This is because penetration of a sandstone acidizing treatment into the formation is generally only about 0.3 m (1 ft). The maximum benefit of enhancing permeability in this limited region around the well for an undamaged formation is only about 20% (Economides at al., 2013). However, there is much less known about sandstone acidizing in siliceous reservoirs with permeable natural fractures, such as in some parts of the Monterey Formation (Kalfayan, 2008). In these circumstances, sandstone acidizing may be able to penetrate and remove natural or drilling-induced blockage in fractures deeper into the formation (Rowe et al., 2004; Patton, Pits, Goeres, and Hertfelder, 2003; Kalfayan, 2008). Kalfayan (2008) indicates that HCl/HF acidizing in naturally fractured siliceous rock uses high volumes > 1.24 m^3/m (> 100 gal/ft). However, both low volume 0.248 m^3/m (20 gal/ft) and higher volume 3.1 m^3/m (250 gal/ft) HCl/HF treatments in fractured Monterey reservoirs have been reported (Patton, et al., 2003; Rowe et al., 2004).

The post-treatment flush displaces any live acid from the well. Flushing may be done with diesel, ammonium chloride solutions, and HCl (Economides et al., 2013). The volume of the post-flush should at least be sufficient to displace acid from the wellbore. After the injection phases are completed, the well is typically flowed back to recover spent-acid-reaction products after most of the acid has been consumed to minimize damage caused by precipitation. Sandstone acidizing for oil wells and gas wells is substantially the same; however, for oil wells, the post-treatment flush is typically larger than the main acid treatment volume, whereas for gas wells, the post-treatment flush volume is typically smaller (Kalfayan, 2008).

2.5.1.1. Sandstone Acidizing Fluid Composition

Similar to hydraulic fracturing fluids, several additives are generally included in the acid treatment fluids. In particular, corrosion inhibitors and iron control agents are always used. Corrosion inhibitors are needed to protect steel components in the well, such as the casing and tubing. Iron control agents react with dissolved iron and other dissolved metals to limit solids precipitation. Surfactants and mutual solvents are also often used. Surfactants increase the removal of spent acid during the backflow and to leave the formation in a water-wet condition (meaning water adheres to the rock more strongly than oil). Mutual solvents have been found to be useful in helping remove corrosion inhibitors that tend to adsorb onto rock and leave it in an oil-wet condition (meaning oil adheres to the rock more strongly than oil, which reduces oil production). Table 2-5 gives further information on these and other additives that are used in some cases.

Table 2-5. *Sandstone acidizing additives (Kalfayan, 2008)*

Additive type	Description of purpose	Examples of chemicals	Injection phase used	Typical concentration range
corrosion inhibitor	prevent corrosion of metallic well components	cationic polymers	all injection phases	0.1 – 2%
iron control agent	inhibit precipitation of iron, prevention of sludge formation	ethylenediaminetetraacetic acid (EDTA), erythorbic acid, nitrilotriacetic acid (NTA), citric acid	all acid phases	EDTA: 30-60* erythorbic acid: 10-100* NTA: 25-350* citric acid: 25-200*
surfactant	aid in recovery of spent acid products	nonionic, such as polyethylene oxide and polypropylene oxide	all acid phases	0.1-0.4%
mutual solvent	help remove corrosion inhibitors	ethylene glycol monobutyl ether (EGMBE)	post-f ush	3-5%
nonemulsifiers	prevent acid-oil emulsions	nonionic or cationic surfactant	all acid phases	0.1-0.5%
antisludging agent	prevents formation of sludge from acid and high asphaltenic oils	surfactant and iron control agents	all acid phases	0.1-1%
clay stabilizer	prevent migration/ swelling of clays	Polyquaternary amines, polyamines	post-f ush	0.1-0.4%
fines-stabilizing agent	prevent migration of non-clay fines	Organosilanes	all phases	0.5-1%
calcium carbonate / calcium sulfate scale inhibitor	prevent formation of calcium scale	phosphonates, sulfonates, polyacrylates	all acid phases	NA
friction reducer	reduce pipe friction	Polyacrylamide	all injection phases	0.1-0.3%
acetic acid	reduce precipitation of aluminosilicates	acetic acid	HCl/HF phase	3%

* pounds per thousand gallons of acid = 0.12 grams per liter (g/l)

2.5.1.2. Diversion

Placement of acid is an important element for effective sandstone acidizing. This is because the acid tends to flow into formation pathways that are most permeable. This is problematic, because acidizing treatments are generally intended to contact and improve the permeability of zones that are plugged and have a low permeability. In addition to permeability variations between zones, diversion also helps improve the acid injection profile because of zonal differences in formation pressure, compressibility, resident fluid viscosity, and fracturing (Trehan et al., 2012b). Therefore, methods to divert acidizing treatments away from permeable zones and into the low-permeability zones are needed (Economides et al., 2013).

The main diversion methods are mechanical—including packer systems, ball sealants, and coiled tubing—and chemical—including particulate diverters, foams, and gels. Direct mechanical diversion is provided by packers which isolate the zones where the acid contacts the formation. Packers are an effective but somewhat resource-intensive diversion method. Ball sealers are also a mechanical diversion method that injects 0.0159–0.0318 m (0.0512–0.104 ft) diameter balls made of nylon, hard rubber, or bio-degradable materials such as collagen, into the well (Kalfayan, 2008). The balls seat on and seal perforations, preferentially closing perforations that are taking most of the flow, thereby diverting flow to other perforations (Samuel and Sengul, 2003). The method requires high pumping rates and perforations that are in good condition to be effective. Coiled tubing is another mechanical diversion method. Coiled tubing is any continuously milled tubular product manufactured in lengths that require spooling onto a take-up reel and have diameters ranging from 0.0191–0.102 m (0.0625–0.333 ft) (ICoTA, 2014). The tubing is sent down the well to the location where treatment is desired, and the treatment fluids are pumped through the tubing. The method is effective at delivering fluids at locations needed, but can result in pump-rate limitations because of the small tubing diameter, and the tubing can be damaged by acid corrosion, causing leaks and tubing failure (Kalfayan, 2008).

Particulate diverters are a chemical diversion technique that uses benzoic acid, which precipitates into flakes or fines when the acid solution mixes with formation waters at reservoir conditions. The particulates then plug off the more actively flowing zones, and the acid treatment is diverted to locations where less of the diverting agent has been deposited. Gels and foams are viscous diversion treatments that reduce flow into higher permeability zones by the establishment of a bank of higher viscosity fluid in the region. Gels are more reliable, but can lead to problems if they cannot be subsequently broken and/or removed after the acidizing treatment (Kalfayan, 2008).

A final method that is applicable for high-rate injection schemes is known as maximum pressure differential and injection rate (MAPDIR) (Paccaloni, 1995). A similar approach is also used for carbonate acidizing (Economides et al., 2013). This method pumps the acid treatments at the highest rate possible without exceeding the formation fracture pressure. One of the advantages of this method is that diverting agents may not be needed. The method is useful for treating long, damaged, naturally fractured intervals.

2.5.2. Surface Operations for Matrix Acidizing

Surface operations for matrix acidizing involve many of the same types of equipment and materials as for hydraulic fracturing. The main difference is that no fractures are formed during the treatment, meaning that injection pressures and rates are typically lower. Also, there is no need for proppant. Nevertheless, there are situations in which acid is injected at the highest possible rate subject to the constraint that the fracture pressure is not exceeded (see Section 2.5.1). This requires chemical storage trucks or tanks, pumps, blending units, and piping.

A surface setup for a large-scale matrix acidizing treatment is described by Trehan et al. (2012a). In this particular operation, the acid is injected at a high rate as an N_2-acid foam, in which both the foam and the high rate act to divert acid from zones that have already been depleted into zones that have not been effectively contacted or produced. The surface operations require storage for acid, nitrogen, and other chemical additives such as corrosion inhibitor, iron control agent, and surfactant. The acid and additives are mixed in a blender unit that is then pumped into the well along with nitrogen. The treatment fluid is delivered in a variety of ways, including through production tubing, coiled tubing, drill pipe or the tubing/casing annulus (Kalfayan and Martin, 2009).

The objectives and execution of matrix acidizing for the offshore environment is similar to onshore acidizing treatments. However, as for hydraulic fracturing, offshore operations are limited by space in comparison with well pads onshore that are sized to accommodate the well stimulation equipment and materials (see Section 2.4.8). This can result in some differences in application details, such as the use of coiled tubing offshore may be limited because of space restrictions (Mishra, 2007). Also, similar to hydraulic fracturing, space limitations on the platform can lead to the use of a temporary support vessel or jack-up platform to conduct matrix acidizing treatments (Ritter et al., 2002; Edwards and Pongratz, 1995).

Transportation of materials is basically the same as for hydraulic fracturing, both onshore and offshore. Hydrochloric acid is typically delivered as a liquid in a specialized truck onshore (Arthur et al., 2008) and in tanks on a supply vessel offshore. But hydrofluoric acid is sometimes produced onsite by mixing ammonium bifluoride (as a dry chemical) with hydrochloric acid rather than being delivered as a live acid (Trican, 2014; Halliburton, 2014b).

2.6. Data Quality and Data Gaps

As discussed in Chapter 1, sources of information cited in this chapter are based to the extent possible on peer-reviewed scientific literature. However, because of the limited information available through peer-reviewed literature other relevant, non-peer-reviewed information was considered. These include government data and reports as well as non-peer reviewed reports and documents if they were topically relevant and determined to be scientifically credible by the authors and reviewers of this volume.

Despite the large quantity of information on well stimulation technology cited in this chapter, some subjects associated with well stimulation appear to be either not as well understood or perhaps just not as well covered by the existing publications.

One aspect of the technical implementation that does not seem to be as clearly discussed or explained in the literature is the different ways hydraulic fracturing treatments are delivered through the well. This concerns the details on the exact injection configuration (through well tubulars, coiled tubing, drill pipe, directly through casing pipe), which

is mainly of concern for hydraulic fracturing. Injection of the high-pressure fracture treatment directly through the well casing poses the potential problem of excess fluid pressure leading to damage to the well-cement-formation interfaces that are critical for zonal isolation. Injection of fracturing fluids and materials through production tubing or through coiled tubing provide a barrier against exposing these components of the well to stresses that may affect their ability to function as designed. This needs to be considered and addressed because wells, including the well under treatment as well as other wells within the zone of influence of the treatment, are potentially an important leakage pathway for fluids to migrate from subsurface locations to potable water supplies or the ground surface.

Another facet of hydraulic fracturing that does not seem to have received much attention is the quantity and composition of flowback for hydraulic fracturing and matrix acidizing. Flowback is known to be important in terms of well stimulation: if the injected treatment fluids for fracturing or acidizing are not adequately recovered, the treatment can be diminished or even fail because of the damage to the effective permeability in the treatment zones that results. Nevertheless, understanding of the factors that influence recovery of treatment fluids and their composition, as well as measurements to characterize these factors, appears to be lacking.

The process of acid fracturing was not emphasized in this chapter because of the evidence that oil and gas production in California, onshore and offshore, is produced from reservoirs that are siliceous and have insufficient carbonate mineral content to be treated by this stimulation technique. Nearly every technical description of acid fracturing has stated that acid fracturing is not applicable for siliceous reservoirs, and no known publications have described this technique as being successfully applied to a siliceous reservoir. Nevertheless, a small number of attempts to use acid fracturing in California appear to have been reported, but no information on the reasons for these specific applications or the results of these attempts have been published.

As discussed in this section, matrix acidizing is mainly used to treat formation damage near the well. This is particularly true for siliceous reservoirs which receive sandstone matrix acidizing treatments that generally do not penetrate more than 1 m (3 ft) away from the well. However some reports of acidizing in the naturally fractured Monterey Formation and in more general descriptions of the technique have indicated that the treatment radius in naturally fractured (or even in hydraulically fractured) formations may see permeability enhancement deeper into the formation. Exactly how matrix acidizing alters reservoir properties for naturally fractured siliceous shales such as the Monterey appears to be poorly documented.

2.7. Findings

The main findings of this chapter are as follows:

1. The design of a hydraulic fracture is a function of the reservoir's flow and mechanical characteristics. Reservoirs that are more permeable (within the permeability range where well stimulation is needed) and ductile tend to require less fracturing. This leads to the use of a more viscous gelled fracturing fluid and a relatively smaller fracture fluid volume. Gelled fluids typically have more types and a higher total mass of chemical additives than slickwater. Reservoirs that have relatively small permeability and are brittle tend to require more intensive fracturing. This leads to the use of a less viscous slickwater fluid and a relatively larger fluid volume injected compared to gelled fracture fluid treatments.

2. Application of acid fracturing is commonly limited to carbonate reservoirs. This is significant because California's hydrocarbon resources are primarily found in siliceous rock rather than carbonate rock, as shown in Chapters 3 and 4.

3. Matrix acidizing for siliceous reservoirs typically has a very limited penetration distance from the well into the formation. Therefore, this type of matrix acidizing tends to have a small effect on larger-scale reservoir permeability, with the possible exception of reservoirs in which acidizing may open up natural fractures by dissolving plugging material.

4. While surface logistics for well stimulation differ for offshore as compared with onshore, the same principles for well stimulation apply for the underground environment, and the kinds of stimulation treatments applied are mainly a function of the reservoir geology. However, offshore fields tend to have moderate-to-high permeability, such that fracture stimulation, when used, is often performed as a frac-pack, with the objectives of bypassing formation damage and controlling sand production.

Chapter 2 References

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Chapter Three

Historical and Current Application of Well Stimulation Technology in California

Abstract

Eight data sets regarding well stimulation in California were identified from four independent sources. None of the sets provides comprehensive information covering a period of time that can be described as having stimulation activity as usual. However, the overlap between the sets and consistency with previous estimates using more limited data provides confidence that assessments of frequency of use, geographic distribution, and stimulation fluid volume and type are accurate, if not precise. The records indicate California operators use three types of well stimulation: hydraulic fracturing, acid fracturing, and matrix acidizing. About 150 wells per month undergo hydraulic fracturing, less than one well a month undergoes acid fracturing, and about 20 wells a month undergo matrix acidizing (although there is uncertainty regarding discriminating matrix acidizing for increased permeability and production from acidizing to remediate damage due to drilling). The number of production wells hydraulically fractured per year has remained relatively constant over the last 12 years studied, while the number of injection wells hydraulically fractured has increased. Hydraulic fracturing facilitates one fifth of the oil and gas production in the state, with most of this gas co-produced with oil. Hydraulic fracturing practice in California differs from that in other states. It primarily occurs in a few established oil fields containing shallow migrated oil in the southwestern portion of the San Joaquin Basin, as shown in Figure 3-1, rather than over more widespread areas in deep source rocks as in some other parts of the country. The average fracturing operation uses 530 cubic meters (m^3; 140,000 gallons, gal) of water, a much smaller amount than used per operation in many other parts of the country. California operations require smaller volumes of water because operators in this state fracture in relatively shallow vertical wells (less than 600 meters (m; 2,000 feet, ft) deep), with shorter treatment intervals than the horizontal wells common elsewhere. In about half the operations, the top of the fracturing interval is less than 300 m (1,000 ft) deep. The nearly exclusive use of predominantly crosslinked gel-based hydraulic fracturing fluids in California compared to less viscous gels and slickwater in other parts of the country also accounts for smaller fluid volumes. Fracturing a well with less viscous fluids typically requires up to several times the volumes used of crosslinked gel fluids.
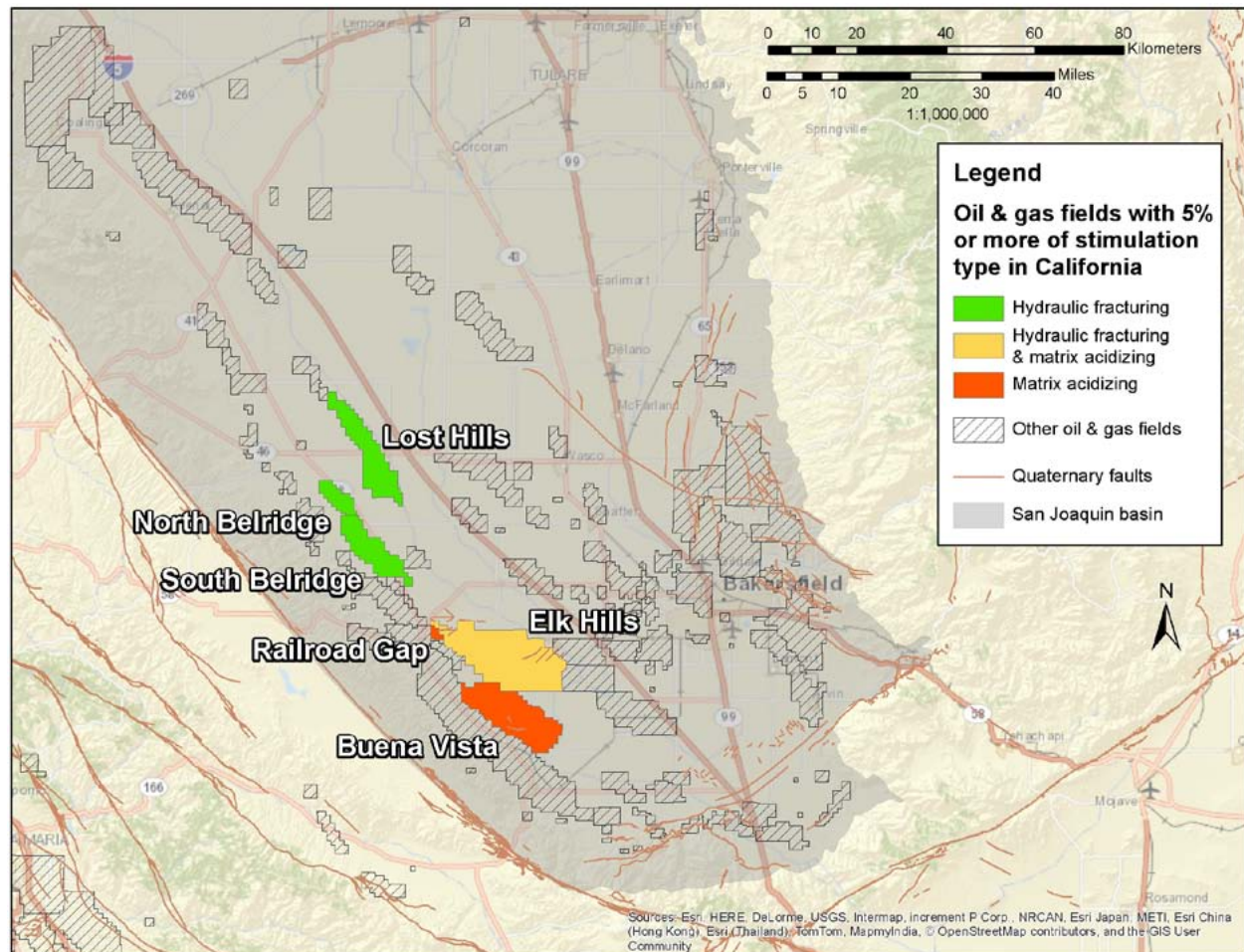
Figure 3-1. *Oil and gas fields with more than 5% of the hydraulic fracturing or matrix acidizing reported in California. In total, 85% of the hydraulic fracturing and over 95% of the matrix acidizing reported occurs in these fields. So few acid fracturing operations are reported that the fields where they occur are not indicated.*

3.1. Introduction

This chapter reviews the application in California of the three well stimulation technologies described in Chapter 2 (hydraulic fracturing, acid fracturing and matrix acidizing), and includes a review of the history of each technology's application, estimates of current deployment rates for each, and the stimulation-fluid volumes and types typically utilized in California. The organization of the chapter is parallel to the organization of Chapter 2, giving the historical and present day practice for each well stimulation technology, first for onshore oil production, then offshore oil production, and finally gas production. No acid fracturing has been reported offshore. No matrix acidizing has been reported offshore since 2010.

As discussed in Chapter 2, horizontal drilling technology is integral to hydraulic fracturing practice in many of the shale oil and gas reservoirs outside California, such as the Eagle Ford and Bakken (primarily in Texas and North Dakota, respectively). Horizontal drilling is much less common in California fields, and is often used without hydraulic fracturing or other well stimulation. The various uses of horizontal drilling in California are discussed in Appendix H.

3.2. Hydraulic Fracturing

3.2.1. Historical Use of Hydraulic Fracturing from Literature

The earliest fracturing reported in California dates back to 1953 in the Cymric field of the San Joaquin Basin (California Division of Oil, Gas and Geothermal Resources (DOGGR), 1998), and in the Brea-Olinda and Esperanza fields in the Los Angeles Basin (Ghauri, 1960). The technique was applied in other fields in the following decades, including the Buena Vista field in the San Joaquin Basin, and the Sespe and Holser fields in Ventura County (Erickson and Kumataka, 1977; Norton and Hoffman, 1982). This early fracturing was accomplished with water- and oil-based fluids, both gelled and ungelled (Ghauri, 1960; Erickson and Kumataka, 1977). Ungelled, oil-based fluids provided the best results (Erickson and Kumataka, 1977; Norton and Hoffman, 1982). These applications were typically in shale or low-permeability sandstone (Ghauri, 1960; Erickson and Kumataka, 1977; Norton and Hoffman, 1982). Hydraulic fracturing of diatomite[1], which requires well stimulation for successful production, is reported as early as the late 1960s in California.

Hydraulic fracturing became common in the production of oil from diatomite, opal CT and siliceous shale, and quartz-phase shale starting in the late 1960s. Gulf Oil successfully treated a 230 m (750 ft) vertical interval of diatomite from a vertical well in the Lost Hills field using multistage fracturing. Oil production increased relative to untreated wells, but only for two months. The increase was insufficient for the treatments to be economic (Yarbrough et al., 1969). Further development of the technique led to its economically viable and widespread application to vertical wells in diatomite by the late 1970s (Emanuele et al., 1998). Hydraulic fracturing of the diatomite in the San Joaquin Basin became relatively standardized within companies in the following decades, but practice varied from company to company (Allan et al., 2010).

Besides diatomite and rock derived from diatomite, hydraulic fracturing has also been used in low-permeability sandstones. For instance, such rocks have been successfully targeted in the Elk Hills, North Coles Levee, and Mount Poso fields (Underdown et al., 1993; Agiddi, 2004; Evans, 2012). Small volume hydraulic fracturing has also been

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1. Diatomite is a high-porosity, low-permeability rock consisting primarily of siliceous matter (material containing silica (SiO2)) from diatoms, a type of marine algae. It is a reservoir rock containing oil in some fields (for more information, see Chapter 4). It occurs in thick sequences (up to 600 m (2,000 ft) thick).

successfully applied in unconsolidated sands in the Kern River field (Jones, 1999). Frac-pack have been applied to sands in the Wilmington and Inglewood fields (Turnage et al., 2006; Moodie et al. 2004). The application of frac-packs to some reservoirs in the Wilmington field allowed production that had previously been prevented by the entry of reservoir sand into wells during production. The central and southern California sandstones discussed above all produce oil. Limited hydraulic fracturing of gas-bearing sands in northern California has also been reported (El Shaari and Minner, 2006).

The first successful production resulting from hydraulic fracturing in diatomite at the South Belridge field in the San Joaquin Basin occurred in 1977 (Allan et al., 2010). By the early 1980s, one operator had hydraulically fractured hundreds of vertical wells in the diatomite at South Belridge, as well as at several other fields (Strubhar et al., 1984). Water flooding of the diatomite in the South Belridge field started in the late 1980s and hydraulic fracturing of both injection and production wells was standard practice (Yang, 2012). Water flooding involves injection of water into an oil reservoir to drive more oil to the producing wells.

In the early 1990s, the first horizontal wells were installed in the South Belridge field in the thinner oil zones consisting of diatomite recrystallized to opal CT (see Section 4.2.2) along some margins of the field. These were subsequently hydraulically fractured in stages. Orienting the wells for longitudinal fractures was found to result in greater production (Allan et al., 2010). Vertical wells were found to be a better approach in zones with oil thicker than 137 m (450 ft) toward the center of the field.

The diatomite in the Lost Hills field in the San Joaquin Basin has a similar development history as that in the South Belridge field in the San Joaquin Basin. Multistage fracturing from vertical wells stimulated a 230 m (750 ft) vertical interval of diatomite in the Lost Hills field in the 1960s, but the increased production was insufficient for the treatments to be economic (Yarbrough et al., 1969). Further development of the technique in the diatomite led to its economically viable application in vertical wells by the late 1970s (Emanuele et al., 1998; Fast et al., 1993; Strubhar et al., 1984; Hansen and Purcell, 1989).

The early 1990s saw the implementation of water flooding of the diatomite in the field to improve production and reduce ground subsidence. This required hydraulic fracturing of both the vertical injectors and producers (Wilt et al., 2001). Between the late 1980s and the mid-1990s, operators completed over 2,700 hydraulic fracture stimulations in diatomite in the Lost Hills field (Nelson et al., 1996). Subsequently, tens to hundreds of hydraulically fractured vertical wells were installed per year through at least 2005 (Hejl et al., 2007). Horizontal wells in the thinner oil zones along the margins of the field were first installed in the mid-1990s. The first test wells were oriented for transverse fractures (perpendicular to well direction). Based on the results, horizontal wells subsequently installed for production along the margins of the field are oriented for longitudinal fractures (Emanuele et al., 1998).

The literature records hydraulic fracturing of the siliceous shales in the Lost Hills field as early as the 1960s as well (Al-Khatib et al., 1984). These are diatomaceous mudstones recrystallized due to the large depth of burial. Hydraulic fracturing during the 1960s through most of the 1970s in an area with naturally occurring fractures did not significantly improve production. In 1979, hydraulic fracturing did enable successful oil production from rocks without natural fractures present nearby. Consequently, in the early 1980s, hundreds of vertical wells were installed and fractured over 30 to 120 m (100 to 400 ft) vertical intervals.

As in the South Belridge and Lost Hills fields described above, a progression from vertical to horizontal wells occurred in the North Shafter field. Production was established from hydraulically fractured vertical wells starting in 1982, and installation of hydraulically fractured horizontal wells commenced in 1997 and subsequently became predominant (Ganong et al., 2003). Horizontal wells in the similar Rose field nearby were oriented for longitudinal fractures, but fracturing resulted in complex fractures with both transverse and longitudinal components. This was attributed to almost equal stress in all directions (Minner et al., 2003). Production from these fields is from a quartz-phase shale (Ganong et al., 2003). This is a more recrystallized form of diatomite, due to greater burial depth, as explained in Section 4.2.2.

The reported hydraulic fracturing fluid types used since the 1970s are primarily water-based and predominantly gels. For instance, Hejl et al. (2007) reports the various gels used to fracture the diatomite at Lost Hills starting in the 1980s. Fracturing with gels is noted in the McKittrick field in the mid-1990s (Minner et al., 1997; El Shaari et al., 2005) and in the Belridge field at the same time (Allan et al., 2010). One of the Stevens Sand reservoirs in the Elk Hills field was fractured with gels starting in the late 1990s (Agiddi, 2004, 2005). An exception is the use of ungelled oils for conducting frac-packs in the Inglewood field (Moodie et al. 2004).

The type of fluid used has changed through time in some locations to better match conditions. For example, successful fracturing in the Edison field used ungelled water, and ungelled water subsequently replaced the gels used for hydraulic fracturing previously in the Tejon field. The ungelled fractures provided economically viable results as opposed to the gelled fractures (Mathis et al., 2000). Research starting in 2002 led to switching from crosslinked gels to low-polymer-concentration gels to minimize plugging of the natural pores in a low-permeability sandstone reservoir in the Elk Hills field (Agiddi, 2005). Foamed linear gels and foamed and unfoamed cross-linked gels have been used in gas sands in northern California (El Shaari and Minner, 2006).

3.2.2. Historical Use of Hydraulic Fracturing from Well Records

3.2.2.1. Historical Use of Hydraulic Fracturing Onshore and in State Waters Combined

DOGGR regulates all oil and gas wells onshore and within three nautical miles of the coast, termed "state waters." The percent of wells regulated by DOGGR that have been hydraulically fractured was estimated by searching well records for wells with first production or injection from 2002 through September 2013. September 2013 was the most recent first production and injection data available at the start of this study in early 2014. The search also identified wells that had been frac-packed.[2] Further details regarding the search procedure are available in Appendix I.

Figure 3-2 shows the sedimentary basins with oil and gas production, and indicates basins with a new oil or gas well since 2001. Appendix J lists the total number of wells, and the number and proportion of well records searched and found to indicate hydraulic fracturing for each geographic area. Tables of the estimated number of well records confirmed as indicating hydraulic fracturing per year per basin and county are available in Appendix K. Appendix L lists the API numbers for wells with a first production date from 2002 through near the end of 2013, or a first injection date if no first production date, along with the date. It also lists whether the record for each well was searched, and which records searched reported hydraulic fracturing.

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2. Frac-packs are described in Section 2.4.5. They are a type of fracturing operation intended to extend granular mate-rial from the well into the formation beyond the zone with reduced permeability due to drilling and to filter out forma-tion solids that would otherwise enter the well along with the fluids produced.
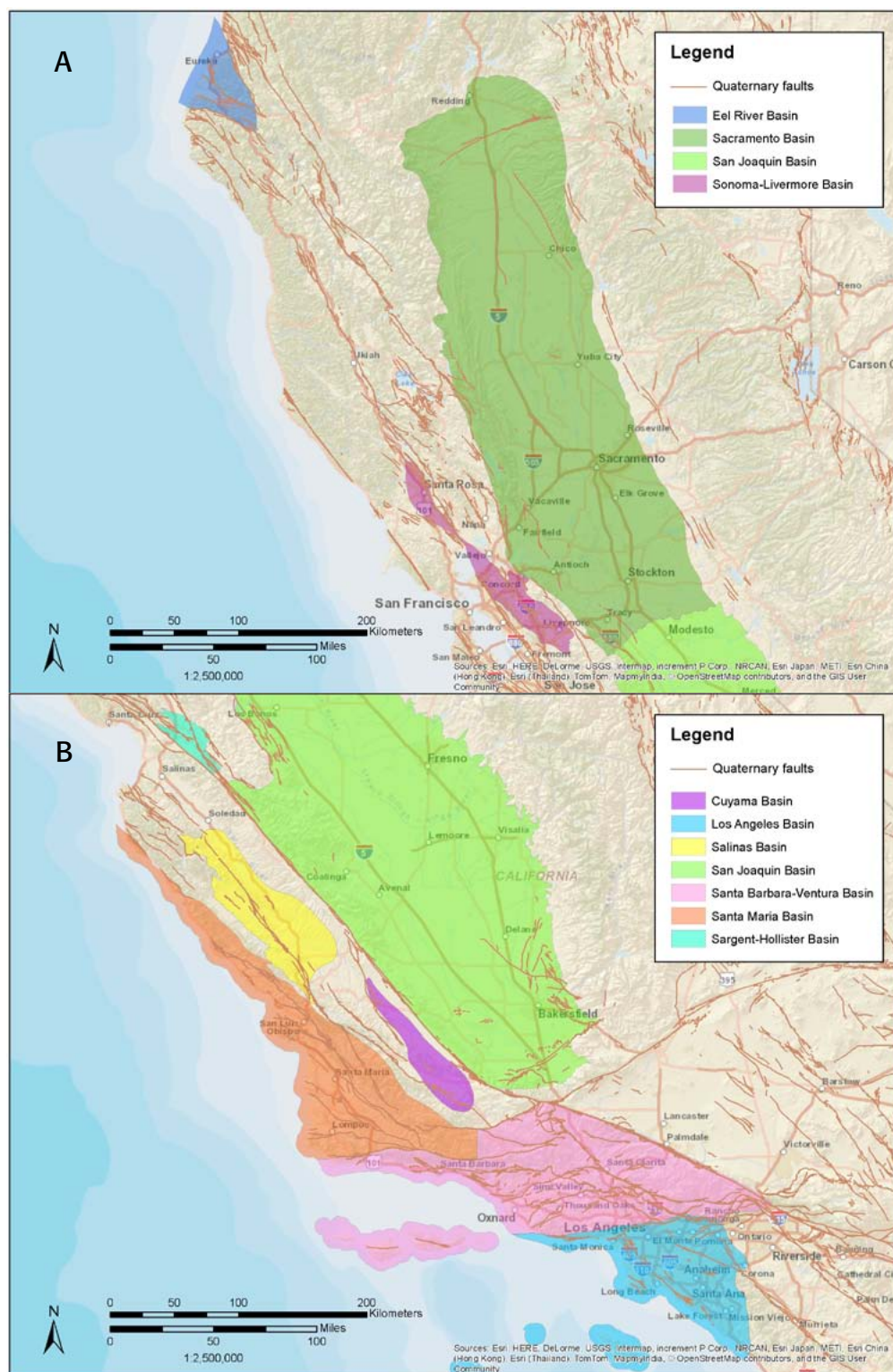
Figure 3-2. *Basins with oil and gas production-related wells first producing or injecting in 2002 to 2013 in (A) northern California, and (B) central and southern California.*

Figure 3-3 plots the average annual number of well records confirmed as indicating hydraulic fracturing in each basin, along with the 95% confidence interval for the annual average number of such records in the entire state. The analysis and interpretation was done for three time periods, from 2002 to 2006, from 2007 to 2011, and from 2012 to 2013. These multi-year periods were chosen to provide a perspective on trends in the utilization of hydraulic fracturing from a manageable well record sample size to attain a desired level of uncertainty. The 2012 to 2013 period was selected to have the greatest overlap with other data sources for assessing levels of underreporting.

The well record search results indicates about 75 wells per month were fractured in California in the decade prior to 2012, rising to closer to 100 wells per month in 2012 to 2013. It also shows that 95% of this activity occurs in the San Joaquin Basin, with most of the rest in the Los Angeles and Santa Barbara/Ventura basins. The well record search results indicate almost all of the activity in the San Joaquin Basin occurs in Kern County.
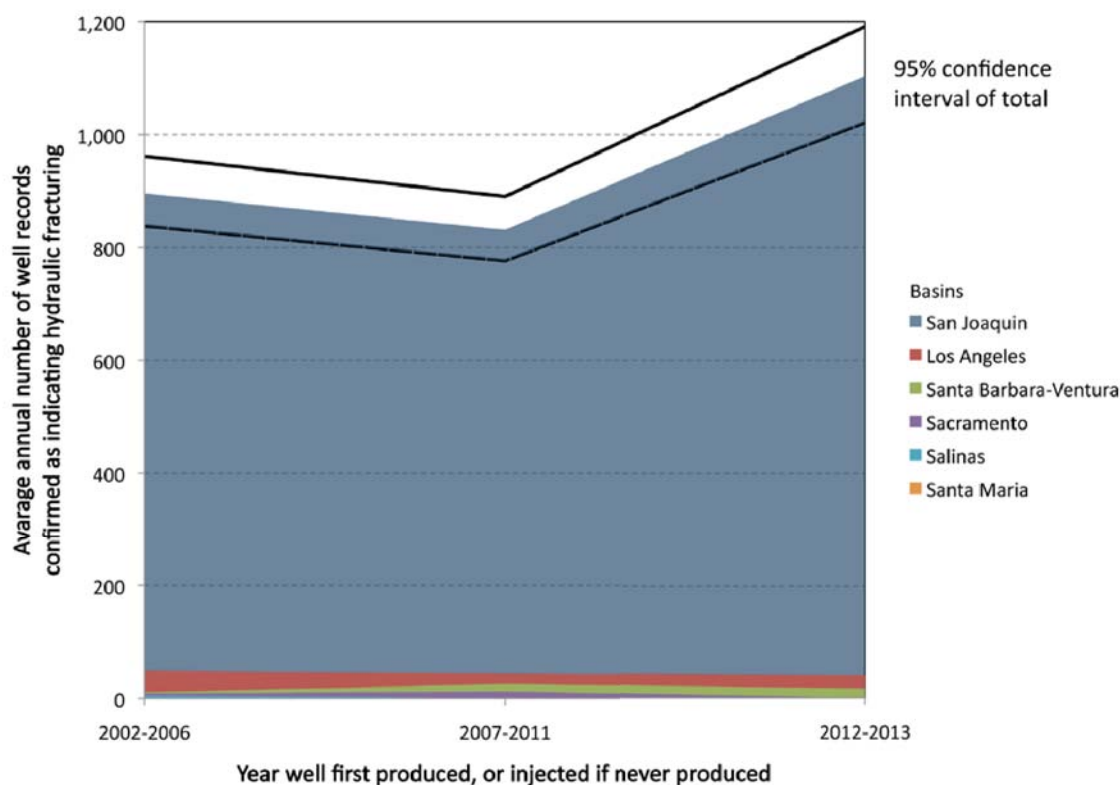
Figure 3-3. *Average annual number of well records confirmed as indicating hydraulic fracturing in each basin for wells first producing or injecting from 2002 to September 2013. The amount of activity in the Santa Maria and Salinas basins is too small to be visible. The confidence interval shown is for activity in the entire State.*

Figure 3-4 shows the annual average total number of well records, and records confirmed as indicating hydraulic fracturing of production and injection wells. About three quarters of the hydraulically fractured injection wells were for water flooding and one quarter for steam flooding.
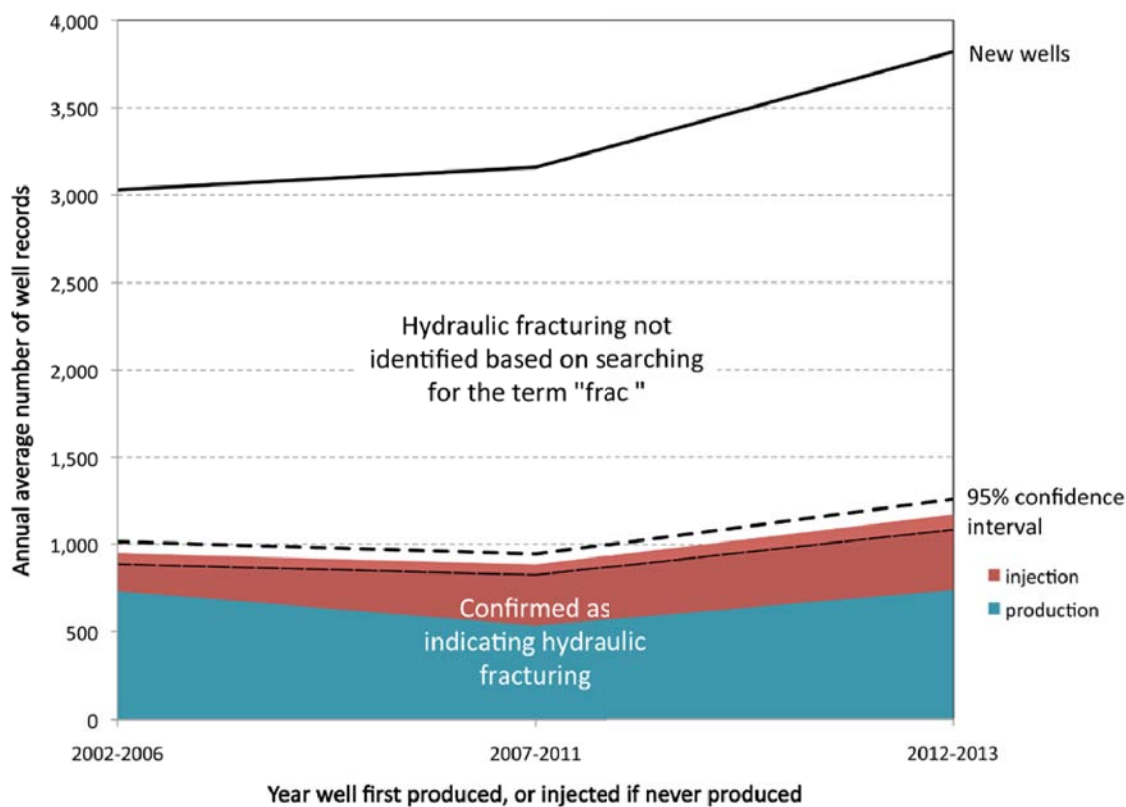
Figure 3-4. *Annual average number of well records confirmed as indicating and likely not indicating hydraulic fracturing for well first producing from 2002 to September 2013.*

Figure 3-5 shows the percentage of all well records confirmed as indicating hydraulic fracturing. The percentage does not vary significantly over time. This indicates the increase in average annual records indicating hydraulic fracturing in 2012 to 2013 scaled with the increase in the total average annual records shown in Figure 3-4. The ratio of injection to production well records indicating hydraulic fracturing increases from 1:5 in 2002-2006 to 1:2 in 2007-2013, though, suggesting a shift toward greater use of hydraulic fracturing for enhanced oil recovery (see Box 3.1). This contrasts with the expansion of hydraulic fracturing for primary oil production in many other parts of the country.
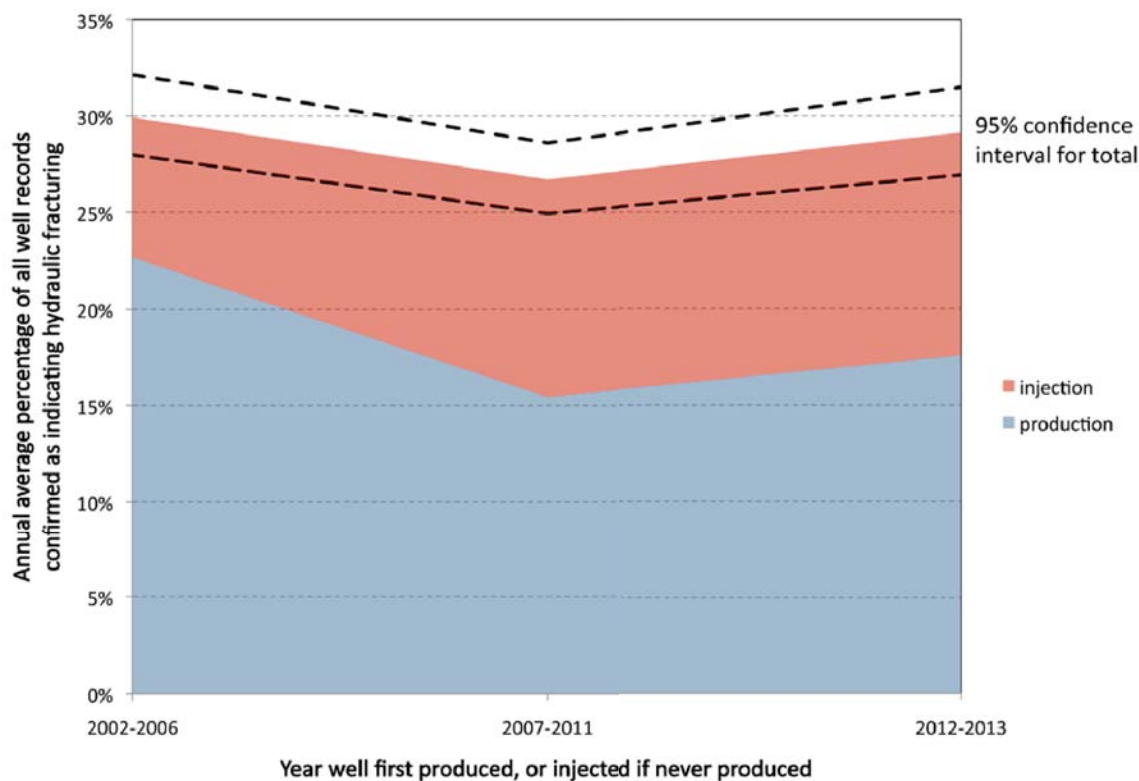
Figure 3-5. *Average annual number of well records confirmed as indicating hydraulic fracturing for wells first producing or injecting from 2002 to September 2013.*

Figure 3-6 plots the estimated annual average number of well records confirmed as indicating hydraulic fracturing in three basins, distinguishing between production and injection wells. These are the only basins that had more than one such record per year on average in each of the three periods assessed.

Figure 3-6(A) suggests the rate of recent hydraulic fracturing operations in production wells in the San Joaquin Basin has returned to, but not exceeded that experienced before the recession in 2008. This contrasts with the increasing number of hydraulically fractured production wells in many other parts of the country. Figure 3-6(A) also indicates an increase in fracturing of injection wells. In contrast the rate of injection well fracturing operations shown in the Los Angeles Basin, shown in Figure 3-6(B), and for the Ventura Basin, shown in Figure 3-6(C), remained more constant, while the rate of production well fracturing operations decreased significantly in the former and increased significantly in the latter.

To the extent the well records indicate the type of hydraulic fracturing fluid utilized, they typically indicate gels carrying proppant. The most prominent exception regards injection wells in Kern County. Most of these operations from 2002 to 2006 and over half from 2007 to 2011 are described as "water fracs." While other records typically indicate the use of proppant, and even the amount, records with the term "water frac" do not. The term and absence of notations regarding proppant suggest no proppant was used in these operations. It is less clear whether they utilized ungelled or gelled water. Records indicating the use of proppant are not consistent in noting the use of gel, even though gel is generally required to carry the proppant loads indicated. Almost none of the hydraulic fracturing operations in injection wells outside Kern County or within the County from 2012 to 2013 are described in the records as water fracs.

Box 3.1. Hydraulic Fracturing of Injection Wells Used for Enhanced Oil Recovery

Enhanced oil recovery (EOR) techniques typically involve modifying fluids in the reservoir to promote additional flow of oil to a well. In California, the most common EOR technique involves injection of steam and hot water to increase the temperature and pressure in the reservoir. The first lowers the viscosity of the oil and the second increases the force driving it to production wells. Hydraulic fracturing is not generally classed as an EOR technique because it alters the solids (rocks), rather than the fluids (oil, gas and water) in the reservoir, in order to increase the reservoir permeability. Hydraulic fracturing of injection wells can contribute to an EOR campaign by allowing more water or steam to be injected.
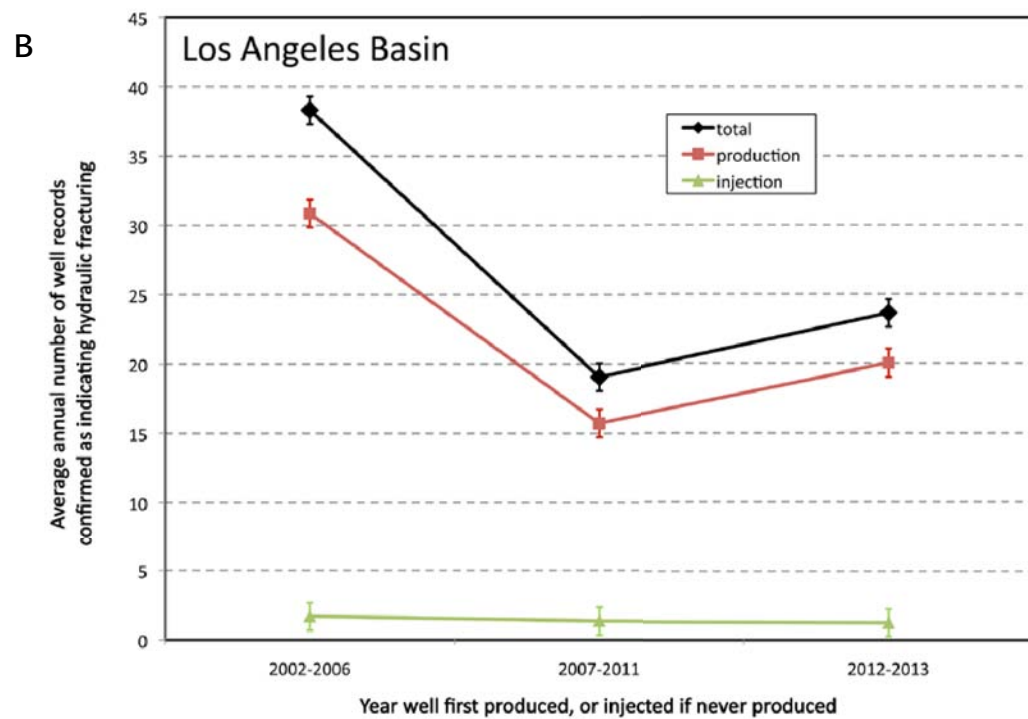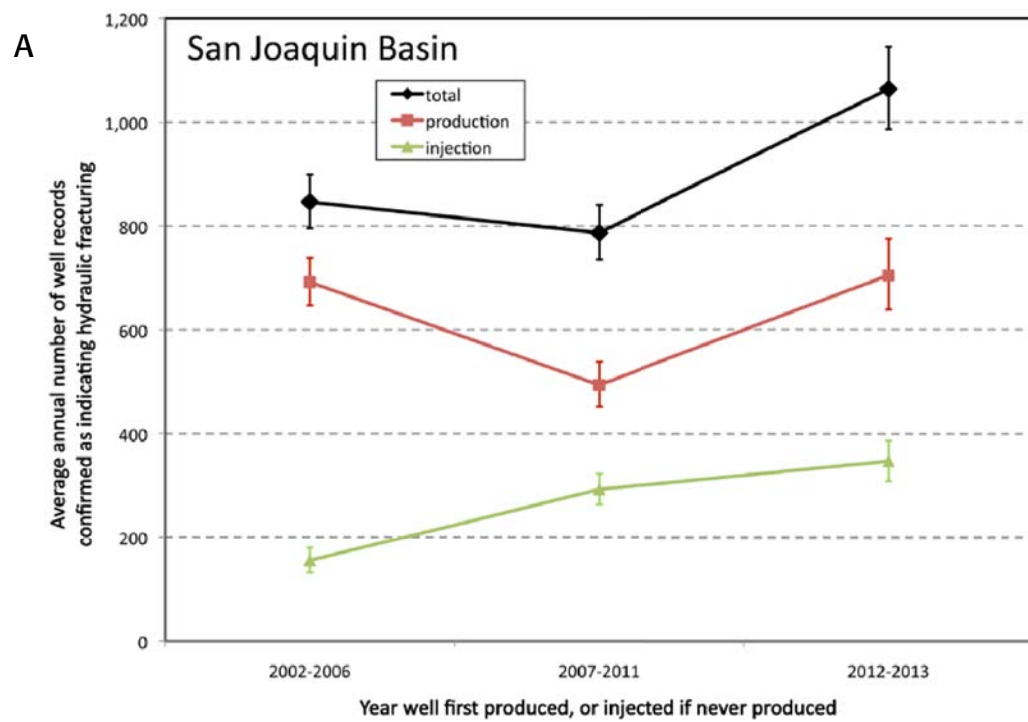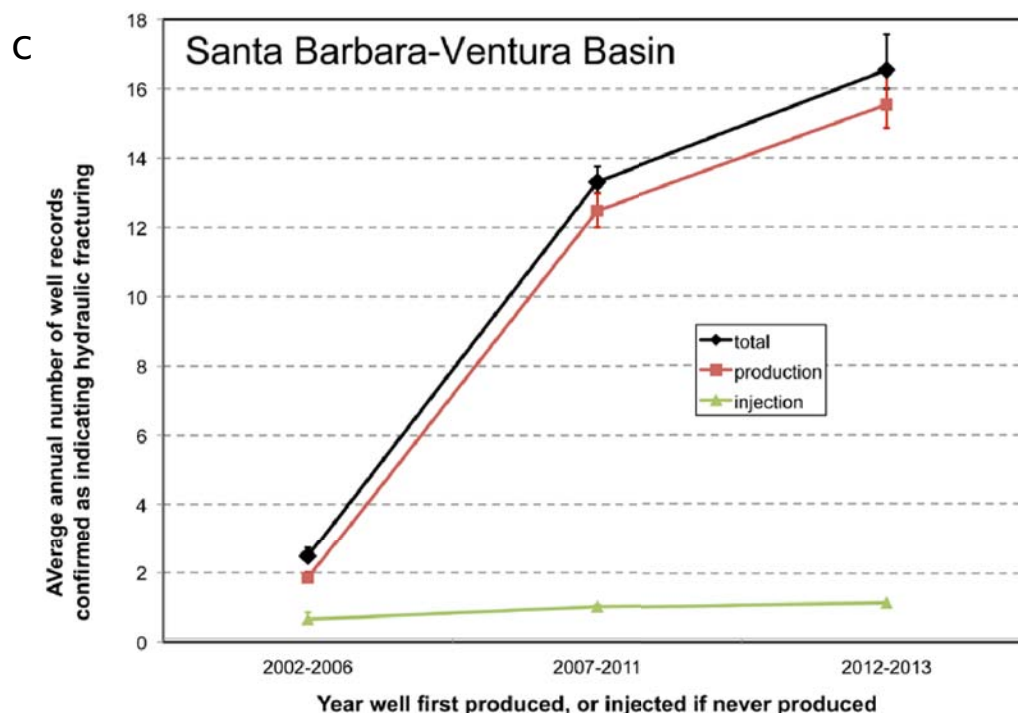
Figure 3-6. *Average annual number of well records confirmed as indicating hydraulic fracturing in the (A) San Joaquin, (B) Los Angeles, and (C) Santa Barbara-Ventura basins. The vertical bars indicate the 95% confidence interval. Note each graph has a different vertical scale.*

3.2.2.2. Historical Use of Hydraulic Fracturing Offshore in State and Federal Waters

As previously mentioned, California has jurisdiction over offshore activities in state waters (within three nautical miles of the coast). The federal government has jurisdiction beyond state waters, termed "federal waters." The Los Angeles, Santa Barbara-Ventura, Santa Maria, and Eel River basins extend offshore. There is no oil or gas production from wells in the offshore portion of the Eel River Basin. Between 2002 to September, 2013, hundreds of wells located in state waters of the Los Angeles Basin came into use. In this time period, fewer than twenty came into use in the state waters portion of the Santa Barbara/Ventura basin, and no wells with first production or injection were located in state waters in the Santa Maria Basin.

The only wells located in California waters with records confirmed as indicating hydraulic are in the Los Angeles Basin. Figure 3-7 shows the annual average number of such records for wells located onshore versus offshore. Figure 3-8 shows the location of all offshore facilities and those where hydraulic fracturing has occurred according to the well record

search. About 89% of the wells located offshore identified with hydraulic fracturing are in the Wilmington field, about 8% in the Belmont Offshore field, and 3% in the Huntington Beach field.

Approximately 12 hydraulic fracturing operations occur per year in wells located in the state waters portion of the Los Angeles Basin based on a search of well records. The State Lands Commission reviewed its files from 1994 to 2013 and provided an estimation of hydraulic fracturing operations to the California Coastal Commission also of about 12 hydraulic fracturing operations per year (November 22, 2013, email from Jennifer Luchesi, State Lands Commission, to Alison Dettmer, California Coastal Commission).

An analysis by the California Coastal Commission of records released by the Bureau of Safety and Environmental Enforcement (BSEE) in response to requests under the Freedom of Information Act identified 22 hydraulic fracturing operations and likely operations in federal waters, of which about a third were frac-packs. These occurred in 20 wells in federal waters. All but six of these occurred prior to 2004, most in the 1990s. One of the operations in federal waters was from Platform Hidalgo in the Point Arguello field in the Santa Maria Basin, two from platform Gail in the Sockeye field in the in the Santa Barbara-Ventura Basin, and the rest from platform Gilda in the Santa Clara field in the same basin. Half of all the hydraulic fracturing operations consisted of frac-packs. There was one hydraulic fracturing operation in each of 2010 and 2011 and another four planned for 2013, all in the Santa Barbara-Ventura Basin (Street, 2014).

From 1992 to 2009 (the most recent data available), over 250 new wells were installed in federal waters according to DOGGR's annual reports, which is an average of over ten per year. This suggests less than 10% of wells are hydraulically fractured in federal waters, including frac-packs, as compared to a third onshore. However, it is not known if the data upon which the activity estimate in federal waters is based is complete or if it under reports the frequency of hydraulic fracturing operations.
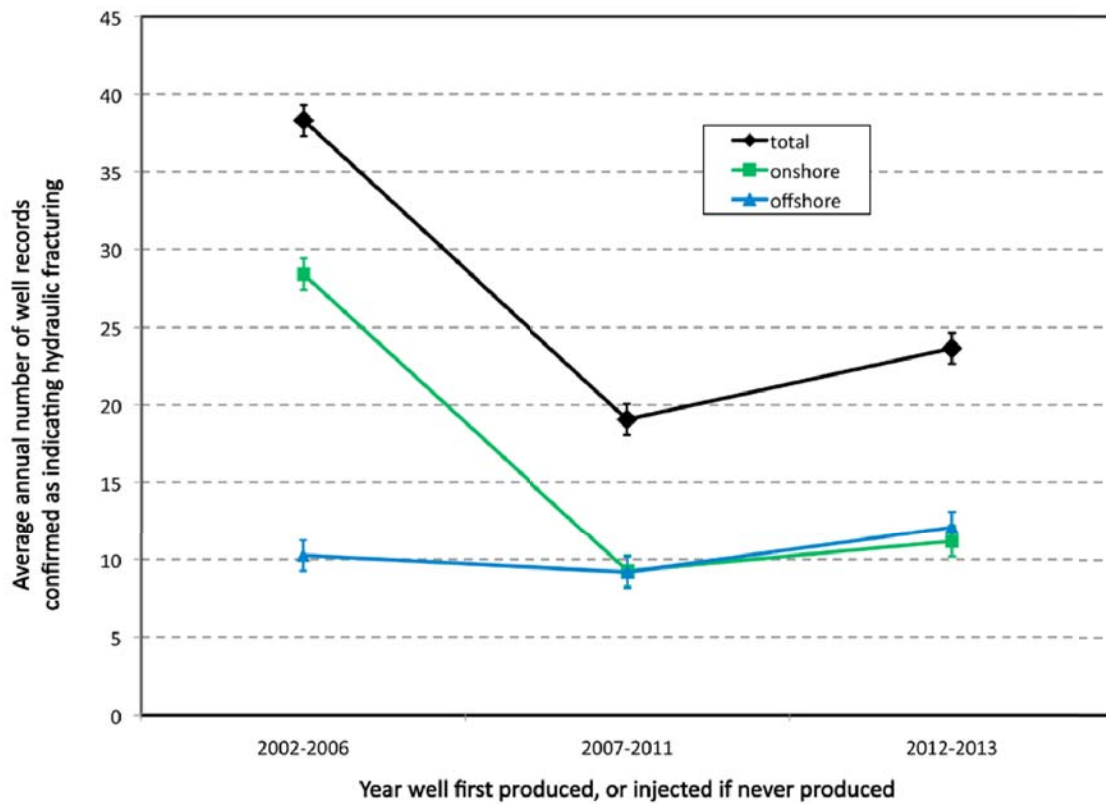
Figure 3-7. *Average annual number of well records confirmed as indicating hydraulic fracturing onshore and in California waters in the Los Angeles Basin. There is a 95% chance that if all the well records had been searched rather than a sample, the average annual number of well records confirmed as indicating hydraulic fracturing would be within the range indicated by the vertical bars.*

A

Santa Maria

Mussel Point
Point Sal

Purisima Point

Lompoc

7

Point Pedernales
Point Arguello
Rocky Point

(a)
(b)
(c)
8

Point Conception

Gaviota

Capitan
Naples

Coal Oil
Point
Goleta

Santa
Barbara

Summerland
Carpinteria
Rincon Point

Santa Paula

Pitas Point

Ventura

Oxnard

Port Hueneme

OFFSHORE PLATFORMS IN CALIFORNIA

FIELD	OPERATOR	PLATFORM
	State Leases	
1 Conception Offshore (Abd.)	DCOR	Harry (a) (removed)
	Texaco	Herman (b) (removed)
2 Cuarta Offshore (Abd.)	Texaco	Helen (removed)
3 South Elwood	Venoco	Holly
4 Summerland Offshore (Abd.)	Chevron	Hilda (a) (removed)
		Hazel (b) (removed)
5 Rincon	Rincon Island L.P.	Rincon Island (man-made island)
6 Carpinteria	**State-Federal Leases**	
	DCOR	Henry (a) (federal)
	POOLLC	Houchin (b) (federal)
	POOLLC	Hogan (c) (federal)
	Chevron	Hope (d) (state) (removed)
		Heidi (e) (state) (removed)

FIELD	OPERATOR	PLATFORM
7 Point Pedernales	**Federal OCS Leases**	
8 Point Arguello	PXP	Irene
	PXP	Hidalgo (a)
	PXP	Harvest (b)
	PXP	Hermosa (c)
9 Santa Ynez Unit		
Pescado	ExxonMobil	Heritage (a)
Hondo	ExxonMobil	Harmony (b)
Sacate*	ExxonMobil	Hondo (c)
10 Dos Cuadras	DCOR	A (a), B (b), C (c),
	DCOR	Hillhouse (d)
11 Pitas Point	DCOR	Habitat
12 Santa Clara Unit		
Santa Clara	Venoco	Grace (a)
	DCOR	Gilda (b)
Sockeye	Venoco	Gail (c)
13 Hueneme	DCOR	Gina
* Produced from Platform Heritage.		

FIELDS WITH SEAFLOOR COMPLETIONS IN STATE TIDELANDS AREAS

A Conception Offshore (Abd.)
B Alegria Offshore (Abd.)
C Caliente Offshore Gas (Abd.)
D Molino Offshore Gas (Abd.)
E South Elwood, Coal Oil Point Area (Abd.)
F Summerland Offshore (Abd.)
G Rincon

3 Nautical Miles

SANTA BARBARA CHANNEL

LEGEND

■ Offshore platform   ■ Offshore platform with hydraulic fracturing

□ Offshore platform removed

⊙ Seafloor completions

SCALE IN STATUTE MILES
0 1 2 3 4 5   10

PACIFIC OCEAN

Figure 3-8. *Offshore production facilities with and without hydraulic fracturing according to the well record search for facilities within three nautical miles of the coast ("state water") and Street (2014) for facilities further from the coast ("federal waters"): (A) Santa Maria and Santa Barbara-Ventura Basin; (B) Los Angeles Basin (modified from DOGGR, 2010).*

3.2.2.3. Historical Use of Frac-Packs

About one quarter and 1- 2% of recorded hydraulic fractures in the Los Angeles and San Joaquin basins are actually frac-packs, respectively. Of the frac-packs recorded, three quarters occurred in the Los Angeles Basin, and the other quarter in the San Joaquin Basin. All the frac-packs identified in state waters were in the offshore portion of the Wilmington field. Frac-packs comprised about 40% of all hydraulic fracturing operations in the offshore portion of this field from 2002 through 2011, and about 10% in 2012 and 2013. These were over half of the frac-packs identified in the Los Angeles Basin. Almost all the remaining frac-packs in the Los Angeles Basin were in the Inglewood field, which is onshore. About 5% of the operations in this field from 2002 to 2006 were described as frac-packs, but almost all of the operations since 2006 are described as frac-packs.

The values in Figures 3-2 through 3-6 do not represent an estimate of the total amount of hydraulic fracturing activity, however, because not all hydraulic fracturing jobs were recorded in the well records. The completeness of the results from the well record search is discussed further in the next section.

3.2.3. Recent Use of Hydraulic Fracturing Onshore and in State Waters

In March 2012, DOGGR sent a request to operators to voluntarily disclose hydraulic fracturing operations (Kustic, 2012). The number of operations subsequently disclosed per month increased significantly after April 2012. Starting in January 2014, operators were required by Senate Bill 4 (SB 4) of 2013 to provide notice ahead of hydraulic fracturing operations and disclosure afterwards starting in January 2014. The period after April 2012 is taken as recent.

There are eight sources of data regarding recent and pending hydraulic fracturing in California covering the period since May 2012 in whole or in part. In aggregate, these sources provide more complete coverage regarding hydraulic fracturing since early 2012 than do the well records alone. This section evaluates hydraulic fracturing operations during this period using a data set integrated from these sources, and considers the number of mandatory hydraulic fracturing notices submitted through August 2014. The data sources are listed below in the order of the accuracy of the date they provide for when a hydraulic fracturing operation occurred. The sources are described in more detail in Section 3.5:

1. Well stimulation completion reports (disclosures) (DOGGR, 2014a),

2. South Coast Air Quality Management District well work data (SCAQMD undated),

3. FracFocus,

4. FracFocus data compiled by SkyTruth (SkyTruth, 2013),

5. Well record search results combined with first production or injection date (described above),

6. Central Valley Regional Water Quality Control Board (CVRWQCB) well work data,

7. Geographic information system (GIS) well layer (DOGGR, 2014b),

8. Well stimulation notices (DOGGR undated a).

These data only regard hydraulic fracturing onshore and in state waters. The integrated data set from these sources is available as Appendix M.

An average of 300 wells per month started producing or injecting during 2012 to 2013. Analysis of the data sources listed above leads to an estimate of 125 to 175 wells hydraulically fractured per month. This indicates two- to three-fifths of all new wells are hydraulically fractured. These use approximately 530 m³ (140,000 gal) per operation on average. Most hydraulic fracturing occurs in wells that are less than 600 m deep.

3.2.3.1. Frequency

After approving 190 hydraulic fracturing notices submitted in December 2013, the number of notices approved by DOGGR decreased to zero from mid-January to mid-February 2014 and has since been increasing, as shown on Figure 3-9. The decrease occurred because DOGGR increased its groundwater monitoring plan requirements as of January 1, 2014 (Vincent Agusiegbe, DOGGR, personal communication). The number of notices submitted decreased while operators took time to comply with the new requirements.
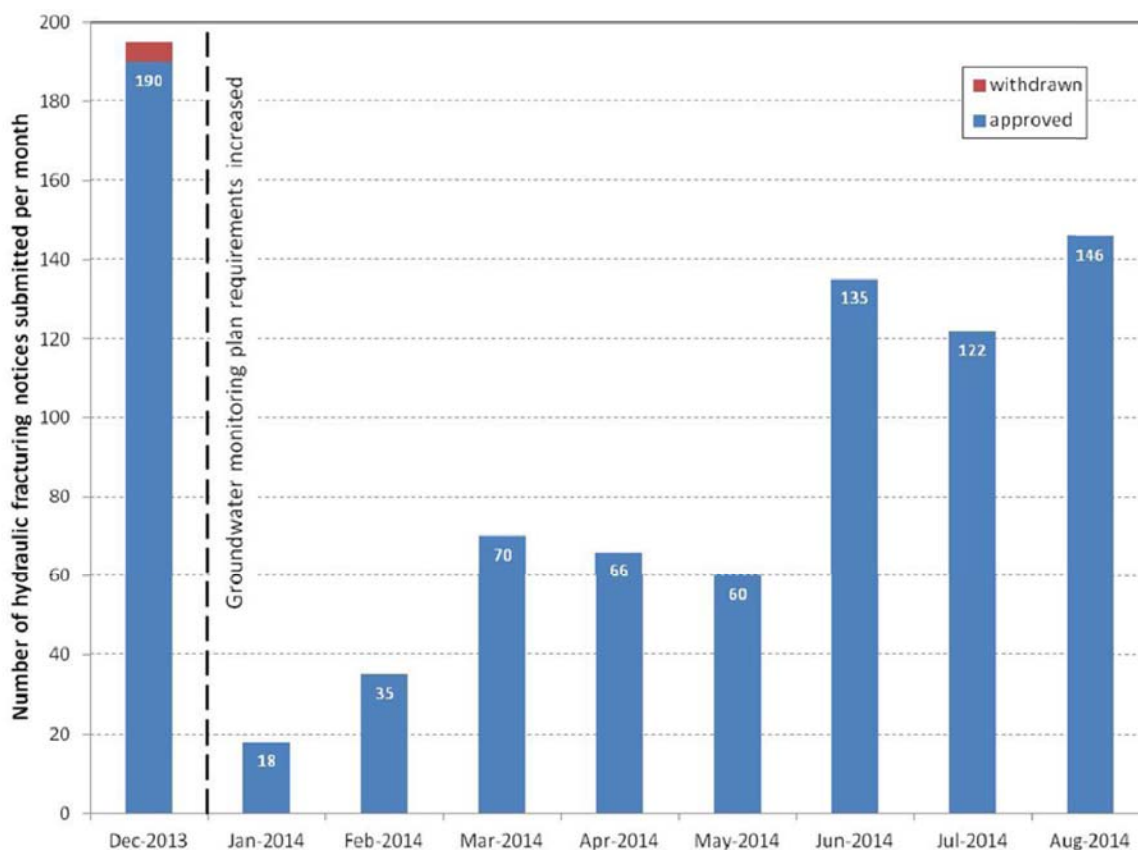
Figure 3-9. *Number of approved hydraulic fracturing notices by month received.*

The monthly average number of operations from the notices shown on Figure 3-10 is 93. Assuming this is representative of the long-term average implies the higher number of notices recently was the result of pent-up demand from the prior period. Alternatively, it could be that the 190 permit applications received in December 2013 is more representative of activity over the longer term as compliance with the new regulations becomes routine. Or it may be that operators submitted a larger than usual number of notices in December 2013, in anticipation of further requirements being implemented, and the higher values from June through August 2014 represent the likely long-term average of about 140 operations per month. Taking into account all these possible interpretations, the notices provide activity estimates ranging from 90 to 190 operations per month. It could be that many of those operations were displaced from months with low activity due to a decrease in activity while operators determined how to comply with the new requirements. In this case, the long-term average would be 90 operations per month.

Box 3.2. Recent hydraulic fracturing activity in gas production and offshore

No gas wells were identified as fractured in the integrated data set between May 2012 and September 2014. The integrated data imply a rate of 16 hydraulic fracturing operations per year offshore in California waters, all in the offshore portion of the Wilmington field. This suggests an estimate of one to two hydraulic fracturing operations per month in California waters. About one sixth of new production or injection wells in state waters were fractured. As mentioned, most of the frac-packs in the state have occurred in the Inglewood field and the offshore portion of the Wilmington field. About five per year occurred from 2012 through 2013 in the former, and one per year in the latter.

As described above, there are two known and four planned hydraulic fracturing operations from 2011 through 2013 in federal waters, all located in the Santa Barbara-Ventura Basin. This suggests an average annual rate of one to two wells hydraulically fractured per year. However, the completeness of the record set made available for searching by BSEE and the thoroughness of the search of those records by the California Coastal Commission are not known, so the actual level of activity could be higher.

Each of the eight available data sources uniquely identifies at least one hydraulic fracturing operation. Consequently, data from these sources were integrated toward developing an estimate of recent hydraulic fracturing activity in the state. The well-record data set discussed above provides this in part, but the goal of its development was to gain perspective on the relative change in hydraulic fracturing activity through time, rather than an absolute estimate of activity.

Integration of the data from the sources prior to 2014 provides a means for checking, and possibly constraining, the range of activity estimates from the notices required for hydraulic fracturing in 2014. The period chosen for analysis is from May 2012 through September 2013. This is the period of greatest overlap between and most comprehensive data among the seven other sources. The CVRWQCB data set covers 2012 and 2013. The number of hydraulically fractured wells reported to FracFocus increased sharply from April to May 2012, following DOGGR's notice to operators in March 2013 requesting voluntary disclosure. So May 2012 was selected as the beginning of the analysis period.

The wells whose records were chosen for searching were based on first production and injection dates that were complete through September 2013, so this was chosen as the end of the period. The SCAQMD data set coverage does not start until June 2013, but there are two-orders-of-magnitude fewer hydraulic fracturing operations in this data set compared to the others in aggregate. So the lack of coverage from May 2012 to May 2013 by this data source does not appreciably degrade the estimate of statewide hydraulic fracturing activity.

In order to determine the full set of operations represented by all the data sources in the time period, operations that occur in more than one source must only be counted once. There is no unique data field that can definitively relate records between the sets. For example, two records in the SCAQMD data set appear to refer to the same operation as one record in FracFocus.

The only data field available to relate records from the various sources is the API number. Using the API number to correlate data sources requires that there is only one instance of each API number in each data source, i.e., refracturing has not been recorded. Refractures are a small proportion of the total data, as discussed below, so this assumption introduces only a small error.

Figure 3-10 shows the average number of wells hydraulically fractured per month in total and according to different data sources, discounting possible refracture events. The overlaps as determined by API number are reflected in the overlap of the bars. The well-record search results contained 19% of the API numbers, which is 84% accounting for the sample proportion. This is the highest proportion of any of the data sources. DOGGR's GIS well layer contained 61% of the numbers, FracFocus 57%, and the CVRWQCB data 55%.
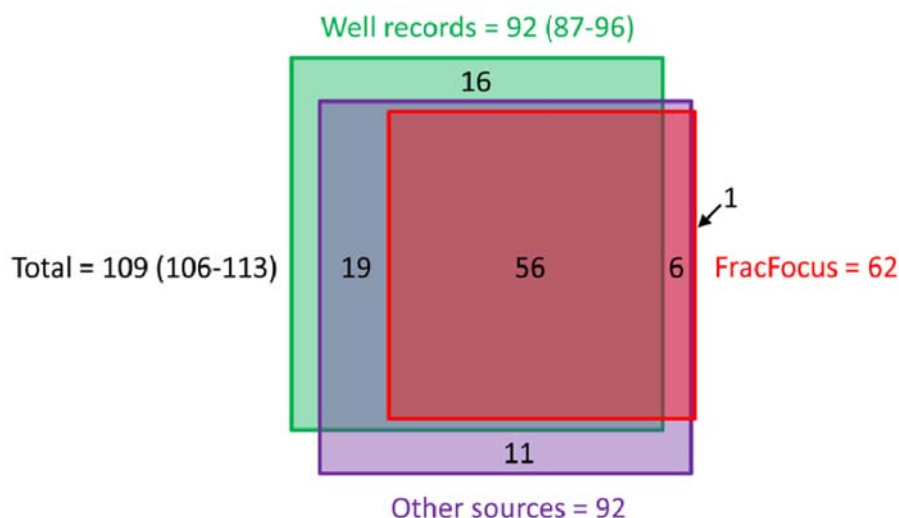
Figure 3-10. *Average number of wells hydraulically fractured per month between May 2012 and September 2013 in total and according to different data sources, discounting possible refracture events. Some values do not sum to the total shown due to rounding. "Other data sources" includes data from DOGGR's well attribute table, the SCAQMD, and the CVRWQCB. The range shown in parentheses for the total and well records is the 95% confidence interval resulting from the well record sampling.*

The analysis of the integrated data indicates fracturing of 109 wells per month, of which about 1.5 per month were offshore in state waters and the rest onshore. All of the offshore operations were in the Wilmington field on four engineered islands built for oil production a short distance offshore: Islands Chafee, Freeman, Grissom, and White, referred to collectively as the THUMS islands based on the partnership of companies that constructed them (Texaco, Humble, Union, Mobile and Shell).

The record of 109 wells fractured per month is based in part on voluntary and incomplete reports, the count of hydraulic fracturing notices received by DOGGR provides a check. The values in Figure 3-9 suggests the average number of notices submitted per month has been fewer than the likely long-term average. However, an average of 130 notices per month was submitted from June through August 2014, suggesting the longer term average may be equal to this amount. It may also be that the number of notices per month is still a bit below the long term average, due to continued compliance efforts with the new regulations by some operators. Given these considerations, for the purposes of this study, the estimated number of hydraulic fracturing operations per month in California is taken as 125 to 175. For comparison, FracFocus contains disclosures for an average of 2,000 operations per month for 2012 to 2013. This indicates less than a tenth of the operations

in the country occur in California. If the fraction of all operations disclosed to FracFocus nationally is similar to that in California during this time period, then less than a twentieth of the operations in the country occur in California.

3.2.3.2. Location

All of the data sources include information about the location of hydraulic fracturing. The well record search indicated 96% of hydraulic fracturing operations were in the San Joaquin Basin in 2012 through 2013. The integrated data set indicated the same percentage. The integrated data also indicated 93% of the operations in California were in fields on the west side of the Basin, with 85% in just the four fields of South and North Belridge, Lost Hills, and Elk Hills.

The oil or gas field where each well is located was taken, in order as available, from DOGGR's GIS well layer, FracFocus, or the well-completion reports. Table 3-1 shows fields with more than 1% of the estimated hydraulic fracturing operations in the state from the integrated data. (Note these estimates applied the county well-record sampling proportions to adjust the number of operations identified only in well records.) More than half of the operations occurred in South Buena Vista field. More than 85% of the operations occurred in the top four fields.

Table 3-1. *Oil and gas fields with more than 1% of the hydraulic fracturing operations in California based on the integrated data set.*

County	Field	% of CA	cumulative % of CA
Kern	Belridge, South	58.6%	58.6%
Kern	Lost Hills	12.7%	71.3%
Kern	Belridge, North	7.7%	78.9%
Kern	Elk Hills	6.4%	85.3%
Kern	Midway-Sunset	2.4%	87.7%
Fresno	Coalinga	1.8%	89.5%
Kern	Round Mountain	1.6%	91.1%
Kern	Buena Vista	1.3%	92.4%

The data sources along with the literature identify 96 fields with a record of hydraulic fracturing out of the 502 oil and gas fields with administrative boundaries mapped by DOGGR (2014c). Hydraulic fracturing was not identified in state waters in any fields in addition to those identified through the well records search, which were the Wilmington, Belmont Offshore and Huntington Beach. Figure 3-11 shows the location of these fields. Forty-four fields have a record of hydraulic fracturing occurring after 2011. This includes no gas fields, and only the Wilmington field for wells in state waters. None of the

data sources described above provides thorough identification of fields that have been hydraulically fractured, and it is unlikely that they provide such thorough identification in combination, so more fields have likely been hydraulically fractured than are shown in Figure 3-11.
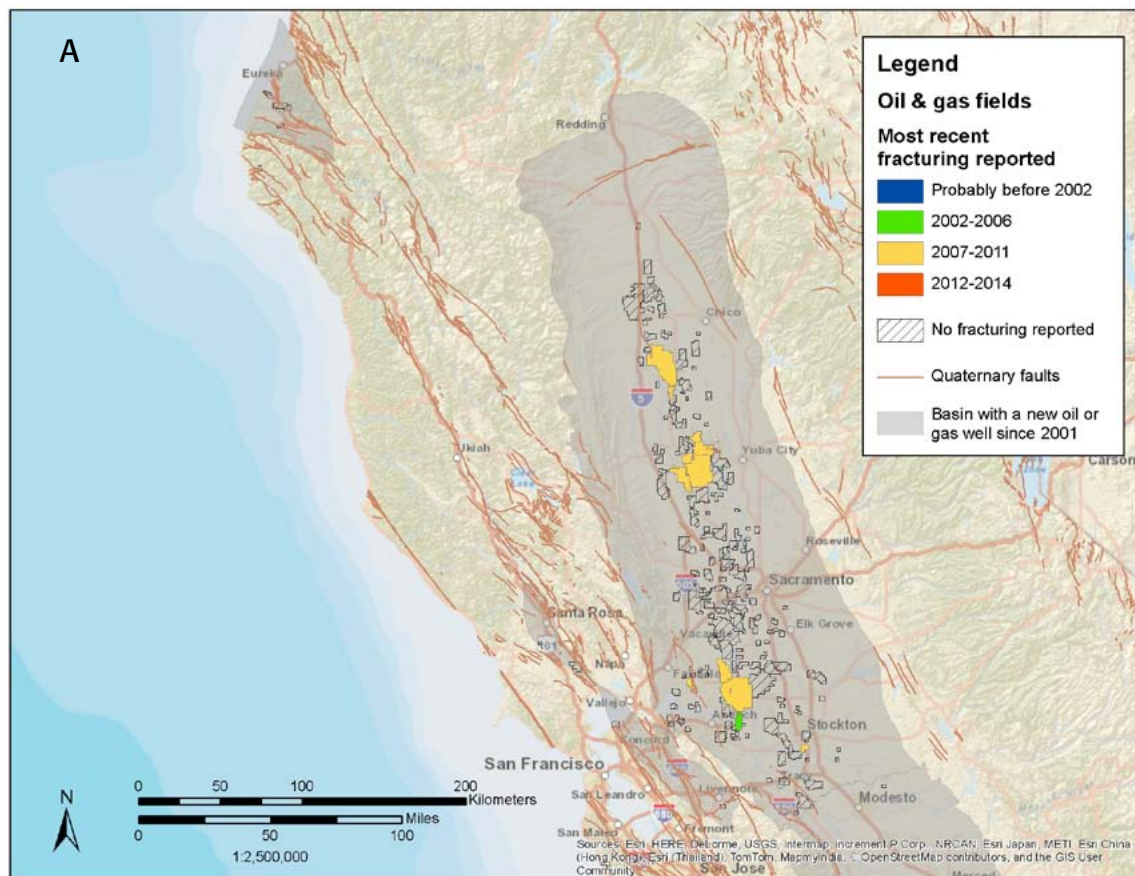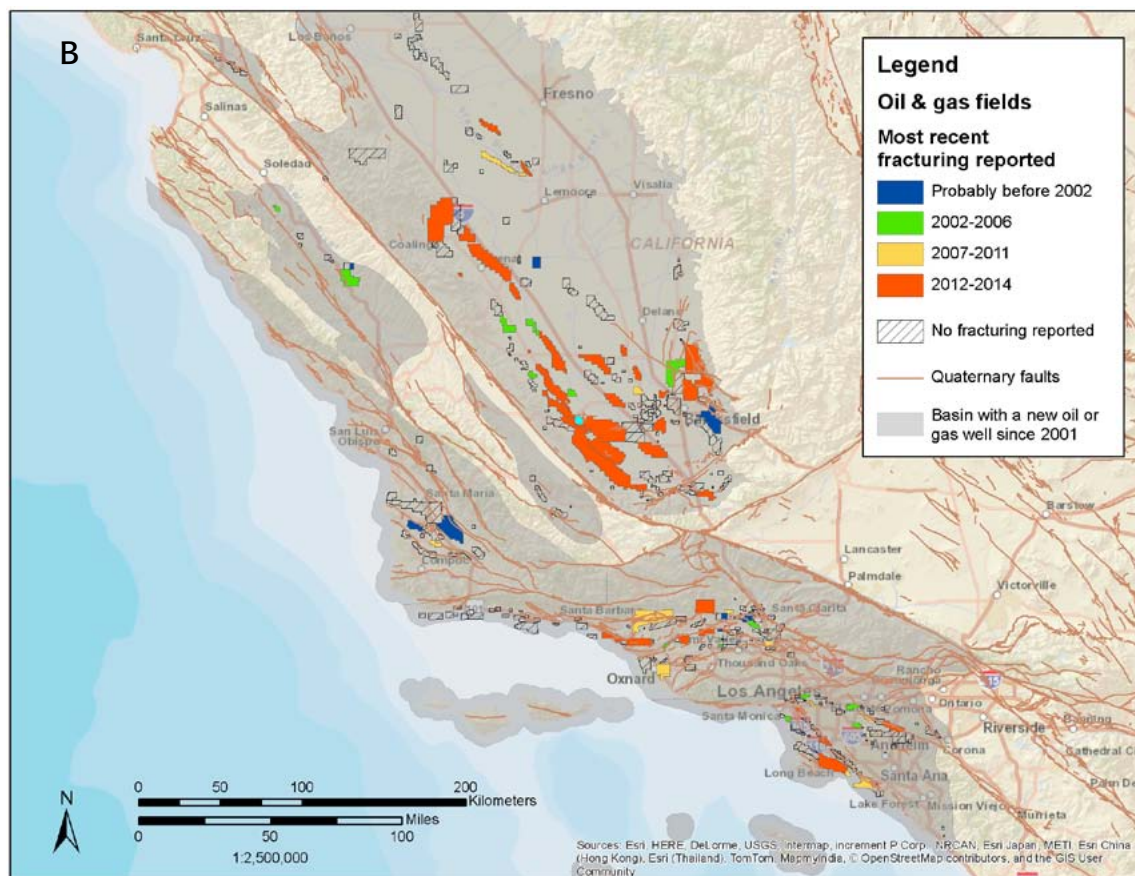
Figure 3-11. *Oil and gas fields with an administrative boundary defined by DOGGR (DOGGR, 2014b) and a record of hydraulic fracturing in (A) northern California, and (B) central and southern California.*

Figure 3-11 also shows the date of the last hydraulic fracturing operation in each field according to the available data sources.

3.2.3.3. Production

Sixty-eight reservoirs (pools) in which more than half of the wells commencing production or injection since 2001 are estimated to have been hydraulically fractured (including frac-packing) were identified from the well-record search results (listed in Appendix N). This analysis was based on the well-record search results because it was the most complete data set identifying hydraulically fractured wells, covered the longest time period, and was the only data set for which sampling statistics were available.

The 68 pools identified produced about a fifth of the oil and gas in California during the period. Figure 3-12 shows the distribution of this production by basin. Most of this was from the diatomite reservoirs in the North and South Belridge and Lost Hills fields and various reservoirs in the Elk Hills, Ventura, Inglewood, and North Shafter fields. About an eighth of the produced water generated in the state was from the 68 pools. The distribution of this water production by basin is shown on Figure 3-13.
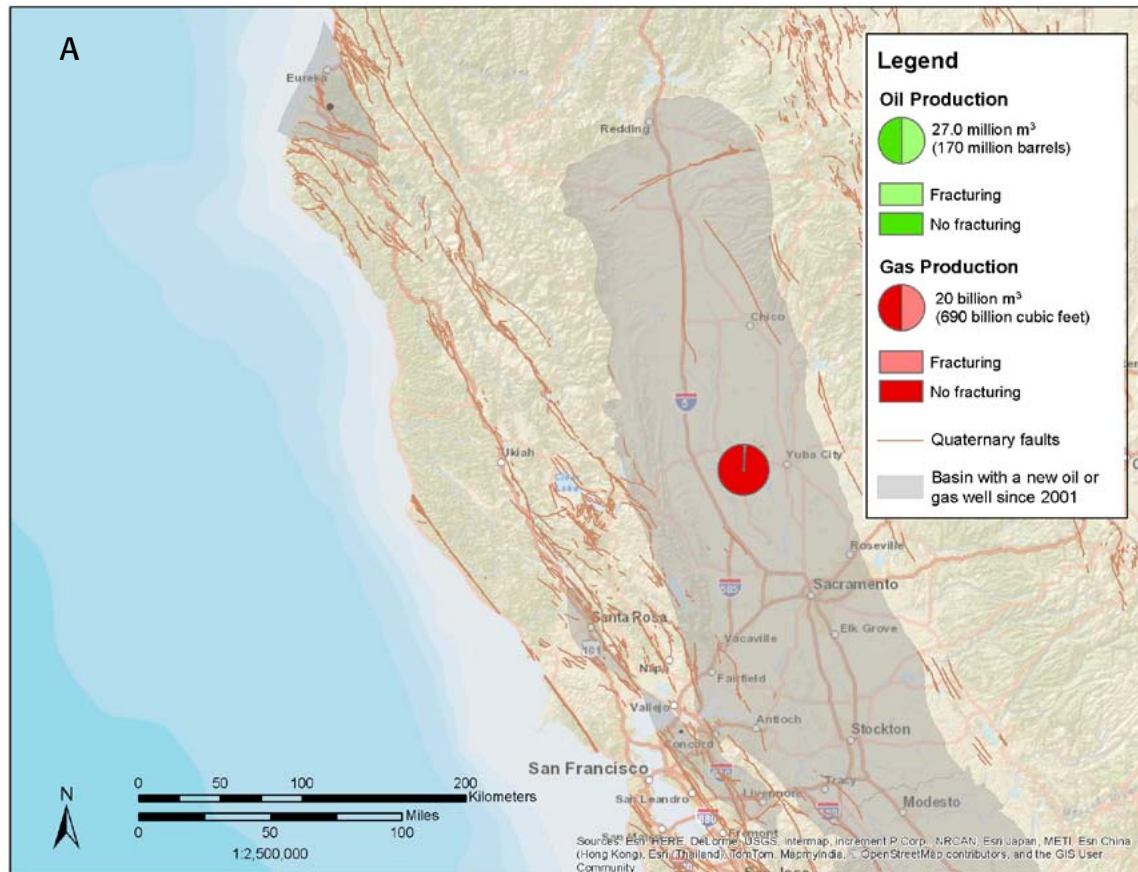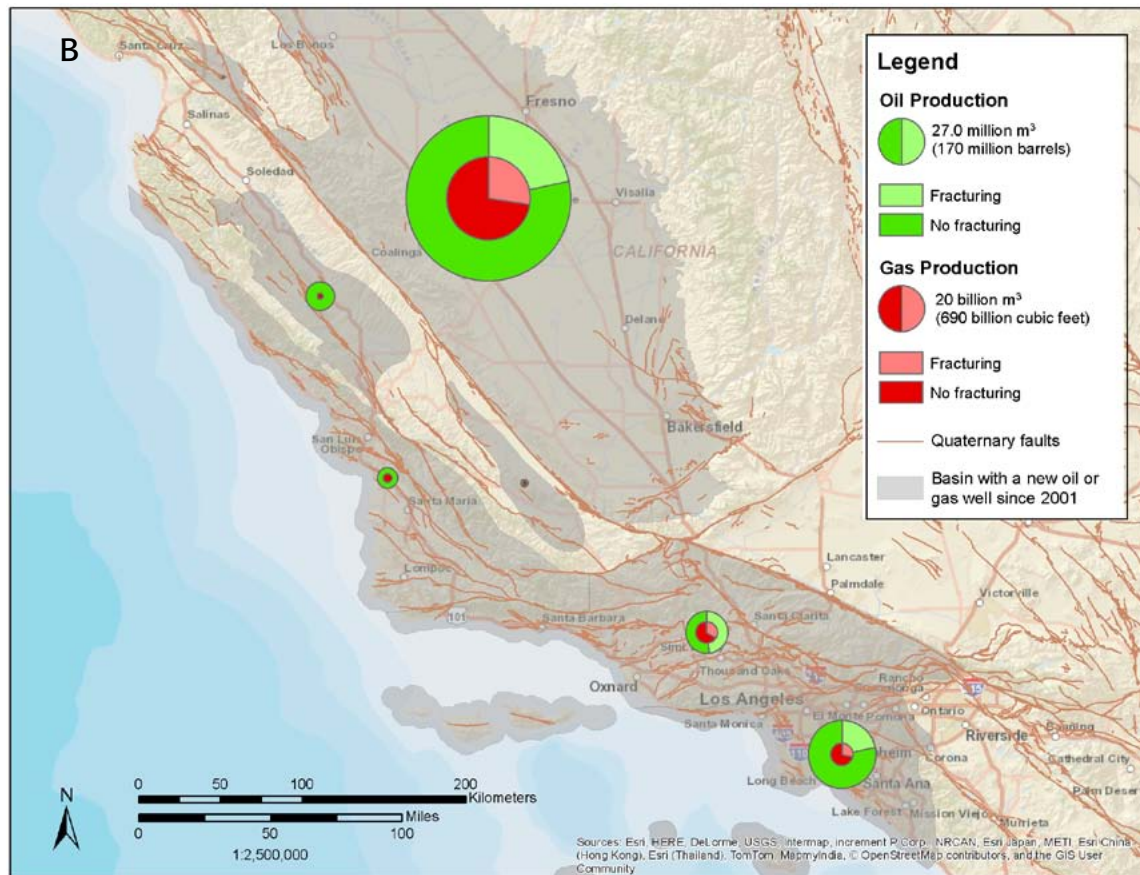
Figure 3-12. *Production of oil and gas with and without hydraulic fracturing in each basin with a new well since 2001 in (A) northern and (B) southern California from 2002 through May 2014. The area of each circle is proportional to the production volume in each basin.*
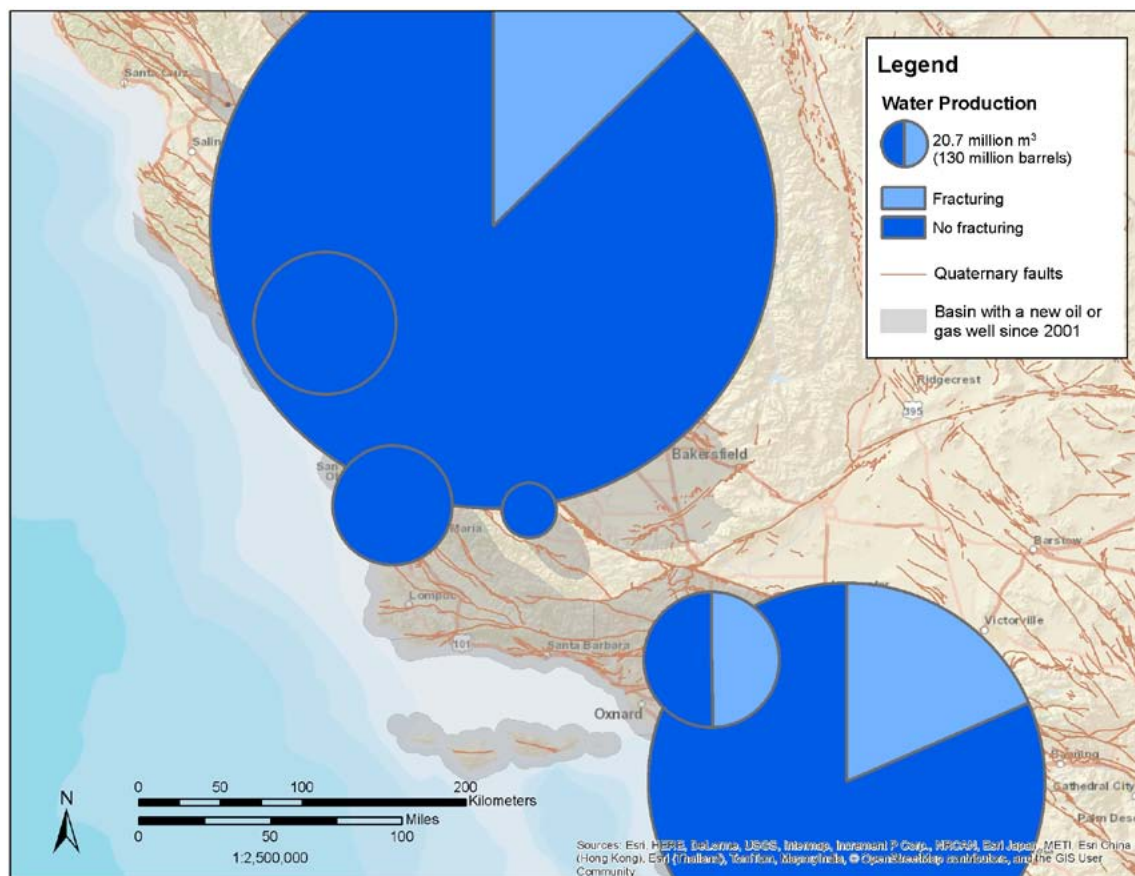
Figure 3-13. *Water produced with oil and gas with and without hydraulic fracturing in each basin with a new well since 2001 in southern California from 2002 through May 2014. Total water production in the northern California basins is smaller than the smallest water production in a single southern California basin. The area of each circle is proportional to the production volume in each basin.*

About 2% of all gas production in California was facilitated by hydraulic fracturing in pools identified as non-associated gas (dry gas)[3] by DOGGR. About 3% of all gas production in the state was facilitated by hydraulic fracturing in pools whose production meets the United States Energy Information Administration's (EIA) definition of a gas well.[4] The remaining gas production facilitated by hydraulic fracturing was from oil pools.

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3. Non-associated (dry) gas is produced from pools that do not also contain oil.

4. The EIA classifies wells producing more than 6,000 standard cubic feet of natural gas per barrel of oil produced as gas wells.

Hydraulic fracturing also facilitated seasonal storage of gas underground in some locations. Gas was stored in 11 pools near the major urban areas in California during all or some of the period since 2001. Gas is stored in the period of low gas demand, typically late spring through early fall, and produced during the period of high gas demand, typically late fall through early spring. This storage allows the construction of smaller long distance pipelines with a constant flow of gas toward the urban areas. Four pools (reservoirs) in which more than half of the wells commencing gas storage since 2001 are estimated to have been hydraulically fractured (including frac-packing) were identified from the well-record search results (listed in Appendix N). This analysis was based on the well-record search results because it was the only data set for which sampling statistics were available. The volume of gas pumped from all the storage in California since 2001 was about three quarters of the volume of new gas produced from natural reservoirs in the state. The four gas storage reservoirs where most new wells were hydraulically fractured provided about a third of the total gas storage in the state. Most of this storage is in southern California, as shown on Figure 3-14.
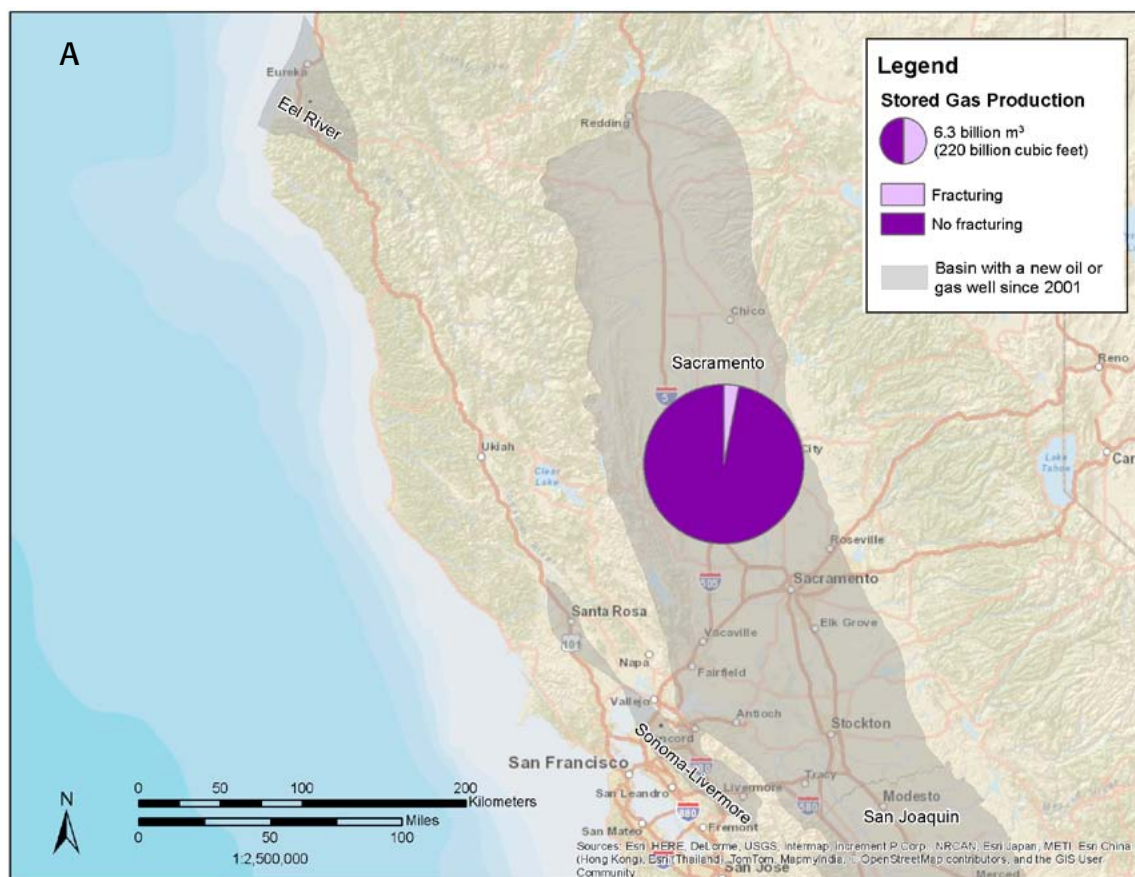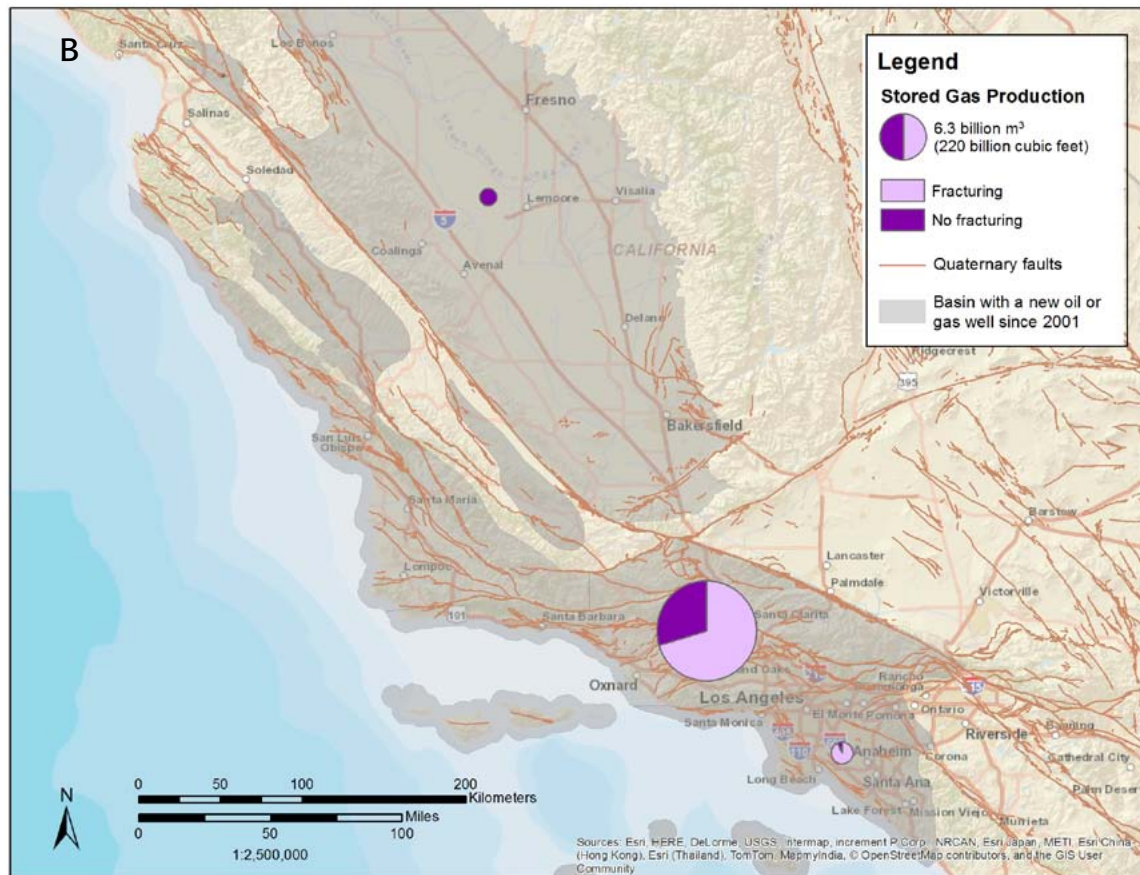
Figure 3-14. *Production of stored gas with and without hydraulic fracturing in each basin with a new well since 2001 in (A) northern and (B) southern California from 2002 through May 2014. Note that many of the basins do not have any gas storage facilities.The area of each circle is proportional to the production volume in each basin.*

3.2.3.3. Depth

Depths related to hydraulic fracturing operations are available from many of the data sources. The disclosures and notices provided to DOGGR list the true vertical depth of the top of the stimulated interval in the well. FracFocus and the data from the CVRWQCB do not include the depth to the top of the interval, but rather the true vertical depth of the well. DOGGR's GIS well layer provides the measured depth of the well. The histogram in Figure 3-15(A) shows the distribution of each of these types of depths for operations since 2011.

For operations with both a true vertical depth for the well and the top of the fractured interval, the interval top is 250 m (820 ft) shallower than the well depth on average, and 340 m (1,120 ft) shallower for 90% of the wells. For fractured wells with both true vertical depth and measured depth, the true depth is 220 m (720 ft) shallower on average and 600 m (1,970 ft) shallower for 90% of wells. These differences generally match the greater depth distribution for measured as compared to true well depth, and true well depth versus true depth of the top of the fractured interval on Figure 3-15(A).

Figure 3-15(B) shows that the small amount of hydraulic fracturing that has occurred in the Sacramento Basin has all been deep relative to operations in California in general. Figure 3-15(C) shows that shallow operations have occurred in many fields on both the west and east side of the San Joaquin Basin.

A
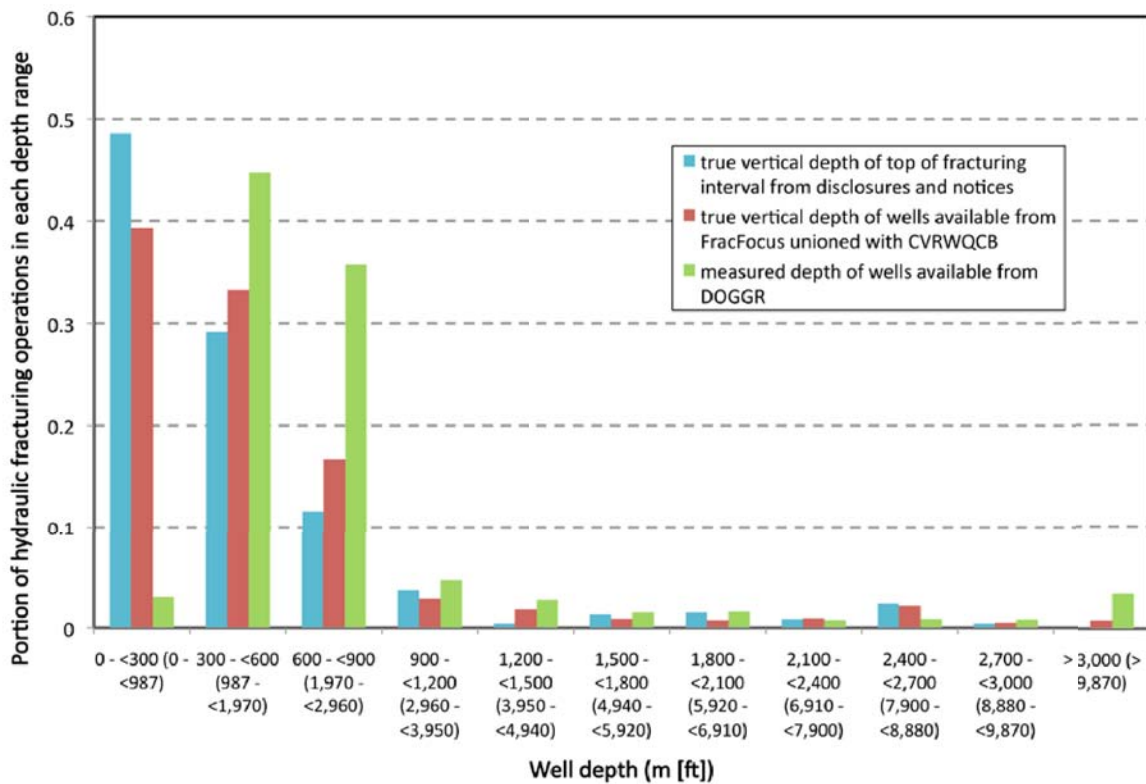
B
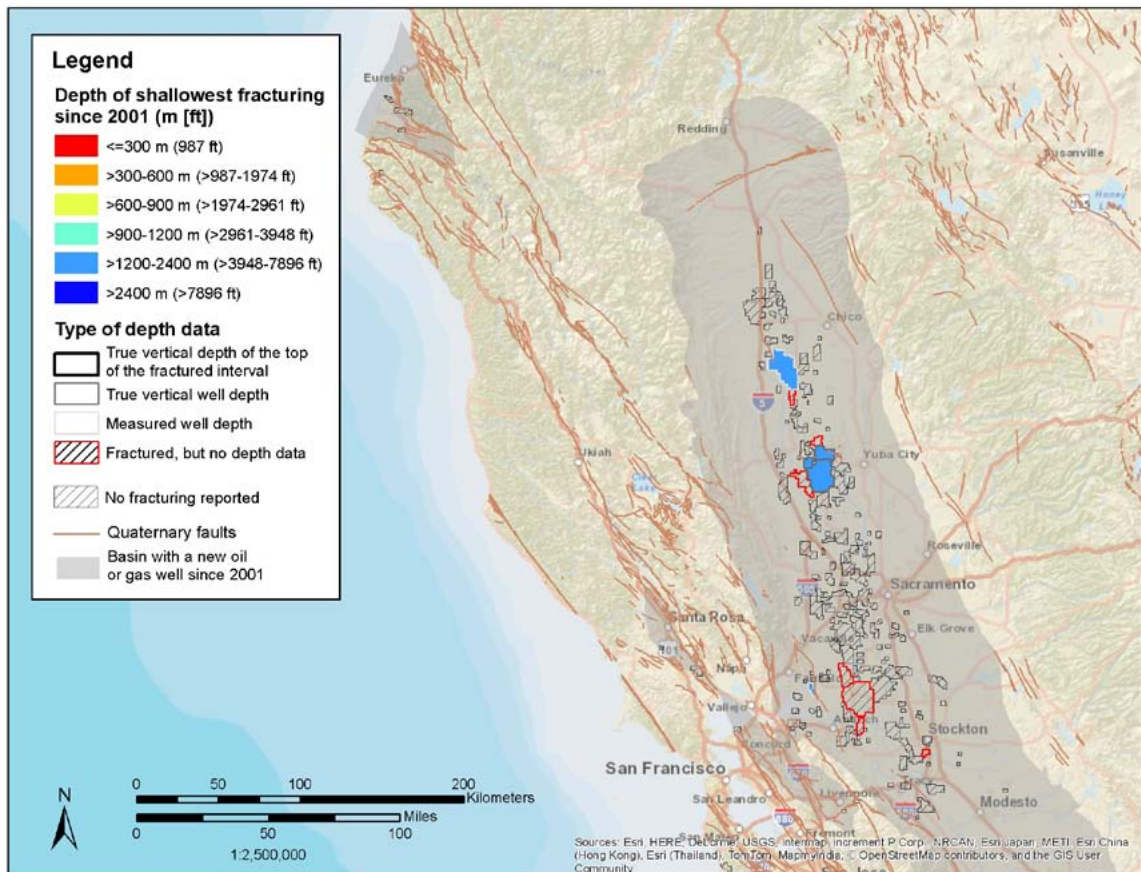
C
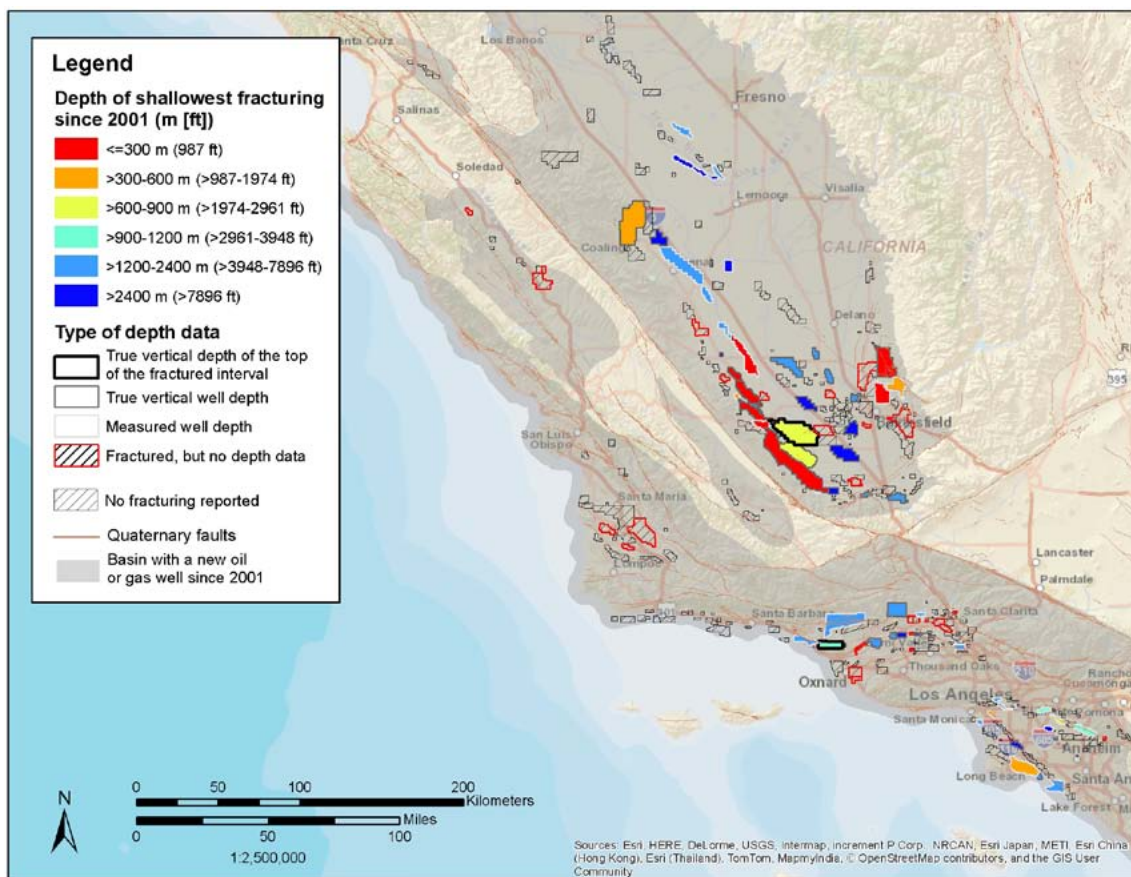
Figure 3-15. *Hydraulic fracturing depths: (A) histogram of various types of depths for operations since 2011, (B) minimum depth for operations in northern California, and (C) central and southern California. For most fields, only the depth of the well rather than the top of the treatment interval in the well is available, so stimulation may be shallower than implied.*

3.2.3.4. Refracturing

As discussed above, some of the data sources list more than one record per well, indicating hydraulic refracturing. It is not possible to definitively count such events across the data sources due to different data values, such as treatment date, and because of the potential for duplication among the different data sources used for this analysis. Consequently, a superset of records from all sources would overcount the number of refracturing operations. Educated guesses can be made regarding whether records from two data sources for the same well indicate one or two hydraulic fracturing operations. For instance, as discussed above, if the water volume for an operation in a well in two different data sources matches exactly, but the dates do not match, it is likely both records refer to the same operation. This type of judgment was also applied to construct the fluid volume per operations set discussed below.

Inspection of the individual data sources provides perspective on the upper limit for refracturing events. The CVRWQCB and SCAQMD data have more than one record for about 1% of the API numbers, and the FracFocus data for about 2%. The rate of refracturing is similar to the rate observed in other regions of the country, as discussed in the Chapter 2.

3.2.4. Fluid Type

Chemical constituents were available in the FracFocus data set for 1,623 onshore oil hydraulic fracturing operations as of June 2014. Guar gum, a gelling agent, was included in over 96% of the operations; borate compounds, which serve as crosslinkers, are included in 90% of the operations. In addition, 210 of the 213 hydraulic fracturing notices received by DOGGR before January 16, 2014, indicate the use of a gelled fluid based on the components listed. These data indicate that hydraulic fracturing in California is primarily performed with gels, and the gels are predominantly crosslinked.

Of the operations with chemical data, less than 4% included a friction reducer, indicating an operation involving slickwater fracturing. This includes all operations using acrylamide compounds, as well as those involving compounds with "friction reducer" listed as the purpose. Compounds with this purpose listed included petroleum distillates (which are likely a carrier fluid in an additive with another friction-reducing compound) and undisclosed constituents.

Operations using slickwater use more water than those which use gel. The average water volume for operations involving slickwater is 2,200 m^3 (590,000 gal), almost four times the average volume for all operations. The three largest volume events for which there is chemistry data from FracFocus (12,900, 13,600 and 16,700 m^3 [3.4, 3.6 and 4.4 million gal]) involved slickwater. There are three larger volume events, 16,700, 17,000, and 18,600 m^3 (4.4, 4.5, and 4.9 million gal), in the CVRWQCB data set, but no information about the type of fluid used.

3.2.5. Fluid Volume

Four of the data sources include information on the water volume used in hydraulic fracturing: FracFocus, CVRWQCB well work, SCAQMD well work, and the well stimulation disclosures. These were combined into a single data set. This resulted in a list of 1,760 events from 2011 through June 2014, included as Appendix O.

Table 3-2 provides statistics regarding the water volume used per operation. Average water use per hydraulic fracturing operation in California was 530 m^3 (140,000 gal). This is similar to the average annual water use of 580 m^3 (153,000 gal) in each household in California over the last decade. This is based on residential water use of 0.54 m^3 (143 gal) per person per day (Department of Water Resources, 2013) and an average household size of 2.93 people (US Census Bureau, 2014). However, water used for hydraulic fracturing

has a larger impact on water supply than water used domestically, because water used domestically may recharge to groundwater through a variety of pathways, while water used for hydraulic fracturing is often disposed of by deep injection.

Table 3-2. *Statistics on water use per operation for hydraulic fracturing treatments on oil wells in California.*

	m³	gal
Minimum	16	4,200
Median	280	75,000
Geometric Mean	310	82,000
Mean (average)	530	140,000
Maximum	18,400	4,860,000
Standard Deviation	1,000	280,000
Coefficient of Variation	2.0	
Coefficient of Skewness	10.4	
Number of Observations	1,760	

There is considerable variation in the water use per operation, as shown on Table 3-2 and Figure 3-16. The minimum water use was 16 m³ (4,200 gal) per well, and the maximum was 18,400 m³ (4.9 million gal) per operation, which is an over three-orders-of-magnitude difference. As a result, the coefficient of variation for these data is high (2.0), meaning that the standard deviation is larger than the mean, or that there is a large spread in the amount of water used.
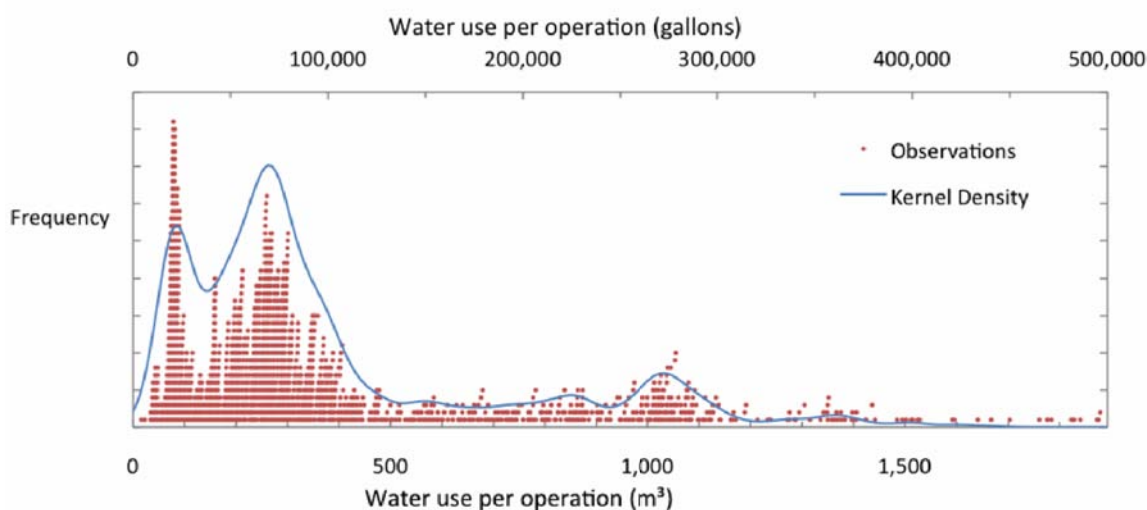
Figure 3-16. *Water use per hydraulic fracturing operation in California.*

In Figure 3-16, each dot represents a single fracturing operation. The overlay line represents the smoothed data density. Note that the bulk of the reported water use from 2011 to 2013 is below 275 m³ (100,000 gal) per operation. Among the observations of water use, 50% are between 280 and 560 m³ (48,000 to 150,000 gal) and 90% are from 80–1,100 m³ (22,000–280,000 gal).

Several high outliers are not shown on this graph. For example, 59 fracturing events had water use greater than 14,000 m³ (500,000 gal), of which about half are shown in Figure 3-16. In addition, there were 17 events over 3,800 m³ (1 million gal), and 3 events greater than 15,100 m³ (4 million) gal.

The data were examined to determine if relationships existed between water use and time, well depth, perforation length, region, or operator[5].

It does not appear there is a significant trend in water use over time as shown in Figures 3-16(A), suggesting volume of water used per operation has not changed significantly during the time period covered by the data. There are a few larger operations in late 2013, suggesting the possibility of an emerging change in practice. The results of these operations are discussed below toward understanding if they were sufficiently successful to suggest they are the leading edge of a change.

While previous work found that the volume of water used for hydraulic fracturing was not correlated with well depth or location (California Council on Science and Technology et al., 2014), re-analysis with updated records and a larger dataset indicates there is a weak but statistically significant relationship between water use and the total vertical depth of the well, as shown in Figure 3-17(B)[6]. There is no evidence for a relationship between the perforated length of the well casing (treatment interval) and water use, as shown in Figure 3-17(C). This is based on substantially less data than the other correlations considered, and so should be revisited in the future when more data are available.

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5. The water volume data were log-transformed to normalize them prior to analyzing these relationships, a standard procedure prior to regression analysis.

6. The correlation between water volume and depth explains about 36% of variance in water use; this relationship is statistically significant (P < 0.001).

A

Time

B

Vertical Depth
R² = 0.13

C

Perforation Length
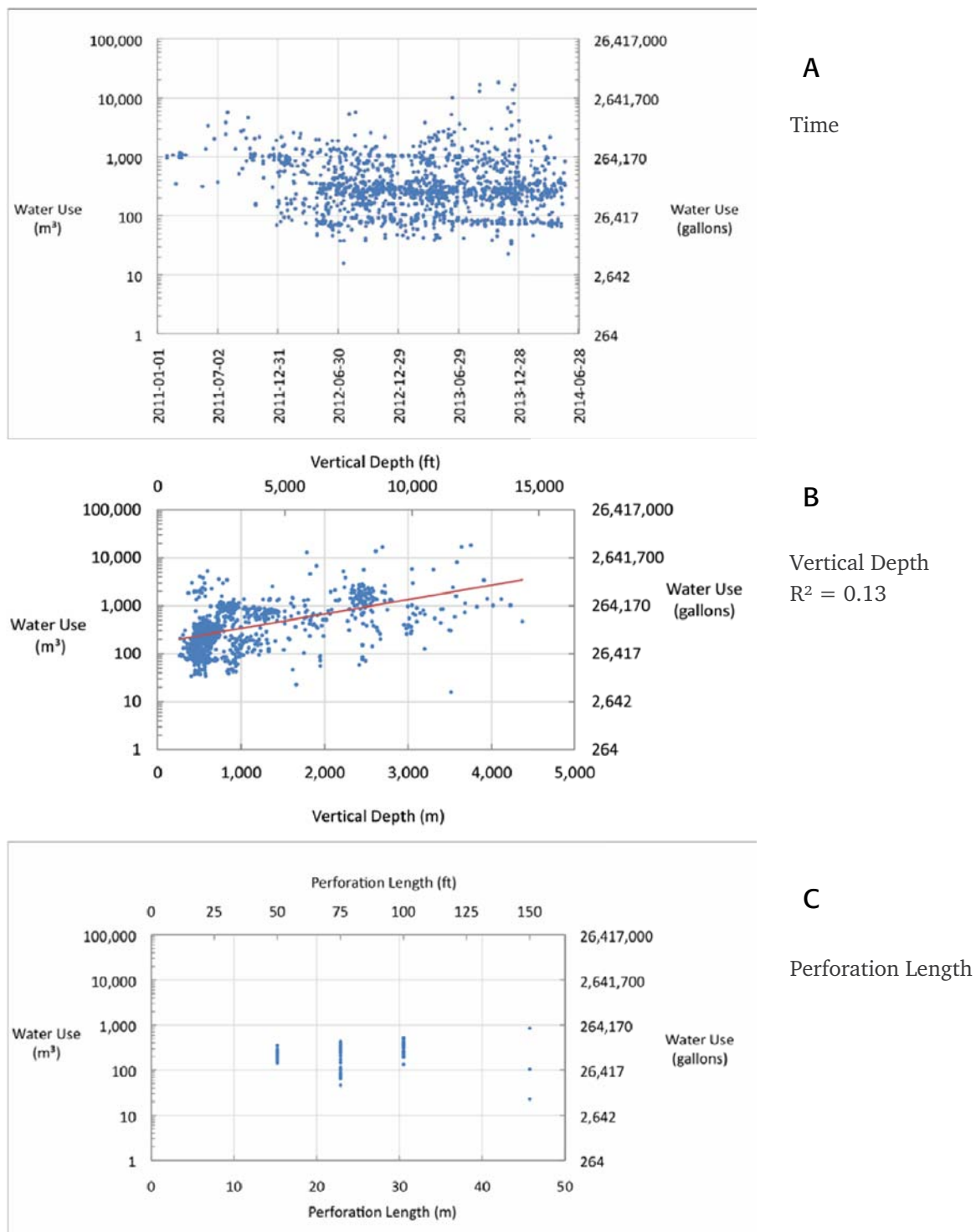
Figure 3-17. *Relationship between water volume used for hydraulic fracturing of oil wells in California and (A) time, (B) vertical well depth, and (C) perforation length.*

It was found that in California, as elsewhere, hydraulic fracturing operations in horizontal wells use more water on average than in directional and non-directional wells[7]. Average water use per operation for each well configuration is shown in Figure 3-18. Water use for operations in directional wells was insignificantly higher on average than for wells that were non-directional. Operations in horizontal wells use nearly three times more water than operations in other wells. Larger volumes of hydraulic fracturing water may correlate to larger production volumes. For instance, in 2013, fracturing of wells in the Rose field, which are all in the McClure Shale and generally horizontal, used about four times as much water per well as stimulation of vertical and near-vertical wells in diatomite in the North Belridge field. The Rose field produced about five times as much oil per well per day in 2013 as was produced from diatomite in the North Belridge field.
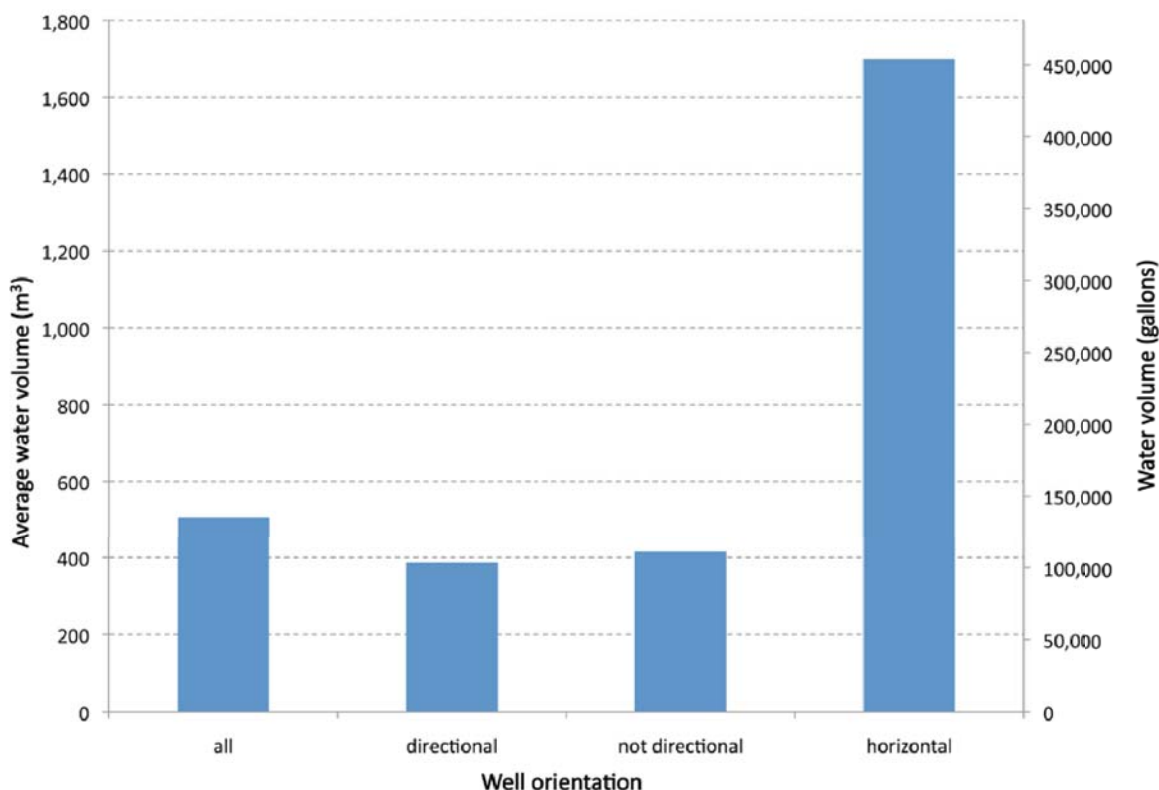
Figure 3-18. *Average volume of water for hydraulic fracturing operations in wells with different orientations. The averages for direction and non direction (vertical) wells are close to the overall average because there are few horizontal wells.*

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7. The DOGGR well database contained data on well configuration for a total of 1,136 wells that are also listed in FracFocus. It classifies wells as non-directional (DOGGR's term for vertical wells), directional or horizontal. Horizontal wells are nearly horizontal in the production interval. Directional wells deviate from vertical between the well pad and the reservoir but are typically near vertical in the production interval

The average volumes from both FracFocus and the notices for California hydraulic fracturing operations contrast with the average volume per operation of 16,000 m^3 (4.25 million gal) reported by Nicot and Scanlon (2012) for fracturing horizontal wells in the Eagle Ford in Texas. Figure 3-18 indicates part of this difference is caused by the predominance of hydraulic fracturing of vertical and directional wells in California, while horizontal wells are predominant in the Eagle Ford. Also, review of a small sample of directionally-drilled-well records indicates these wells are typically vertical or close to vertical through the producing zone. The well path usually deviates from vertical above the production zone in order to offset the location at which the well enters the producing zone relative to the well pad. The well records available from DOGGR for wells indicated as horizontal in DOGGR's GIS well layer and reported as hydraulic fractured were also examined. Only half of these wells are actually horizontal according to their well records. The average hydraulic fracturing water volume per operation in just these wells is 1,700 m^3 (410,000 gal). This volume is about one-tenth the average volume per well in the Eagle Ford.

Water-use intensity was calculated for the horizontal wells. The hydraulic fracturing treatment length is not available for these wells, so the intensity calculation used the distance between the shallowest and deepest production casing perforations listed in well records. This small data set contained a high outlier where the water-use intensity (water volume per well length stimulated) was 13 m^3/m (1,000 gal/ft). The average water-use intensity for these horizontal wells, excluding this high observation, is also given on Table 3-3. The perforated length explains about 40% of the variability in water use among the remaining operations. The comparison to average water use intensity in the Eagle Ford and Bakken on Table 3-3 indicates intensities in California are similar to gels in the Bakken, but considerably less than the average intensity in the Eagle Ford and slickwater in the Bakken.

Table 3-3. *Average water use intensity from hydraulic fracturing notices and FracFocus horizontal well disclosures compared to average intensity in the Eagle Ford (Nicot and Scanlon, 2012) and for different fluid types in the Bakken (described in section 2.4.8)*

	CA horizontal	Eagle Ford	Bakken		
			Crosslinked	Hybrid	Slickwater
			m³/m (gal/ft)		
Average intensity	2.3 (180)	9.5 (770)	3.4 (277)	3.9 (315)	13.2 (1063)

The water volume per hydraulic fracture operation was mapped to determine whether there are geographic patterns to water use. There are several apparent clusters of similar water use, as shown in the example in Figure 3-19. This figure shows XTO Energy/Exxon Mobil and Brietburn use more water per operation than does Area Energy LLC in its immediately adjacent operations.

The data indicate that the water volume used in each fracturing operation varies by company, and that the operator of a well is a more important predictor of water use than any other factor, as shown in Table 3-4. A statistical test (single factor or one-way ANOVA) among the ten companies with volumes for more than 10 hydraulically fractured wells was performed to evaluate the difference between the operators. There is evidence that Aera Energy, MacPherson, and LEC have a lower average water use than the other operators (P<0.001). This is consistent with the statement by Allan et al. (2010) that fracturing of diatomite has become relatively standardized within companies, but varies from company to company. Among the other large operators, the 95% confidence interval for the sample mean shows some overlap, indicating that we do not have sufficient evidence of a significant difference in water use among the top seven operators.
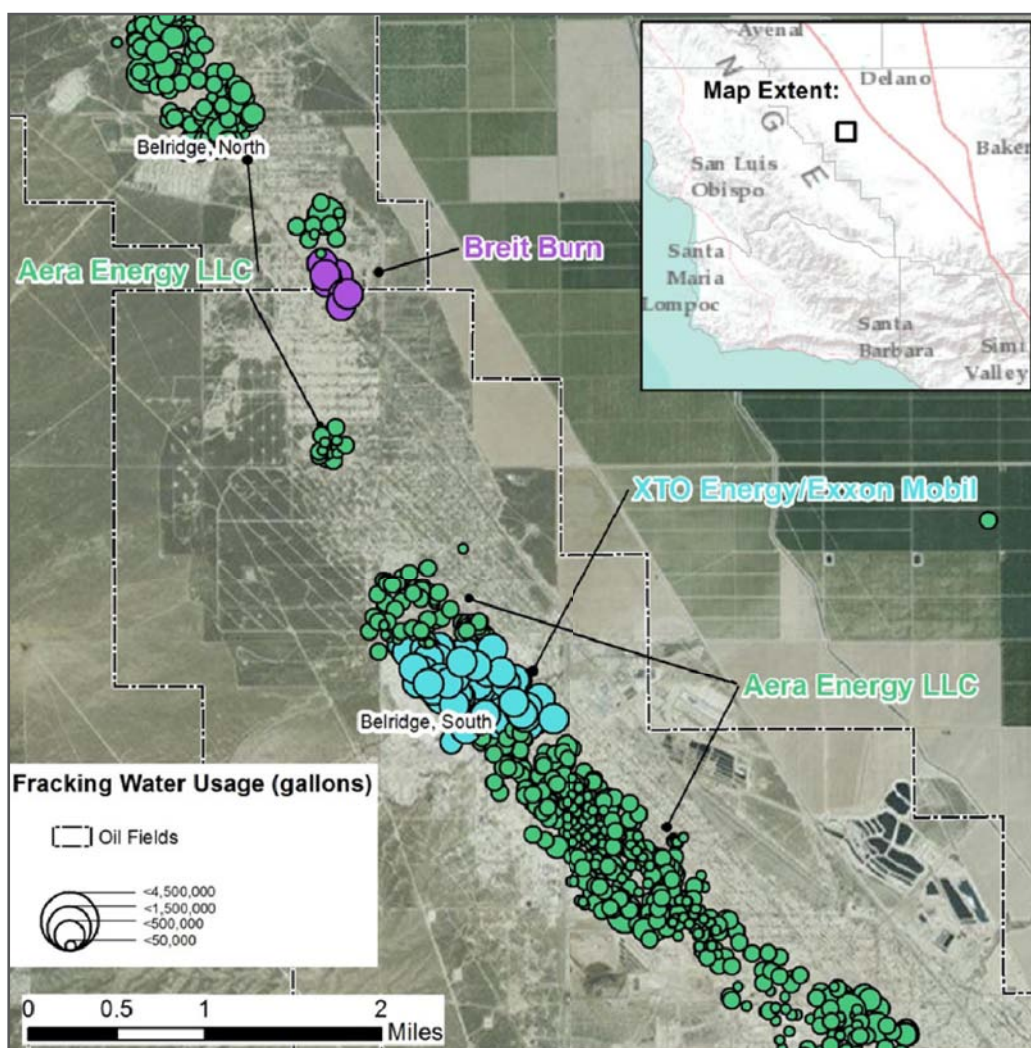
Figure 3-19. *Hydraulically fractured oil wells in the Belridge North and Belridge South fields in Kern County, California. The diameter of the point is proportional to the volume of water used in hydraulic fracturing.*

Table 3-4. *Water volume used per hydraulic fracturing operation per operator according to data for January, 2011, to May, 2014. Only operators with more than ten operations with water volume are included.*

Operator	Number of Reported Fractures	Average (m³)	Average (gal)	95% Confidence Interval for the Sample Mean (gal)		
Seneca Resources Corporation	18	182,000	600,000	230,000	–	970,000
ExxonMobil Production Company	10	85,000	280,000	270,000	–	280,000
XTO Energy/ExxonMobil	100	82,000	270,000	265,000	–	275,000
Chevron	60	82,000	270,000	210,000	–	320,000
Occidental Oil and Gas	322	76,000	250,000	210,000	–	290,000
BreitBurn	24	70,000	230,000	210,000	–	260,000
Occidental of Elk Hills Inc.	12	43,000	140,000	4,500	–	280,000
Aera Energy LLC	1,160	23,000	75,000	69,000	–	80,000
Macpherson Operating Company	26	10,300	34,000	30,000	–	39,000
LEC	13	7,000	23,000	17,000	–	30,000

There are only 19 records with well stimulation fluid volume in offshore waters. All 19 of these are hydraulic fractures listed in Frac Focus, while 6 are also listed in the SCAQMD data set. Occidental Oil and Gas conducted these 19 hydraulic fracturing operations on oil wells from February 2011 to December 2013, located in state waters in the Wilmington field in the Los Angeles Basin. The average water use for these 19 operations ranged from 110 to 800 m³ (30,000 to 210,000 gal), with a mean of 530 m³ (140,000 gal) and a standard deviation of 180 m³ (49,000 gal). This is the same mean as for all hydraulic fracturing operations in California.

3.2.6. Large-volume Fracturing Results

Data regarding oil production subsequent to the 13 of the 15 hydraulic fracturing events using more than 4,000 m³ (1,050,000 gal) of water were available from DOGGR's online production and injection database. Average daily production statistics by months on production is shown on Figure 3-20.
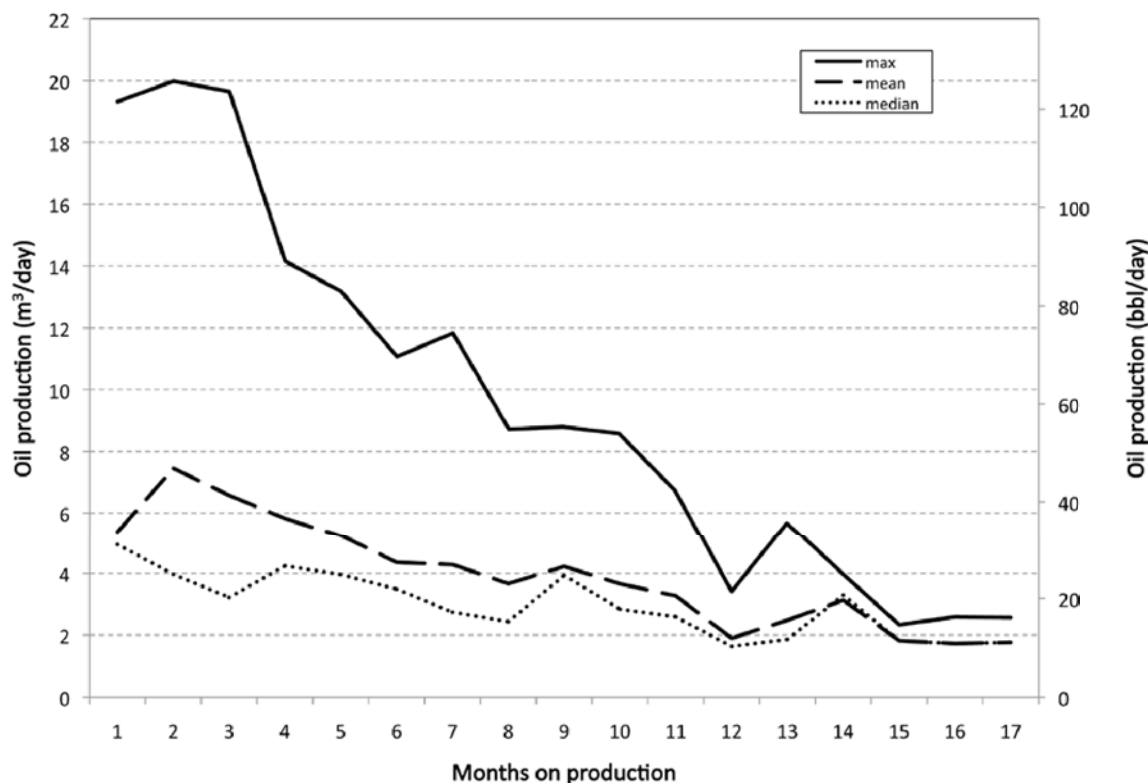
Figure 3-20. *Average daily production by months on production following hydraulic fracturing operations using more than 4,000 m³ (1,050,000 gal) of water.*

The maximum average daily production shown is the maximum among all the operations for that month. The maximum and the mean average daily production decline by about two-thirds in the first year. The three largest operations used over 16,000 m³ (4.25 million gal) of water. The two largest operations took place in the Kettleman Middle Dome field at depths of 3,650 m (12,000 ft) and greater in the Temblor and Kreyenhagen formations. The third largest occurred in the Elk Hills field in the Monterey Formation at a depth of 2,685 m (8835 ft). The first two operations using more than 4,000 m³ (1,050,000 gal) of water resulted in one of the largest daily average production rates recorded in California, but production declined over time. The Elk Hills operation resulted in near-mean oil production for all the operations using more than 4,000 m³ (1,050,000 gal) of water.

Average daily production per well in the Rose field provides a comparison. This field produces from horizontal wells hydraulically fractured with average fluid volumes containing about one quarter of the water of the average large volume operations. about half of the Rose field wells had been in production for more than five years as of 2013 and about a third for more than ten years. Yet, the average daily production per well in this

field in 2013 equals the mean initial daily production from the large volume hydraulically fractured wells shown on Figure 3-20, and is more than twice the mean daily production from those wells one year after their start of production. This indicates the high volume hydraulic fracturing conducted in the state has not been very efficient.

3.3. Acid Fracturing

No reports of the use of acid fracturing in California were found in the literature, but the well stimulation notices and the CVRWQCB data indicate a small amount of acid fracturing has occurred in the state. According to these data sources, operators used acid fracturing in fewer than 1% of reported well stimulations currently identified and noticed through May 2014 in California, all located in two fields in the southwestern San Joaquin Basin. This low level of activity is consistent with the fact that acid fracturing is generally used in carbonate (including dolomite) reservoirs, which are rare in California. A few carbonate reservoirs in California have been identified in some of the fields in the Santa Maria Basin and possibly the Los Angeles Basin (Ehrenberg and Nadeau, 2005). The fields consist of naturally fractured dolomite (Roehl and Weinbrandt, 1985). The dolomite reservoir in one of the fields in the Santa Maria Basin (West Cat Canyon) was characterized as producing oil from the natural fractures in dolomite, a type of carbonate, (Roehl and Weinbrandt, 1985) which means hydraulic fracturing is not likely to increase production.

DOGGR's notice forms only have one check box each for hydraulic fracturing and matrix acidizing. However, three hydraulic fracturing notices received from Occidental Petroleum by DOGGR on 31 December, 2013, indicate acid fracturing by specifying a sandstone matrix acidizing fluid without gel or friction reducers. The fluid components, including hydrochloric acid and ammonium biflouride, are the same as those listed on about half of the matrix acidizing notices submitted by Occidental and received by DOGGR on or before January 15, 2014. The planned stimulations are in the Elk Hills field at vertical depths ranging from 2,100 to 3,224 m (6,888 to 10,575 ft).

The estimated water volume for these three planned acid-fracturing stimulations ranges from 493 to 760 m^3 (130,000 to 200,000 gal). This is less than or almost equal to the average volume for hydraulic fracturing from the notices. Based on the top and bottom depth of the treatment interval listed, the water use per well length ranges from 0.60 to 0.74 m^3/m (48 to 72 gal/ft). This volume per treatment length is less than that from the matrix acidizing notices given in Section 3.4.3. This raises the question of whether the notices that indicate acid fracturing are actually matrix acidizing, with the wrong box checked on the notice. If these notices really do represent acid fracturing, the treatment volumes per treatment length suggest limited penetration into the reservoir. Another possibility is that the treatment is applied to only a portion of the well length implied by the top and bottom depth of the treatment interval listed on the notices, such as if multiple short intervals were treated within that depth range.

The CVRWQCB data set contained records of four acid fracturing operations, three in the Monument Junction field and one in the Mount Poso field from June 2012 to August 2012. The Mount Poso field operation has the same operator, date drilled and treated, treatment and discharge volume, and zone treated as one of the operations in the Monument Junction field. Further, the treatment horizon listed for the Mount Poso field operation does not exist. For all these reasons, it is likely the Mount Poso operation data are in error. The volume of fluid used for the Monument Junction field treatments ranged from 150 to 220 m³ (39,000 to 58,000 gal), with an average of 180 m³ (47,000 gal). This is considerably less than indicated on the three notices for the other operations, which could be consistent with operators overestimating water use on the notices, or could reflect a different treatment design.

No acid fracturing operations in California appear to be recorded in FracFocus. The highest concentration of hydrochloric acid in hydraulic fracturing fluid disclosed in this data set is less than 3.5%, and the highest concentration of hydrofluoric acid is less than 0.5%. These concentrations are too low to indicate an acid fracturing operation (Economides et al., 2013). In addition, most of the operations with greater than 1% hydrochloric acid in the hydraulic fracturing fluid also include guar gum and borate crosslinkers, indicating that the fluid was intended to carry proppant to hold the fracture open rather than use acid to etch the fracture walls. Four of these, along with the one operation without guar gum or borate crosslinkers, also included polyacrylamide or another component identified as a friction reducer, indicating a slickwater rather than acid fluid.

3.4. Matrix Acidizing

3.4.1. Historical Use of Matrix Acidizing

The use of sandstone matrix acidizing for well stimulation in the Monterey Formation is relatively recent. The first and most detailed report of production enhancement with sandstone acidizing is reported by McNabe et al. (1996) in the C/D shale in the Elk Hills field. These stimulations were to remediate plugging of small fractures by drilling mud invasion and subsequent scaling and oil emulsion blocks. High-volume sandstone acidizing of the "NA shale" in the same field was subsequently reported by Rowe et al. (2004). A series of 21 horizontal wells were drilled and stimulated between 1999 and 2001. The treatment process started from low-volume sandstone acidizing treatments, first using 0.0248 m³/m (2 gal/ft) of production interval with a 17% HCl acid. Diversion was accomplished by a mechanical method employing coiled tubing. Subsequent wells were treated with an increased volume of 0.35 m³/m (28 gal/ft). Apparent damage due to the water-based drilling mud led to drilling with an oil-based mud. Despite the use of a nondamaging mud, HCl acid treatments were effective for roughly doubling oil production. Subsequent wells were then treated with 17% HCl followed by a 12% HCl, 3% HF acid, with 0.256 m³/m (20.6 gal/ft) and 0.373 m³/m (30 gal/ft), respectively. Treatment volumes were increased to 1.86 m³/m (150 gal/ft) of the 12% HCl, 3% HF

acid, resulting in nine-fold oil production increases. Treatments were eventually tested with 3.1 m^3/m (250 gal/ft) of 17% HCl and 3.1 m^3/m (250 gal/ft) 12% HCl, 3% HF, which was found to be optimum. The reported recovery of spent acid from the formation was 50%, either by natural flowback or using nitrogen gas lift. Although fracture characterization was not presented, Rowe et al. (2004) concluded that the acidizing treatment must have resulted in the mitigation of drilling damage from natural fractures. While this is possible, the use of nondamaging drilling muds in some of the wells and the positive response to acidizing suggests that the treatment may also be opening up natural fractures plugged with some type of natural fracture-filling material.

The use of successful sandstone acidizing at Elk Hills is also reported by Trehan et al. (2012), who employed a high-rate injection (MAPDIR)/foam diversion approach to the acid treatment. The treatment was applied to intervals of 457 to 610 m (1,500 to 2,000 ft) in length. A foamed HCl/HF acid was successfully applied to producing wells in shallow sands with steam injection in the South Belridge field in the early 1990s as an improvement over previous sandstone acidizing with lower concentrations and volumes per treatment length in the same reservoir (Dominquez and Lawson, 1992). The more successful treatment used 1.9 m^3/m (150 gal/ft) of 15% HCl and 5% HF.

The possibility of successful high-volume sandstone acidizing treatment in naturally fractured siliceous shales is supported by Kalfayan (2008), who states, "There are few cases requiring greater volumes of HF than 1.86 to 2.48 m^3/m (150 to 200 gal/ft). These are limited to high-permeability, high-quartz sands and fractured formations, such as shales, where high volumes of acid can open fracture networks deeper in the formation." Similar conclusions were reached by Patton et al. (2003), who utilized sandstone acidizing for offshore production from the Monterey. The hypothesis for the improvement in production is that the HCl/HF treatment is effective at removing clay and chert from natural fractures and improving permeability of the fracture system. However, note that the injection volumes cited by Patton et al. (2003) are not large, only 0.248 m^3/m (20 gal/ft) for the 12%/3% HCl/HF acid.

A review of stimulation methods in the Monterey Formation by El Shaari et al. (2011) provides an alternative view that sandstone acidizing in the Monterey is effective at removing formation damage in fractures, but that good fracture-network permeability must exist naturally beyond the near-wellbore region if the treatment were to result in high oil production rates. For poorly fractured zones, such as at Elk Hills, El Shaari et al. (2011) postulate that either the treatment provides improved connection between the well and fractured calcareous intervals, or that the treatment in long production intervals characteristic of the Monterey, such as reported by Trehan et al. (2012), can significantly boost the overall magnitude of production, if not provide a large increase in the stimulation ratio.

A different acid system has been applied to the Stevens Sandstone in the North Coles Levee field in the early 1980s and continuing at least through the early 1990s (Hall et al., 1981; McClatchie et al., 2004). Termed "sequential hydrofluoric acid," the system involves alternating injection of HCl and ammonium fluoride. These react on clay surfaces producing HF, thus targeting the fine-grained material in the sandstone for dissolution. The HCl concentration used in these treatments was 5%. Typical treatment volumes were 36 m³ (9,750 gal). The typical treatment volume per well length was 0.44 m³/m (49 gal/ft). This treatment resulted in an approximately four times larger increase in production compared to stimulation with an HCl and HF mix (Marino and Underwood, 1990).

Another acid system for stimulation of a sandstone reservoir was applied in the Wilmington field, where almost all wells are acidized. Conventional acidizing with HCl and HF was found to increase production for only a few months. Phosphonic acid was applied experimentally in combination with HF. The purpose of the phosphonic acid was to preferentially combine with minerals containing aluminum in order to allow the HF to penetrate further into the formation and react preferentially with pure silicates minerals. The treatment was found to result in a similar production increase as treatment with HCl and HF, but with a much slower decline in production post-treatment.

3.4.2. Recent Use of Matrix Acidizing

The CVRWQCB data indicates 295 matrix acid treatments in the San Joaquin Basin in 2012 to 2013, for an average of 12 per month. Three out of four were in the Elk Hills field. The other fields were, in descending number of treatments, Buena Vista (17% of operations), Railroad Gap (5%), Asphalto (2%), and Midway-Sunset (1%), which are all located in the southwestern portion of the San Joaquin Basin. The location of the Elk Hills, Buena Vista, and Railroad Gap fields is shown on Figure 3-1.

A total of 25 notices were received by DOGGR and approved in the month from December 11, 2013, through January 12, 2014. No further notices were submitted as of June 2014. All notices were for operations in the Elk Hills field.

The SCAQMD data only reports one matrix acid treatment. No notice regarding this treatment was filed with DOGGR, though it took place in 2014. The total stimulation fluid volume was about 30 m³ (6,000 gal). This volume is generally too small for matrix acidizing and smaller than the fluid volume of most other treatments in the data set involving acid.

Matrix acidizing is reported to occur in California waters only occasionally, with the last event in 2011 (February 6, 2014, email from Chris Garner, Director, Long Beach Oil and Gas, to Joseph Street, California Energy Commission). There are five reports of matrix acidizing in US waters, with the earliest in 1988 and the most recent again in 2011 (Street, 2014).

Matrix acidizing is distinguished from maintenance acidizing by purpose. In contrast to matrix acidizing, the goal of maintenance acidizing is to restore reservoir permeability near the well that has been reduced due to invasion of drilling mud and other types of damage or remove scale (precipitates) that have formed in the well or in the reservoir near the well. In practice, these two treatments appear to exist in a continuum. This makes distinguishing them based on data difficult, as discussed further in Section 3.4.5. Consequently, there may be more matrix acidizing in practical effect than reported in the data sets considered above.

3.4.3. Fluid Volume

Based on CVRQCB data, observed water use for matrix acidizing of oil wells ranged from 5 to 1,900 m^3 (1,300 to 490,000 gal), with a median of 200 m^3 (54,000 gal) as shown on Table 3-5. The data are approximately log-normally distributed. Planned water use, as reported by operators in well stimulation notices, ranged from a low of 29 m^3 (7,600 gal) to a high of 550 m^3 (145,000 gal), and averaged 160 m^3 (42,000 gal).

Table 3-5. *Water volume used per matrix acidizing operation according to data for 2012 through 2014 from two sources.*

Source	Number	Minimum	Median	Average	Maximum
CVRWQCB Survey (2012-2013)	295	5 m^3	200 m^3	300 m^3	1,900 m^3
		1,260 gal	54,000 gal	79,000 gal	492,000 gal
DOGGR WST Notices (planned for 2014)	36	29 m^3	130 m^3	160 m^3	550 m^3
		7,600 gal	34,000 gal	42,000 gal	145,000 gal

As described above, operators tend to overstate their anticipated water use in the hydraulic fracturing notices, with actual water use being somewhat lower. This may also be the case for matrix acidizing. However, no disclosures for matrix acidizing treatments are available through June 2014. It is not known if no matrix acidizing treatments have occurred, or if they have but operators have not submitted data, or if the data has been submitted but not released by DOGGR pending quality control.

However, based on pre-stimulation notices filed by operators, longer treatment interval lengths are correlated with higher *planned* water use, as shown in Figure 3-21. There were only 9 paired observations of planned water use versus treatment interval, as most operators did not report both the minimum and maximum depth of planned stimulation. The average planned water-use intensity was 1.0 m^3/m (90 gal/ft), while the median was 0.5 m^3/m (40 gal/ft). As with hydraulic fracturing, operators may overstate their planned water use in well stimulation notices, so the values shown in Table 3-5 and Figure 3-21 may turn out to be overestimates of water-use intensity for matrix acidizing.
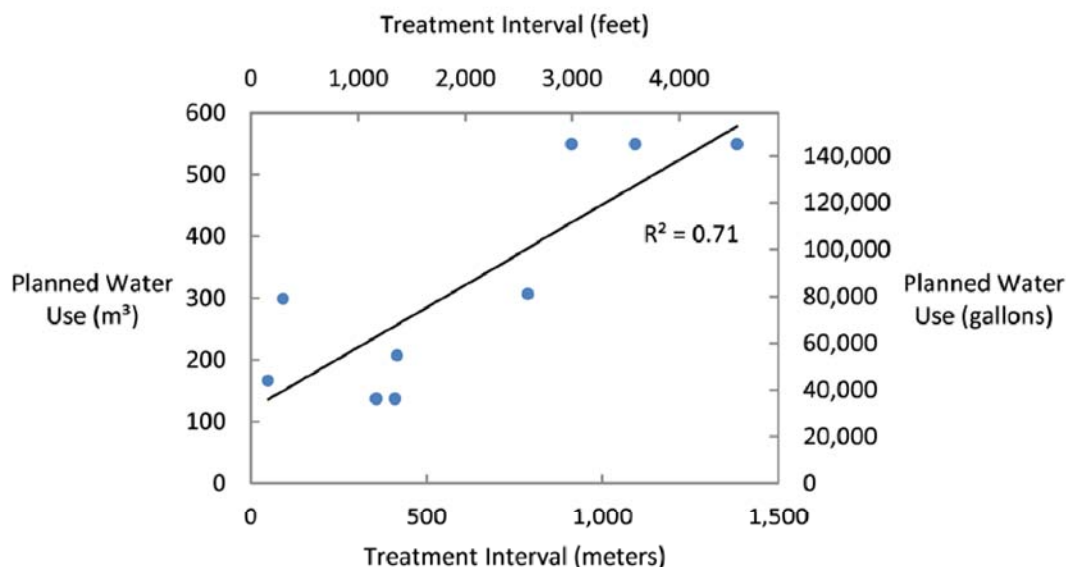
Figure 3-21. *Relationship between the perforation length or treatment interval and planned treatment water volume for matrix acidizing operations.*

3.4.4. Fluid Type

All the matrix-acidizing notices indicated the use of HCl. About half of the treatments included HF and half included ammonium biflouride. However, ammonium bifluoride produces HF acid when mixed with HCl acid (McClatchie et al., 2004).

3.4.5. Additional Operations in the SCAQMD Data?

Although the SCAQMD dataset only identifies one operation as matrix acidizing, the data regarding fluid volume and average acid concentration suggest there may be more matrix acidizing treatments that have not been identified as such. The volume and average acid concentration for treatments including HCl in the SCAQMD data set are shown on Figure 3-22. Section 1780, paragraph (a), of DOGGR's interim well stimulation regulations states the regulations "do not apply to acid matrix stimulation treatments that use an acid concentration of 7% or less." It is unclear if the concentration in this definition is averaged over the total fluid, including the pad and flush, or if it applies just to the acidizing phase. Figure 3-22 indicates there are treatments in 2014 that meet the 7% criterion even averaging over the entire fluid volume.

According to Section 1781, Paragraph (a) (1), of the interim regulations, "well stimulation treatment does not include routine well cleanout work; routine well maintenance; routine

treatment for the purpose of removal of formation damage due to drilling; bottom hole pressure surveys; routine activities that do not affect the integrity of the well or the formation; the removal of scale or precipitate from the perforations, casing, or tubing; or a treatment that does not penetrate into the formation more than 36 inches (in; 91 centimeters, cm) from the wellbore." It may be that none of the operations in 2014 using a greater than 7% acid concentration is well stimulation according to this definition.
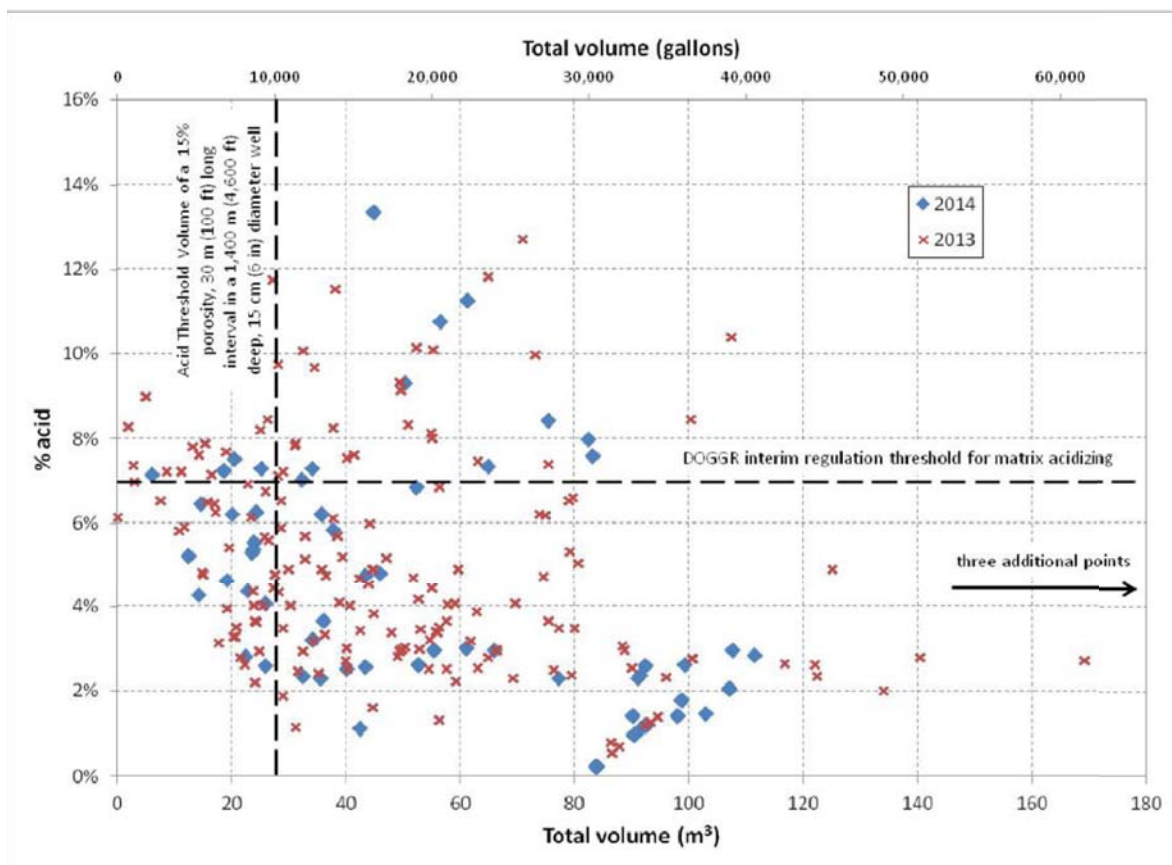
Figure 3-22. *Average acid concentration versus total fluid volume for treatments involving hydrochloric acid in the SCAQMD data set.*

There are 20 treatments per month involving hydrochloric acid in the SCAQMD data set, which is equivalent to the number of wells first producing or injecting each month. DOGGR's draft final regulations define any treatment injecting a volume of acid that would fill the reservoir pore space more than 0.9 m (3 ft) around the well as matrix acidizing. For comparison, the treatment volume for a 1,400 m (4,600 ft) deep, 15 cm (6 in) diameter well with a 30 m (100 ft) long treatment interval in a 15% porosity reservoir is about 27 m³ (10,000 gal). More than half of the treatments with hydrochloric acid in

the SCAQMD data, or 11 per month, have a volume above this threshold and greater than 1% acid concentration. This is equivalent to more than half the wells first producing, or first injecting if never producing, per month.

It is unclear how many operations will be classified as matrix acidizing under the final regulations compared to the current regulations. Figure 3-23 compares the fluid volume distribution of matrix acidizing volumes in the CVRWQCB data set and DOGGR notices to the distribution of treatment volumes containing HCl in the SCAQMD data. While the distribution of SCAQMD volumes is narrower and has a smaller mean and median that the other distributions, it entirely overlaps the low end of the CVRWQCB distribution and mostly overlaps the low end of the DOGGR notice distribution. This suggests a portion of the SCAQMD operations represent matrix acidizing, and also indicates that it is difficult to distinguish matrix acidizing from other acidizing operations based on volume alone.

C
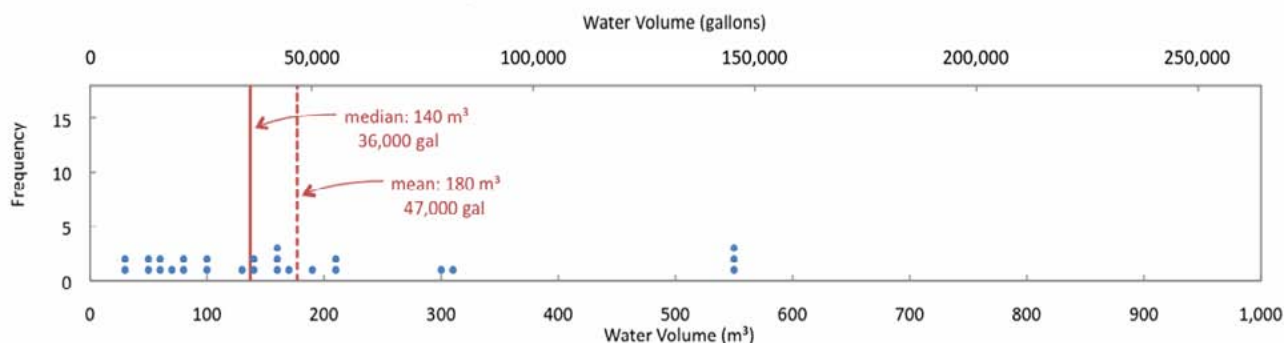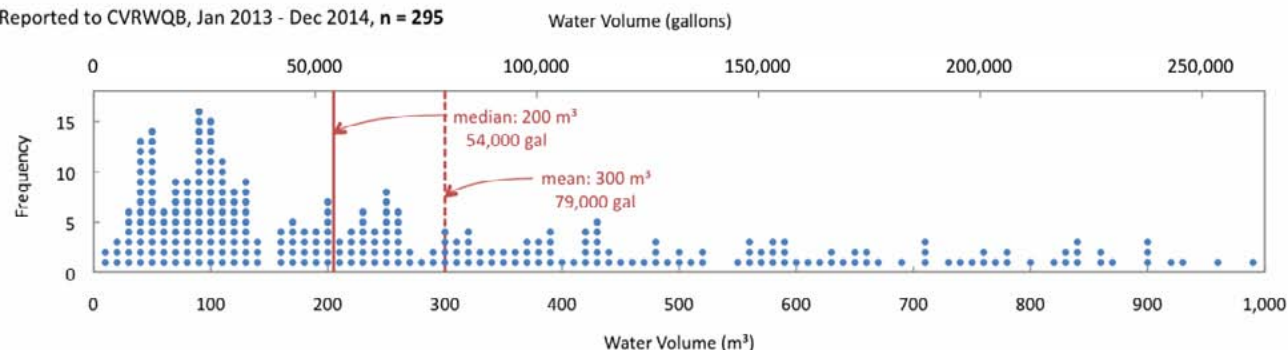
Reported to SCAQMD, Jan 2013 - Dec 2014, n = 246
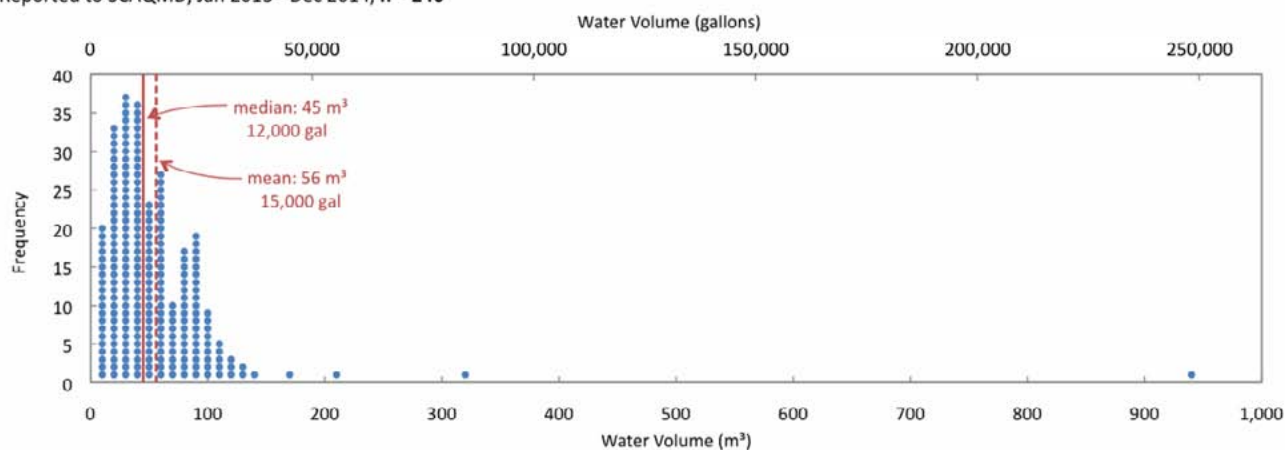
Figure 3-23. *Distribution of matrix acidizing volumes from (A) the CVRWQCB data set, and (B) notices to DOGGR, compared to (C) treatment volumes for operations with HCl in the SCAQMD data set.*

The location of these operations is shown in Figure 3-24. About 70% are in the Wilmington field and 10% in the Inglewood field. Over 55% are offshore, all of which are in the Wilmington field. It is unclear whether similar operations will be considered matrix acidizing after the final well stimulation regulations take effect in 2015.
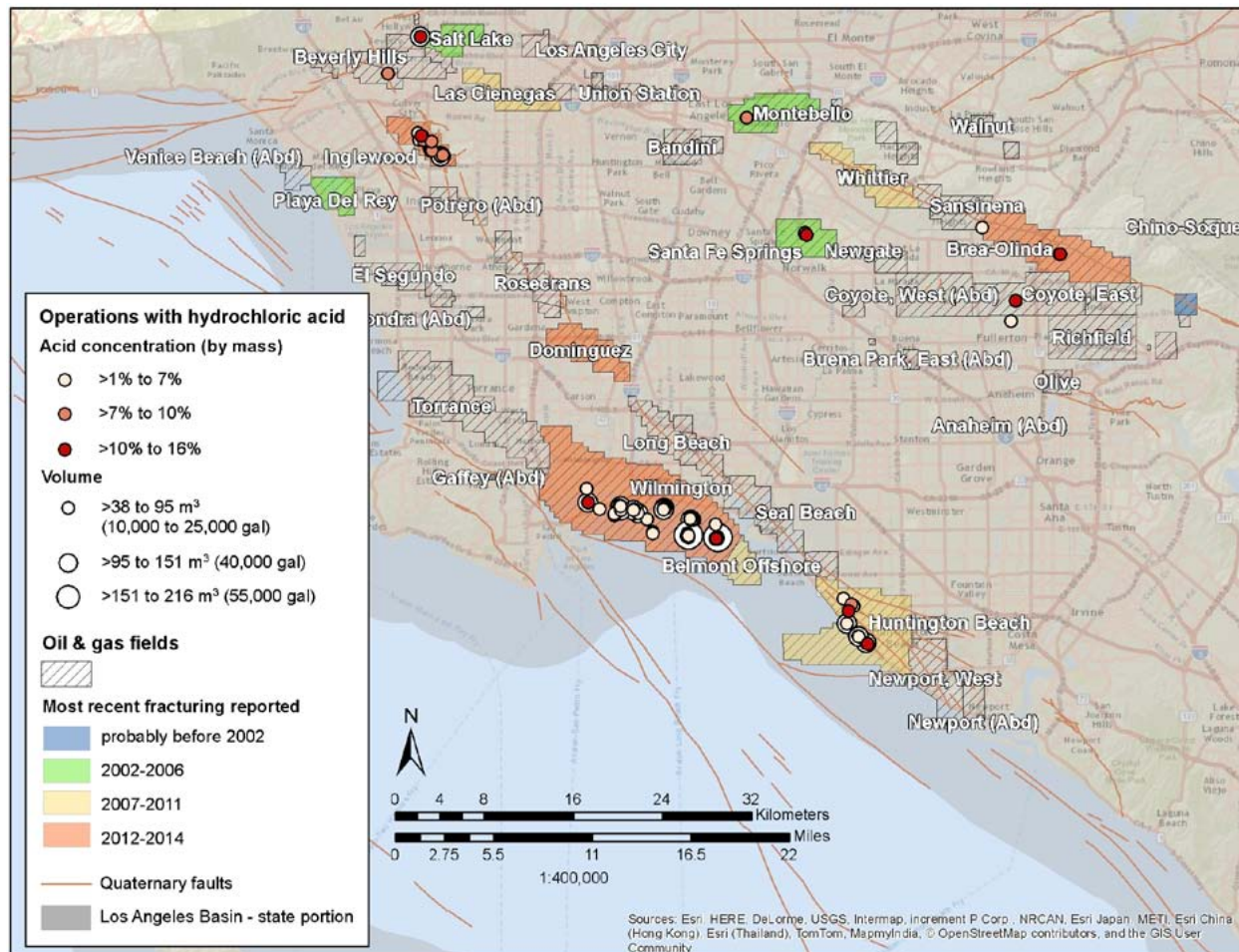
Figure 3-24. *Operations in the SCAQMD data set utilizing hydrofluoric acid, with a total hydrochloric and hydrofluoric acid concentration greater than 1%, and with a fluid volume greater than 38 m³ (10,000 gal). The highest concentration operations are plotted on top of the others. Oil field tinting indicates when the most recent hydraulic fracture operation occurred for comparison. Note the names of some fields are not shown.*

Considering the 12 matrix acidizing treatments per month on average reported to the CVRWQCB and the 26 notices filed in the first month under the current regulations, the estimated range of matrix acidizing activity is 15 to 25 treatments per month statewide. This may be different in the future depending upon the definition used to differentiate matrix acidizing from other uses of acid.

3.5. Data Quality, Availability, and Gaps

This review is based on available data, which are of varying quality and completeness. Quality and completeness were assessed to the extent possible, primarily by comparing data for stimulations covered by multiple sources.

There is no comprehensive source of information on well stimulation activities in California. However, there are eight sources of data regarding recent and pending hydraulic fracturing in California. Each source contains unique data. In aggregate, they provide more complete coverage regarding hydraulic fracturing since early 2012 than do the results of the well-record search alone. The sources are listed below in the order of the accuracy of the data they provide for hydraulic fracturing operations:

1. Well stimulation completion reports (disclosures) (DOGGR, 2014a),

2. South Coast Air Quality Management District well work data (SCAQMD undated),

3. FracFocus,

4. FracFocus data compiled by SkyTruth (SkyTruth 2013),

5. Well record search results combined with first production or injection date (described above),

6. Central Valley Regional Water Quality Control Board (CVRWQCB) well work data,

7. Geographic information system (GIS) well layer (DOGGR, 2014b),

8. Well stimulation notices (DOGGR undated a).

Table 3-6 provides an index of some of the types of data included in each source. Each of the data sources has strengths and weaknesses, as discussed further below.

Table 3-6. *Index of data in each data source. HF = hydraulic fracturing; AF = acid fracturing; MA = matrix acidizing; TVD = true vertical well depth; MD = measured well depth*

Data source	Years	Required	HF	AF	MA	API #	Location	Date	Volume	Chemicals	Depth
DOGGR disclosures	2014	x	x	x	x	x	x	x	x	x	x
SCAQMD	2013-2014	x	x	x	x	partial	x	x	x	x	
FracFocus	2011-2014	partial	x			x	x	x	x	partial	TVD
Well record search	2002-2013		x			x					
CVRWQCB	2012-2013	x	x	x	x	x	x	x	x		TVD
DOGGR GIS well table	all		x			x	x				MD-partial
DOGGR notices	2014	x	x	x	x	x	x		x	x	x

Five of the eight data sources result from partially correlated processes. Operations identified in FracFocus, DOGGR's GIS well table, and the notices and disclosures submitted to DOGGR replicate each other to some extent by design. Operations completed in 2014 are noticed and subsequently disclosed to DOGGR and FracFocus by requirement. In the year and a half prior to mandatory reporting commencing in 2014, operations voluntarily disclosed in both versions of FracFocus were also identified to DOGGR, which flagged them in its GIS well table. The other three data sources (CVRWQCB, SCAQMD, and well records) result from independent data collection processes.

An integrated data set was constructed from all the sources for analysis of location, date, and depth of hydraulic fracturing, available as Appendix M. This data set included the data from the source assessed to be the most accurate for each data type. This assessment was based on the specifics of the data in each source, the regulatory requirement for the data in each source, and comparing the data for operations included in multiple sources. The sources are each described below. Cross checking of operation dates between sources is described in some of the sections below as an example. The discussion is based on data regarding operations through the end of May 2014 available as of July 2014, unless otherwise stated.

3.5.1. Well Stimulation Disclosures

SB 4, which took effect on January 1, 2014, requires operators to disclose well stimulation data within 60 days following the stimulation. The reporting requires identification of the stimulated well, treatment depth and date, and volume, composition, and disposition of well stimulation and flowback fluids. For stimulations involving fracturing, the orientation and extent of fracturing is also required. The well stimulation disclosure data available from DOGGR contained records of 165 well stimulation events at 165 distinct wells, suggesting that wells were not treated more than once (DOGGR, 2014a). All of

the disclosures indicated hydraulic fracturing as the treatment type. This data is of high quality because its disclosure is required, it covers all types of stimulation, and because DOGGR performs some data quality checks before releasing the data (Emily Reader, personal communication). For instance, DOGGR checks if the reported stimulation fluid constituent percentages added up to 100%. If any data fail a check, DOGGR requests the responsible operator to correct the data before it will make the data public. This contrasts with FracFocus, which passes data submitted by operators through to the public automatically.

Because data submitted for some of the operations at the time of this report did not pass these checks, they were not disclosed to the public. Operators are required to also disclose operations to FracFocus, which does not perform the same level of data quality checks. Consequently the operations covered by this data set are a subset of those in FracFocus for the same period. However, the DOGGR disclosures are the only data set that reports certain data, such as the actual top and bottom depth of treatment intervals. It is also the only data set resulting from a mandatory requirement to disclose all stimulation fluid constituents.

As mentioned above, from all the data sets and records available, the well stimulation notices are of the highest quality. It is unfortunate that due to the timing of this study only 6 months of data following institution of mandatory reporting could be assessed. Future assessments will be able to analyze longer reporting periods.

3.5.2. SCAQMD Well Work

On June 4, 2013, the SCAQMD commenced requiring operators to submit notice and data regarding various well activities, including drilling, well completion, rework, maintenance, and stimulation of oil and gas wells within its boundaries (SCAQMD 2014). SCAQMD provides public access to this data (SCAQMD undated). Oil and gas operators are required to submit general information about the well, the type of well activity, and the type and quantity of chemicals used, among other information.

Prior to April 2014, the data structure included a flag for acidizing, which did not distinguish maintenance acidizing, such as to remove scale in a well, from matrix acidizing designed to increase the permeability of the reservoir rocks. Near the beginning of April 2014, this generic flag was eliminated from the data structure in favor of separate flags to indicate maintenance acidizing, matrix acidizing, and acid fracturing (Ed Eckerle, SCAQMD, personal communication).

The SCAQMD database contains records regarding thousands of events. It includes notices of events that were subsequently canceled or modified by submission of another notice. Developing an accurate activity count requires filtering out superseded notices as well as notices of cancellation. SCAQMD provided a method, but it inadvertently filtered notices for some operations that actually occurred. An accurate filtering method was developed and applied.

Most of the SCAQMD notices describe drilling and routine well work, but 15 regard well stimulation events. Fourteen of these were hydraulic fracturing operations, which all occurred in 2013 in the Brea-Olinda field onshore and the offshore portion of the Wilmington field. Water volume injected was reported for only seven of these, and only six of these represented complete hydraulic fracturing events. The seventh appeared to cease early in the operation, as it entailed injection of only 11 m³ (3,000 gal) of water and was followed a few weeks later by an operation that injected 720 m³ (190,000 gal). FracFocus also reported hydraulic fracturing of the same well, but with a start and end date that spanned the two operations in the SCAQMD data and a water volume that was slightly larger than both SCAQMD events combined.

The American Petroleum Institute (API) number is a unique identifier for each well involved in oil and gas production across the entire country. The API number was not reported for the wells stimulated offshore. For this study, the missing API numbers for the offshore stimulations were identified and added from DOGGR's GIS well layer using the latitude, longitude, and well name in the SCAQMD data, so that operations in this data set could be compared to those in other data sets.

The SCAQMD data are of relatively high quality because their disclosure is required, and this requirement started earlier than the statewide disclosure requirement. However, as indicated above, its use requires some care in order to accurately identify operations that actually occurred. API numbers were not required and are not disclosed for many operations, and it did not discriminate between types of acid use.

Because of its longer period of coverage, it uniquely reports some hydraulic fracturing operations. This is also the only data set that covers all well operations, including any operation involving the introduction of any substance into a well. This makes it valuable for assessing identification of well stimulation operations as separate from other types of operations (e.g., well maintenance). Unlike the state disclosure requirements, however, disclosure of all substances is not required.

3.5.3. FracFocus

FracFocus is a website used by the oil and gas industry to disclose information about drilling and chemical use in hydraulic fracturing. Disclosure prior to 2014 was voluntary, and so not required to be complete or accurate. As mentioned above, disclosure of operations in California to FracFocus became mandatory in 2014.

The site was created by two industry groups, the Interstate Oil and Gas Compact Commission and the Groundwater Protection Council, and commenced operation at the beginning of 2011. Operators upload information on their hydraulic fracturing activities, which are posted on the site as PDF documents for each individual fracturing operation. The reports include the API number, well location, and information about the type and quantity of chemicals used. Many of the reports also include the volume of water used,

although they do not report the source or type of water, i.e., operators do not report whether they used freshwater or produced water, nor whether water was withdrawn from a well, public supply, or another source.

As of January 2014, operators have been submitting data to FracFocus in fulfillment of the public registry submission requirement in the current regulations. FracFocus' data structure does not accommodate all of the data required to be disclosed, though. For instance, FracFocus does not provide fields for the stimulated depth interval. Consequently, the well stimulation disclosures available from DOGGR described above are more complete.

However, as mentioned, FracFocus reported more hydraulic fracturing operations for 2014 than did the disclosure data available from DOGGR. For instance, DOGGR checks if the reported stimulation fluid constituent percentages added up to 100%. If any data fails a check, DOGGR requests the responsible operator to correct the data before it will make the data public (Emily Reader, DOGGR, personal communication). This contrasts with FracFocus, which passes data submitted by operators through to the public automatically.

FracFocus data for hydraulic fracturing in California, available as of mid-June 2014, were provided for this review by a DOGGR staff member with administrative access to the site (Emily Reader, DOGGR, personal communication). The number of operations per week declined substantially after the first week of May 2014. This could indicate a reduction in activity at this time, but it is more likely due to the lag in data entry to FracFocus. This suggests the data set considered is relatively more complete through the first week of May 2014 than afterward.

The data set included operations at some wells located outside California according to their coordinates and API number, but which listed California as the state. These were deleted from the data set assembled for analysis.

The FracFocus data are of moderate quality for hydraulic fracturing because their disclosure is voluntary, and it appears to result from fewer, if any, data quality checks, as demonstrated by assignment of operations to California that are demonstrably located outside the state. Once this was taken into account, almost all the operations in FracFocus were also reported by another data source, instilling confidence.

The main strength of FracFocus was that it provided more hydraulic fracturing stimulation fluid constituent data than any other source. However, not all constituents were disclosed for many operations. FracFocus also provided true vertical well depth information, which is not as useful as the state disclosure data regarding treatment interval depth, but was available for many more operations. FracFocus also provided better operation dates than the sources listed below.

3.5.4. FracFocus Data Compiled By SkyTruth

The FracFocus data file discussed above, which was provided by DOGGR, has missing data for some operations and fields. To accommodate these gaps, we used data are from a second version of FracFocus, which was assembled and archived by the non-governmental research organization SkyTruth (Skytruth, 2013) based on the first version of FracFocus available as of the end of July 2013. This included data on hydraulic fracturing operations through April 2013. However, it appears that some of the data from the first version were not imported into the second version. Also, the data structure for the first version of FracFocus differs from the current version, and is generally slightly less comprehensive. For instance, it has a single date for operations, rather than a start and end date. It also entailed two related tables, as opposed to three in the current version.

Data from the first version of FracFocus were used to fill in almost all the missing records in the data from the second version of FracFocus. Some additional missing water volumes in the FracFocus data provided by DOGGR were obtained from individual PDF reports posted on the current FracFocus website. The resulting set had information on 1,686 operations, and is referred to as the FracFocus data set in the following discussion.

3.5.5. Well Record Search Results

The well record search results are discussed in more detail in earlier sections of the report and in appendices than the other data sets, because they were generated as a part of this study. The results are a high quality, but very limited, source of data. The identification of wells that are hydraulically fractured is accurate, but no other information regarding the operations identified was captured from the records. Date, depth, and to some extent basic fluid type information is available in the records, but it was beyond the capacity of this project to capture those data.

Consequently, the first production or injection date was used as a proxy for operations uniquely identified in well records. This was demonstrably accurate to within six months for a high percentage of operations.

The main strengths of this data set are that it identifies more hydraulically fractured wells than any other single data source, covers a longer time period than any other data source, has sampling statistics that allow more quantitatively accurate interpretation of its results, and provides more confidence in the identification of hydraulically fractured wells by a high degree of overlap with other data sources for the time periods they cover in common.

This source does not include data regarding acid treatments.

3.5.6. CVRWQCB Well Work Data

The Central Valley Regional Water Quality Control Board (CVRWQCB) provided data regarding well work. These data were provided to the CVRWQCB in response to California Water Code Section 13267 Orders seeking information from oil and gas operators in the Central Valley Region, and were provided by a CVRWQCB staff member (Douglas Wachtell, CVRWQCB, personal communication). This dataset contains records of well work that generated water discharges in 2012 and 2013. It includes information on the type of work, the volume of water used, and disposal of any resulting fluids.

The data set identifies 1,801 well stimulation operations generically, but only specifies the type of stimulation for 663 operations. The type of stimulation is not specified in the records for some operators, particularly Aera Energy LLC, which is listed for 1,126 of the generic stimulations.

This data source results from a mandatory data requirement. This suggests its accuracy should be greater than that of FracFocus, so it should appear above FracFocus in the list of data sources. However, the CVRWQCB data have unexplained inconsistencies. Some of the dates in this source were a year and more later than dates in FracFocus for the same well. It is possible this represents two operations in the same well (fracturing followed by refracturing). However, the water volumes reported in each source, which are five digits on average, are the same. The probability of multiple pairs of operations using the exact same water volume is low.

It is more likely each data pair regards one operation, but the date is incorrect in one of the records. Even though the CVRWQCB data results from mandatory reporting and the FracFocus data are voluntary, evidence supports the FracFocus data being more accurate. Operators generally stimulate wells immediately following installation and prior to first production or injection. The date in FracFocus is typically closer in time to, and slightly before, the first production date, or first injection date if there is no first production date. The date in the CVRWQCB data set was further in time from, and after, the first production date, or first injection date if there is no first production date. Consequently, the dates in FracFocus were taken as more accurate.

The CVRWQCB data is of moderate quality. It covers all types of well stimulation, so it is the only source of information regarding the intensity of acid stimulation in the San Joaquin Basin prior to the statewide disclosure requirements. Consequently, it uniquely reports the most acid treatment operations. About nine out of ten hydraulic fracturing operations in this data set are reported in others as well, instilling confidence in its unique coverage of some other operations.

It also reports the largest volume hydraulic fracturing operations publicly disclosed so far in California. It does appear to include some erroneous data entries, and it has many operations flagged as stimulation without specifying the type. It does not contain any constituent data that could be used to determine the type of these operations.

3.5.7. DOGGR GIS Well Layer

DOGGR maintains a geographic information system (GIS) layer regarding oil, gas, and geothermal wells in California (DOGGR, 2014a). The attribute table includes voluntary identification of some wells that were hydraulically fractured. The attribute table also includes some information not available from other sources, such as whether a well had been directionally or horizontally drilled, the date drilling commenced, and the measured well depth. Based on comparison with operations in common in other data sources, the date drilling commenced has the least correlation to when the operation occurred.

The DOGGR GIS well layer table is a poor source of data regarding hydraulic fracturing, and it does not have any data regarding acid stimulation. The table includes a flag to indicate if a well has been hydraulic fractured. This largely replicates operations disclosed in FracFocus. There are some other wells uniquely identified as hydraulically fractured, but the number of these indicates the coverage is low outside of the main period of FracFocus disclosures starting in May 2012. The table also does not have operation dates, although the date drilling was initiated is occasionally available as a proxy.

3.5.8. Well Stimulation Notices

Under SB 4, operators must provide DOGGR notice at least 30 days prior to commencing a well stimulation treatment. The notices must include basic information about water and chemical use (Pavley, 2013), and DOGGR must provide approval for the work to proceed. These are notices of intention, but an operator does not have to perform the work even though DOGGR has permitted the operation, and if the work is performed, it may not go exactly as proposed in the notice.

The quality of the notice data is limited because they are prospective and occasionally contain errors. A strength is that these data cover all types of well stimulation. Operators began filing notices in December 2013, for operations beginning in January 2014. A total of 477 well stimulation notices were filed through the end of May 2014, although 15 of these were withdrawn (DOGGR, undated a). Of the 462 approved notices, 436 are for hydraulic fracturing. Two records are missing information on water use, providing a total of 460 records of planned water use for well stimulation. While the well stimulation notices are of some use, they only represent an operator's planned activities and may not reflect actual operations.

3.5.9. Data Quality in Aggregate

Integration of the eight available data sources demonstrates they overlap considerably with regard to identifying hydraulically fractured wells in the time periods they have in common. Given the geographic areas covered and mix of mandatory and voluntary reporting, this provides some degree of confidence that the estimated number of hydraulic fracturing operations that are occurring is accurate, if not precise. Given the number and

nature of data sources regarding hydraulic fracturing fluid volume, there is confidence in the accuracy of the understanding of the distribution of these volumes. There is confidence in the identification of the predominant class of hydraulic fracturing fluid used in the state, given the number of data sources from which this is interpreted, including the literature. Likewise, the integration of the data sets provides confidence that the areas where hydraulic fracturing commonly occurs onshore and in California waters have been accurately identified. The available data on stimulation depth is less specific for hydraulic fracturing and less available for acid stimulation, and so confidence in the accuracy of understanding the distribution of depths at which these methods are applied is lower.

Comparison with the frequency, size, and location of hydraulic fracturing given by the recent report undertaken for the Bureau of Land Management concerning well stimulation in California by California Council on Science and Technology (CCST), Lawrence Berkeley National Laboratory (LBNL), and Pacific Institute (CCST et al., 2014) supports confidence in the accuracy of those results in this report. CCST et al. (2014) assessed these results for onshore hydraulic fracturing based on five of the eight data sources considered by this report (completion reports and disclosures were not available from DOGGR or the CVRWQCB at the time, respectively, and data from SCAQMD were not considered). Four of the five sources considered were voluntary, whereas this report considered an additional three mandatory data sources. Six months less data were considered by CCST et al. (2014). Only production well records were searched for CCST et al. (2014) as compared to production and injection well records for this report, and few well records were available for searching in some basins (such as Los Angeles) by CCST et al. (2014). Nonetheless, CCST et al. (2014) estimated hydraulic fracturing operations occurred at a similar rate (100 to 150 operations per month), were of a similar size (490 to 790 m^3; 130,000 to 210,000 gallons), and predominantly occurred in the same locations (85% in the North and South Belridge, Lost Hills, and Elk Hills fields) as does this report. Confidence regarding acid stimulations is lower because there are fewer data sets, and they do not overlap in geography or time for the most part.

Additional data becoming available in the future might change some of the quantitative findings in this report, but would not likely fundamentally alter the report conclusions about well stimulation in California.

3.5.10. Data Gaps

Many of the most obvious data gaps, such as the underreporting in the past of stimulated wells, have been closed by the mandatory reporting requirements in SB 4 and the regulations that implement its mandates. For the analyses in this report, however, only six months of reporting time and eight month of notices were available, which raises the question as to whether this is sufficient time for the number and type of operations to stabilize. In addition, some potential gaps and data quality issues relevant to the understanding of well stimulation in California in the future that are not addressed by SB 4 and its current implementing regulations were encountered during this study, as follow:

- The well stimulation notice form does not currently provide for operators to indicate planned acid fracturing operations. Adding this capability to the form would make identifying, and so analyzing, this type of well stimulation easier.

- The notice forms do not allow differentiating between hydraulic fracturing and frac-packing. Given the difference between these two types of operations, adding this capability to the form would again facilitate analysis of operational prevalence and trends.

- Neither the notice forms nor the completion reports provide for identifying the company performing the stimulation. This is typically a service company hired by the operator rather than the operator. Adding a requirement to disclose the company performing the stimulation would allow analysis of whether stimulation practices vary from one service company to another, as they appear to vary from operator to another.

- Most hydraulic fracturing operations are listed as occurring within one day, which suggests they occurred in less than 24 hours. Providing for operators to report the number of hours required for a hydraulic fracturing operation would provide a more accurate understanding of the duration of hydraulic fracturing fluid pressure application.

- A review of records for a few tens of wells that are reported as hydraulically fractured and indicated as horizontal in DOGGR's GIS well layer found about half were not horizontal, but rather directional and nearly vertical in the reservoir. Improving the accuracy with which horizontal wells are identified going forward could assist in early identification of a trend toward horizontal well fracturing in California.

Other data gaps involve the federal government. There is currently no reporting requirement regarding well stimulation in federal waters, so stimulation activity in this area cannot be accurately assessed. DOGGR and the EIA appear to have different criteria for designating gas versus oil wells. It is unclear if DOGGR has quantitative criteria for making this determination. It might be useful to conform to federal criteria in order to provide regulatory and reporting uniformity.

3.6. Findings

Hydraulic fracturing has been applied in numerous oil fields in California for decades, starting in 1953. The use of hydraulic fracturing increased substantially with the development of some of California's largest oil accumulations in the late 1970s and early 1980s, just before oil production in the state peaked (DOGGR, 2010). About 25% of wells going into production or injection are fractured, and this rate has remained relatively constant over the last twelve years analyzed. Because more wells went into production

or injection annually during the last two years than the previous ten, the average annual number of hydraulic fracturing operations in 2012 to 2013 was about 25% higher than in the previous decade. The ratio of injection wells to production wells hydraulically fractured increased from 1:5 to 1:2 over the last twelve years, suggesting an increase in enhanced oil recovery efforts.

Data indicate hydraulic fracturing is performed in more than 109 wells per month on average, and perhaps up to 190 wells in some months. Given this range, hydraulic fracturing of 125 to 175 wells per month is a reasonable estimate, with about one percent consisting of frac-packs. This is shown on Figure 3-25, along with estimated rates for other types of well stimulation in California. Almost all the onshore frac-packing since 2011 has occurred in the Inglewood field.
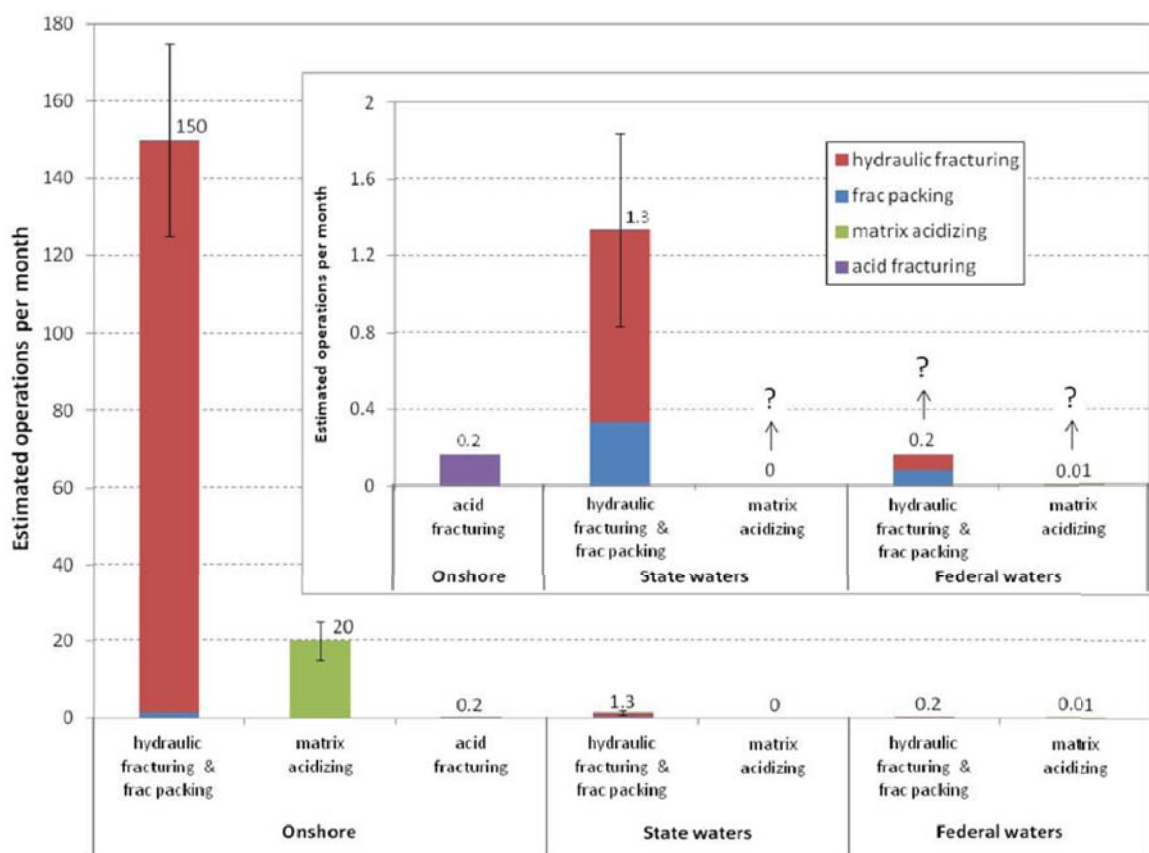
Figure 3-25. *Estimated recent well stimulation activity in California (2012 and 2013). The inset shows the smaller rates on an expanded scale. Arrows marked with question marks indicate rates estimated from one, non-comprehensive data source.*

Since 2011, all reported stimulation in California has been in oil wells and none in gas wells. About 40%- 60% of the wells that have gone into production or injection during this time have been fractured. About 30% of the wells fractured since 2011 have been injectors.

On average, about one to two wells per month have been hydraulically fractured offshore in California waters over the last decade, which is about one sixth of the wells installed. One fourth of these operations consisted of frac-packs. This activity primarily occurs on the THUMS islands in the Wilmington field constructed off the coast of Long Beach in the Los Angeles Basin.

The available information regarding hydraulic fracturing offshore in federal waters indicates two operations per year, which is about 10% of the wells installed. One half of these operations consisted of frac-packs. This information was only available from one source that reviewed records, and so this estimate may be low.

About 95% of hydraulic fracturing in California in 2012 and 2013 occurred in the southern San Joaquin Basin, and about 85% in four fields on the west side of the Basin: North and South Belridge, Elk Hills, and Lost Hills. Two thirds of hydraulic fracturing in California occurs in diatomite reservoirs in the North and South Belridge and Lost Hills fields. About a fifth of oil and gas production in California is from reservoirs (pools) in which a large proportion of the wells have been hydraulically fractured.

References to acid fracturing in California were not identified in the literature. Chapter 2 indicates that acid fracturing is generally applied in carbonate reservoirs. Only a few such reservoirs exist in California, and these are naturally fractured, suggesting that acid fracturing is not applicable. However, three hydraulic fracturing well stimulation notices for wells in the Elk Hills field specify use of an HCl and HF mix, indicating acid fracturing.

The use of matrix acidizing is reported in far fewer fields in the literature than is hydraulic fracturing, and the number of notices submitted for the use of this technology is a small fraction of the number submitted for hydraulic fracturing. A total of 26 notices were received and approved in the first month. The CVRWQCB data set, which covers a longer time period, identifies 13 wells per month matrix acidized on average. Data from the Los Angeles and part of the Ventura basins suggests the number of acidizing operations classified as matrix acidizing may increase after the regulation currently being developed goes into effect, in which case 15 to 25 matrix acidizing operations per month is a reasonable estimate of activity. The notices and reports of matrix acidizing are all located in a few fields in the southwest San Joaquin Basin, primarily the Elk Hills field.

Figure 3-26 shows the median, minimum, maximum, and second and third quartile water use per hydraulic fracturing operation for different types and settings of wells. Table 3-7 shows the median water use. Data indicate average water use per hydraulic fracturing operation of 530 m^3 (140,000 gal). This is considerably less than in other hydraulically

fractured plays in the United States. For instance, average water use per operation in a horizontal well in the Eagle Ford in Texas is 16,000 m^3 (4.25 million gal). The difference results in part from the predominance of fracturing in relatively shallow vertical wells in California, which have shorter treatment intervals, as compared to the predominance of horizontal wells in major unconventional oil plays like the Eagle Ford and Bakken, as well as the use of gel as opposed to slickwater in those other plays.
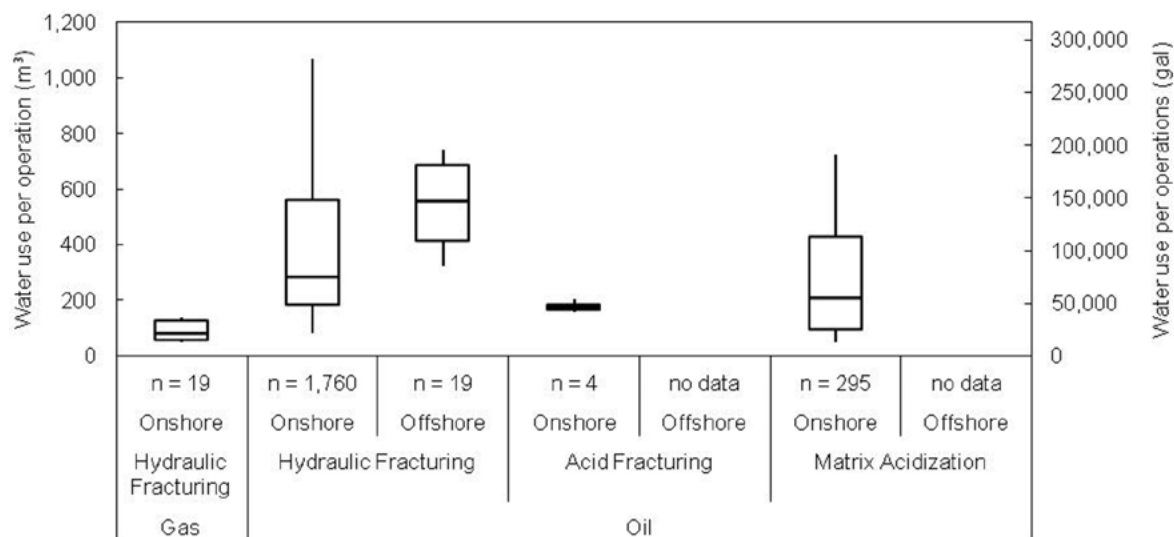
Figure 3-26. *Distribution of water use per different type of well stimulation operation in different settings in California.*

Table 3-7. *Median water use per different type of well stimulation operation in different settings in California.*

| | Oil | | Gas |
	Onshore m^3 (gal) [sample size]	Offshore m^3 (gal) [sample size]	Onshore m^3 (gal) [sample size]
m^3			
Hydraulic fracturing	284 (75,000) [1,760]	550 (150,000) [19]	77 (21,000) [19]
Acid fracturing	180 (47,000) [4]		
Matrix acidizing	200 (54,000) [295]		

Water use per treatment length is also lower in California than elsewhere in the country. The average water use in a set of horizontal wells disclosed as fractured is 2.3 m^3/m (180 gal/ft). This compares to an average of 9.5 m^3/m (770 gal/ft) in the Eagle Ford (Nicot and Scanlon, 2012) and 3.4 m^3/m (280 gal/ft) for crosslinked gel, 3.9 m^3/m (320 gal/ft) for hybrid gel and 13 m^3/m (1,100 gal/ft) for slickwater used in the Bakken.

As indicated by the information from the Bakken, as well as engineering guidance discussed in Section 2.4.2.1, gels are associated with lower volumes per treatment length than slickwater, and crosslinked gel is associated with the least water volume among the gel types. The predominant fracturing fluid type in California is gel, of which most is crosslinked.

Median water use for acid fracturing was 170 m^3 (45,000 gal) per operation. The minimum and maximum water volumes per acid fracturing treatment length implied by the three available notices are 0.60 and 0.74 m^3/m (48 and 72 gal/ft), respectively. This is smaller than indicated by the notices for matrix acidizing, and far less than the water-use intensities for hydraulic fracturing. This suggests the treatment extent relative to the well is quite limited.

Median water use for matrix acidizing was 200 m^3 (54,000 gal) per operation. The volume per treatment length from the notices averaged 1.0 m^3/m (90 gal/ft). This is somewhat less than for hydraulic fracturing, but in the higher part of the range identified for matrix-acidizing stimulations in general discussed in Chapter 2. This suggests that the treatments are targeted more toward treating natural fractures than the rock matrix (pores in the rock itself).

For both matrix acidizing and acid fracturing, the acidizing fluid contains both HCl and HF. The latter is often produced from other components in the fluid, rather than being added to the fluid directly.

3.7. Conclusions

Hydraulic fracturing has been the main type of well stimulation applied in California to date, based both on the total number of wells and fields where it has been used as compared to other stimulation methods. Over the last decade, operators fractured about 125 to 175 wells of the approximately 300 wells installed per month. The number of production wells fractured per year has remained relatively constant during the last 12 years studied. The number of injection wells fractured has increased during this time. Two to three fifths of new wells in California are estimated to be hydraulically fractured. Hydraulic fracturing facilitates approximately a fifth of the oil and gas production in the state. Most hydraulic fracturing occurs in the southwestern portion of the San Joaquin Basin. There has been little hydraulic fracturing in gas fields, and none reported since 2011.

Available data suggest the practice of hydraulic fracturing for oil production in California differs significantly from practices outside the state. For example, California hydraulic fractures tend to use less water and the wells tend to be more vertical than in those for producing oil from source rock in North Dakota and Texas. As pointed out in Chapter 4, the majority of the oil produced from fields in California is not from the source rock (i.e., shale in the Monterey Formation), but rather from reservoirs containing oil that has migrated from source rocks. These reservoirs do not resemble the extensive and continuous layers that are amenable to oil production with high water-volume hydraulic fracturing from long-reach horizontal wells, such as found in the Bakken in North Dakota and Eagle Ford in Texas. Rather, hydraulic fracturing in California is most often employed in both injection and production wells in combination with enhanced oil recovery techniques, such as water and steam flooding, to produce migrated oil from more geographically limited areas than is typical for production from source rocks.

The majority of offshore production takes place without hydraulic fracturing. Ninety percent of the limited hydraulic fracturing activity in California waters is conducted on man-made islands close to the Los Angeles coastline in the Wilmington field; little activity is documented on platforms. Operations on close-to-shore, man-made islands resemble onshore oil production activities. On these islands, operators conduct about 1-2 hydraulic fracturing operations in the 4-9 wells installed per month. The only available survey of stimulation in federal waters records 22 fracturing stimulations occurred or were planned from 1992 through 2013 in the context of more than 200 wells installed during that period. All but one of these hydraulically fractured wells were in the Santa Barbara-Ventura Basin. About 10-40% of fracturing operations in wells in California waters and half of operations in US waters were frac-packs.

Acid fracturing is less than 1% of reported fracturing operations to date in California, all for onshore oil. Acid fracturing is usually applied in carbonate reservoirs, and these are rare in California. Matrix acidizing has been used effectively but only about 10% as often as hydraulic fracturing onshore in California. Its use in California and US waters is occasional, with the most recent operation in each in 2011. However, it is hard to assess the extent of acidizing in the state because the definition of routine well maintenance versus stimulation varies from one regulatory agency to another, and within one agency through time. More complete data on acid use in one data source suggests it is difficult in practice to definitively categorize acidizing to remediate drilling damage from that to alter reservoir permeability. In general, though, acid fracturing and matrix acidizing technologies are not expected to lead to major increases in oil development in the state.

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Chapter Four

Prospective Applications of Advanced Well Stimulation Technologies in California

Abstract

Although hydraulic fracturing has been employed since the 1950s, it is not a widespread or intensive practice in California, with the exception of diatomite oil reservoirs in certain fields of the San Joaquin Basin (Section 3.2), where hydraulic fracturing is necessary for sustained production. Future growth of reserves will likely include additional development of oil in low-permeability diatomite reservoirs. Such development would require continued widespread application of well stimulation technology (WST).

Recently, low-permeability source-rock (shale oil) resources have been postulated to exist in the San Joaquin Basin, in the Los Angeles Basin, and in parts of the Salinas, Santa Maria, and Ventura basins, where Monterey-equivalent and other petroleum source rocks are deeply buried. If present, development of such resources would likely require the extensive application of WSTs, such as hydraulic fracturing. However, feasible development of shale oil in California remains highly uncertain. Petroleum source rocks of California differ significantly from those of Texas and North Dakota in both lithologic and structural complexity. If shale oil production is to be realized here, its development engineering will need to be specifically designed for California. Recent exploration wells that have targeted deep shale oil potential have not yet resulted in the identification of new petroleum reserves; however, exploration for this potential resource continues.

Although natural gas production is volumetrically much less important than oil in California, significant quantities of natural gas have been produced in the Sacramento Basin and in association with oil in some fields of the San Joaquin Basin and elsewhere. Natural gas production in California has not generally entailed WST. Large-scale development of unconventional natural gas resources such as shale gas, basin-center "tight gas," and coal bed methane is geologically unlikely in California.

Based on the current state of knowledge, the extensive application of WST as practiced in Texas, North Dakota, and Pennsylvania is not expected to become widespread in California in the near future.

4.1. Introduction

California's rich petroleum resources have been exploited since prehistoric times and produced commercially for more than 150 years. In spite of intensive development, large quantities of recoverable oil are believed to remain in the petroleum basins of California. These resources include undiscovered conventional accumulations, especially in federal waters, and potential growth of reserves from further development of existing oil fields. The following points summarize our assessment of California's petroleum resource potential, and whether development of such resources may require use of WSTs or not:

- California's petroleum resources have been exploited since prehistoric times and commercial oil production has a 150 year history. California remains one of the leading oil producing areas of North America.

- Oil in California is closely associated with the Monterey Formation and its geological equivalents.

- In spite of a long history of intensive oil production, large quantities of technically recoverable oil remain in California petroleum basins.

  - The remaining resource potential can be considered in three broad categories: (1) Undiscovered conventional accumulations, (2) Additional petroleum reserves, both conventional and unconventional, which could be developed in existing oil fields, and (3) Postulated, but largely untested and unproven, petroleum accumulations in source-rock systems (shale oil and shale gas), comparable in type to those that are being extensively developed in other parts of the United States, such as the Bakken Formation in North Dakota or the Eagle Ford Shale in Texas.

  - Undiscovered conventional petroleum

    - Undiscovered oil and gas fields in onshore basins are expected to be small and difficult to find. Some of these undiscovered fields could have low-permeability reservoirs amenable to application of WSTs.

    - Billions of barrels of undiscovered and undeveloped petroleum are estimated to be present offshore, particularly in the Santa Barbara/ Ventura and Santa Maria/Partington basins.

    - If additional offshore resources are developed, the use of WST would most likely be incidental and not fundamental to production.

  - Growth of reserves in existing fields

- Given current knowledge and technology, additional development of existing oil fields is the most likely source of significant new reserves in California. The USGS recently estimated that from 0.6 to 2.5 billion cubic meters (m^3; 4 to 15.6 billion barrels) of additional oil could be recovered from 19 giant oil fields of the San Joaquin and Los Angeles basins with current technology, including WST.

- Much of the reserve growth will come from additional development of heavy, high-viscosity oil in fields of the San Joaquin Basin. Large quantities of undeveloped heavy oil are also present in Los Angeles, Santa Maria, and Santa Barbara/Ventura basins. This does not generally require WST.

- Large quantities of potentially recoverable oil remain in fields of the Los Angeles Basin, the development of which would involve the occasional application of WST.

- Large volumes of recoverable oil exist in low-permeability diatomite reservoirs in the San Joaquin Basin. Production of oil from diatomite generally requires WST.

- Unconventional resources in source-rock (shale oil) systems

  - Large oil and possibly gas resources in deeply buried, thermally mature Monterey and Monterey-equivalent source rocks have been postulated, but feasible development remains highly uncertain. Recent exploration wells that have targeted deep Monterey source rocks have not resulted in identification of new petroleum reserves. If these postulated resources exist and could be developed, their production would probably require widespread application of WSTs.

  - If significant shale oil resources can be exploited in California, they probably would be first developed in restricted areas of the San Joaquin Basin where Monterey-equivalent and other source rocks are in the "oil window".

  - Low-permeability source-rock (shale oil) resources are also postulated in the central Los Angeles Basin, and in parts of the Salinas, Santa Maria, and Ventura basins, where Monterey-equivalent source rocks are deeply buried.

- Large quantities of natural gas are produced in California. Petroleum produced in the Sacramento Basin is mainly non-associated gas. Non-associated gas fields also have been found in the San Joaquin, Eel River, and other basins, both onshore and offshore. Associated and dissolved natural gas is also produced from various oil fields. This production has not involved the widespread use of WST.

- Large-scale development of unconventional natural gas resources (which would entail extensive use of WSTs), such as shale gas, basin-center "tight gas," and coal bed methane, is geologically unlikely in California.

4.2. Source Rocks and Petroleum Systems

4.2.1. Organic Origin of Petroleum

An overwhelming body of geological, biological, chemical, and thermodynamic evidence shows that nearly all oil originates from the thermochemical transformation of sedimentary organic matter, much of which was originally marine phytoplankton (Hunt, 1995). Most natural gas forms in the same way, although large quantities of natural gas are also generated by the thermochemical alteration of terrestrial organic matter derived from higher land plants. Gas is formed simultaneously with oil (associated and dissolved gas), by the thermal breakdown of oil under elevated temperatures ("cracking") and by microbial metabolism at relatively low temperatures (biogenic methane) (Figure 4-1).
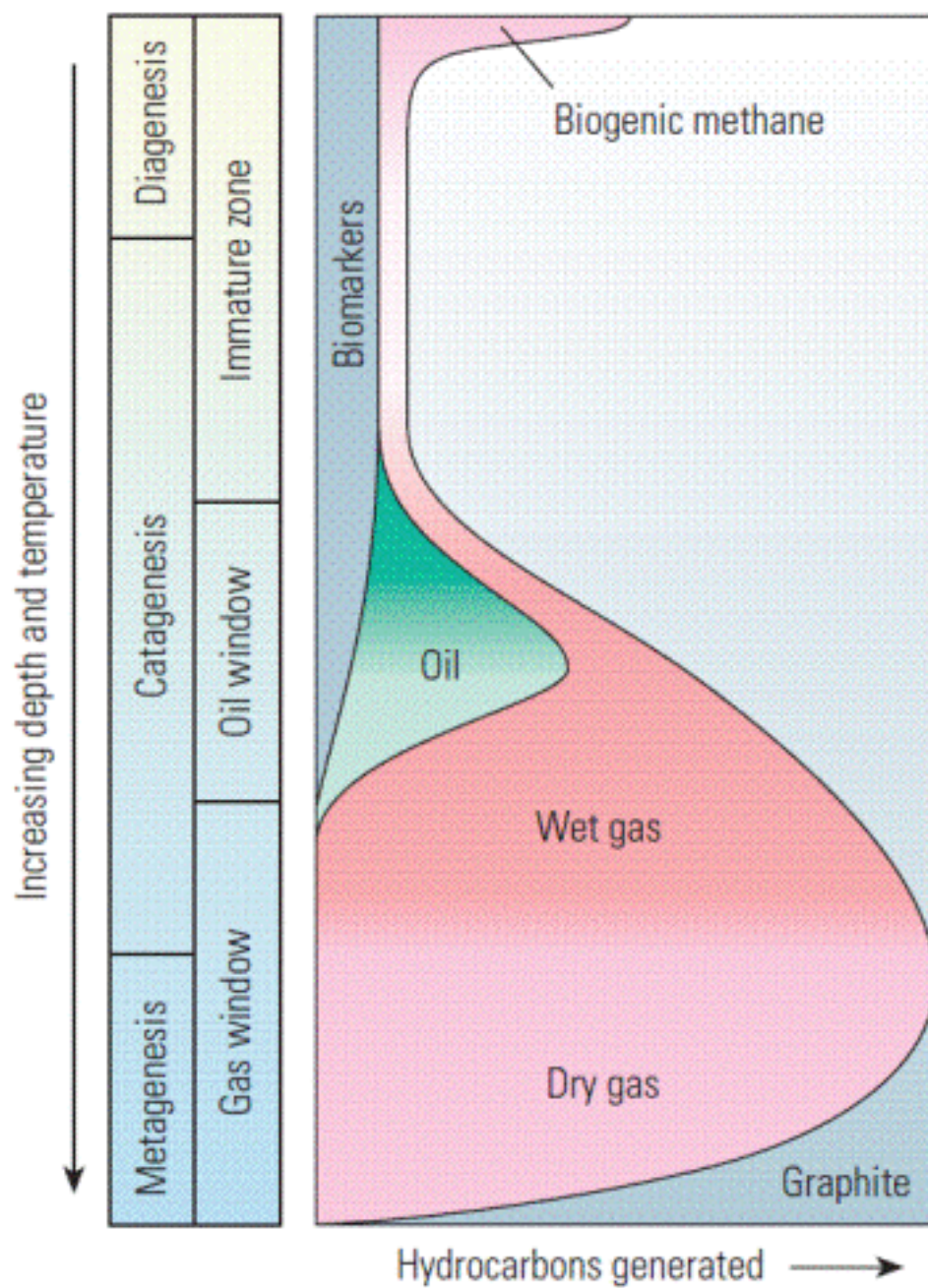
Figure 4-1. *Thermal transformation of kerogen to oil and gas, depicting the depths of the oil window (McCarthy et al., 2011).*
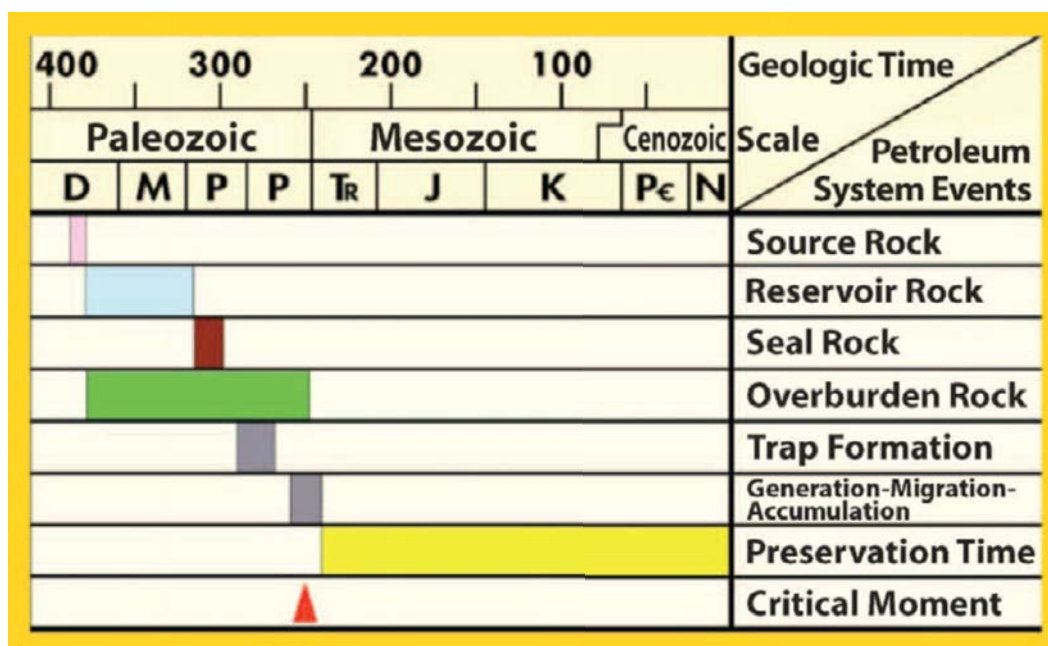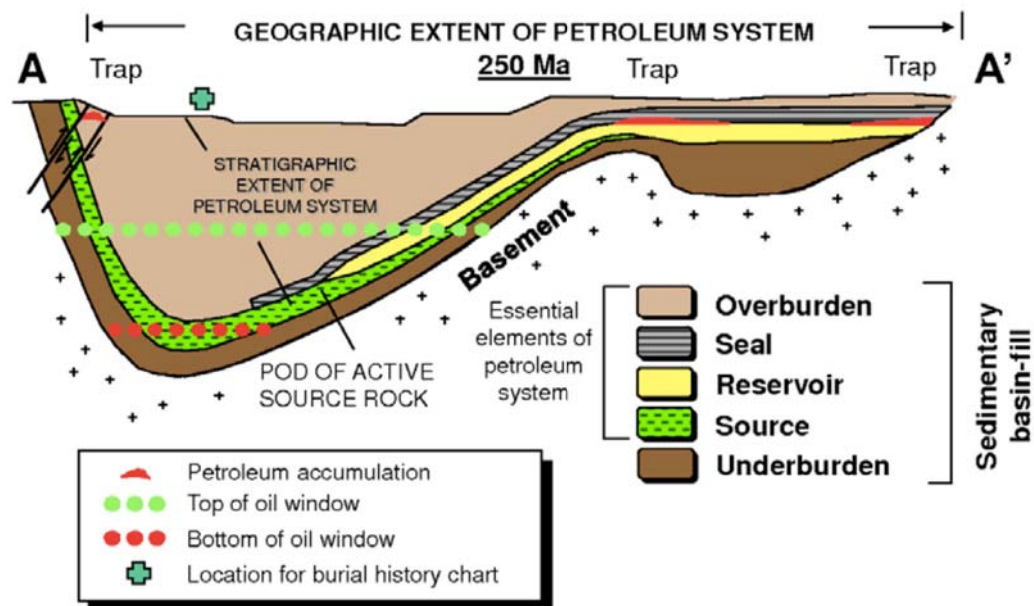
Figure 4-2. *Example of a hypothetical petroleum system showing cross section and timeline for system formation. Figure from Magoon and Dow (1994).*

4.2.2. Petroleum Systems

Petroleum, for the purposes of this report, includes crude oil, natural asphalt, both thermal and biogenic gas, and liquid hydrocarbon condensates formed during production.

A *petroleum system*, as described by Magoon and Dow (1994), is a natural system that includes concentrated insoluble sedimentary organic matter (kerogen) in a source rock, the related petroleum generated from the source rock by thermochemical or metabolic processes, and all of the other geological elements and processes necessary for a hydrocarbon accumulation to form (Figure 4-2).

Petroleum systems comprise several key components:

1. A *source rock* that contains concentrated sedimentary organic matter (kerogen). In many cases this source rock is an organic-rich marine mudstone deposited under conditions of high oceanic productivity and slow sedimentation rate in bottom waters that are depleted in oxygen. The Monterey Formation is the most important source rock in California and one of the most prolific source rocks in the world.

2. An *energy source* sufficient to cause the transformation of sedimentary organic matter to petroleum. Typically this is the internal heat of the Earth, which increases with burial depth (the geothermal gradient). Kerogen in the source rock must undergo sufficient heating over time for it to become "thermally mature" for the generation of oil and/or gas (McCarthy et al., 2011). The "oil window" and "gas window" are defined as the ranges of depths and temperatures over which a source rock will generate oil and gas, respectively (Fig. 4-1). The types of hydrocarbons formed and the specific rates, temperatures and depths of maturation are functions of both the type of kerogen and its integrated time-temperature history. The reaction rates of Monterey-equivalent source rocks remain incompletely understood, and the depths and temperatures of oil generation in many California basins are uncertain (e.g., Walker et al., 1983; Kruge, 1986; Kaplan et al., 1986; Petersen and Hickey, 1987; Isaacs, 1989; Isaacs and Rullkötter, 2001).

3. A *reservoir* is a rock with a pore network within which the petroleum generated during maturation accumulates and is contained. In conventional hydrocarbon accumulations, this reservoir is a porous and permeable rock, such as sandstone or limestone, which is distinct and at some vertical and/or horizontal distance from the thermally mature source rock.

4. A *trap* is a permeability barrier that allows petroleum to accumulate in a reservoir rock. The permeability barrier is also termed the seal. Various trapping mechanisms and geometries are recognized, including structural traps,

stratigraphic traps, and diagenetic traps. In the case of certain unconventional petroleum accumulations, such as shale oil or shale gas, no permeability barrier is present other than the very small matrix permeability of the shale.

5. *Migration* is the movement of generated hydrocarbons from the mature source rock to the reservoir; the route taken is the *migration pathway*. Migration results mainly from the buoyancy of petroleum in formation waters owing to the difference in density between petroleum and water. Migration from the source rock is halted by a trap, and the oil and gas can accumulate in the reservoir rock. This sequence of events can develop a conventional oil deposit. The vast majority of produced oil, including that from the producing oil fields in California, is migrated oil. However, in many unconventional petroleum accumulations, such as the Eagle Ford and Bakken shale oil petroleum systems, the source rock and reservoir rock are essentially one and the same, and the migration distance is negligible (Harbor, 2011; Sonnenberg et al., 2011). Profitably producing oil from such low permeability source/reservoir rocks generally requires hydraulic fracturing (a type of WST) to create the permeability that allows extraction of oil and gas.

4.2.3. Source Rocks of California

Every petroleum accumulation can be attributed to at least one source rock. In California, the predominant source rocks, accounting for 80–95% of all petroleum, are in the Monterey Formation and its stratigraphic equivalents (meaning formations with similar qualities and ages, but with different names) (Appendix N). However, other source rocks are important in certain basins. California source rocks are briefly summarized below and are also illustrated on a stratigraphic section for the San Joaquin Basin (Figure 4-3). A more detailed description of the Monterey Formation is presented in Section 4.4.

Monterey Formation and its Equivalents

The Miocene Monterey Formation and its geological equivalents (herein referred to as the Monterey) were deposited as deep-water marine sediments on the continental margin of California during the middle to late part of the Miocene Epoch (Isaacs, 2001). 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. It is a highly heterogeneous deposit that characteristically consists of biogenic sediments that are variously siliceous, phosphatic, calcareous and, in many cases, highly enriched in organic matter. (Bramlette, 1946; Isaacs et al., 1983; Graham and Williams, 1985; Isaacs, 1989; Behl, 1999; Tennyson and Isaacs, 2001; Isaacs and Rullkötter, 2001). More than 80% of the known oil in the San Joaquin Basin and practically all of the oil in the Los Angeles, Santa-Barbara/Ventura, and Santa Maria basins was generated from the Monterey and its equivalents. The Monterey is discussed in more detail in Section 4.4, The Monterey Formation, below.

SAN JOAQUIN BASIN PROVINCE
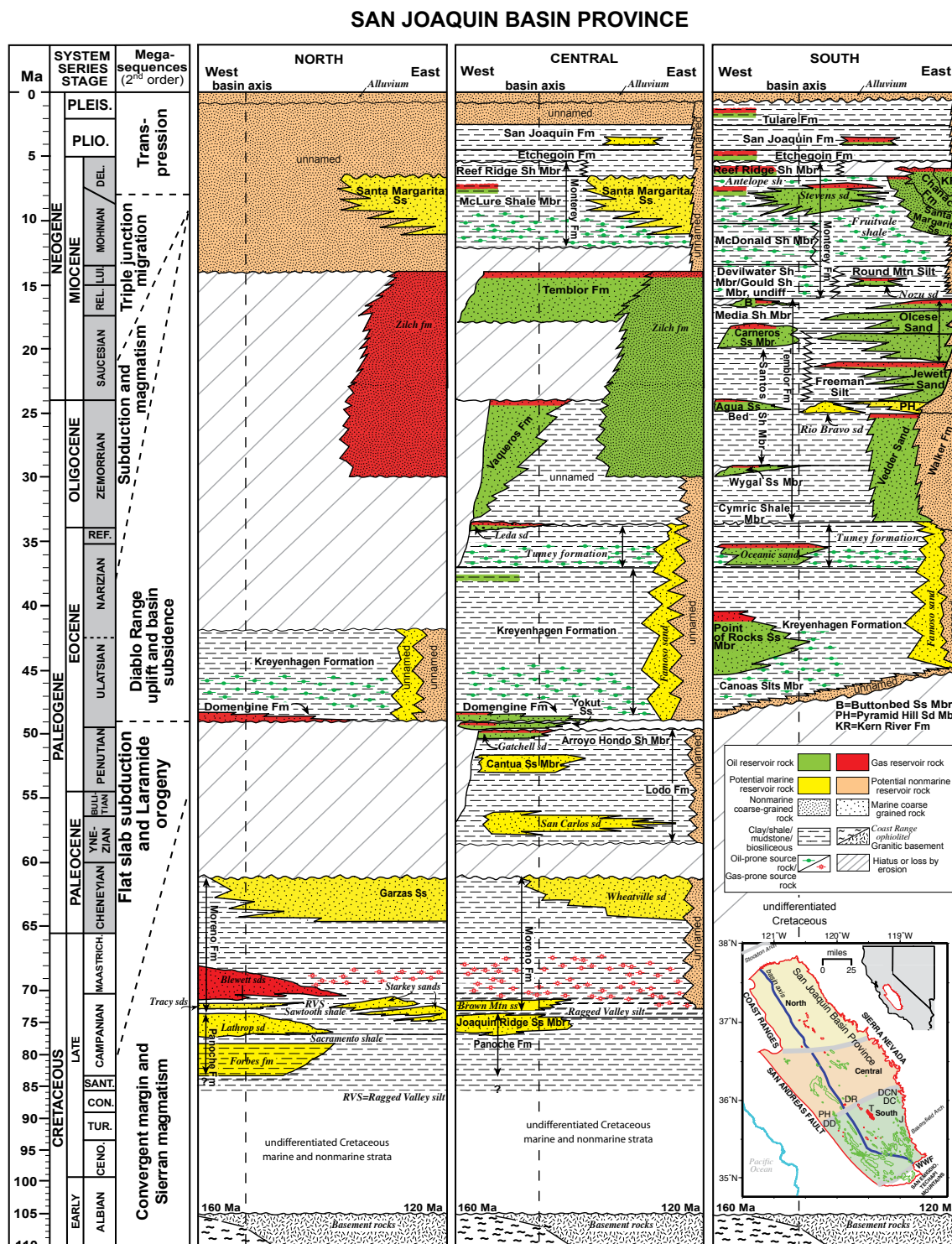
Figure 4-3. *Summary stratigraphic sections for the San Joaquin Basin, highlighting relative locations of source and reservoir rocks (Hosford Scheirer and Magoon, 2008a)*

Vaqueros Formation

The Vaqueros Formation is an early to mid-Miocene marine sedimentary rock consisting of sandstones and shales in basins on the western side of the San Andreas Fault (Dibblee, 1973). In the Cuyama Basin, the lower portion of the Vaqueros includes kerogen-rich mudstone (a fine-grained sedimentary rock) called the Soda Lake Shale Member. On the basis of stable carbon isotope and biological marker data from kerogens and oils, Lillis (1994) concluded that much of the oil produced in the Cuyama Basin was generated from the Soda Lake Shale.

Tumey Formation

The Tumey consists of sandstone and shale of Late Eocene age. It contains thin calcareous shale and is often combined with the underlying Kreyenhagen Formation in stratigraphic sections (Milam, 1985; Peters et al., 2007). The Tumey is considered by Magoon and others (2009) to be the source rock for more than 130 million m^3 (800 million barrels) of oil (estimated ultimate recovery) in accumulations along the west side of the San Joaquin Basin.

Kreyenhagen Formation

The Kreyenhagen Formation is a shale-rich formation of Eocene age that is also a petroleum source rock in the San Joaquin Basin. At its reference section location at Reef Ridge, just south of Coalinga in the San Joaquin Basin, it is more than 305 meters (m; 1,000 feet, ft) thick (Von Estorff, 1930). The Kreyenhagen consists of shales, laminated sandstones and shales, siltstones, and pebbly green sandstones (Isaacson and Blueford, 1984; Johnson and Graham, 2007; Milam, 1985). In some locations, it contains turbidite deposits more than 488 m (1,600 ft) thick, known as the Point of Rocks sandstone; in these areas, the lowermost member of the Kreyenhagen is known as the Gredal Shale member, and the uppermost Kreyenhagen is the Welcome Shale member (Dibblee, 1973; Johnson and Graham, 2007). Hydrocarbons derived from the Kreyenhagen can be chemically distinguished from the Tumey and Monterey on the basis of isotope geochemistry and biological markers (Clauer et al., 2014; Lillis and Magoon, 2007; Peters et al., 1994; 2013). 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).

Moreno Formation

The Moreno is a shale-rich formation of Cretaceous to Paleocene age (McGuire, 1988). It comprises four members that represent different clastic depositional facies. The stratigraphic section of the Moreno Formation, exposed in Escarpado Canyon in the Panoche Hills on the western margin of the central San Joaquin Valley, is about 800 m

(2600 ft) thick. He et al. (2014) have characterized the geochemical signature of oils sourced from this formation, as did Peters et al. (2007; 2013). The Moreno is known to be the source rock for the small quantities of oil produced from the Oil City field (Magoon et al., 2009). It may also be the source rock for other small oil accumulations in the Sacramento and San Joaquin basins.

Winters Formation

The Upper Cretaceous Winters Formation of Edmondson (1962) is a thick succession of shales, mudstones, and sandstones deposited in a complex delta slope and submarine fan system in the Sacramento Basin (Garcia, 1981). Like most of the Great Valley sequence strata, the Winters contains abundant terrestrial (Type III) kerogen, which is believed to explain the strongly gas-prone character of the Sacramento and northern San Joaquin basins (Jenden and Kaplan, 1989). Various shales within and stratigraphically adjacent to the Winters Formation, possibly including the Moreno Formation, are inferred, on the basis of their stratigraphic occurrence, and on the chemical and isotopic composition of gases, to be the principal source rock for the non-associated gas in the Sacramento Basin. The largest gas field in the state (Rio Vista) in southwestern part of the basin, as well as most of the other non-associated gas fields in the Sacramento and northern San Joaquin basins (Magoon and Valin, 1996; Hosford Scheirer and Magoon, 2008b) were probably derived from the Winters Formation. Shales in the Winters Formation may also be the source rock for the small volumes of light (39 to 49 °API) oils that are also produced in the Sacramento Basin.

Dobbins-Forbes

The Upper Cretaceous Dobbins Shale and shales of the Forbes Formation are inferred, largely on the basis of stratigraphic relationships and stable isotopic gas compositions, to be a second source-rock system in the Sacramento Basin. Like the somewhat younger Winters Formation, the Dobbins and Forbes Formations were deposited in a large deltaic/slope/submarine fan system that was actively filling the proto-Sacramento fore-arc basin during early Late Cretaceous time. The Dobbins and Forbes shales are believed to account for more than 57 billion m³ (2 trillion standard cubic feet, scf) of non-associated gas in the Sacramento Basin (Magoon and Valin, 1996).

Other Petroleum Source Rocks

In addition to the well-documented petroleum source rocks described above, small quantities of hydrocarbons may have been generated from various other source rocks, including the Sacramento Shale in the Sacramento Basin, Paleocene, and Eocene shales in some fields of the Santa Barbara/Ventura Basin, and Pleistocene mudstones in the southern San Joaquin Basin, which are source rocks for shallow, biogenic methane accumulations.

4.3. Migrated vs. Source-rock Petroleum Accumulations

4.3.1. Introduction to Unconventional Resources in the United States

Over the past few decades, changes in oil and gas drilling and well completion technologies have led to the recovery of extensive petroleum resources that were previously uneconomic. These petroleum resources, whose porosity, permeability, fluid trapping mechanism, or other characteristics differ from conventional sandstone and carbonate reservoirs, have been called "unconventional resources" (Schlumberger Oilfield Glossary - http://www.glossary.oilfield.slb.com/en/Terms/u/unconventional_resource.aspx). Shale oil, shale gas, tight gas sands, coal bed methane, gas hydrates, and oil shale are all considered to be unconventional resources—these are described below in Section 4.3.2.

Unconventional resources have also been defined using explicit engineering criteria (see Section 2.2) relating to (1) reservoir permeability and (2) the gravity and viscosity of oil. Thus, an unconventional accumulation under this definition can be one with low permeability, defined as a matrix permeability of less than 0.1 millidarcies (md), whether it contains oil, gas, or natural gas liquids as its principal commodity, or it can be a reservoir containing heavy oil or extra heavy oil, defined as having a measured API gravity of less than 22° for heavy oil or less or 10° for extra-heavy oil, respectively.

For the purposes of this chapter, we have adopted the USGS geologic definitions for conventional and unconventional (continuous) oil and gas (petroleum) resources (accumulations), as listed below: (http://energy.usgs.gov/GeneralInfo/HelpfulResources/EnergyGlossary.aspx#uvwxyz). Under this definition, heavy oil accumulations are not considered to be an unconventional resource.

- "**Conventional oil & gas accumulations**—Are discrete accumulations with well-defined hydrocarbon-water contacts, where the hydrocarbons are buoyant on a column of water. Conventional accumulations commonly have relatively high matrix permeabilities, have obvious seals and traps, and have relatively high recovery factors."

- "**Continuous oil & gas accumulations**—Commonly are regional in extent, have diffuse boundaries, and are not buoyant on a column of water. Continuous accumulations have very low matrix permeabilities, do not have obvious seals and traps, are in close proximity to source rocks, are abnormally pressured, and have relatively low recovery factors. Included in the category of continuous accumulations are hydrocarbons that occur in tight sand reservoirs, shale reservoirs, basin-centered reservoirs, fractured reservoirs, and coal beds."

In recent years, the petroleum industry of the United States (US) has experienced a remarkable transformation. After decades of more or less steady decline, US oil and gas production has surged upward in the last 5-10 years (Figures 4-4 and 4-5), greatly

reducing the volumes of oil being imported. As a result, the US is currently the world's largest petroleum (combined oil and gas) producer, ahead of Saudi Arabia and Russia (US EIA, 2014c). Most of the increase in US oil and natural gas production has come from the extensive application of directional drilling and WST to unconventional "shale oil" deposits such as the Bakken and Three Forks Formations in the Williston Basin of Montana and North Dakota and the Eagle Ford Shale in south-central Texas, and to unconventional "shale gas" deposits such as the Marcellus Shale in Pennsylvania, the Barnett, Haynesville, and Woodford shales in Texas, and the Antrim Shale in Michigan.

U.S. Field Production of Crude Oil
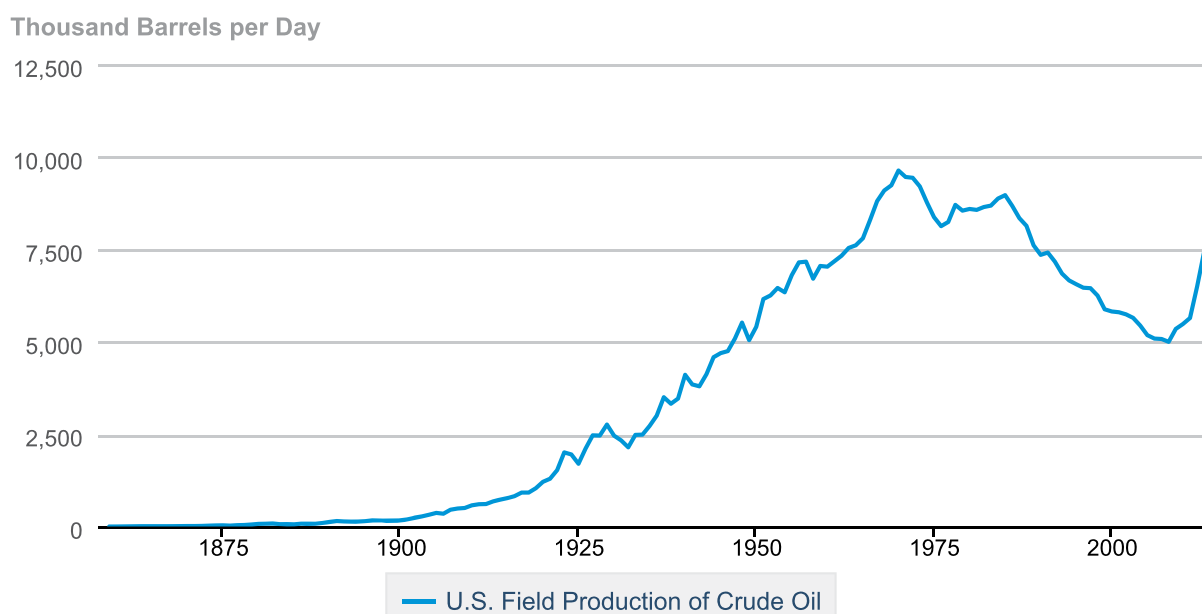
Source: U.S. Energy Information Administration

Figure 4-4. *US annual oil production vs. time (downloaded from US EIA website on 9/12/14)* http://www.eia.gov/dnav/pet/pet_crd_crpdn_adc_mbbl_m.htm.

Natural Gas Gross Withdrawals and Production
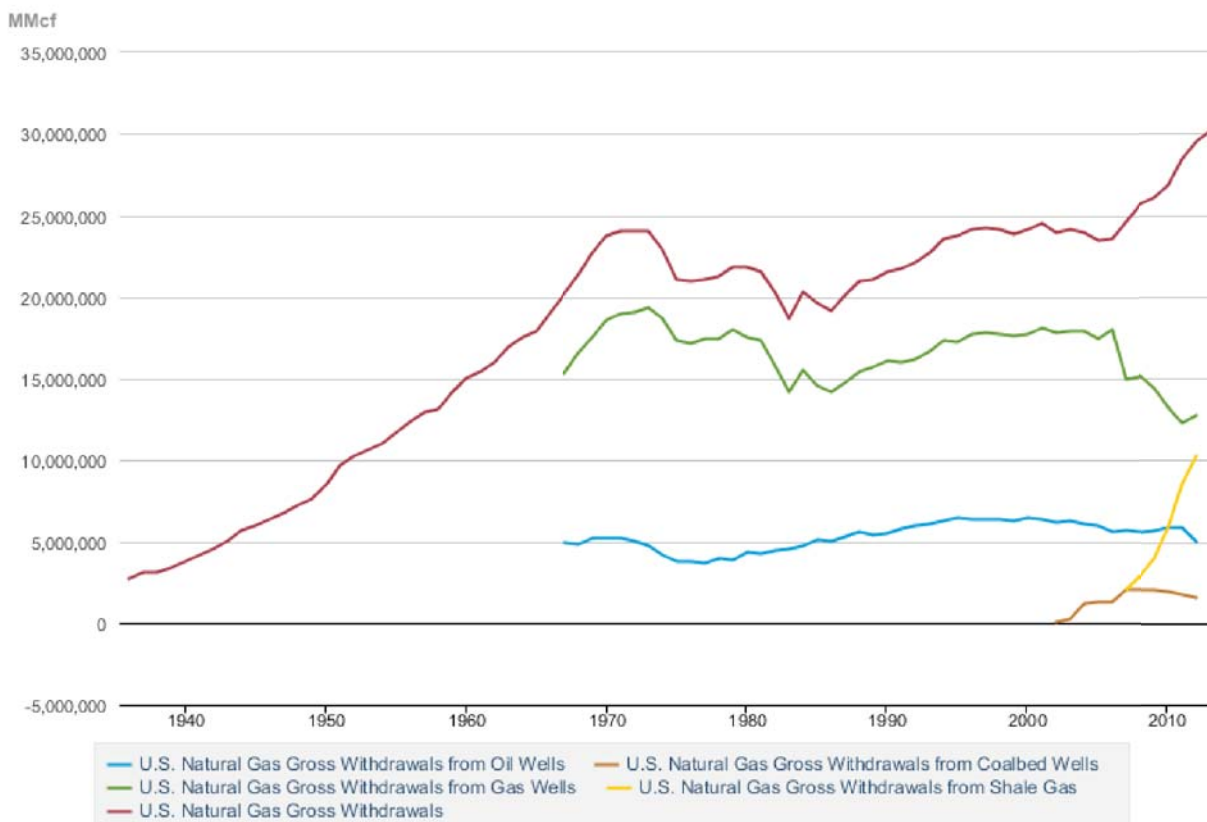
Source: U.S. Energy Information Administration

Figure 4-5. *US annual natural gas production vs. time (downloaded from US EIA website on 9/18/14) http://www.eia.gov/dnav/ng/ng_prod_sum_dcu_NUS_a.htm*

As mentioned above, we have adopted in this chapter a geological definition of unconventional petroleum as "continuous" accumulations. The distinction between "continuous" accumulations and "conventional" accumulations used by the US Geological Survey (US Geological Survey National Resource Assessment Team 1995) separates petroleum accumulations consisting of "migrated" oil in structural traps, such as the accumulations of oil in low-permeability diatomite reservoirs of California, from source-rock system (shale oil) accumulations such as the Eagle Ford shale oil in Texas. Both types of accumulations are appropriately considered unconventional from an engineering perspective, in that they share the quality of low permeability. However, they differ greatly in their geological setting, in their geographical extents, and in numbers of wells and types of technology required for production. This distinction is significant for considerations of development scenarios and potential impact of WST.

4.3.2. Types of Unconventional Resources

1) Source-rock Systems (Shale Oil and Shale Gas)

In shale oil and shale gas accumulations, the source rock and the reservoir rock are one and the same. Examples of such source-rock systems include the Barnett Shale in the Fort Worth Basin of Texas (Pollastro et al., 2007), the Eagle Ford Shale in the Gulf Coast Basin of southern Texas (Harbor, 2011; Hentz and Ruppel, 2011), and the Bakken Formation in the Williston Basin of Montana and North Dakota (Nordeng, 2009; Price and LeFever, 1992). A more detailed discussion of the Bakken example can be found in Section 4.4.3.

Production from such source-rock systems has become important in the United States. Most of the recent increases in US oil and gas production have come from just a few of these systems. This large-scale production has reduced the quantities of imported petroleum (US EIA, 2014c), caused the collapse of natural gas prices in the US (US EIA, 2014d), and displaced significant quantities of coal in the generation of electricity (Macmillan et al., 2013). Production of oil and gas from these low-permeability reservoirs is only possible through the drilling of thousands of directional wells, coupled with multi-stage massive hydraulic fracturing (a type of WST) (e.g., Texas Railroad Commission, 2014 - http://www.rrc.state.tx.us/oil-gas/major-oil-gas-formations/eagle-ford-shale/).

2) Tight-gas Sands

Extremely large quantities of natural gas are known to be in-place in thick successions of low-permeability sedimentary rocks in various basins. These "basin-center, tight-gas" accumulations are characterized by reservoirs with permeabilities of less than 0.01 md, abnormally high pore pressures, and a down dip occurrence of natural gas relative to water, combined with an absence of hydrocarbon-water contacts, and large in-place gas volumes.

Well-known examples of such "basin-center" accumulations are in the Uinta-Piceance Basin of Colorado (Spencer, 1995; Johnson et al., 2010a, b) and in the Green River Basin of Wyoming (Johnson et al., 2011). These unconventional reservoirs are being extensively exploited through closely spaced vertical wells and multiple well completions combined with massive hydraulic fracture treatments.

Although such accumulations are not known in California, they have been considered as a possibility in the deep parts of the largest basins, such as the deep depocenters of the southern and western San Joaquin (Gautier et al., 2007), deep in the Los Angeles Basin, and below the Delta depocenter of the Sacramento Basin (Hosford Scheirer et al., 2007). If such accumulations exist and could be exploited, their production might require the intensive application of WST.

3) Coal-bed Methane

Most coal seams consist of thick concentrations of terrestrial organic matter, originally formed through photosynthesis by higher land-plants. Thermal maturation of coal seams commonly results in the generation of significant quantities of natural gas that are retained in the coal beds (Geoscience Australia, 2012). In addition to being hazardous to coal miners, such natural gas accumulations are commonly produced and sold as energy commodities.

Production of coal-bed gas usually entails removing most free water from the coal seams (so-called dewatering) prior to successful production. This water can constitute an environmental hazard if not disposed of properly. Large quantities of coal-bed gas are produced in New Mexico, Colorado, and Wyoming, not to mention Australia, where it constitutes a significant part of that nation's resource base.

Coal beds are known in California, especially in and adjacent to the Sacramento Basin, where they may serve as one of the source rocks for natural gas generation. In general, California coal beds are thin and discontinuous (e.g., Bodden, 1983; Sullivan and Sullivan, 2012). Therefore, significant coal-bed gas production is not considered likely in California.

4) Gas Hydrates

Methane hydrates are crystal structures of water and methane molecules that are thermodynamically stable only under restricted conditions, usually with relatively high pressures and low temperatures. Gas hydrates are known from many deep ocean basins of the world, including the US Gulf of Mexico (Boswell et al., 2012). They are also commonly observed beneath permanently frozen ground—terrestrial permafrost—in the Arctic, including northern Alaska and northwestern Canada (Dallimore and Collett, 2005).

Compared to ordinary gas accumulations, gas hydrates contain extremely high concentrations of methane. Assessments suggest that methane hydrates probably contain more natural gas than all other known occurrences on earth.

While gas hydrates are present in offshore areas of California (BOEM, 2012), their near-term development is not considered likely. And, in any case, their production would probably not entail application of WST.

5) Oil Shale

Not to be confused with shale oil, oil shale is a sedimentary rock containing high concentrations of thermally immature kerogen (Dyni, 2005). In certain settings, it is possible to heat these kerogen concentrations to artificially generate oil and gas. Such artificial heating is termed retorting. Retorting of hydrocarbons was once a commonly used chemical practice for estimating the content of producible oil in certain sedimentary

successions. For example, in 1935, retorting studies of the Monterey-equivalent Nodular Shale in core samples recovered from the Playa del Rey oil field in the Los Angeles Basin were used to argue for both the organic origin of petroleum and for the exceptional richness of the Miocene strata of the Los Angeles Basin (Hoots et al., 1935).

The largest known oil shale deposits in the world are in the Uinta, Piceance and Green River basins of Colorado, Utah, and Wyoming, where the Eocene Green River Formation contains lake beds that are extremely rich in highly reactive and oil-prone kerogen (Johnson et al., 2010a, b; 2011). Engineering research continues to look for economically viable ways to produce the hundreds of billions of barrels of oil that could conceivably be retorted from the Green River Formation.

Large resources of oil shale are not known to be present in California.

4.4. The Monterey Formation

4.4.1. Characteristics of the Monterey Formation

In its lithology and thickness, the Monterey Formation varies greatly from place to place (Figure 4-6). However, in most basins, it includes some combination of thinly laminated diatomite, chert, siliceous mudstone, porcelanite, phosphatic shale, marlstone, clay shale, and dolomite (Behl, 1999; Bramlette, 1946; Dunham and Blake, 1987; Isaacs et al., 1983; Isaacs, 1980). While many of these lithologies have been described as "shales," they are more appropriately considered mudstones, given that they are fine-grained but relatively poor in clay mineral content (e.g., Behl, 1999; MacKinnon, 1989). The lithological variability of the Monterey has been characterized through studies of outcrops and cores, and in the subsurface through the use of geochemical (e.g., Hertzog et al., 1989) and integrated formation evaluation (e.g., Zalan et al., 1998) logging tools.

In areas closer to onshore uplifts (e.g., the San Joaquin and Los Angeles basins) Monterey-equivalent strata contain greater proportions of terrestrially-derived clastic sediments, particularly sandstones deposited in submarine channels and basin floor fans (Link and Hall, 1990; Redin, 1991). These coarser grained deposits can provide important reservoirs within the Monterey. Examples include the Stevens and Santa Margarita sandstones in the San Joaquin Basin (e.g., Magoon et al., 2009) and some reservoirs in oil fields of the Los Angeles Basin (Redin, 1991).

Several lithological characterizations of the Monterey have been published, based upon the relative abundance of silica, carbonate, phosphate, and detrital minerals (e.g., Carpenter, 1989; Dunham and Blake, 1987; Isaacs, 1981a, 1981b). In the coastal Santa Maria and Santa Barbara/Ventura basins, the lower portion of the Monterey is carbonate-rich, the middle section has abundant phosphatic and organic-carbon-rich shales, and the upper section is dominated by siliceous mudstones, porcelanite, chert, or diatomite, depending upon the degree of thermal exposure (Behl, 1999; Govean and Garrison, 1981; Isaacs et al., 1983; Isaacs, 1981b) (Figure 4-7). In the southwestern San Joaquin Basin, at Chico Martinez Creek, the Monterey is more than 1,830 m (6,000 ft) thick, and

contains four major shale sequences: the Gould, Devilwater, McDonald, and Antelope shales (Mosher et al., 2013). In the Los Angeles Basin, where the tectonic history during the middle to late Miocene is quite complex, Monterey equivalent strata vary greatly from one side of the basin to the other (e.g., Wright, 1991; Yeats and Beall, 1991).
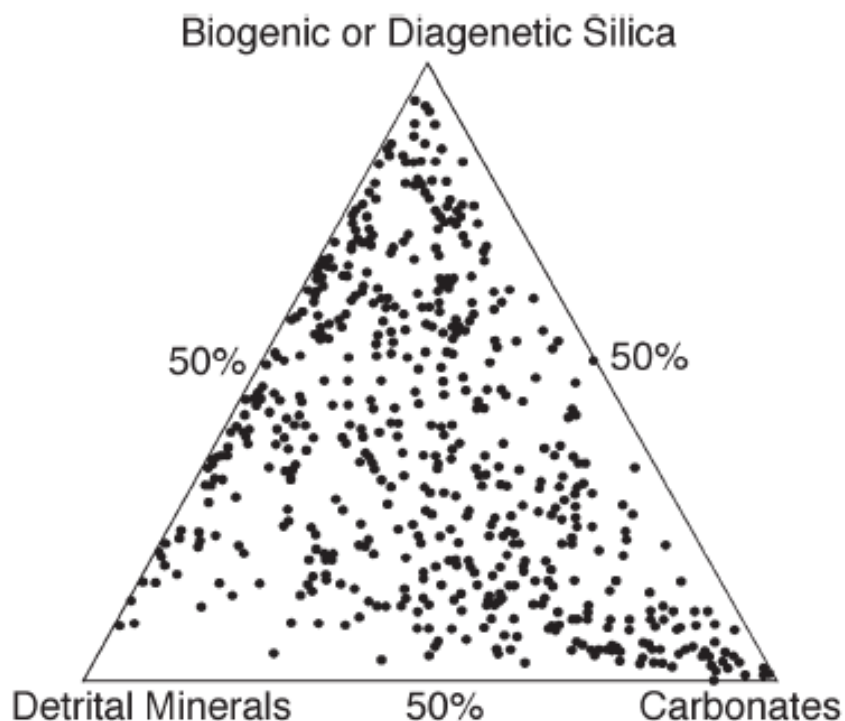
Figure 4-6. *Lithologic variability of the Monterey Formation (Behl, 1999).*

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 (Figure 4-8). This 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 and Dunham, 1992; Isaacs, 1984).

Parts of the Monterey that are enriched in marine kerogen are prolific petroleum source rocks (Isaacs, 1989, 1992a; Peters et al., 2013, 2007; Tennyson and Isaacs, 2001; Isaacs and Rullkötter, 2001). Graham and Williams (1985) reported TOC values for shales of the Monterey in the San Joaquin Basin ranging from 0.40 to 9.16 wt. %, with a mean value of 3.43 wt. %. Isaacs (1987) reported even higher TOC concentrations, ranging between 4

and 8% TOC (6 and 13% organic matter) for the Santa Maria Basin and the Santa Barbara coast. TOC abundances are generally highest in the phosphatic shales of the middle Monterey (Figure 4-9), where sedimentation rates were low and dilution by biogenic sediments was minimal (Bohacs et al., 2005). Where thermally mature, such TOC-rich Monterey strata could be a target for unconventional shale oil production.
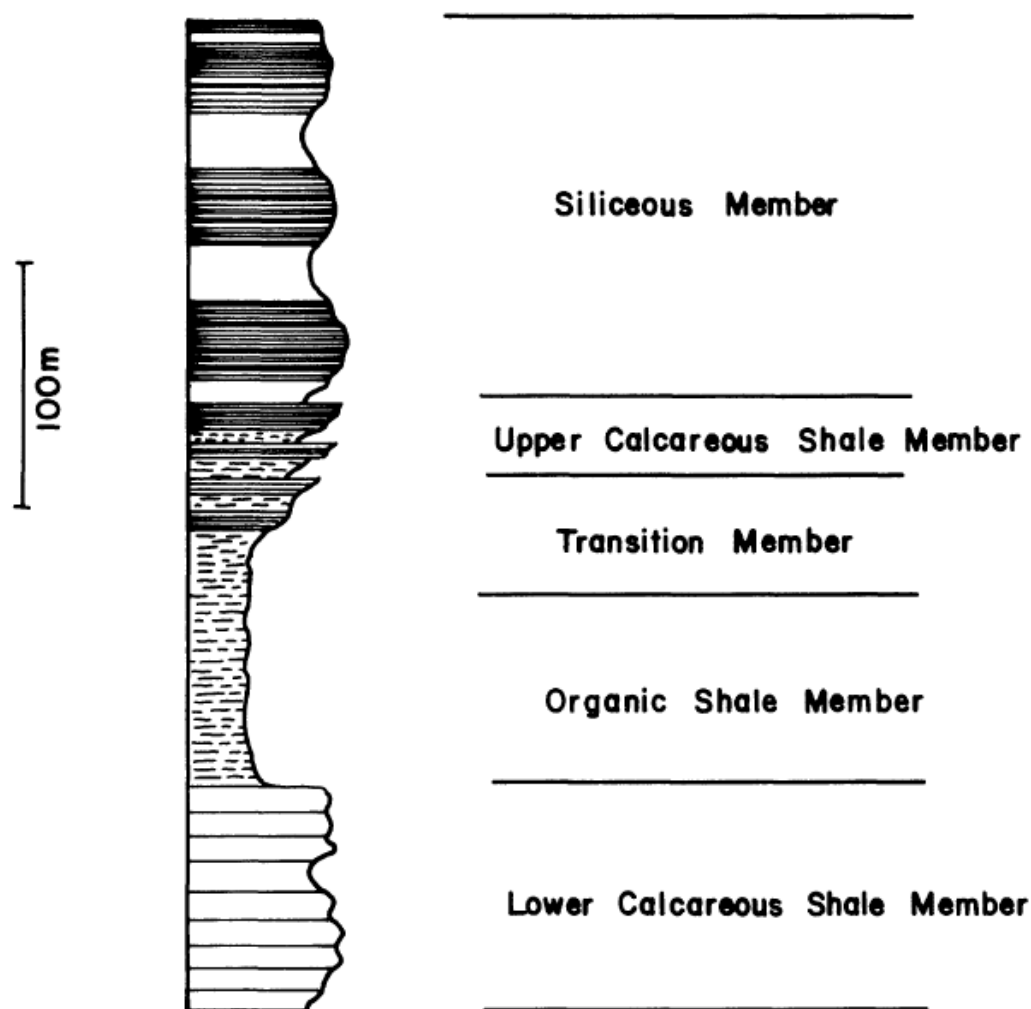
Figure 4-7. *Generalized stratigraphic section of the Monterey Formation from the Santa Barbara coastal region (Isaacs, 1980). Open pattern depicts massive units, broken stipple indicates irregularly laminated beds, and thinly lined pattern denotes finely laminated units.*
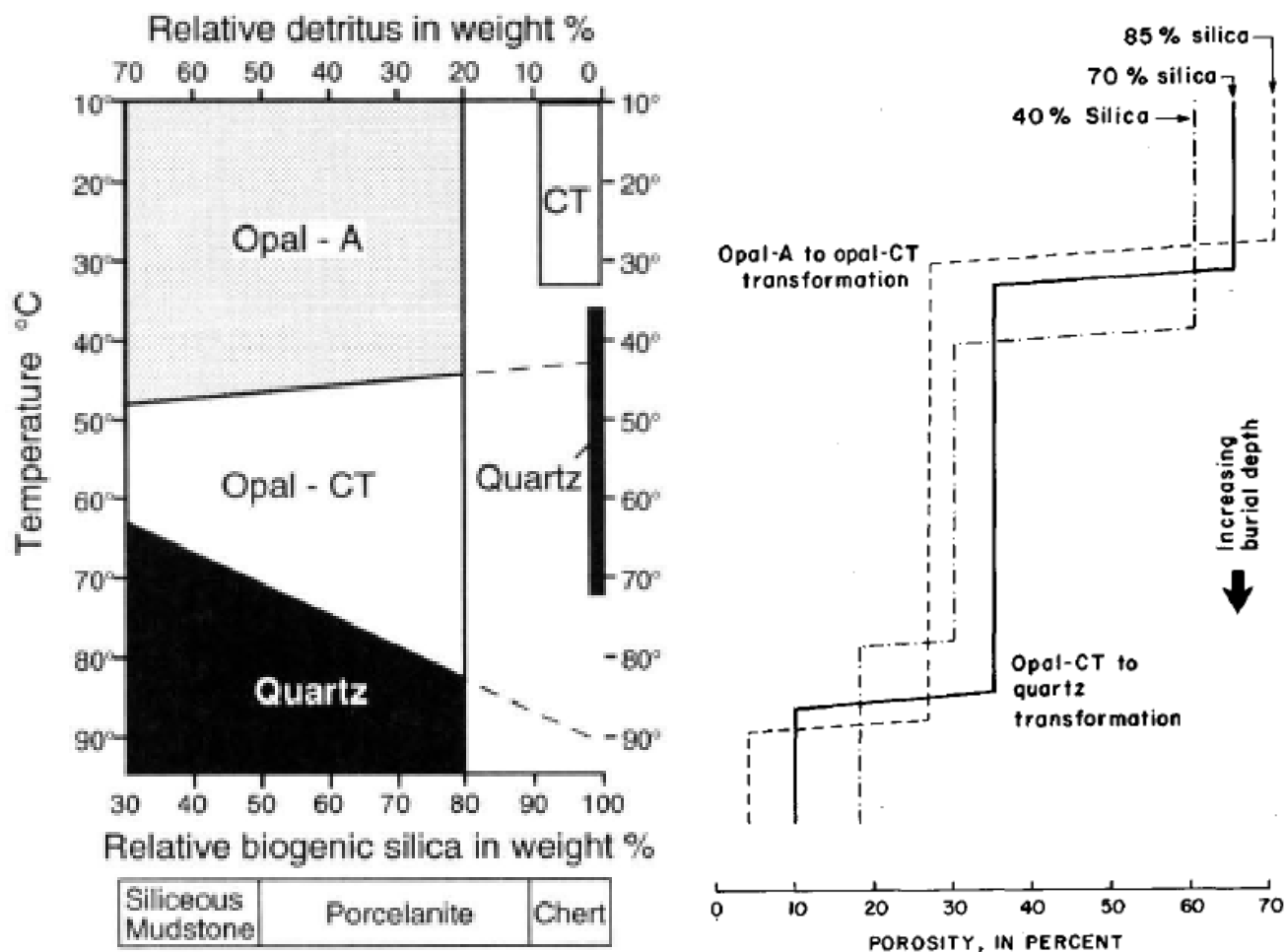
Figure 4-8. *(A) Sediment composition and temperature effects on silica phase changes in the Monterey Formation (Behl and Garrison, 1994). (B) Changes in porosity as a function of silica phase transformation and burial (Isaacs, 1981c).*
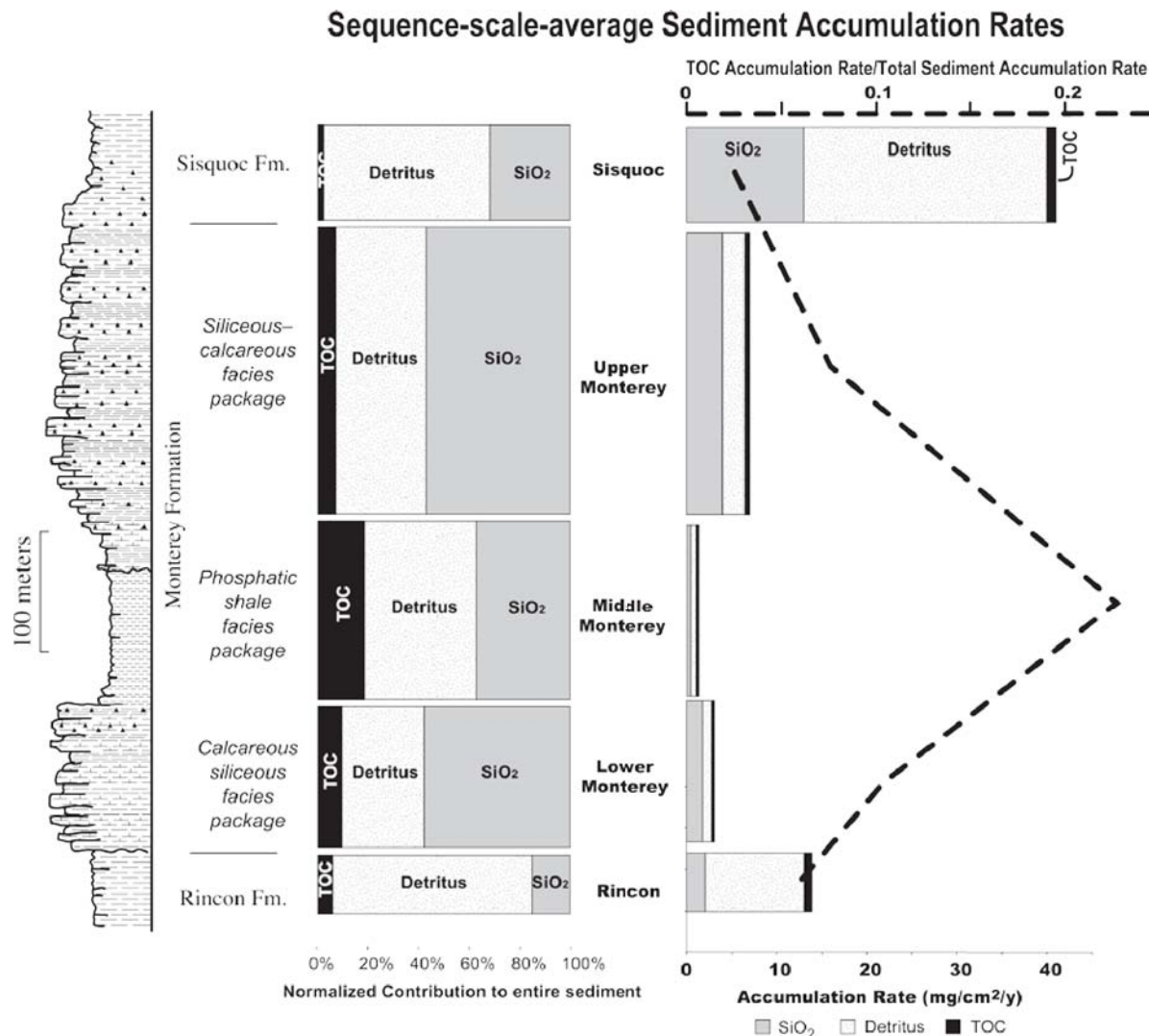
Figure 4-9. *Distribution of organic matter, detrital sediments, and biogenic silica accumulations as a function of stratigraphic position in the Monterey Formation (Bohacs et al., 2005).*

4.4.2. Physical Properties of the Monterey Formation

Physical properties determine if a rock can serve as a reservoir, and if and how it might be stimulated by hydraulic fracturing. Porosity is the open pore and fracture volume of a rock. The matrix and fracture porosity not only provide storage volumes for fluids, but also potential pathways for fluid flow, provided the pores and fractures are interconnected. The permeability of a rock is its ability to transmit fluids; the goal of well stimulation is to improve production by enhancing the effectiveness of the wellbore connection into the reservoir. Successful stimulation of a reservoir through hydraulic

fracturing depends on the ability to open existing fractures or to create new fractures. The spatial distribution of strength, elasticity, and stress within the rock influence the natural fracture system and how hydraulic fractures develop. Young's modulus, the ratio of longitudinal stress to longitudinal strain, is used to estimate the rigidity of a rock. The composition and concentration of organic matter determines whether a particular lithology is a potential hydrocarbon source rock.

Physical properties (porosity, permeability, total organic carbon [TOC], Young's elastic modulus) have been measured in many Monterey rock samples.

The Newlove 110 well (API 08222212) in the Orcutt field of the Santa Maria Basin was the subject of an early detailed hydrofracture research study conducted jointly by Unocal and the Japan National Oil Company (Shemeta et al., 1994). Prior to hydrofracture, a thick section of continuous core was sampled from the Monterey, which extends from 619 to 855 m (2,030 to 2,805 ft) in the well. Core Laboratories drilled 239 one-inch-diameter (in; 2.54 centimeter, cm) core plugs parallel to bedding between the depths of 735 and 860 m (2,412 and 2,820 ft) and measured horizontal air permeability, helium porosity, fluid saturation, and grain density. The measured porosities ranged from 3.7 to 37%, with an arithmetic average of 22.8% and a median value of 23.4% (Figure 4-10a). Matrix horizontal air-permeability values ranged from 0.00 md to 5,080 md, with an arithmetic average of 99.6 md, a geometric average of 2.59 md, a median value of 1.67 md, and a harmonic average of 0.12 md (Figure 4-10b). Grain density values ranged from 2.19 to 2.96 grams per cubic centimeter (g/cm^3), with an arithmetic average of 2.50 g/cm^3 and a median value of 2.49 g/cm^3.
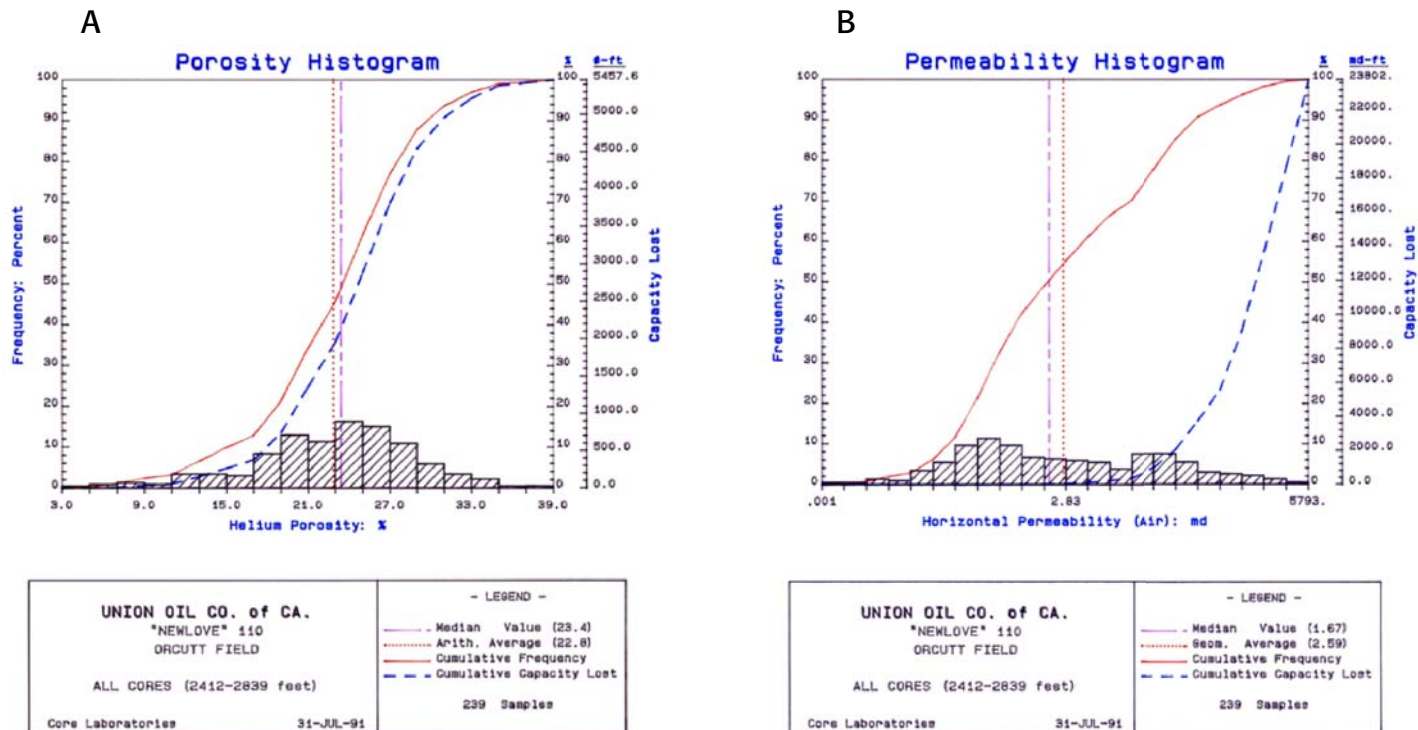
Figure 4-10. *Helium porosity (A) and horizontal air permeability (B) measurements of 239 Monterey Formation core samples from the Newlove 110 well, Orcutt oil field, Santa Maria basin. The Core Laboratories report can be found on the DOGGR website at:* http://owr. conservation.ca.gov/WellRecord/083/08322212/08322212 Core Analysis.pdf

Isaacs (1984) reports the physical properties of three siliceous Monterey lithologies that illustrate the effects of diagenesis (Table 4-1). Chaika and Williams (2001) observed that permeability reductions associated with silica phase transformation at increasing depth of burial in the Monterey appear to have two different trends: (1) a silica-rich host rock that has an abrupt porosity reduction (from 55 to 45%) associated with the change from opal-A to opal-CT, lending itself to a more brittle, fractured rock below this transition, and (2) a more gradual porosity reduction associated with this transformation of siliceous mudstones with a higher abundance of detrital minerals. This more clay-rich rock tends to retain higher matrix porosity, which could lead to higher volumes of hydrocarbon storage. Contrasts in rock properties associated with these changes in mineralogy in the Monterey Formation can result in the formation of diagenetic oil traps, such as those observed in the Rose oil field, where the top of the reservoir in the McLure shale member occurs at the transition from opal-CT to quartz (Ganong et al., 2003).

Table 4-1. *Physical properties of siliceous Monterey lithologies reflecting impacts of diagenesis (Isaacs, 1984).*

Lithology	Porosity (%)	Permeability (md)	Grain density (g/cm³)
Opal-A bearing diatomaceous mudstones	50-70	1-10	2.2-2.4
Opal-CT porcelanites	30-40	<0.01 to 0.1	2.2-2.35
Quartz porcelanites	10-20	<0.01 md	2.1-2.4

Measurements of physical properties were conducted on samples of the Antelope Shale member of the Monterey Formation in the Buena Vista Hills field, located between the giant Elk Hills and Midway-Sunset fields in the SW portion of the San Joaquin Basin (Montgomery and Morea, 2001). Four different rock types were studied: opal-CT porcelanite, opal-CT porcelanite/siltstone, clay-poor sandstone, and sandstone/siltstone (Table 4-2).

Table 4-2. *Physical properties of Antelope Shale member lithologies of the Monterey, Buena Vista Hills field (Montgomery and Morea, 2001).*

Lithology (number of samples)	Average porosity (%)	Median permeability (md)	Average grain density (g/cm³)
Opal-CT porcelanite (399)	33.8	0.1	2.31
Opal-CT porcelanite/siltstone (451)	25.7	0.07	2.36
Clay-poor sandstone (19)	21.1	6.3	2.62
Sandstone/siltstone (57)	20.8	0.16	2.57

Liu et al. (1997) analyzed a number of Monterey core samples from the Santa Maria Basin. They reported lithotype, porosity, density, and TOC values (Table 4-3) for 10 Monterey Formation samples obtained from two wells (with sample depths ranging from 1,390 to 1,693 m (4,560 to 5,553 ft)) in the Santa Maria Basin (Liu, 1994).

Table 4-3. *Physical properties of Monterey core samples from the Santa Maria Basin (Liu et al., 1997).*

Lithology	Number of core samples	Porosity (%)	Grain density (g/cm³)	Total organic carbon (wt. %)
Porcelanite	2	10-11.4	2.14-2.17	2.28-2.4
Siliceous shale	1	4.3	2.24	6.81
Shale	3	18-21	2.02-2.35	8.19-18.2
Siliceous dolomite	3	11-19	2.38-2.70	0.52-8.12
Dolomite	1	3.0	2.72	0.19

Morea (1998) performed reservoir characterization studies of siliceous shales and mudstones from the Antelope and Brown shale members of the Monterey Formation from the Buena Vista Hills field. As part of the study, seven core samples recovered from

depths ranging from 1,277.4 – 1,462.8 m (4,191 – 4,799.3 ft) were analyzed for Young's modulus. These samples, consisting of porcelanite and clayey porcelanite, have values ranging from 8.8 to 18.9 gigapascals (GPa) (1,172,000 to 2,724,000 pounds per square inch (psi)), with an average value of 13.7 GPa, (1,990,000 psi).

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

In conclusion, the lithologies of the Monterey Formation exhibit a wide range of physical properties. Diatomites have the highest porosities of any Monterey lithology (typically > 50%), but with diagenesis, these rocks are converted into porcelanites and with increasing temperature to quartz cherts, which have significantly lower porosities (generally 20-40%). Most of the Monterey lithologic units have intrinsically low matrix permeabilities (typically less than a millidarcy). The porcelanites, cherts, siliceous shales and mudstones, and dolomites are quite brittle, and often develop natural fractures, which can lead to higher fracture permeability for these rock types. The presence of natural fractures has a significant impact on oil migration (Behl, 1998; Eichhubl and Behl, 1998; Hickman and Dunham, 1992). Most of the shale (clay-rich) lithologies in the Monterey have TOC values greater than 2%, making them prospective hydrocarbon source rocks. The organic-rich phosphatic shales found within the Middle Monterey are the most prospective source rocks and, therefore, the most likely unconventional shale oil targets.

4.4.3. Conventional and Unconventional Resources in the Monterey Formation

The Monterey is the dominant petroleum source rock in California. It also forms important reservoir rocks for migrated oil in numerous active fields in the San Joaquin, Los Angeles, Santa Barbara/Ventura and other basins. Monterey reservoir lithologies include sandstones such as those of the Stevens Sand in the San Joaquin Basin, diatomite such as the reservoir at South Belridge field, and fractured siliceous rocks such as the reservoir at Hondo offshore. The large areal extent of the Monterey and its great thickness (up to 1,830 m [6,000 ft]) make it a significant petroleum resource target.

Nearly all major Monterey oil reservoirs occur at depths that are shallower than the oil window, suggesting that the reservoirs contain oil that migrated updip from where it formed to where it became trapped (Figure 4-11). This is confirmed by geochemical evaluation of biological markers and other maturity indicators, which demonstrate that the oil found in most Monterey reservoirs in the San Joaquin was not generated in situ, but instead was sourced from Monterey shales deeper in the Basin (Kruge, 1986).
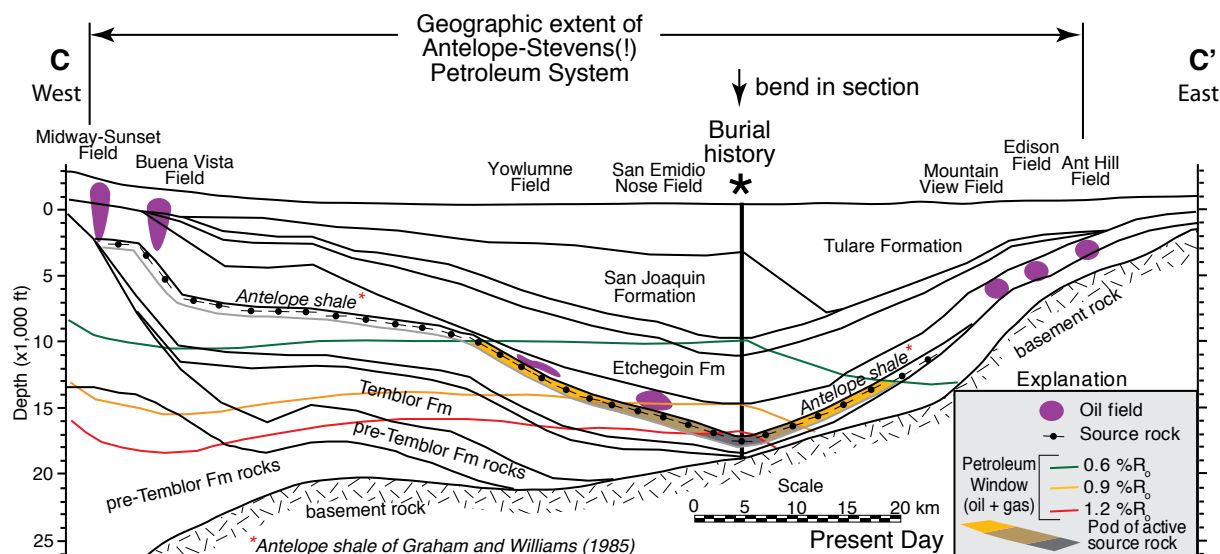
Figure 4-11. *Cross section depicting the Antelope-Stevens Petroleum System in the southern San Joaquin Basin (Magoon et al., 2009). The Antelope Shale and Stevens Sand are subunits of the Monterey Formation. Note that the bulk of the oil fields are located on the margins of the Basin, and that the oil appears to have migrated updip from the source region (below the top of the petroleum window) in the center of the Basin.*

If Monterey source rocks are also to serve as reservoirs for unconventional source–rock system (shale) oil, they would need to retain significant amounts of producible oil that has been generated but not migrated. Portions of the Monterey Formation are located within the oil window in the deeper parts of most major petroleum basins in California. However, only organic-rich stratigraphic intervals, such as the organic-rich phosphatic shales in the middle Monterey of the coastal basins, are prospective unconventional oil shale targets. These source-rock intervals may have retained oil that could be extracted using advanced well stimulation methods. However, there is little published information on these deep sedimentary sections on which to base assessments of potentially recoverable resources. A few deep wells have been drilled, but there are no reports of commercially successful production from such depths (Schwochow, 1999; Burzlaff and Brewster, 2014).

Because of the depths and temperatures encountered in the oil window, compaction and diagenetic effects would have converted any original biogenic opal-A to opal-CT and quartz chert. This would reduce matrix porosity, thus lowering reservoir capacity, while increasing brittleness and natural fracturing (Chaika and Dvorkin, 2000; Chaika and Williams, 2001), which would favor oil migration.

As described in Section 4.4.4 below, the Monterey differs from other unconventional shale oil accumulations, such as the Bakken and the Eagle Ford, in its highly variable mineralogy, lithology, and silica phase behavior (El Shaari et al., 2011), and in the structural complexity of the basins where it is found (e.g., Wright, 1991; Ingersoll and Rumelhart, 1999). This variability makes it challenging to discover and develop source-rock oil, as evidenced by the results of deep drilling in the San Joaquin Basin (Burzlaff and Brewster, 2014).

4.4.4. Comparison of the Monterey Formation with the Bakken Formation

The Bakken, along with the Eagle Ford Formation of Texas, is one of the largest producing unconventional shale oil units in the United States (Figure 4-12) (US EIA, 2014a). The jump in oil production from the Bakken and Eagle Ford through the use of unconventional well completion and stimulation techniques led to the identification of the Monterey as a potentially important shale oil target (US EIA, 2011). A comparison of the Bakken and the Monterey may provide insights into the possibility of increasing oil production in California through implementation of well stimulation methods.
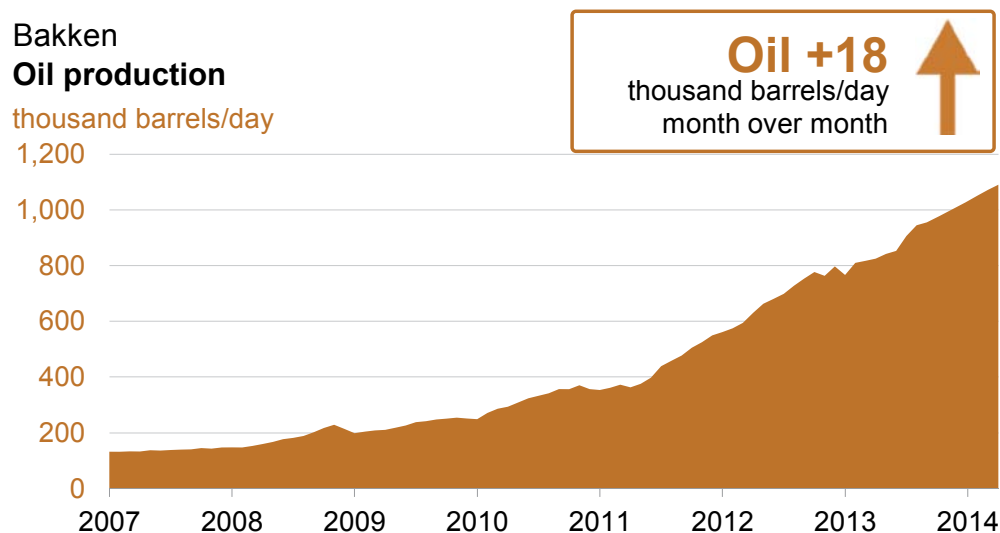
Figure 4-12. *Increases in oil production from the Bakken Formation (US EIA, 2014a).*

The Upper Devonian-Lower Mississippian Bakken Formation is best known from the Williston Basin in North Dakota, Montana, Saskatchewan, and Manitoba (Gaswirth et al., 2013). It consists of three main zones: (1) an upper organic-rich black shale; (2) a middle unit, consisting mainly of silty dolostone or dolomitic siltstone and sandstone, and (3) a lower unit, similar to the upper zone, also consisting of organic-rich black shale (Pitman et al., 2001). A fourth unit has been proposed for the Bakken, the Pronghorn unit, a sandy unit previously known as the Sanish (LeFever et al., 2011) that underlies the lower black shale.

The Bakken has a maximum thickness of 49 m (160 ft) in the central part of the basin (Figure 4-13), decreasing to zero thickness on the margins. The unit generally has a total thickness of less than 30 m (100 ft) (Lefever, 2008). The main target for production has been the middle dolomitic member, while the upper and lower shales are considered the source rocks for petroleum in the Bakken and Three Forks Formations. The Bakken shales have TOC values ranging from less than 1% to as much as 35%, averaging around 11 wt. % (Webster, 1984). Most of the Bakken petroleum system is in the oil generation window (Figure 4-14) and hydrocarbons sourced from the Bakken in North Dakota have generally migrated no more than a meter or two into the adjacent middle dolomite unit and underlying sandstones (Sonnenberg et al., 2011).

As explained in Section 4.3.1, this type of petroleum system is sometimes called a continuous petroleum accumulation (Gautier et al., 1995; Nordeng, 2009). Unconventional techniques (horizontal drilling into the middle Bakken combined with multiple zone well stimulation) have been employed to maximize oil production from this formation (Jabbari and Zeng, 2012). Around 72 million m³ (450 million barrels) of oil were produced using these techniques from the Bakken and Three Forks Formations in the Williston Basin between 2008 and 2013 (Gaswirth et al., 2013). The successful production of oil from the Bakken has prompted discussions regarding the possible recovery of oil from other shale oil formations such as the Monterey (Price and LeFever, 1992).
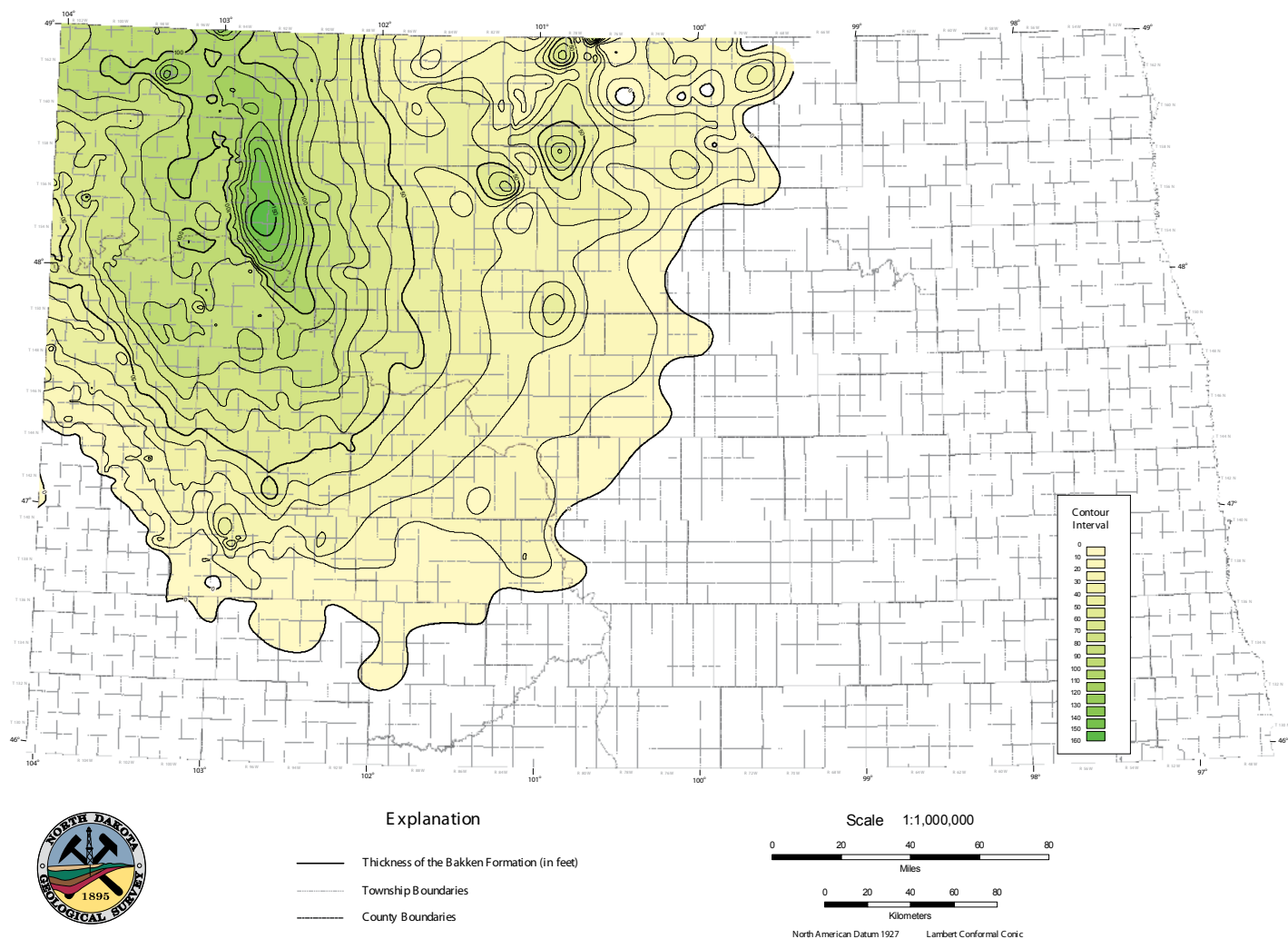
Figure 4-13. *Isopach map of the Bakken Formation (Lefever, 2008).*
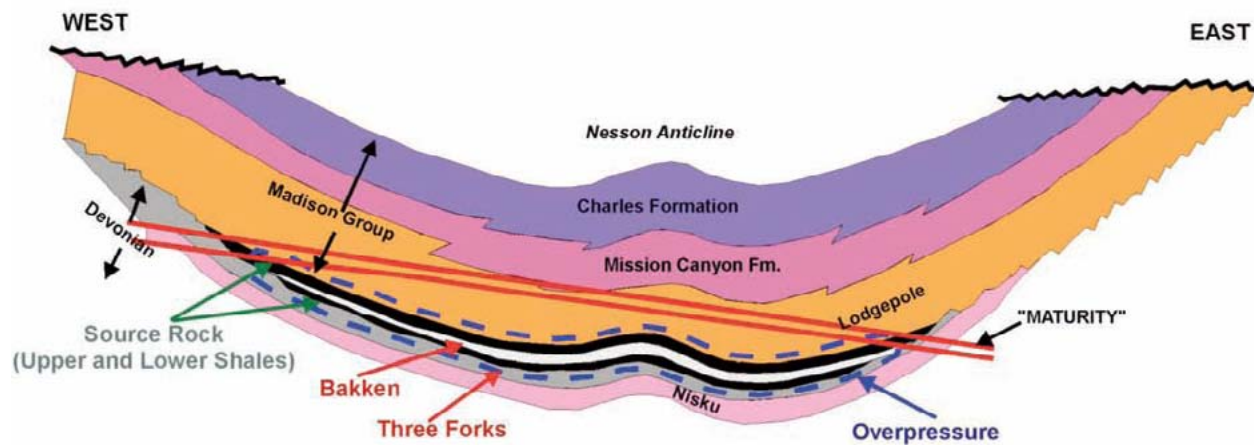
Figure 4-14. *Schematic EW cross section of the Bakken petroleum system. Note that the Bakken lies below the top of the oil window (Sonnenberg et al., 2011).*

4.4.4.1. Physical Properties of the Bakken Formation

Core samples from the Middle Bakken from the Parshall field have porosities ranging from 1 to 11% and permeabilities that average 0.0042 md (Simenson et al., 2011); a similar range of values of 1.1 to 10.2% (porosity) and <0.001 to 0.215 md (permeability) were reported by Ramakrishna et al. (2010). Production sweet spots involve areas with enhanced porosity and the presence of natural fractures (Pitman et al., 2001; Sonnenberg et al., 2011). Log-derived Young's modulus values for the Middle Bakken are around 7 GPa (1,000,000 psi) (Ramakrishna et al., 2010).

4.4.4.2. Similarities and Differences of the Monterey and Bakken Formations

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

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

The thicknesses of these units are also dramatically different. The Bakken is typically less than 30 m (100 ft) thick and the productive Middle member is generally less than 15 m (50 ft) thick. In contrast, the Monterey in the San Joaquin Basin is about 1,830 m

(6,000 ft) thick (Mosher et al., 2013), and even greater thicknesses can be encountered in some of the basin depocenters. It is important to note that the organic-rich phosphatic shale portion of the Monterey, which would be a primary candidate for an unconventional shale oil reservoir in this formation, is considerably thinner (less than 200 m thick for the Santa Maria–Santa Barbara Channel basin section depicted in Figure 4-7).

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

The structural setting of the Williston Basin in which the Bakken Formation resides is much less complex than the petroleum-rich basins of California. The Williston Basin is a structurally simple intracratonic basin (Sloss, 1987), whereas the Neogene sedimentary basins in California are tectonically controlled, with faults and folds strongly influencing the trapping and accumulation of hydrocarbons in most of the major oil fields (Wright, 1991). The presence of wrench faults, combined with a basement of highly deformed Mesozoic subduction complex rocks, has led to the creation of wide varieties of trapping structures (Graham, 1987).

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

While the style of oil accumulation of the discovered resources associated with the Monterey Formation differs greatly from the Bakken Formation, the postulated Monterey source rock play is similar. The producing oil fields that are hosted in the Monterey represent conventional oil accumulations (Figure 4-11) where the oil has migrated from the source rock up into a reservoir zone in a structural, stratigraphic, or diagenetic trap. The Bakken petroleum system represents a continuous petroleum accumulation (Figure 4-15), where the oil formed in organic-rich upper and lower shales migrates locally into the adjacent dolomitic strata of the Middle Bakken (Nordeng, 2009). We note that the dolomitic middle Bakken still has low enough permeability so that it requires stimulation for commercial production. It is possible that a similar type of continuous oil accumulation exists within and immediately adjacent to deeply buried Monterey as a source rock. However, in contrast to the Bakken, significant amounts of oil that have been generated from the Monterey source rocks are known to have migrated and accumulated to form the main oil fields in California. The complex tectonic history for sedimentary basins in California and the extensive presence of natural fractures in the siliceous Monterey mudstones have facilitated the migration of oil generated in the basin depocenters via higher permeability fracture and fault pathways to the producing conventional fields.

The amount of hydrocarbons remaining within these deep basin Monterey source rocks as a potential source rock play is not known, and the possibility of insufficient oil retention is seen as a significant risk for exploration.
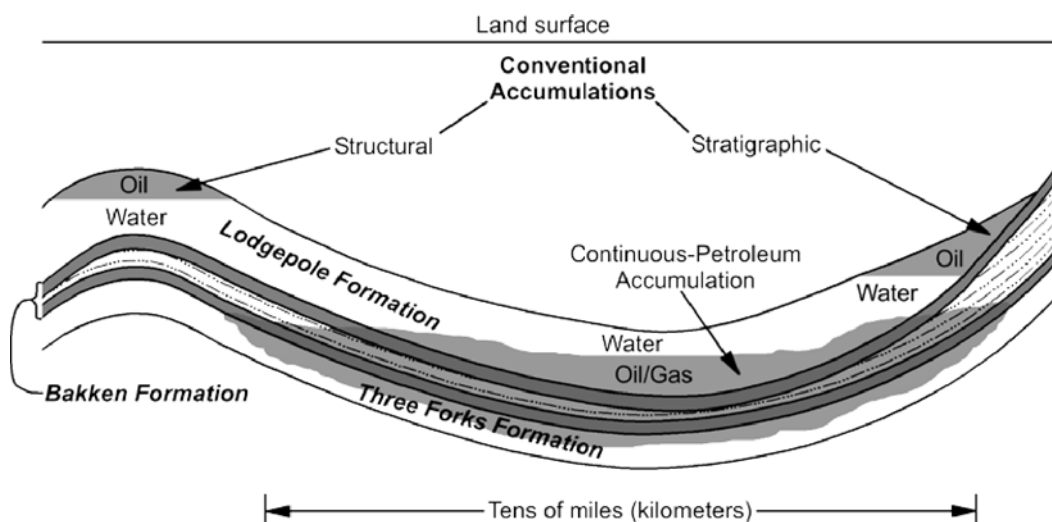
Figure 4-15. *Schematic cross section illustrating conventional oil reservoirs (with migrating oil) and a continuous petroleum accumulation, as illustrated by the Bakken petroleum system (Nordeng, 2009).*

4.5. Petroleum Geology of California

4.5.1. Neogene Basins of California

Most of the oil and gas fields in California are located in structural basins (DOGGR, 1982; 1992; 1998) formed over the past 23 million years. These basins (Figure 4-16) are filled with mainly marine sedimentary rocks, originally including both biogenic (produced by marine organisms) and clastic (derived by erosion of existing rocks) sediments. In each basin, geologists have identified distinct packages of sedimentary rocks as *formations*, which share similar time-depositional sequences and have distinctive characteristics that can be mapped. Formations can be divided into subunits, known as *members*, which in turn have specific lithologic characteristics. Similarly named geologic formations are commonly found in adjacent basins, where they were deposited at about the same time, and presumably under similar conditions.
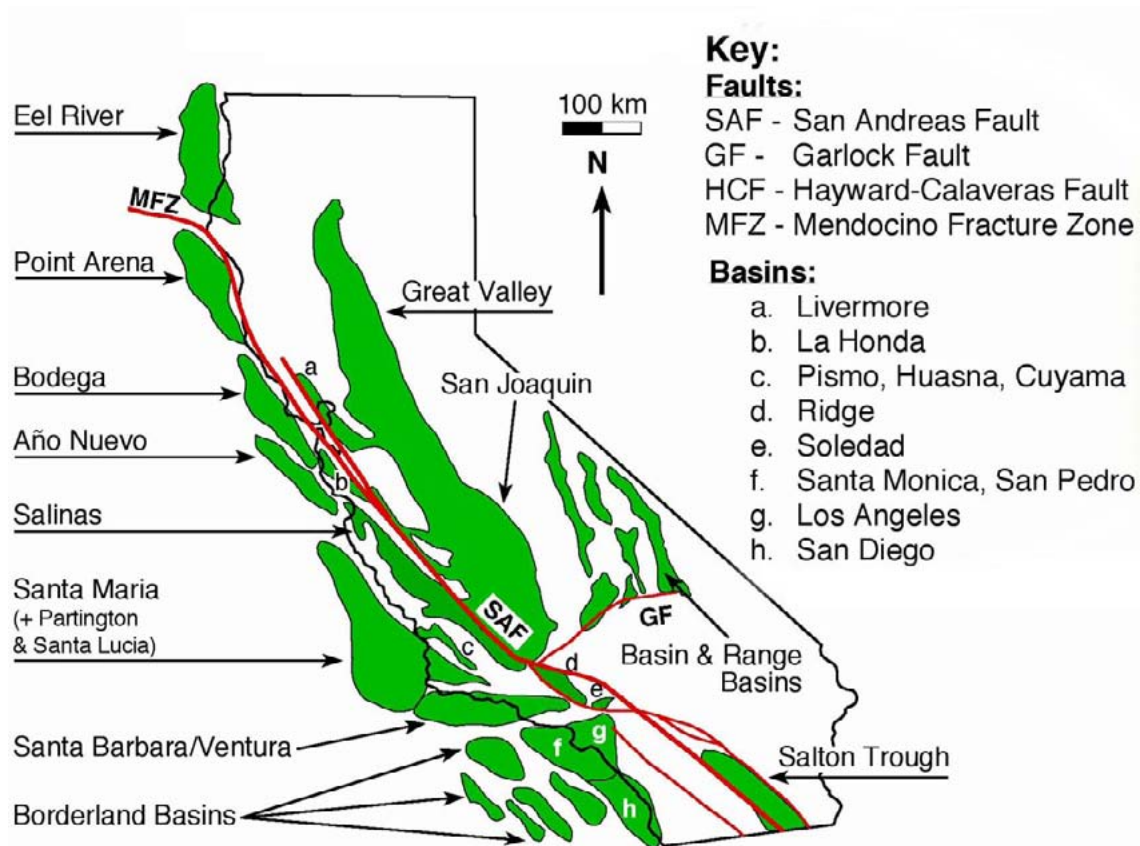
Figure 4-16. *Neogene sedimentary basins in and along the coastal margins of California (from Behl, 1999).*

Most oil reservoirs in California have a complex structural history of folding, faulting, subsidence, and uplift driven by the tectonic evolution of the western margin of North America. The result is numerous uplifts and adjacent structural depressions (basins) where sediments with a wide range of compositions accumulated. These sediments have themselves been subjected to subsequent burial and deformation.

Faults, folds, and fractures play a critical role in the migration and accumulation of hydrocarbons in most California oil fields (Chanchani et al., 2003; Dholakia et al., 1998; Dunham and Blake, 1987; Finkbeiner et al., 1997). Compressive stresses can lead to the development of folds, which can form structural traps with effective seals. Under such conditions, the more brittle rocks develop fractures that provide flow pathways for upward hydrocarbon migration. Fracture permeability is especially important when matrix permeabilities are low in clay-rich shales and siliceous mudstones (Hickman and Dunham, 1992).

4.5.2. California Basins: Geology, Resources, and Potential for WST

In this section, we present a summary of the oil and gas resource potential of the petroliferous basins of California. We summarize the geography and geology of each basin, keyed to a location map, and interpret the resource potential of the basin and the likelihood of future application of WST.

4.5.2.1. Northern Coastal Basins—Onshore

4.5.2.1.1. Geography and Geology

The Northern Coastal Basins—Onshore includes an area of about 37,000 square kilometers, (km^2; 14,300 square miles, mi^2) from north of Crescent City in Del Norte County southward to San Benito County between the San Andreas Fault and the 4.8 kilometer (km; 3 mile, mi) limit offshore; and the Coast Range Thrust (as far south as Lake Berryessa), the Hayward Fault (as far south as the southern boundary of Alameda County), and the Tesla and Ortigalita faults (Stanley, 1995a). The province is about 660 km (410 mi) long from northwest to southeast and about 113 km (70 mi) wide at its widest point near Fort Bragg (Figure 4-17).

Two of the North Coastal basins, Eel River and the Sargent-Hollister, have a history of demonstrated petroleum production, albeit at minor levels. Gas in the Eel River Basin and oil and gas in the Sargent-Hollister Basin have been produced from reservoirs in gently to moderately deformed Neogene (Miocene and Pliocene) sedimentary successions. The Neogene strata overlie moderately to intensely deformed rocks of the Jurassic to Tertiary Franciscan Complex. Over most of the north-coastal area, the Franciscan is regarded as economic basement; however, the Franciscan has been considered prospective for hydrocarbons in some areas of Humboldt and San Benito Counties (Stanley, 1995a).

The earliest exploratory drilling in California occurred in 1865 near surface seeps in the Petrolia area, in western Humboldt County (Rintoul, 1990). Dozens of wells have since been drilled near Petrolia; some of them found evidence of oil in fractured Franciscan rocks, but no commercial production has been established. Oil has been produced from Neogene sandstones in the Sargent field since 1906, and commercial production of non-associated gas was reported in the Hollister field beginning in 1951. In the Eel River Basin, non-associated gas has been produced since 1937 from Pliocene sandstones in the Tompkins Hill field (DOGGR, 1982).
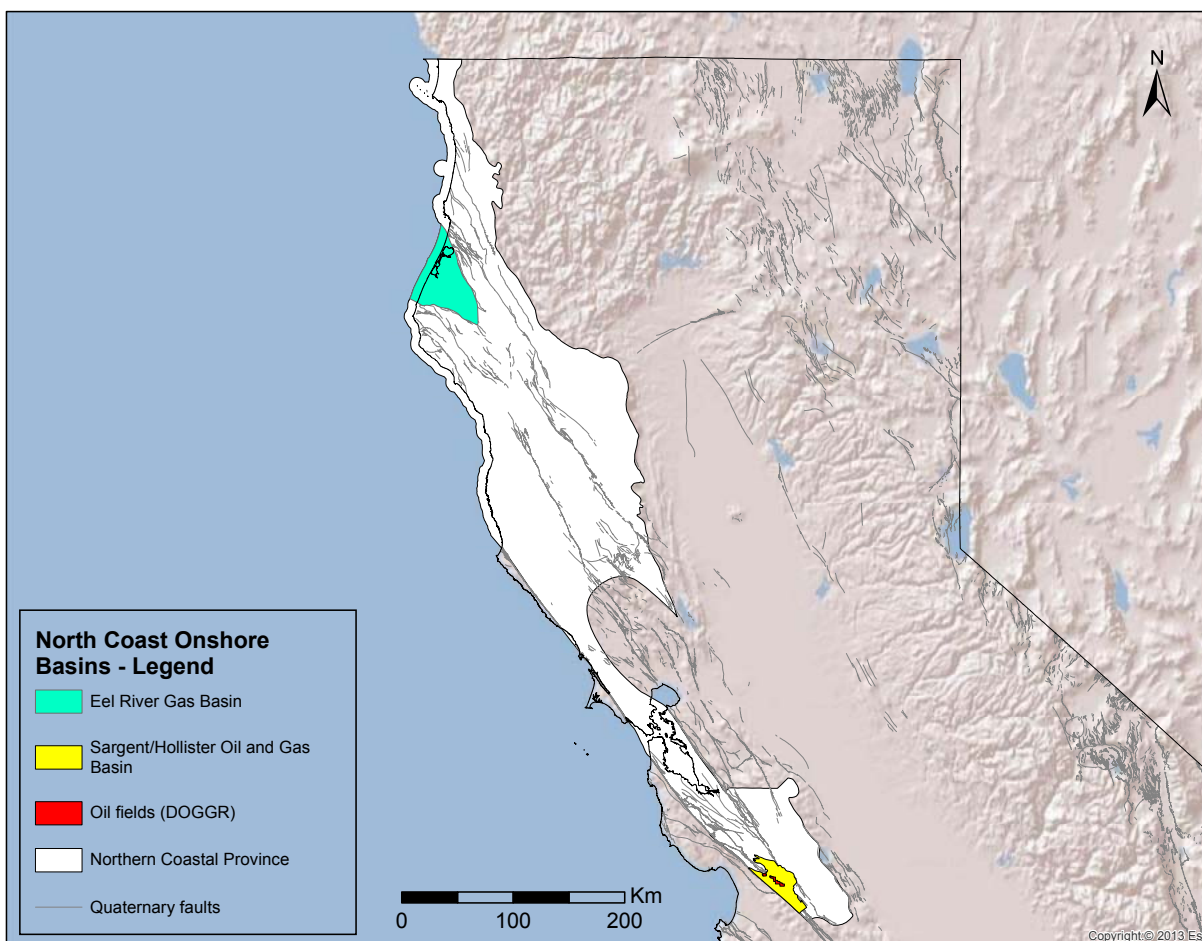
Figure 4-17. *Map depicting Northern Coastal Province and associated basins. Basin outlines from USGS 1995 National Assessment of US Oil and Gas Resources (*http://certmapper.cr.usgs. gov/noga/broker1995.jsp?theServlet=NogaGISResultsServ&theProvince=07&thePage=gis*).*

4.5.2.1.2. Resource Potential

The last systematic assessment of the resource potential was published by the USGS in 1995 (Gautier et al., 1995). At that time, the mean undiscovered petroleum resource was estimated to be about 4.8 million m³ (30 million barrels) of oil, 31 billion m³ (1080 billion scf) of gas, and less than 1.6 million m³ (10 million barrels) of natural gas liquids (NGL), distributed among all the basins in the North Coast (Gautier et al., 1998).

4.5.2.1.3. Potential Application of WST

The North Coast is a vast area, where small quantities of hydrocarbons have been discovered and produced over many years. The possibility exists that additional discoveries will be made in the future and that some of them will have reservoirs that could be enhanced by hydraulic fracturing or other means of WST. It is also possible that previously discovered accumulations could be redeveloped using WST to enhance hydrocarbon production. That said, current evidence suggests that this large area has sparsely distributed, small, and economically marginal hydrocarbon accumulations. Even if new accumulations were discovered or previously recognized ones were redeveloped today, the level of activity involved in the development would most likely be local and volumetrically small. The likelihood of large-scale, industrial-type resource development with thousands of wells and extensive massive hydraulic fracturing technology is considered extremely low.

4.5.2.2. Northern Coastal Basins—Offshore - Eel River Basin

4.5.2.2.1. Geography and Geology

The Eel River Basin extends from just north of Cape Mendocino to the Oregon border and beyond (Piper, 1997; Piper and Ojukwu, 2014) (Figure 4-18). Its southern part is the offshore extension of the onshore Eel River Basin, which has proven gas production. The offshore basin encompasses an area of more than 8,300 km² (3,200 mi²) with water depths ranging from sea level to about 1,200 m (4,000 ft). As with the onshore basin, the offshore Eel River Basin is underlain by basement rocks of Jurassic to Cretaceous mélange similar to the Franciscan Complex exposed in the coastal ranges (Jayko and Blake, 1987). Tertiary strata ranging in age from Paleocene to Pleistocene overlie the basement (Blake et al., 1978).

During the 1960s through the 1980s, industry acquired a relatively dense array of seismic data in the Eel River Basin. In addition, four exploratory wells were drilled in the Basin, all in the 1960s. The wells tested structural highs and encountered thin successions of Tertiary strata before bottoming in the Franciscan basement. One well encountered veins of asphalt ("gilsonite"). Natural gas has been recovered from unconsolidated sediment, and numerous gas seeps have been mapped in the area, suggesting that the onshore Eel River gas play may extend beneath the offshore basin (Piper, 1997).

Figure 4-18. *Map of Eel River Basin (adapted from Piper, 1997).*

4.5.2.2.2. Resource Potential

The Bureau of Ocean Energy Management/Bureau of Safety and Environmental Enforcement (BOEM/BSEE) (formerly known as the Minerals Management Service) defined four hypothetical geologically defined plays in the Basin. These included two Neogene sandstone plays, a Paleogene sandstone play, and a play involving the basement mélange itself (Piper, 1997; Piper and Ojukwu, 2014). The assessment relied heavily on analogous rocks and petroleum discoveries onshore. The undiscovered technically recoverable petroleum resource was estimated (mean values) at 11 million m^3 (70 million barrels) of oil, and 43 billion m^3 (1.52 trillion scf) of gas (Piper and Ojukwu, 2014). Given the offshore location, its geological complexity, and the relatively small size of the postulated oil accumulations, it is difficult to envision these resources, even if found, being developed any time soon.

4.5.2.2.3. Potential Application of WST

The small volume and gas-prone nature of undiscovered resources of the Eel River Basin Offshore suggest that, even if found, the widespread application of WST is unlikely.

4.5.2.3. Central Coastal Basins—Onshore

4.5.2.3.1. Geography and Geology

The Central Coastal basins area includes an area of about 21,000 km^2 (8,000 mi^2) from Point Arena on the north to the western Transverse Ranges to the south (Stanley, 1995b). The San Andreas Fault forms the eastern boundary. The southern limit is the Big Pine Fault. The southwest limit is the Sur-Nacimiento Fault, and the western boundary is the 4.8 km (3 mi) limit offshore. The area is about 630 km (390 mi) long from northwest to southeast, and about 64 km (40 mi) wide near Soledad (Figure 4-19). The Cuyama Basin is thus geographically within the Central Coastal area, but it is discussed separately in this report.

The main petroleum potential in the Central Coast (excluding the Cuyama Basin) is in moderately deformed Tertiary sedimentary rocks that locally exhibit a composite thickness of more than 14,600 m (48,000 ft). Upper Cretaceous sedimentary rocks as thick as 4,000 m (13,000 ft) are also present but probably have little or no petroleum potential. In most areas, Tertiary and Upper Cretaceous strata overlie Cretaceous and older granitic and metamorphic rocks of the Salinian block. Parts of the Santa Cruz Mountains are underlain by Franciscan rocks, and a small coastal area near Point Arena appears is underlain by unnamed and undated fragments of Mesozoic oceanic crust (Stanley, 1995b).
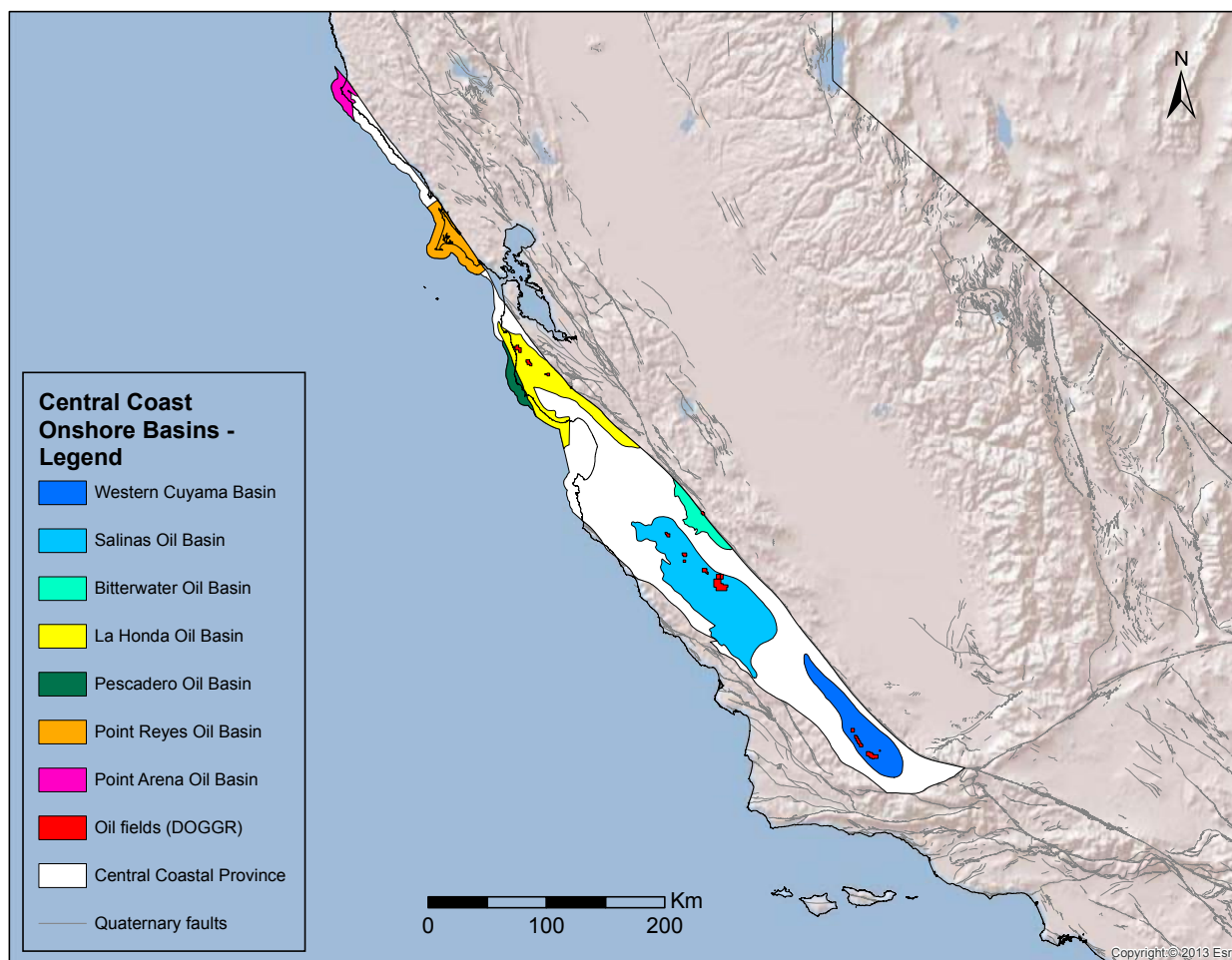
Figure 4-19. *Map depicting Central Coastal Province and associated basins. Basin outlines from USGS 1995 National Assessment of US Oil and Gas Resources* http://certmapper.cr.usgs.gov/noga/broker1995.jsp?theServlet=NogaGISResultsServ&theProvince=11&thePage=gis
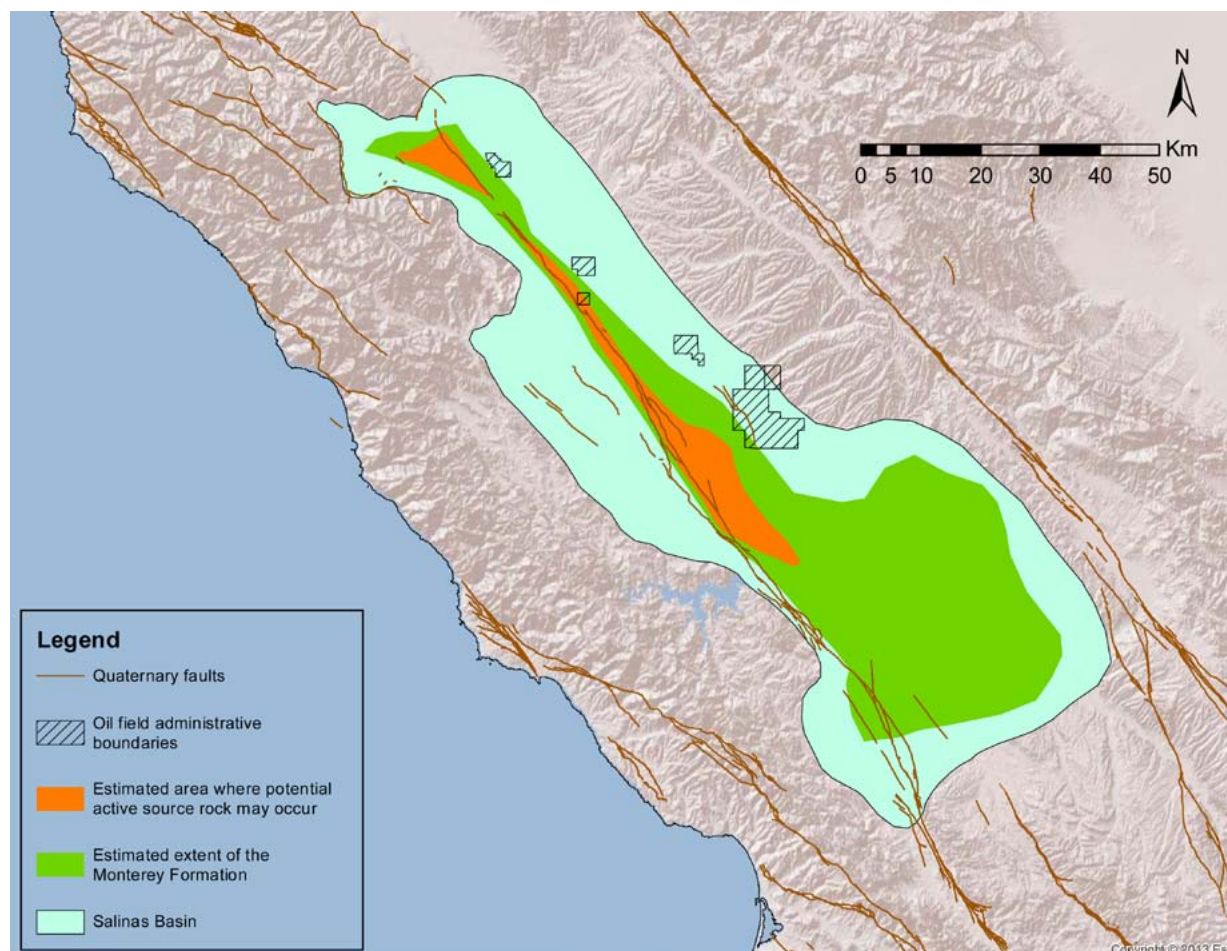
Figure 4-20. *Salinas Basin and associated oil fields (DOGGR), along with distribution of source rock (green) and portion below top of oil window (~2,000 m - Menotti and Graham, 2012), with data from Durham (1974) and Menotti and Graham (2012).*

The Salinas Basin is a Neogene basin dominated by wrench tectonics, with mid-Miocene transtensional subsidence and subsequent uplift, folding, and faulting associated with transpression (Colgan et al., 2012; Durham, 1974; Graham, 1978; Menotti and Graham, 2012) (Figure 4-20). The period of basin subsidence coincided with deposition of as much as 3 km (1.9 mi) of Monterey-equivalent strata (Menotti et al., 2013). Laminated marine shales in the lower part of the Monterey have elevated total organic carbon (TOC), with moderately laminated shales averaging 3.12 wt. % TOC and well-laminated hemipelagic Monterey rocks having average TOC value of 4.59 wt. %, making them good candidates for oil source rocks (Mertz, 1989). The Salinas Basin contains a giant heavy oil accumulation, the San Ardo field (Baldwin, 1976; Isaacs, 1992a). A cross section through this field (Figure 4-21) illustrates the important role that structural features have played in the migration and trapping of oil (Menotti and Graham, 2012).
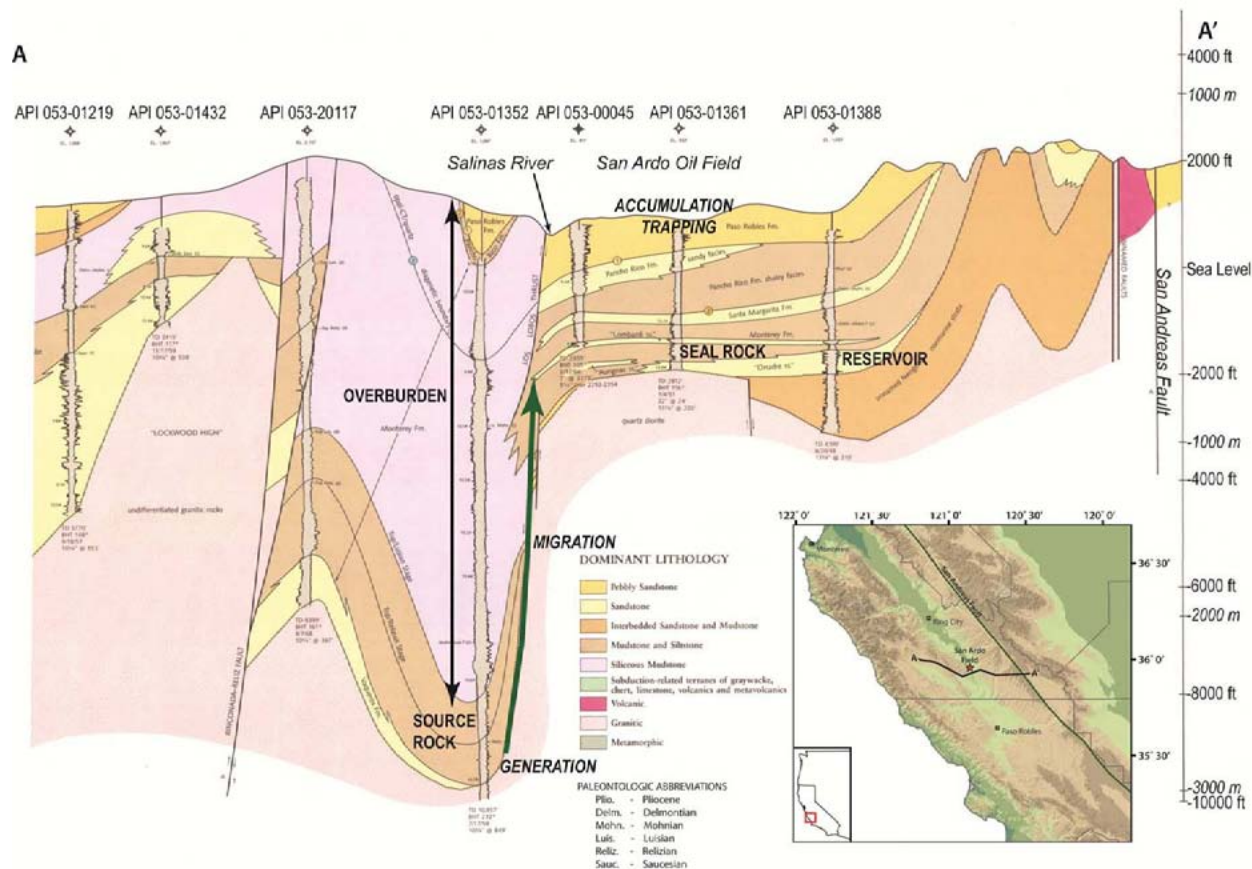
Figure 4-21. *East-West cross section through the San Ardo oil field, Salinas Basin, depicting key components of the petroleum system (Menotti and Graham, 2012).*

The first exploratory wells in the Central Coast were drilled in 1867 adjacent to surface oil seeps near Half Moon Bay (Rintoul, 1990). The biggest oil field in the area, San Ardo, probably originally contained more than 160 million m³ (1 billion barrels) of heavy oil. It was discovered in 1947 (Baldwin, 1976; Stanley, 1995b). Several smaller fields have also been found in the Salinas, La Honda, and Bitterwater basins; the largest of these is the King City oil field (0.32 million m³ (2 million barrels) of oil), found in 1959 (DOGGR, 2010).

Nearly all (more than 90%) of the known petroleum in these basins has been found in Miocene sandstones. The remainder was found in Eocene and Oligocene sandstones and in Miocene limestone (Stanley, 1995b). Excluding the Cuyama and Santa Maria basins, only three of the Central Coastal basins, Salinas, La Honda and Bitterwater, have confirmed production. The Bitterwater Basin contains just one commercial oil field, Bitterwater, which is smaller than 0.16 million m³ (1 million barrels) of oil (DOGGR, 2010). In addition to Salinas, five basins were estimated by the USGS in 1995 to have

additional petroleum potential: La Honda, Point Arena, Point Reyes, Pescadero, and Bitterwater (Gautier et al., 1995). Surface indications of oil and gas, such as tar sands and oil and gas seeps, are known from every one of the basins.

4.5.2.3.2. Resource Potential

The last systematic assessment of the Central Coastal basins resource potential was published by the USGS in 1995 (Gautier et al., 1995). At that time the mean undiscovered petroleum resource was estimated to be about 78 million m^3 (490 million barrels) of oil, 4.2 billion m^3 (150 billion scf) of associated and dissolved gas, and about 1.6 million m^3 (10 million barrels) of NGL, which is a considerable volume of petroleum (Gautier et al., 1998). Of these amounts, well over half of the undiscovered resource was estimated to be the two proven petroleum basins: La Honda, with about 8.3 million m^3 (52.4 million barrels) of oil and 0.44 billion m^3 (15.7 scf) gas (http://certmapper.cr.usgs.gov/data/noga95/prov11/tabular/pr1104.pdf), and Salinas, with 36 million m^3 oil (223.6 million barrels) of oil and 1.3 billion m^3 (44.7 billion scf) of associated and dissolved gas (http://certmapper.cr.usgs.gov/data/noga95/prov11/tabular/pr1106.pdf). The remaining basins were estimated to contain small, widely distributed oil and gas accumulations. Within the large area of the Central Coastal basins, the Salinas Basin, in particular, has significant potential for undiscovered conventional petroleum accumulations and for further development of heavy oil within the giant San Ardo field. The existence of the giant San Ardo oil field also demonstrates the presence of active and effective Monterey-equivalent petroleum source rocks deep in the basin. Therefore a source-rock system "shale oil" play with significant recoverable resources is considered a real possibility in the Salinas Basin.

2.5.2.3.3. Potential Application of WST

The Central Coastal basins encompass a large area, where numerous accumulations of hydrocarbons have been discovered and produced over many years. Therefore, it is likely that additional accumulations could be found in the future, the production of which might be enhanced by hydraulic fracturing or other WST. It is also possible that previously discovered accumulations could be redeveloped using WST to enhance production. However, with the exception of the Salinas Basin, this large area probably only has sparsely distributed, relatively small, and economically marginal hydrocarbon accumulations. If such accumulations were discovered or redeveloped, the level of activity involved in their development would be quite local and volumetrically small. Except for Salinas, the likelihood of large-scale, industrial-type development using extensive hydraulic fracturing technology is considered extremely low.

The Salinas Basin, however, is a proven petroleum province that contains a giant oil field (San Ardo). Geological evidence is strong that an active and prolific Monterey Formation source rock system is present at depth in the basin (Menotti and Graham, 2012; Isaacs, 1992b). It is therefore considered possible that a source-rock system (shale oil) play could be developed in the Salinas Basin, whereby the thermally mature, oil-bearing Monterey source rocks would be developed using widespread application of WST.

4.5.2.4. Central California Coastal Basins—Offshore

4.5.2.4.1. Geography and Geology

The central coastal area of offshore California, which extends from Cape Mendocino southward to Point Concepcion, contains three geologically defined but untested sedimentary basins: Point Arena Offshore, Bodega Basin, and Año Nuevo (Figure 4-22). The Central Coast also includes the Partington and Santa Maria offshore basins, but these are considered separately in this report.

Northwest-southeast structural features, identified by seismic surveys to include faults, folds, and paleo-uplifts, characterize the continental margin of central California and define the three basins (Dunkel et al., 1997). The basins probably formed in early to middle Tertiary time by tectonic extension, which by middle Tertiary time was already dominated by right-lateral strike-slip tectonics of the emerging San Andreas Fault (SAF) system (Blake et al., 1978). Consequently the three basins are bounded on the east by the SAF and, in the case of the Año Nuevo Basin, by the San Gregorio Fault.
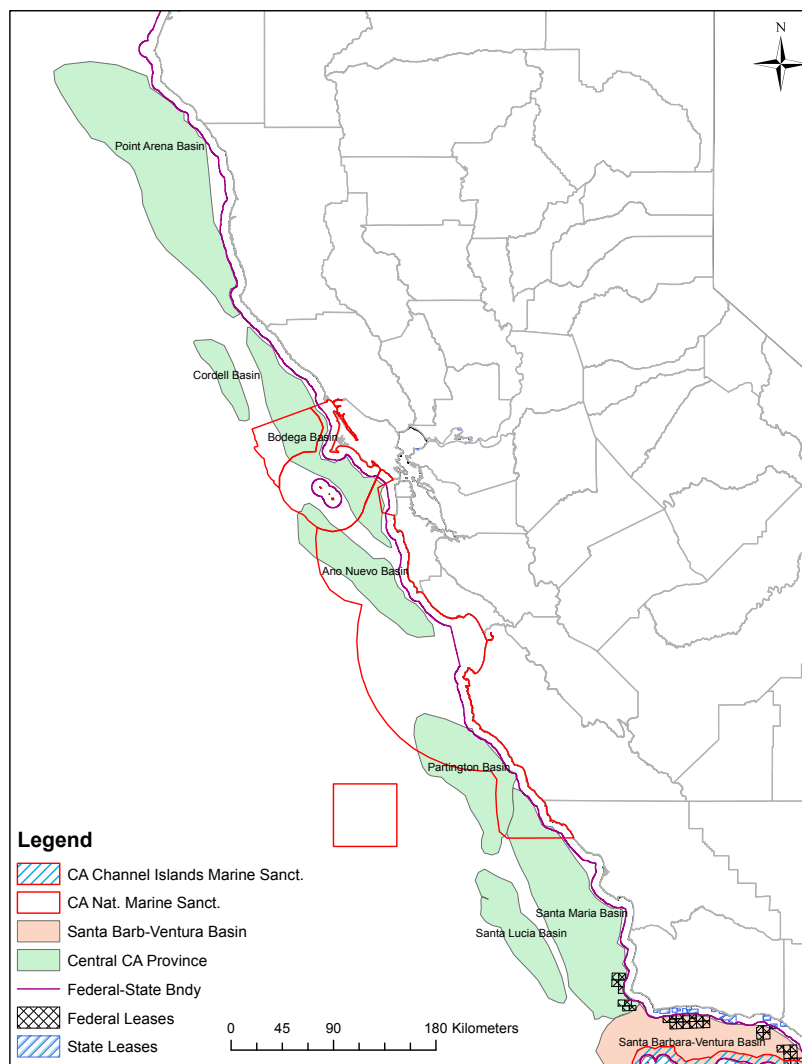
Figure 4-22. *Map of Central California Coastal Offshore Basins, adapted from Dunkel et al., 1997.*

4.5.2.4.2. Resource Potential

In the 1960s, three exploratory wells were drilled in the Point Arena Basin. All three wells encountered oil shows. Ten wells were drilled at about the same time in the Bodega Basin. Two exploratory wells were drilled in Año Nuevo, which also encountered shows of oil in the Monterey Formation (Dunkel et al., 1997; Piper and Ojukwa, 2014). Although the three basins are largely unexplored, the similarities of their inferred geology to the highly productive Santa Maria and related Partington basins is reason enough to postulate the presence of significant hydrocarbon accumulations in one or all of the basins. In

each basin, three potentially productive stratigraphic intervals have been identified, which are geologically similar and analogous to the occurrence of petroleum in the Santa Maria and Santa Barbara-Ventura basins: (1) Neogene sandstones, (2) fractured quartz-phase siliceous Monterey strata, and (3) pre-Monterey sandstones. In 1995, the Minerals Management Service (MMS) estimated that the Point Arena, Bodega, and Año Nuevo basins contain a mean undiscovered oil resource of about 0.67 billion m^3 (4.2 billion barrels) of oil, and about 130 billion m^3 (4.5 trillion scf) of natural gas, with the highest potential being in the Point Arena Basin (Dunkel et al., 1997; 2001). The more recent (2011) BOEM assessment of the West Coast OCS (Piper and Ojukwu, 2014) has downgraded this estimate slightly, with mean combined estimates of 0.66 billion m^3 (4.12 billion barrels) of oil, and about 124 billion m^3 (4.37 trillion scf) for these three offshore basins.

4.5.2.4.3. Potential Application of WST

Although the three basins are thought to contain significant quantities of oil and gas, presumably mostly in conventional accumulations, widespread application of WST is considered extremely unlikely, for two reasons: First, the three basins are largely located in the federally defined Cordell Bank, Gulf of the Farallones, and Monterey Bay National Marine Sanctuaries, within which petroleum exploration is permanently forbidden. Second, by analogy with developments of conventional fields in Santa Maria and Santa Barbara basins, hydraulic fracturing is not a necessary part of petroleum development in the postulated reservoirs.

4.5.2.5. The Central Valley—Sacramento Basin

4.5.2.5.1. Geography and Geology

The Central Valley of California is what remains of a long-lived fore-arc basin that developed along the western margin of the North American continent between Late Jurassic and Early Cenozoic time (Ingersoll, 1979). For more than 100 million years, the western edge of North America was an actively convergent tectonic plate margin, within which oceanic crust from the west was more or less continuously subducted in a deep trench. To the east and largely parallel to the trench was a volcanic arc and massif, the ancestor of the modern Sierra Nevada. The fore-arc basin initially received sediments eroded only from the proto-Sierra Nevada. However, over time, parts of the subduction zone to the west of the trench were uplifted to form an archipelago from which sediments were also shed eastward into the evolving fore-arc basin. The subduction zone is represented today by the Franciscan Complex that comprises much of the Coast Ranges and the basement rocks of the western part of the Great Valley. The Sacramento Basin, which occupies the north half of the Central Valley, is what remains of the fore-arc basin; it contains as much as 12,000 m (40,000 ft) of Jurassic-to-Holocene, marine and nonmarine strata, significant quantities of non-associated natural gas, and small volumes of oil.

The fore-arc basin evolved through time, widening as the trench-slope break shifted to the west and the volcanic arc progressively moved to the east (Ingersoll et al., 1977). This expansion is documented by the successively younger ages of the Franciscan Complex and radiometric ages from granitic intrusive rocks of the Sierran plutons, which become progressively younger from west to east across the Sierra Nevada.

The basin, which is about 340 km (210 mi) long and 100 km (60 mi) wide, is bordered on the west by the Coast Range Thrust, on the north by the Klamath Mountains, on the east by the Cascade Range and Sierra Nevada, and arbitrarily on the south by the Stockton Arch in the subsurface near the Stanislaus-San Joaquin County line (Magoon and Valin, 1996). The province covers an area of 30,600 km² (11,820 mi²) (Figure 4-23).
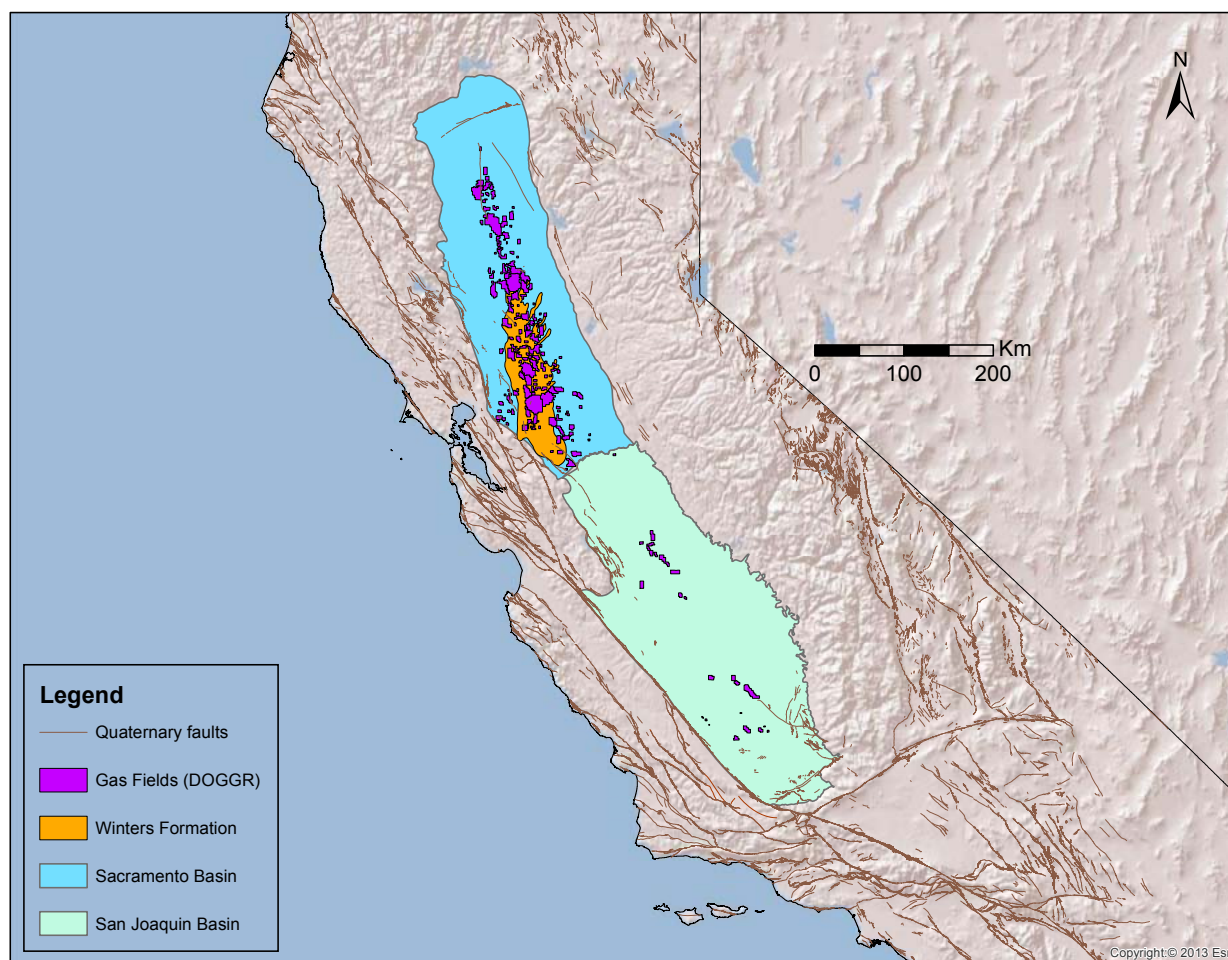
Figure 4-23. *Map of the Central Valley, depicting location of gas fields (DOGGR) and extent of Winters Formation from Garcia, 1981.*

Petroleum exploration began in 1918, but the most active period of exploration was between 1960 and 1980. To date, almost 3,000 wells have drilled to depths from 3,000 to nearly 20,000 ft (900–6,100 m). The Sacramento Basin is primarily a gas-producing region with 73 gas fields and only two small oil fields (Brentwood and West Brentwood (1.5 million m^3 [9.3 million barrels] of oil; field size values listed here are based on cumulative production through 2009 plus reserve estimates—DOGGR, 2010). Major gas fields are Rio Vista (the largest in the Sacramento Basin, with about 113 billion m^3 (4 trillion scf) of gas, Grimes (~ 22 billion m^3 (780 billion scf) of gas), Willows-Beehive Bend (~17 billion m^3 (600 billion scf) of gas), Lathrop (~10 billion m^3 (370 billion scf) of gas), Lindsey Slough (~9.6 billion m^3 (340 billion scf) of gas), and Union Island (~8.2 billion m^3 (290 billion scf) of gas). Almost 280 billion m^3 (10 trillion scf) of gas and 2.1 million m^3 oil (13 million barrels) of oil have been produced from the Basin (DOGGR, 2010). Trap geometries for the known gas accumulations were largely established by Oligocene time, prior to deposition of the late Eocene through Miocene-Pliocene nonmarine sedimentary rocks (<1,200 m(< 4,000 ft)) that overlie the faults (Graham, 1981).

Based on their stratigraphic and geographic distribution and chemical composition (Jenden and Kaplan, 1989), two principal gas systems are recognized in the Sacramento Basin: the Dobbins-Forbes and the Winters-Domingene systems (Beyer, 1988a). Most of the hydrocarbons in both systems apparently originate from gas-prone source rocks in the area of the "delta depocenter" (Garcia, 1981; Zieglar and Spotts, 1978) (Figure 4-24). Regional seals that partition the systems are in the Prince Canyon fill and Capay Shale in the north and in the Sacramento Shale in the south. The burial-history curve of Zieglar and Spotts (1981) indicates that gas started to migrate by the early Tertiary for the Dobbins-Forbes system and by the Oligocene time for the Winters-Domingene system.
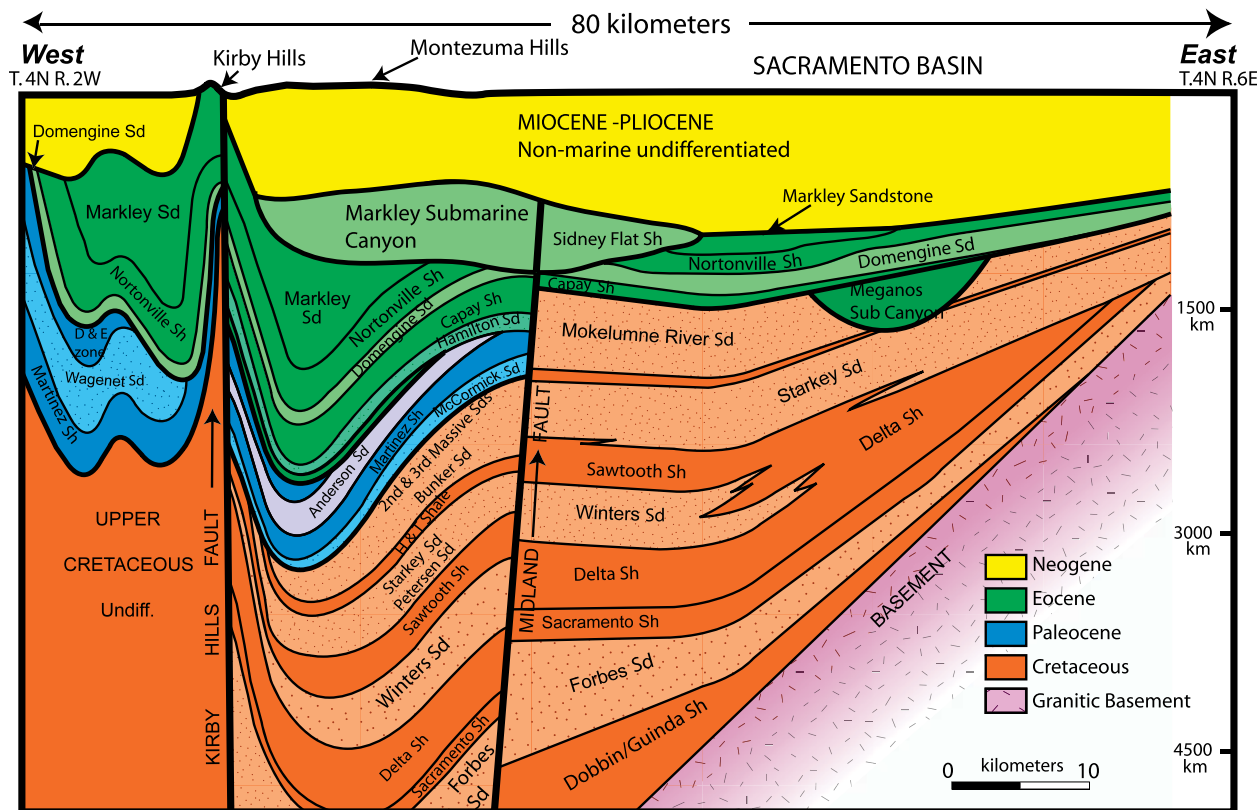
Figure 4-24. *EW cross section through the Sacramento Basin, depicting the Delta depocenter by the Rio Vista gas field (Sullivan and Sullivan, 2012).*

4.5.2.5.2. Resource Potential

Undiscovered Conventional Accumulations

In 2007, scientists of the US Geological Survey completed an assessment of undiscovered petroleum (oil, natural gas, and natural gas liquids) resources of the Sacramento Basin (Hosford Scheirer et al., 2007). However, the study reported only non-associated natural gas resources. Undiscovered oil, if any, was considered to be present in such small volumes as to be insignificant. The assessment considered two petroleum systems separately: the Dobbins-Forbes and the Winters-Domingine. Throughout much of the Basin, the two petroleum systems are separated by the regionally extensive Sacramento Shale, which serves as a seal. For the Basin as a whole, the USGS estimated undiscovered, conventional resources of between 3.9 and 30 billion m³ (139 and 1,067 billion scf) of natural gas, with a mean estimate of 15 billion m³ (534 billion scf) (Hosford Scheirer et al., 2007). Of that amount, approximately 40% was estimated to be in the Dobbins-Forbes petroleum system. Most of the undiscovered gas, about 60%, was interpreted to

be in Upper Cretaceous submarine-fan and deltaic-sand reservoirs, with minor amounts in reservoirs of Cenozoic age. The USGS anticipates that the majority of undiscovered natural gas is to be found in Upper Cretaceous deltaic and submarine-fan sandstones reservoirs of the Winter-Domingine system. In addition to the non-associated gas resources, the USGS estimated a small volume, a mere 51,000 m^3 (323 thousand barrels), of natural gas liquids would be found in connection with the natural gas resources. Approximately 280 billion m^3 (10 trillion scf) of natural gas had been discovered and produced in the Sacramento Basin as of 2010. The remaining undiscovered resources thus represent a relatively small fraction of the total recoverable resource. The undiscovered resources are believed to exist mostly in small, hard-to-find accumulations that may not warrant extensive exploration and development investment.

Undiscovered Unconventional Gas Resources

The Sacramento Basin exhibits several geological features in common with basin-center "tight gas" accumulations: a thick sedimentary succession containing gas-prone organic matter, a demonstrated occurrence of natural gas resources, a deep basin depocenter, and abnormally high pore fluid pressures in numerous reservoirs. Taken together, these features superficially suggest the possibility of a basin center gas accumulation in the Delta Depocenter beneath the vicinity of the Rio Vista gas field. However, a more careful analysis indicates that the conventional reservoirs of the Sacramento Basin actually exhibit few of the features of true basin-centered accumulations, such as regional water expulsion, abnormal fluid pressures resulting from hydrocarbon generation, and absence of hydrocarbon-water contacts. It is therefore considered unlikely that a basin-center gas accumulation exists in the Sacramento Basin, at least at the depths that have been explored so far.

4.5.2.5.3. Potential Use of WST

Many of the conventional gas accumulations in the Sacramento Basin have reservoirs with relatively low permeability. It is therefore likely that the production rates of at least some of these reservoirs could be enhanced by application of hydraulic fracturing. Such WST applications would probably be of limited scope and volume, however, owing to the restricted geometries of the small conventional gas accumulations. As described above, widespread development of unconventional gas resources in the basin using WST is unlikely.

4.5.2.6. The Central Valley—San Joaquin Basin

4.5.2.6.1. Geography and Geology

The San Joaquin Basin (SJB) lies beneath the southern portion of the Central Valley, the large topographic depression between the Sierra Nevada and the Coast Ranges (Beyer, 1995a). The southern Diablo and Temblor ranges, separate the SJB from the Carrizo Plain

and Cuyama Basin on the west. It is bounded on the south by the Transverse Ranges, which separate it from southern California and the Mojave Desert. The northern limit of the San Joaquin Basin is the Stockton Arch, a subsurface feature in the vicinity of the Stanislaus-San Joaquin County line. The San Joaquin Basin is an asymmetrical trough filled with some 125,000 km³ (30,000 mi³) of Cretaceous to Quaternary marine and continental sediments (Callaway, 1971; Varnes and Dolton, 1982), which, in places are almost 12,000 m (40,000 ft) thick (Hosford Scheirer and Magoon, 2008a; Johnson and Graham, 2007; Schwochow, 1999).

Like the Sacramento Basin, the San Joaquin Basin first formed during the Jurassic as a fore-arc basin along the continental margin, located between a subduction zone and a volcanic arc. In Neogene time, the southern and western parts of the Basin subsided and were compressed by tectonic plate motions along the active California margin. Thick successions of biogenic marine sediments including organic-rich shales and diatomites, interspersed with submarine fan sandstones, were variously deformed, uplifted, and buried deeply within the complex tectonic environment. The end result is an extraordinarily rich petroleum province with a wide variety of reservoir rocks and traps that contain at least 3.2 billion m³ (20 billion barrels) of known recoverable oil (cumulative production plus reported remaining reserves). Most of the known oil is concentrated along the western, southwestern, and southeastern margins of the Basin, where oil and gas continually leak to the surface. The oil seeps, which have been known and exploited by locals and travelers for centuries, led to the discovery of some of the largest oil fields (DOGGR, 1987; Rintoul, 1990).

The Monterey is the source rock for most producing oil fields in the San Joaquin Basin (Figure 4-25). It also serves as a reservoir rock in numerous oil fields. Most of the Monterey reservoirs are located above the oil window, and the kerogen present at reservoir depths is thermally immature, suggesting that the oil migrated updip from deeper in the basin (Graham and Williams, 1985; Kruge, 1986).
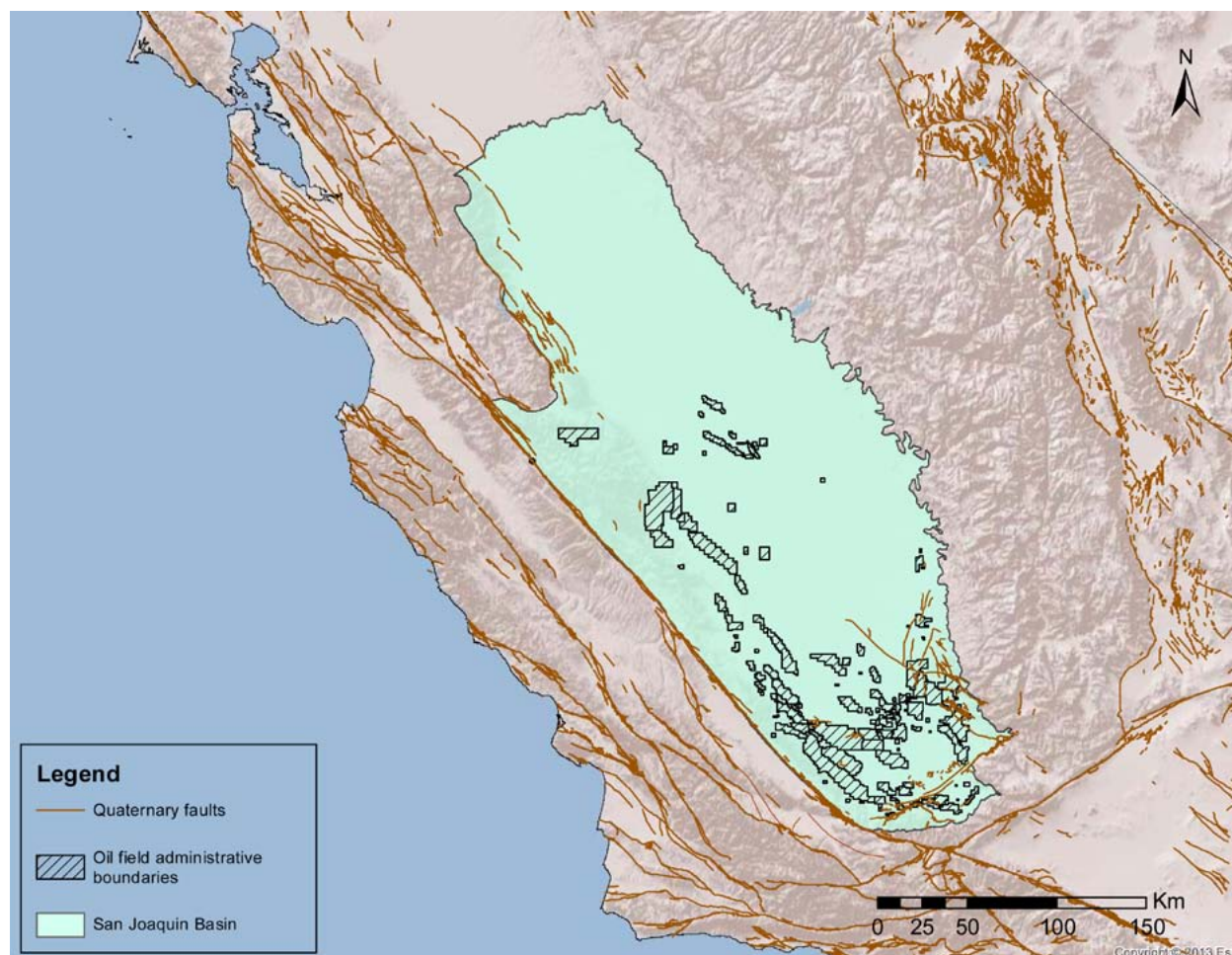
Figure 4-25. *The San Joaquin Basin and producing oil fields (Oil field data from DOGGR).*

In several fields, including South Belridge and Lost Hills, oil is produced from Monterey diatomite (Bowersox, 1990; Schwartz, 1988). Diatomite reservoirs have high matrix porosities but low permeabilities. Directional wells targeting specific pay zones coupled with hydraulic fracturing, water flooding and steam flooding (Figure 4-26) have been used to improve oil recovery from the diatomite reservoirs in South Belridge and Lost Hills fields (Allan et al., 2010; El Shaari et al., 2011; Emanuele et al., 1998; Wright et al., 1995). At Midway-Sunset, the largest field in the San Joaquin Basin, some oil is also produced from diatomite and fractured siliceous mudstones. However, so far, the most productive intervals at Midway-Sunset have been interbedded sandstones (Figure 4-27) (Link and Hall, 1990; Mercer, 1996; Underwood and Kerley, 1998). These sands have much more favorable reservoir properties (porosity ~33%, permeabilities between 800-4,000 md) than the Monterey lithologies that surround them (Link and Hall, 1990).
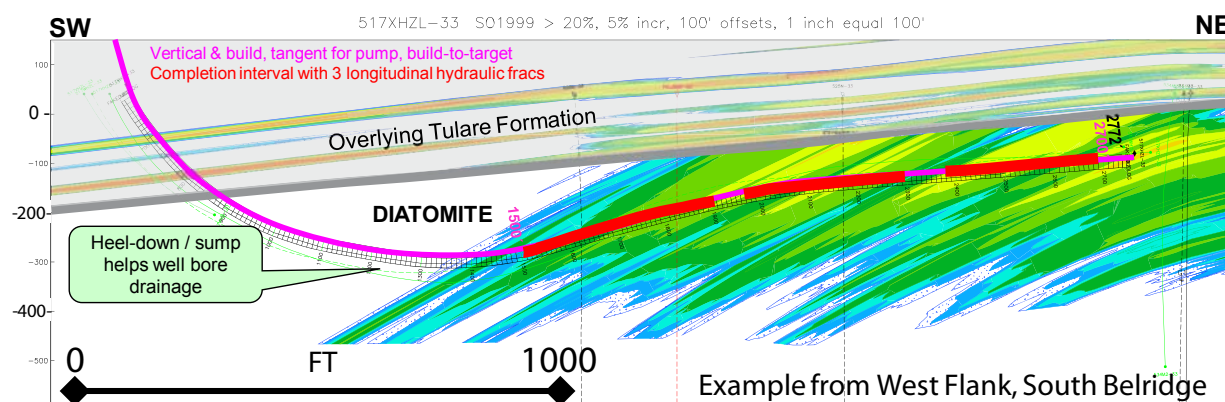
Figure 4-26. *Schematic of directional well for the South Belridge field targeting the top of the diatomite unit, oriented longitudinally along the flanks of the anticline, with hydraulic fracturing to improve well performance (Allan and Lalicata, 2012).*
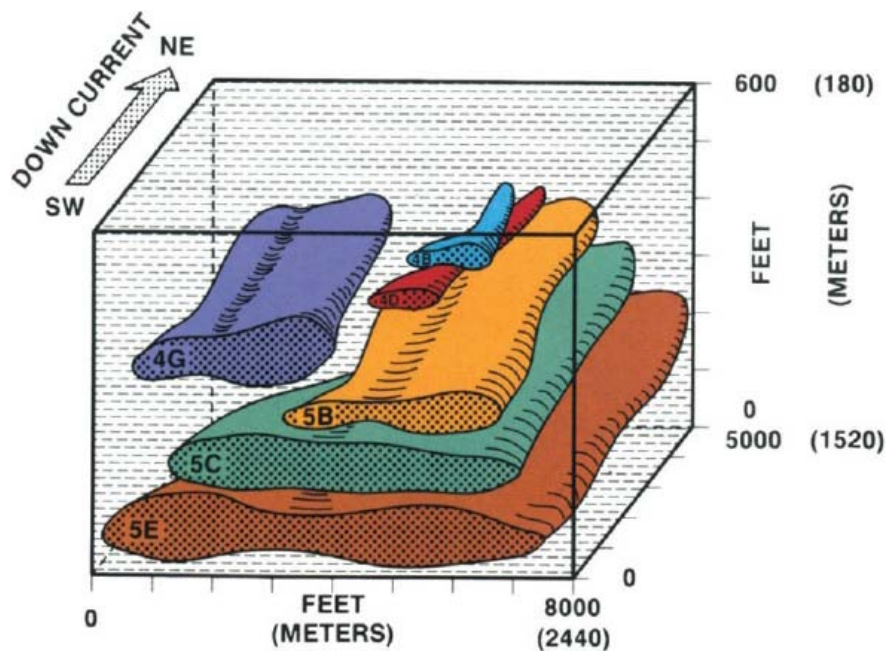
Figure 4-27. *Block diagram depicting location of Webster sand turbidite lobes within the Antelope Shale Member of the Monterey Formation in the Midway-Sunset field (Link and Hall, 1990).*

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

4.5.2.6.2. Resource Potential

Undiscovered Conventional Accumulations

The most recent assessment of undiscovered, conventional petroleum in the San Joaquin Basin was completed by the USGS in 2003 (Gautier et al., 2007). The USGS estimated that between 13 and 136 million m^3 (80 and 853 million barrels) of oil and 9.1 to 123 million m^3 (321 to 4,331 billion scf) of gas as well as significant quantities of natural gas liquids could be recovered with existing technology. The mean estimates of 62 million m^3 (393 million barrels) of oil and 50 billion m^3 (1,756 billion scf) of gas were of total resources in five petroleum systems and ten separately defined "Assessment Units" (AU) (Gautier et al., 2007).

Miocene petroleum systems, principally derived from Monterey-equivalent source rocks, were estimated to account for more than 80% of the remaining undiscovered oil. Most (well over 50%) of the estimated undiscovered gas resources was attributed to the "Deep Fractured Pre-Monterey" along the southwestern margin of the basin at great depths (>4,300 m(>14,000 ft)) in folded and faulted reservoirs in the Temblor, Oceanic, and Point of Rocks formations as well as in other sandstones of Eocene age. Undiscovered accumulations were estimated to exist in fractured reservoirs with extremely high pore pressures. The existence of this play was confirmed by the "East Lost Hills Blowout," when the Bellevue No. 1 well blew out and caught fire in December 1998 (Schwochow, 1999).

Proposed as a theoretical possibility many years ago by Caroline Isaacs (e.g., Isaacs, 1992a), a diagenetic trap play has been demonstrated in two fields of the San Joaquin Basin: North Shafter and Rose oil fields (e.g., Ganong et al., 2003). In these small fields, oil is trapped at the permeability barrier formed by the diagenetic phase transition of opal CT to quartz phase in siliceous strata. The fractured quartz phase serves as the reservoir rock. In the USGS assessment, similar small diagenetically trapped oil accumulations are predicted to exist at various other places in the Basin where siliceous Monterey lithologies are at the appropriate diagenetic phase transition. Although the diagenetic traps were recognized as exploration targets both before and after the USGS assessment, no additional commercially viable accumulations similar to Rose and North Shafter have been put on production since the assessment.

The estimated volumes of undiscovered resources in the San Joaquin Basin would be considered significant in almost any basin of the world. However, only one new field, Rose (Ganong et al., 2003), has been discovered in the San Joaquin since 1990 and the USGS study concluded that there is a 50% chance that there is no remaining undiscovered field in the Basin with more than 3.3 million m^3 (21 million barrels) of recoverable oil, and that there is a less than 5% chance of any yet-to-find oil field larger than 9.5 million m^3 (60 million barrels). Given that these undiscovered accumulations probably represent a scattered remnant of relatively small oil fields within a volumetrically large petroleum province, their significance is relatively low.

Reserve Growth

Growth of reserves in existing fields, also called reserve growth, inferred reserves, or growth-to-known (GTK), refers to increases in successive estimates of recoverable volumes of crude oil, natural gas, and natural gas liquids in discovered fields (Klett, 2005). These increases result from a variety of mechanisms including: (1) identification of new reservoirs or pay zones within previously defined fields, (2) extensions of producing reservoirs, (3) reserve revisions resulting from evaluation of production performance and/or more efficient operations, (4) improved recovery resulting from infill drilling, well stimulation, and recompletions, and (5) application of new technologies to previously recognized oil accumulations.

In the San Joaquin Basin, the past half-century has been a time of extraordinary development of existing fields. Since the middle 1960s, more than 1.3 billion m^3 (8 billion barrels) of recoverable oil have been added to reserves of existing fields, thereby greatly extending California oil production and slowing the decline of US domestic oil production (Tennyson et al., 2012). Beginning in the 1960s, the application of various thermal recovery technologies has resulted in rapid and voluminous additions to reserves in fields that contain heavy oil (Tennyson et al., 2012). Heavy oil is defined by the American Petroleum Institute as oil having API gravity of 22 degrees or less. Additions to reserves of heavy oil have continued more or less continuously to the present day in the San Joaquin Basin. Beginning in the 1980s, large reserve additions have also come from the application of hydraulic fracturing coupled with water flooding and steam flooding to diatomite reservoirs of the Monterey Formation (Tennyson et al., 2012).

In order to evaluate the remaining potential for additions to reserves of existing fields in the San Joaquin Basin, a team of scientists from the US Geological Survey (Tennyson et al., 2012) undertook an assessment of nine selected oil fields, most of which had already demonstrated significant reserve growth. The fields considered in the USGS study were: Coalinga, Cymric, Elk Hills, Kern River, Lost Hills, McKittrick, Midway-Sunset, North Belridge, and South Belridge. Using published literature and data from the California Division of Oil, Gas, and Geothermal Resources, the geology of each field was analyzed and its development history was reviewed. The team estimated the ranges of original oil in place (OOIP) for each field and the range of possible recovery efficiency

that could be realized by the application of existing technology. The distributions were combined in a Monte Carlo-type simulation, which generated a probability distribution on potentially recoverable oil from each field. The results of the study indicated that from 0.6–1.5 billion m³ (3.6–10 billion barrels) (mean of 1.0 billion m³ (6.5 billion barrels)) of additional oil could be produced from the nine fields. Much of the assessed potential development was expected to come from further development of diatomite reservoirs in Cymric, Lost Hills, Midway-Sunset, North Belridge, and South Belridge fields, presumably in large part through hydraulic fracturing. Also, more oil could be developed from the further application of thermal-recovery technologies to shallow reservoirs containing heavy and extra-heavy oil, and from injection of carbon dioxide in deep sandstones reservoirs containing light oil, such as the sandstone reservoirs in the Elk Hills oil field. The USGS study also suggested that additional oil might be developed in other, smaller fields of the San Joaquin Basin as well.

Growth of reserves in existing fields of the San Joaquin Basin has been the most important source of additional reserves in California in recent decades. The large remaining resource potential of these reasonably well understood oil accumulations suggests that additional development of the San Joaquin Basin oil fields is likely to continue to be an important source of reserve additions in California for years to come. In addition to the potential of the intensively developed large fields, some less developed smaller fields of the San Joaquin Basin also have significant potential as well. While additional development of heavy oil resources does not generally entail well stimulation technology, much of the additional oil in San Joaquin Basin fields is expected to be developed in low-permeability reservoirs, particularly diatomite. Such developments would require the systematic application of hydraulic fracturing and other stimulation technologies.

Unconventional Resources in the San Joaquin Basin

It is possible (but quite uncertain) that significant quantities of petroleum remain in the San Joaquin Basin source rocks themselves. If they could be directly produced, these resources would be unconventional and conceptually similar to the oil shale formations such as the Bakken and Eagle Ford.

The depths and temperatures where the source rocks have reached maturity for oil generation have been studied in some detail by Peters et al. (2007; 2013) and approximately located and mapped by Magoon et al. (2009). The mapped areas are shown in Figures 4-28 through 4-31.
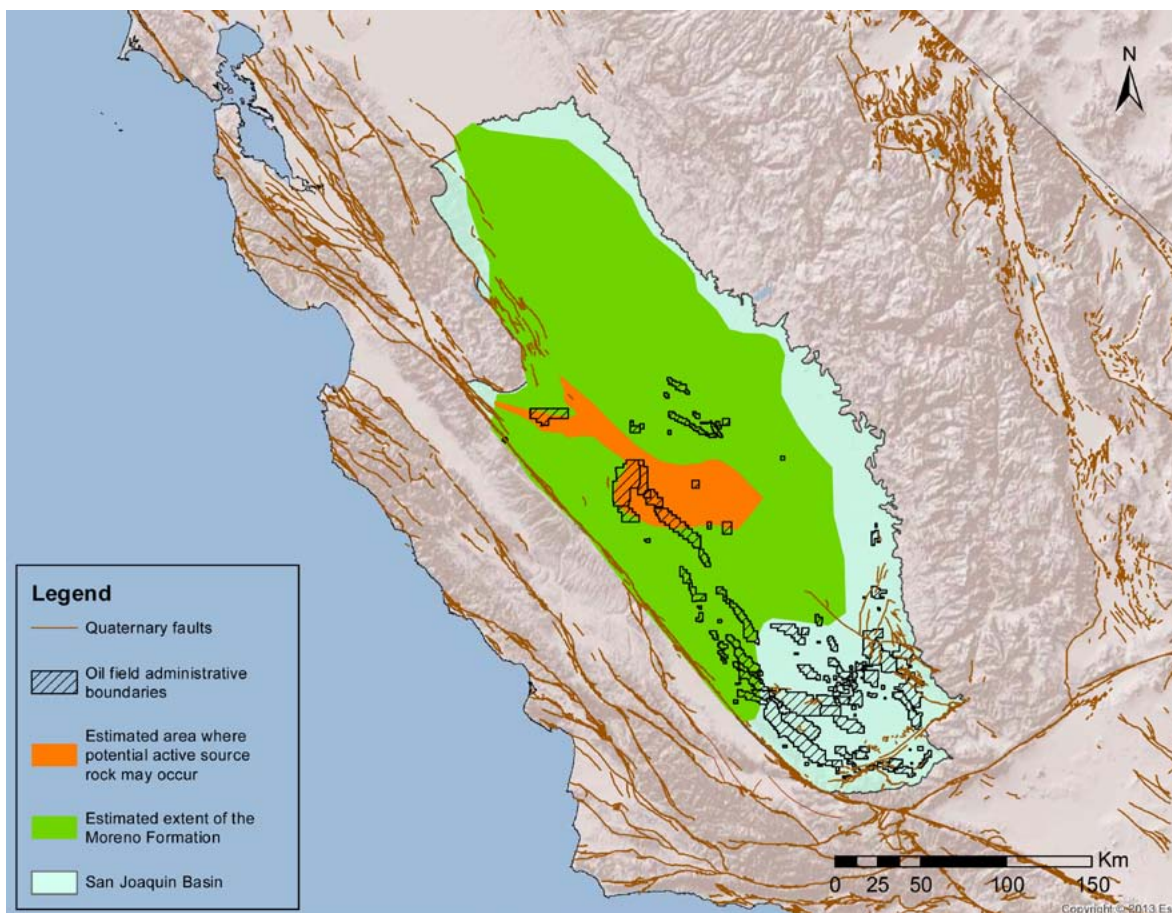
Figure 4-28. *Distribution and estimated active source area of the Moreno Formation in the San Joaquin Basin (Magoon et al., 2009).*
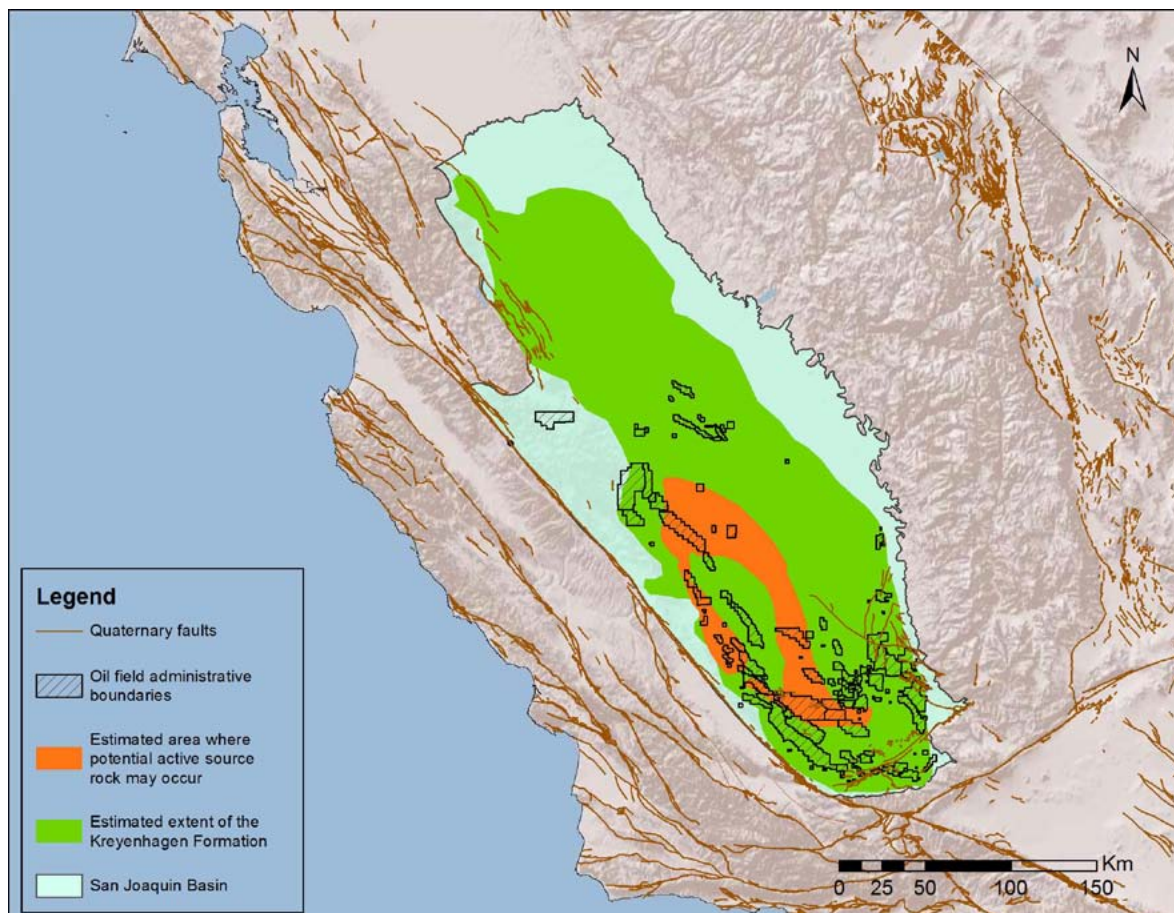
Figure 4-29. *Distribution and estimated active source area of the Kreyenhagen in the San Joaquin Basin (Magoon et al., 2009).*
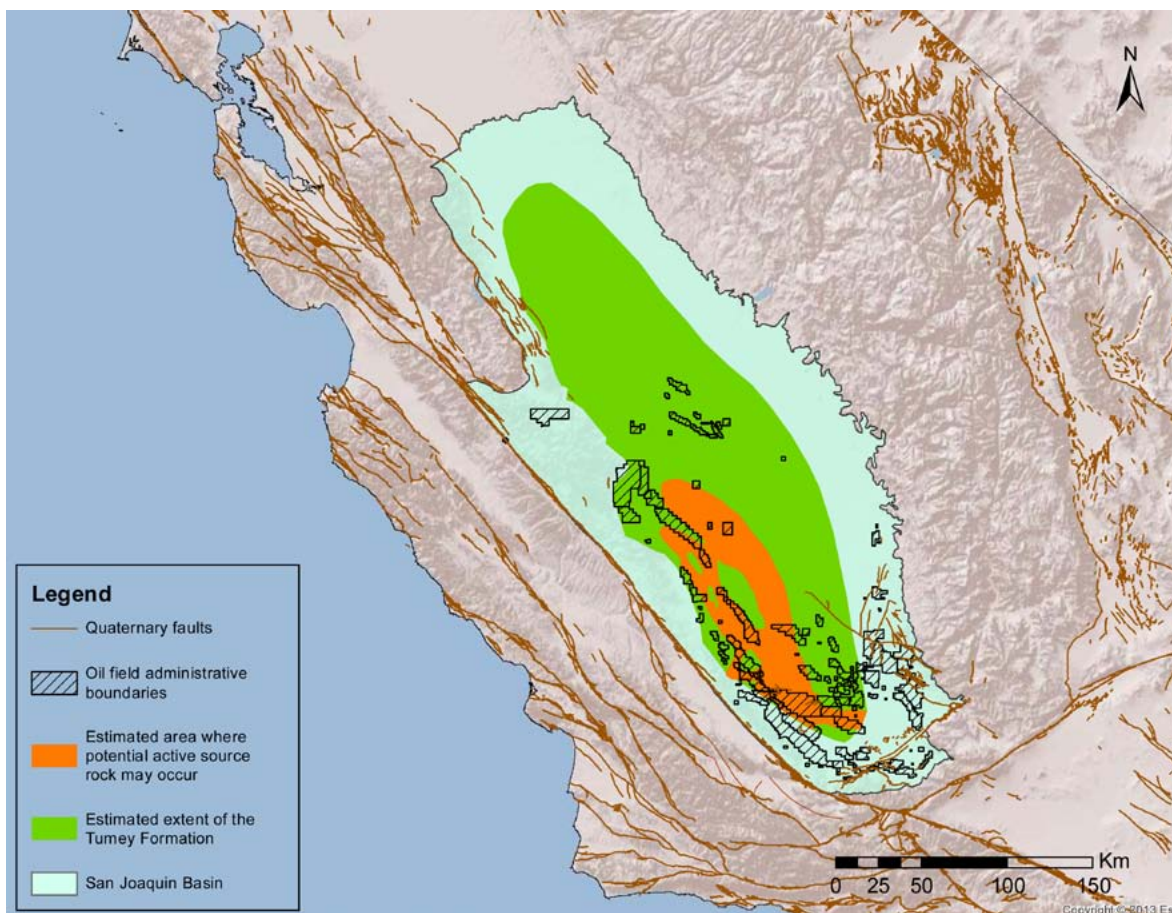
Figure 4-30. *Distribution and estimated active source area of the Tumey in the San Joaquin Basin (Magoon et al., 2009).*
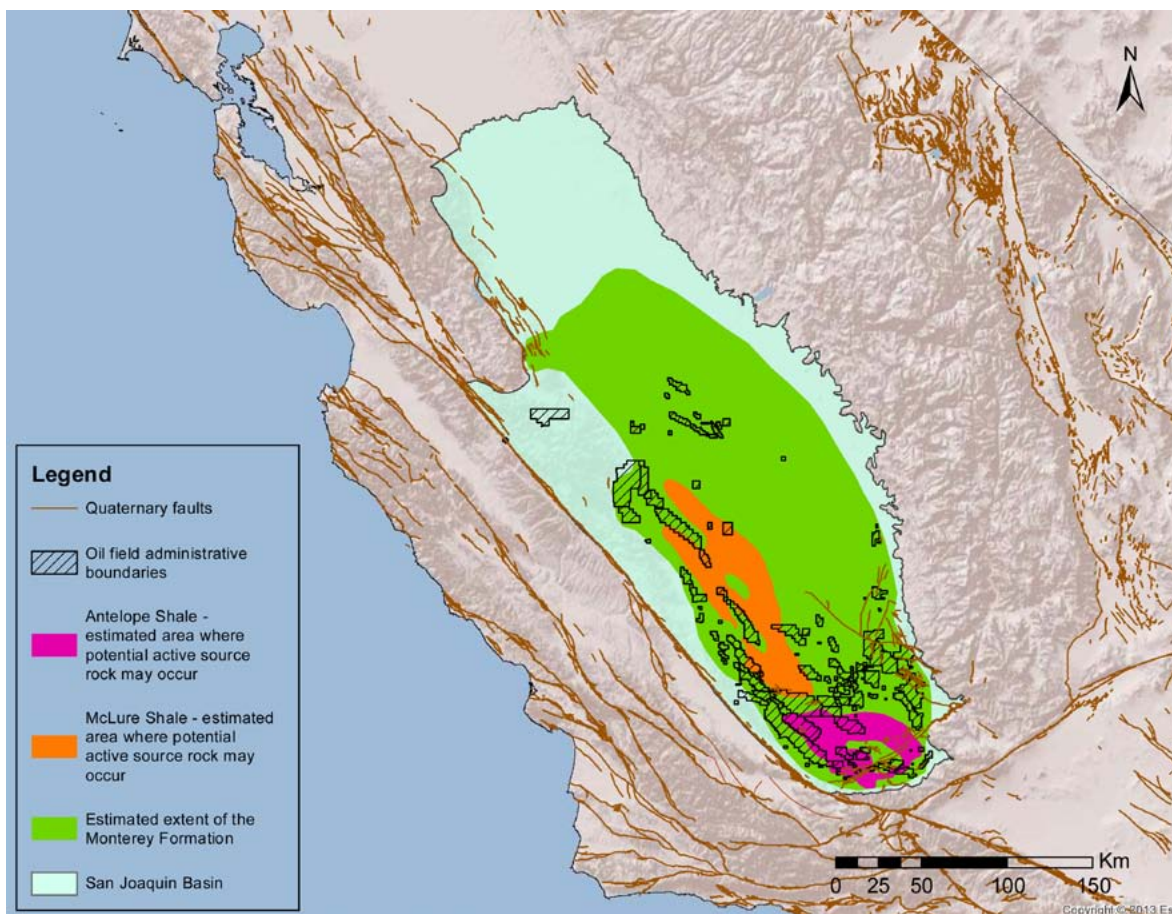
Figure 4-31. *Distribution and estimated active source area of the Monterey in the San Joaquin Basin (Magoon et al., 2009).*

With the success of source-rock shale oil development in other areas of North America, there has been renewed focus on the Monterey to explore the effectiveness of using similar methods (Durham, 2010, 2013; Redden, 2012). Venoco and Occidental Petroleum have drilled a number of wells targeting zones between 1,830 and 4,270 m (6,000 and 14,000 ft), and have employed various well stimulation techniques in an attempt to stimulate hydrocarbon production from possible source-rock intervals. As part of this exploration effort, Venoco drilled several deep wells in the Semitropic field that target the Monterey below the Pliocene Etchegoin Formation, where most current Semitropic production occurs. One of these wells, the Scherr Trust et al., 1-22 (API 03041006), was spudded in December 2010 and drilled to a depth of 4,272 m (14,015 ft) (4,243 m (13,921 ft) total vertical depth). The primary objective was the Monterey "N" chert, which was perforated at a depth interval of 3,808-3,813 m (12,495-12,510 ft) and fractured, but only a limited amount of oil was produced in subsequent flow tests.

DOGGR records for new wells at Semitropic and neighboring Bowerbank field suggest that these deeper Monterey wells have not been particularly successful. Drilling for unconventional oil reservoirs in the Monterey between 2009 to 2013, reported by Burzlaff and Brewster (2014), suggest that average initial production rates are on the order of 12-24 m³ (75-150 barrels) of oil per day. Expected ultimate recovery (EUR) from these wells is on the order of 3,200–4,000 m³ (20,000–25,000 barrels) for wells in fields on the west side of the San Joaquin Basin and 14,000–16,000 m³ (90,000–100,000 barrels) for wells in fields on the east side of the Basin, with much higher gas-to-oil ratios for the west side wells. An industry report (Petzet, 2012) concerning testing of hydraulic fracturing and oil production in the Eocene Kreyenhagen Formation indicates the presence of mobile oil. However, no further development or oil production from the Kreyenhagen is indicated.

The Monterey and Kreyenhagen source rocks in the San Joaquin Basin are the most likely potential reservoirs for development of shale oil in California, at least in the immediate future. So far, the limited exploratory drilling has not resulted in the addition of significant reserves, and the shale oil resource potential remains highly uncertain. Additional exploratory drilling of deep wells to test the possibility of production from shales in the depocenters is needed to reduce the uncertainty surrounding the resource potential. Importantly for this study, large areas underlain by thermally mature source rocks lie outside the boundaries of existing fields. One of several notable exceptions is the Elk Hills oil field, below which Miocene source rocks are believed to presently be in the oil window.

Relatively few of the hundreds of thousands of oil wells drilled to date in California have targeted deep exploration zones (Schwochow, 1999), in part due to the higher costs, and also because many of the discovered oil fields are hosted in relatively shallow reservoirs with structural traps that lie well above the oil window. Thermally mature source rocks in the Neogene sedimentary basins in California are typically found at depths of 2,440–3,050 m (8,000–10,000 ft) or more, depending upon the local geothermal gradient. Additional deep wells are needed to ascertain if the source rocks retain significant hydrocarbons and could serve as unconventional oil reservoirs.

Deep drilling beneath the existing oil reservoirs at the Elk Hills field was conducted by the US Department of Energy (DOE) to evaluate the prospects for hydrocarbon production from deeper reservoir intervals (Fishburn, 1990). Three wells were drilled to depths of 5,569–7,455 m (18,270–24,426 ft). While the wells did not find commercial hydrocarbons, they did have oil and gas shows. Cores of shale recovered from the Eocene Kreyenhagen Formation, the top of which was encountered at a depth of 4,785 m (15,700 ft) in the 987-25R well, exuded oil and gas from fine fractures. The Kreyenhagen overlies a 99 m (325 ft) thick section of oil-stained sands from the Eocene Point of Rocks sandstone, which is just above a 244 m (800 ft) thick section of salt. Measured porosity for Point of Rocks sandstones ranged from 14-16% in the 987-25R well, but are quite a bit lower (around 6%) for the same stratigraphic interval in the 934-29R well, which encountered Point of Rocks between 6,596–6,977 m (21,640–22,890 ft). Higher porosities

(20–35%) are observed in the Point of Rocks at shallow depths (<910 m(<3,000 ft)) in other oil fields (Schwochow, 1999), suggesting that compaction due to burial and diagenesis has led to significant porosity reduction. Average measured core permeabilities for this sandstone were around 4 md in the 987-25R well and less than 1 md in the 934-29R well. The location of the oil window at the Elk Hills field is estimated to be at depths of 3,930–5,850 m (12,900–19,200 ft). The only oil field that has reported significant production of oil from the Point of Rocks Sandstone at depths greater than 2,740 m (9,000 ft) is the McKittrick field, where substantial gas production (Schwochow, 1999) is also reported.

Another potential deep target is shale that has been displaced due to thrust faulting and folding, such as a fault displacement gradient fold at the Lost Hills field (Figure 4-32) described by Wickham (1995). Based upon a subthrust play developed for the East Lost Hills, several exploratory deep wells were drilled into the footwall. The first well, spudded in 1998, encountered high gas pressures in the Temblor Formation at 5,377 m (17,640 ft). As the crew attempted to circulate out the gas, the venting gas and hydrocarbons ignited, engulfing the rig in flames. It took more than six months to bring the well under control (Schwochow, 1999). However, of the 65–70 deep wells that had drilled to depths greater than 4,570 m (15,000 ft) in the San Joaquin Basin by 1999, none was commercially productive (Schwochow, 1999).

In summary, large areas of the San Joaquin Basin display the geological characteristics necessary for the presence of hydrocarbons in low-permeability source-rock (shale-oil) systems. These characteristics include several prolific petroleum source rocks with thermal maturity in the "oil window," the presence of mobile hydrocarbons at abnormally high fluid pressures, and brittle formation lithologies with natural fracture systems. On the other hand, the San Joaquin Basin source rocks systems differ significantly from the highly productive shale oil reservoirs in Texas and North Dakota in their lithological variability, great structural complexity, and known expulsion efficiency. In addition, the results of limited exploratory drilling intended to test the shale oil potential have so far been unsuccessful in adding new reserves. No quantitative assessment of the shale oil potential for the San Joaquin Basin has been published to date, but it seems likely that any such assessment would need to reflect not only the possibility of significant recoverable hydrocarbon volumes, but also a high probability of low recoverable resources.
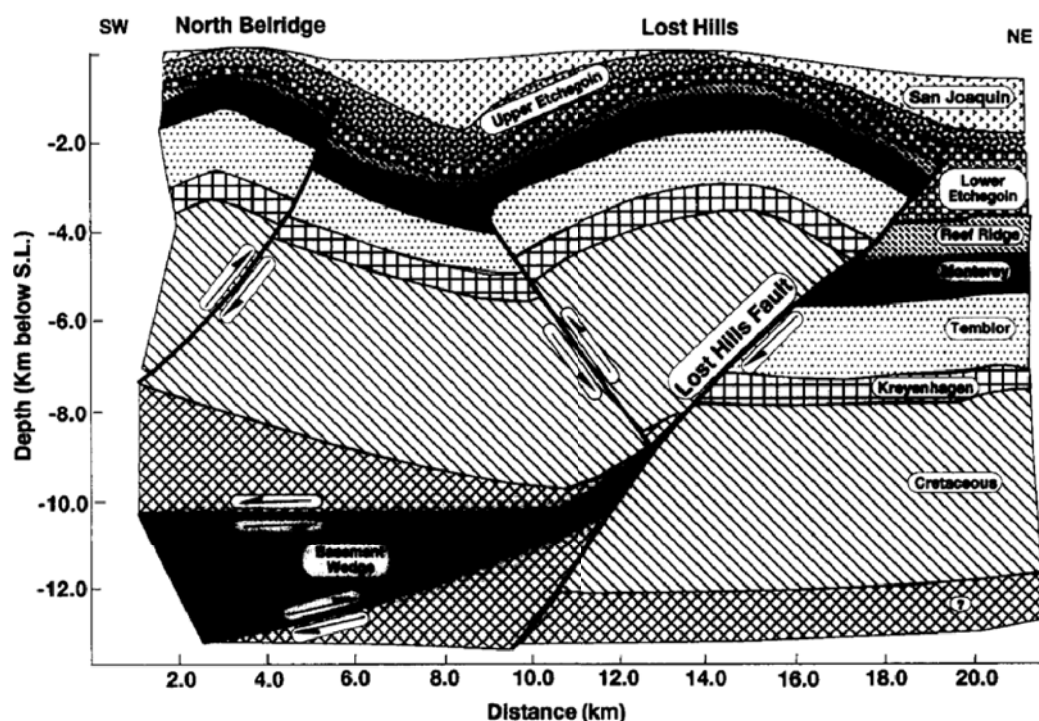
Figure 4-32. *Cross section through the Lost Hills oil field constrained by seismic data depicting relative downward offset of Monterey and other units in footwall block of Lost Hills thrust fault. (Wickham, 1995)*

4.5.2.6.3. Potential for Application of WST

WST has been an important part of San Joaquin Basin oil production for more than 30 years, and much of the potential for future oil production will probably also involve WST. Although volumetrically small compared to other resources, development of the undiscovered fields estimated by USGS (Gautier et al., 2004) could involve some WST, particularly for development of the deep fractured pre-Monterey and oil in the diagenetic traps in the central basin. The largest potential resource in the San Joaquin is for growth of reserves in existing fields, much of which would, as in the past, probably entail extensive hydraulic fracturing of low-permeability diatomite reservoirs.

It is also geologically possible that large recoverable resources are present in deep Monterey source rocks (so-called shale oil) along the west side and southwest margins of the San Joaquin Basin, in the Buttonwillow and Tejon depocenters (Figure 4-28 to 4-31). The possibility of large-scale production of these unconventional resources would be in addition to the large quantities of Monterey-sourced and Monterey-reservoired resources that have already been produced, reported as reserves, or identified as possible future additions to reserves in existing fields. If developed, such self-sourced, source-rock systems would probably require the application of hydraulic fracturing, and other WST.

4.5.2.7. Cuyama Basin

4.5.2.7.1. Geography and Geology

The Cuyama Basin is a Neogene basin located about 60 km (40 mi) north of the Santa Barbara coast, between the Temblor Range and the Sierra Madre Range of the southern Coast Ranges (Stanley, 1995b). Its northwestern end is continuous with the southeastern end of the Salinas Basin, and the San Andreas Fault separates it from the Temblor Range on the southwestern side of the San Joaquin Basin. The southwestern margin of the Cuyama Basin is structurally complex, having experienced several episodes of strike-slip and normal faulting. This basin contains both nonmarine and marine sediments, and has been affected by strike-slip and thrust faulting (Baldwin, 1971). The southern edge of the basin is a down-to-the-north normal fault. The basin is about 140 km (85 mi) long and 30 km (20 mi) across at its widest point, encompassing about 3,600 km² (1,400 mi²) (Figure 4-33).

In the Cuyama Basin, the Saltos shale forms the lower part of the Monterey Formation and the Whiterock Bluff shale forms the upper part. The Branch Canyon sandstone is intercalated with both of these shale units, but it is more abundant in the SE part of the basin, which had a larger input of terrigenous sediments (Lagoe, 1982; 1984; 1985). The Saltos shale has a larger terrigenous sedimentary component than the Whiterock Bluff shale, consisting of interbedded sandstones, mudstones, and impure carbonates. In contrast, the Whiterock Bluff shale is dominated by biogenic sediments, and consists of siliceous and diatomaceous shales and mudstones with minor dolomitic interbeds (Lagoe, 1985). Oil is produced predominantly from the Painted Rock Sandstone member of the Miocene Vaqueros Formation, which underlies the Monterey (Isaacs, 1992a) (Figure 4-34). On the basis of stable carbon isotope and biomarker data, Lillis (1994) concluded that the principal Cuyama Basin source rock is the Soda Lake shale member of the Vaqueros Formation.
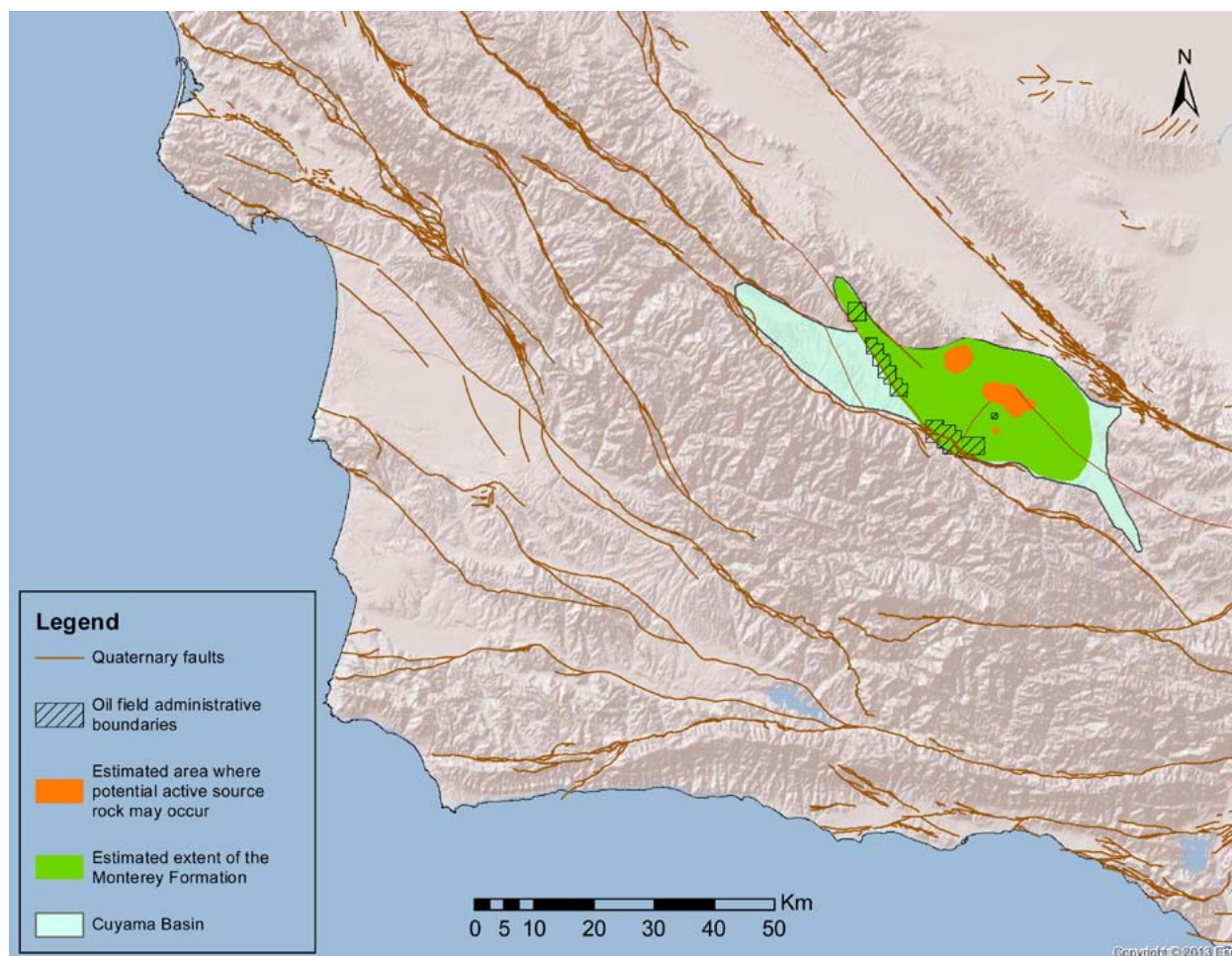
Figure 4-33. *Cuyama Basin and associated oil fields (DOGGR), along with distribution of Monterey source rock (Sweetkind et al., 2013) and portion below top of oil window (~2.7 km (1.7 mi) depth based on data from Lillis (1994)).*
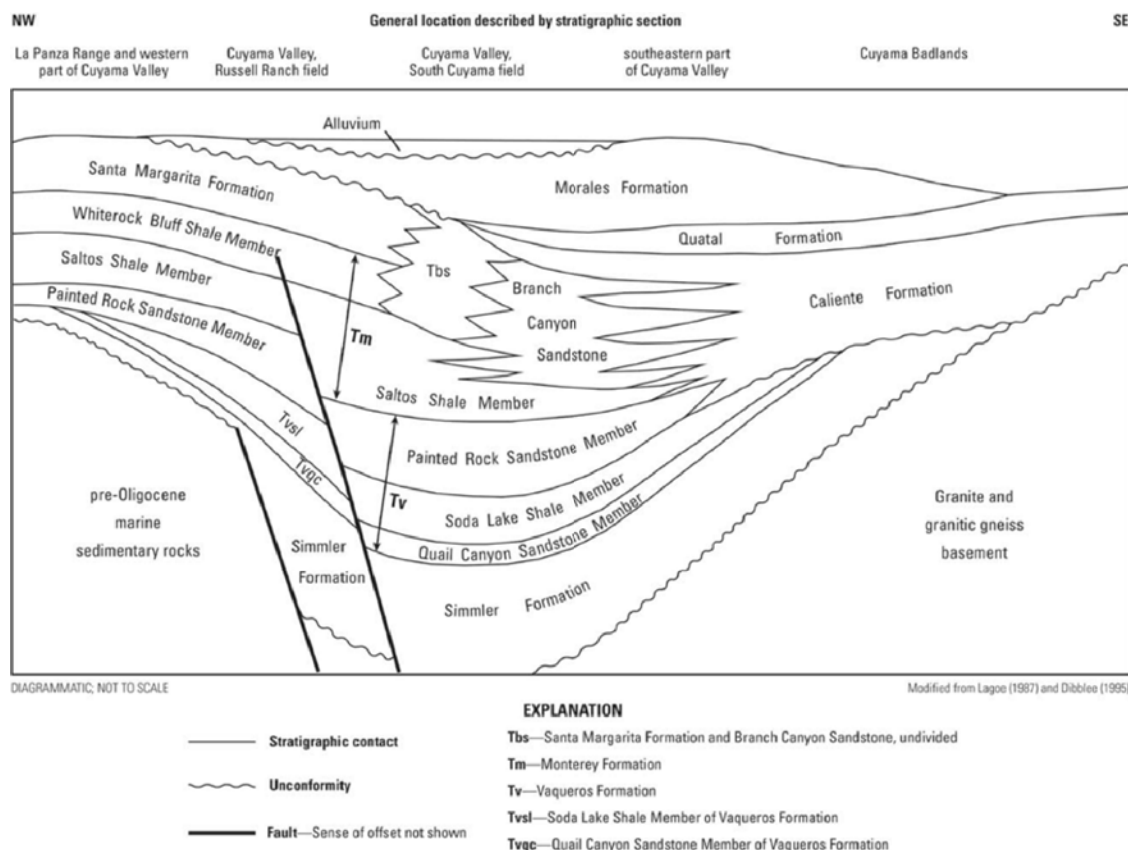
Figure 4-34. *Diagrammatic NW–SE stratigraphic section across the Cuyama Basin (Sweetkind et al., 2013).*

4.5.2.7.2. Resource Potential

The last systematic assessment of the resource potential for the Cuyama Basin was published by the USGS in 1995 (Gautier et al., 1995). The USGS assessed undiscovered resources in two geologically defined plays: a structural oil play, named the "Western Cuyama Basin Play," which included all of the known accumulations in the basin, and a hypothetical structural/stratigraphic play in the Cox Graben named the "Cox Graben Play" (Stanley, 1995b). The mean undiscovered petroleum resource in the Western Cuyama Basin Play was estimated to be about 9.4 million m^3 (59 million barrels) of oil and 1.3 billion m^3(44.3 billion scf) of gas (http://certmapper.cr.usgs.gov/data/noga95/prov11/tabular/pr1107.pdf). The Cox Graben was estimated to contain about 1.0 million m^3 (6.6 million barrels) of oil and small amounts of associated and dissolved gas (http://certmapper.cr.usgs.gov/data/noga95/prov11/tabular/pr1109.pdf). The most likely situation is that these undiscovered resources exist in small accumulations. However, the USGS assessors explicitly allowed the possibility of a large (16-32 million m^3 [100 to

200 million barrels] of oil) undiscovered accumulation in the deep part of the Western Cuyama Basin and an undiscovered accumulation of 3.2-4.8 million m³ oil (20 to 30 million barrels) of oil somewhere in the Cox Graben (Stanley, 1995b).

In addition to the undiscovered conventional accumulations, unconventional resources are possible. The Soda Lake Shale of the Vaqueros Formation, the principal source rock, is surely mature with respect to oil at depth in the Cuyama Basin (Kornacki, 1988; Lillis, 1988; 1992). The Soda Lake Shale ranges from 0 to 370 m (0 to 1,200 ft) thick (Hill et al., 1958) and contains 0.5%–6.7 wt. % TOC (average 2.13 wt. %) in mixed marine and terrestrial organic matter (Lillis, 1992). Therefore, development of an unconventional source-rock system "shale oil" play in the Soda Lake Shale of the Cuyama Basin is a possibility.

4.5.2.7.3. Potential Application of WST

WST has not been widely used in the known accumulations of the Cuyama Basin. However, some of the undiscovered accumulations could possibly benefit from application of WST. In addition, if the postulated source-rock system (shale oil) play in the Soda Lake shale existed (Figure 4-35) and could be developed, it would probably require the routine application of hydraulic fracturing for permeability enhancement and production. Development would occur in the area beneath which the Soda Lake shale is thermally mature with respect to oil (Figure 4-35).
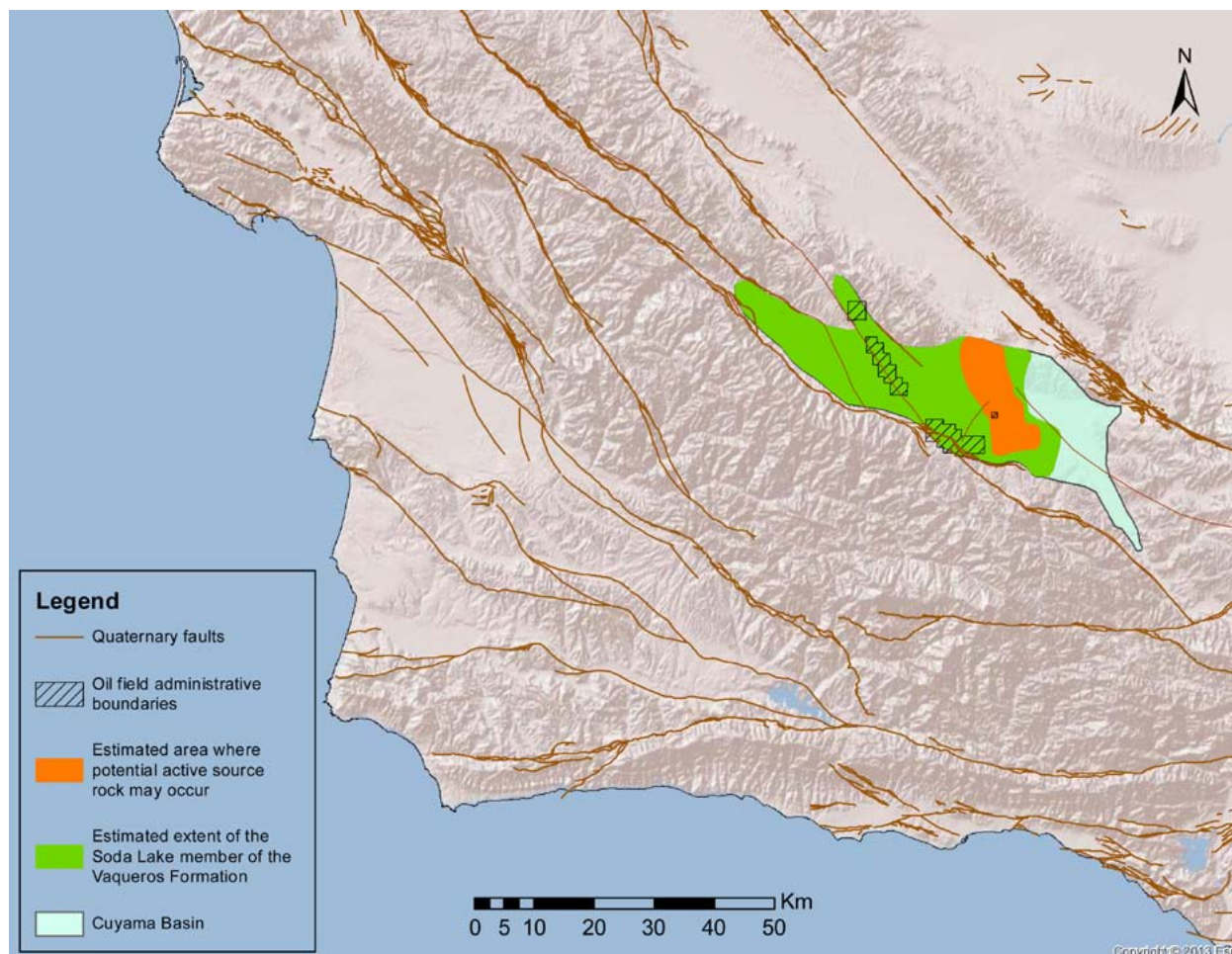
Figure 4-35. *Cuyama Basin and associated oil fields (DOGGR), along with distribution of Vaqueros source rock (Sweetkind et al., 2013) and portion below top of oil window (~2.5 km (1.6 mi) depth based on data from Lillis (1994)).*

4.5.2.8. Santa Maria Basin—Onshore

4.5.2.8.1. Geography and Geology

The greater Santa Maria Basin encompasses about 7,800 km² (3000 mi²) along the coast of California between Point Arguello and San Luis Obispo. It is bounded by the San Rafael Mountains and the Sur-Nacimiento fault to the northeast and by the Santa Ynez Mountains and Santa Ynez fault to the south (Sweetkind et al., 2010; Tennyson and Isaacs, 2001; Tennyson, 1995). The Santa Maria Basin extends westward to the 4.8 km (3 mi) limit of the California waters along the coast. The basin is about 240 km (150 mi) long and 16 to 80 km (10 to 50 mi) wide (Figure 4-36).
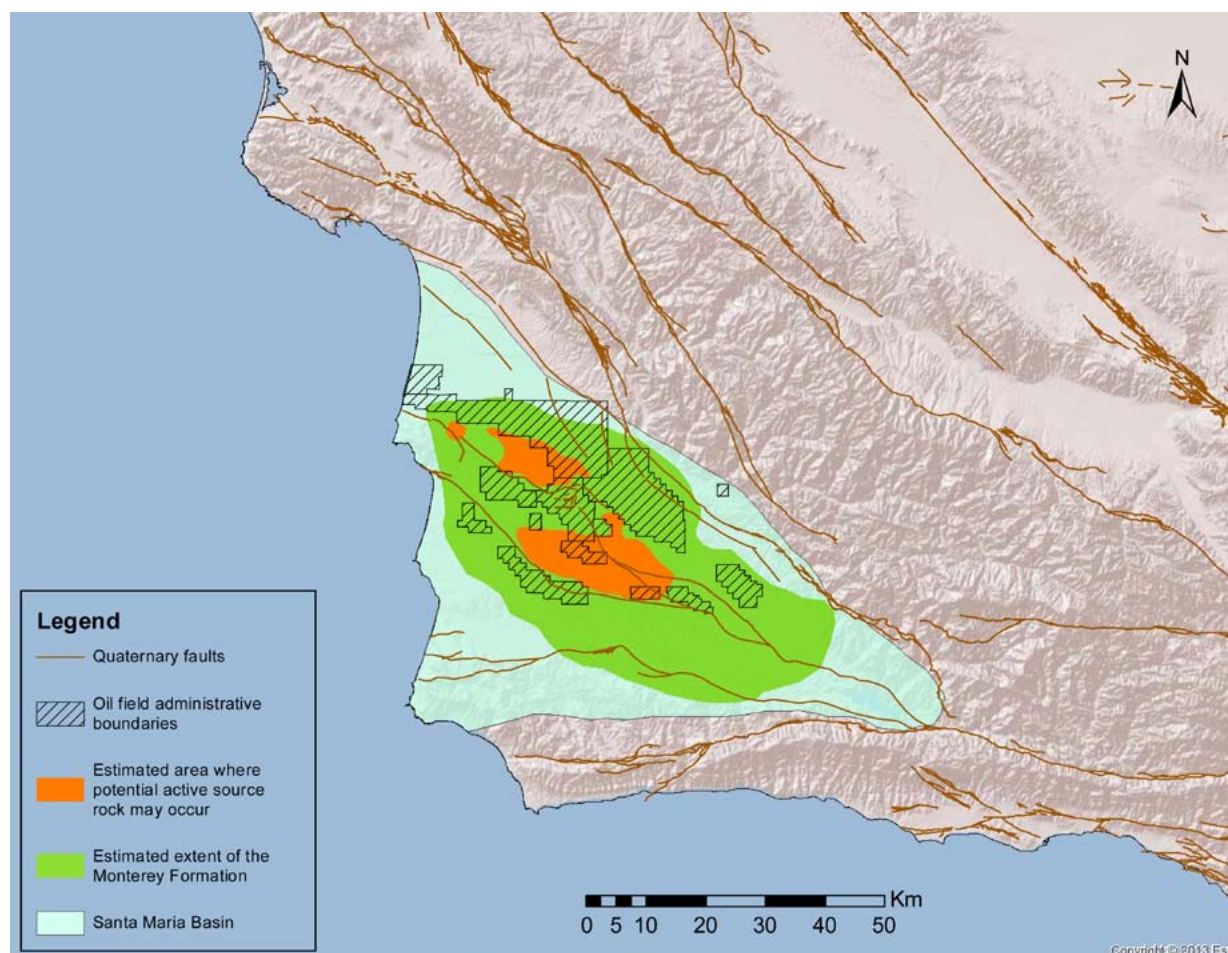
Figure 4-36. *Santa Maria Basin and producing oil fields (Oil field data from DOGGR). Distribution of Monterey Formation (green) and portion below top of oil window [(~2,040 m) (~6,700 ft) depth - Tennyson and Isaacs, 2001] (highlighted in orange) determined using data from Sweetkind et al. (2010).*

Changing plate interactions have led to a complex tectonic evolution of the Santa Maria Basin, with episodes of extension and subsidence, shortening and uplift, and rotation (McCrory et al., 1995). The Basin contains a thick sequence of strata, most of which are Miocene and younger. The Monterey is the principal source rock for oil fields in this basin, and most of the production occurs from fractured siliceous mudstone, porcelanite, chert, and dolomite in the Monterey (Isaacs, 1992b; MacKinnon, 1989; Tennyson and Isaacs, 2001). Fractured authigenic (diagenetic-formed) dolomites have been identified as a significant component of some of the producing oil fields (Roehl and Weinbrandt, 1985). Most Santa Maria oil fields are localized in faulted anticlines. Synclines adjacent to the anticlines are interpreted to be the source region ("the kitchens") for the migrated hydrocarbons produced from these fields.

The Santa Maria Basin has been explored for petroleum since the latter part of the 19th century (Tennyson, 1995). Initial exploration focused on the areas adjacent to the seeps and tar sands that are found throughout the Basin. Orcutt, with about 31 million m³ (193 million barrels) of recoverable oil (cumulative production plus estimated reserves based on DOGGR, 2010), was found 1901, followed by Lompoc (7.9 million m³ oil (50 million barrels) of oil), Casmalia (7.2 million m³ oil (45 million barrels) of oil), Arroyo Grande (4.0 million m³ (25 million barrels) of oil), and Cat Canyon (48 million m³ oil (305 million barrels) of oil) in 1915. The stratigraphically trapped Santa Maria Valley field (33 million m³ oil (208 million barrels) of oil) was found in 1934. Since 1940, ten additional oil fields have been found, none larger than 11 million m³ (70 million barrels). Since the mid-1970s, no field larger than a few million barrels has been found. Minor volumes of gas are associated with most of the oil accumulations, but no non-associated gas has been identified. Santa Maria Basin oil is generally heavy, averaging about 20 °API, although gravities range from 10 to 35 °API.

4.5.2.8.2. Resource Potential

The undiscovered resources of the onshore part of the Santa Maria Basin were last systematically assessed by the USGS in 1995 (Gautier et al., 1995). At that time, the USGS assessors evaluated four geological plays: (1) Anticlinal Trends–Onshore, comprising any part of the section in anticlinal traps, normal-fault traps on the crests of anticlines, and structural traps in the footwalls of reverse faults that cut the anticlines; (2) the Anticlinal Trends in Offshore State Waters; (3) a Basin Margin Play in the northeast part of the basin; and (4) a Diagenetic Traps Play, similar to that in the San Joaquin Basin—a hypothetical play comprising oil in fractured reservoirs in quartz-phase siliceous rocks sealed by overlying unfractured or less-fractured opal CT-phase rocks.

In its 1995 assessment, the USGS estimated a mean undiscovered technically recoverable oil resource for the Santa Maria Basin of about 33 million m³ (210 million barrels) of oil and a mean undiscovered gas resource of 3.4 billion m³ (120 billion scf) of gas, plus another 1.6 million m³ (10 million barrels) of natural gas liquids in all four assessed plays (Gautier et al., 1998). The undiscovered conventional accumulations in the Santa Maria Basin are probably relatively small compared to those discovered in the past. However, the Santa Maria is one of several Neogene basins in California with a demonstrated petroleum source rock that could, at least theoretically, serve as a source-rock system "shale oil" reservoir. In addition to the conventional plays assessed by the USGS in 1995, we therefore postulate a possible source-rock system play in the deep synclinal areas of the basin where the Monterey Formation source rocks have reached thermal maturity (Figure 4-37). Results of drilling have so far not resulted in significant oil production from the source rock system.
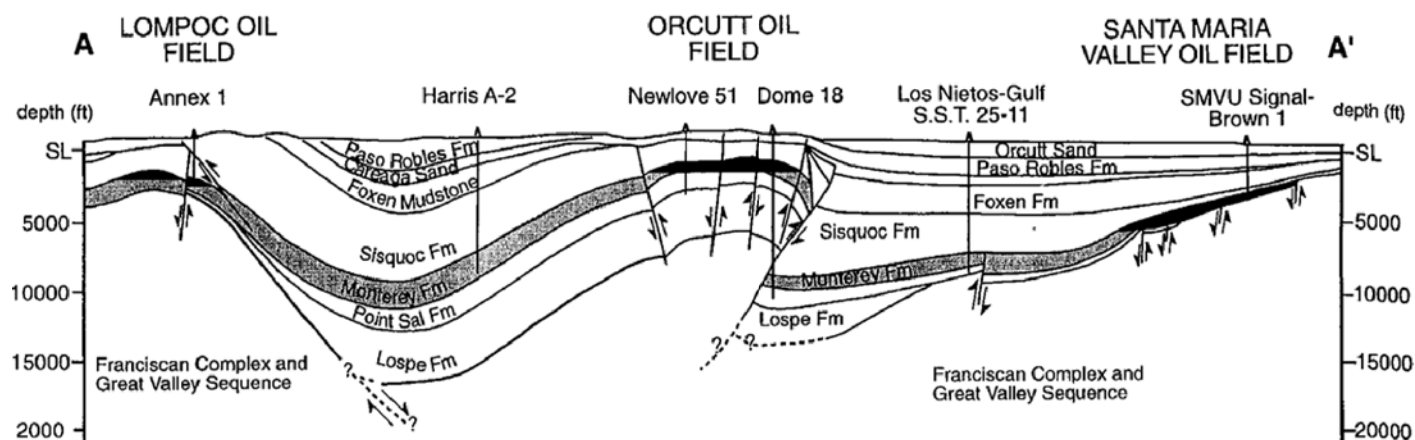
Figure 4-37. *NS cross section through the Santa Maria Basin (Tennyson and Isaacs, 2001). Oil fields are located in faulted anticlinal traps – oil presumed to be generated in deeper synclines.*

This postulated unconventional source-rock system play may have been partially tested in the Los Alamos field, when innovative drilling techniques were used to drill a deep target ~3,050 m (~10,000 ft) true vertical depth (TVD)) in a fractured siliceous shale in the Monterey (Witter et al., 2005). Even though it was highly deviated, and intersected numerous fractures, the well did not result in sustained oil production.

4.5.2.8.3. Potential Application of WST

WST has not been widely used in the Santa Maria Basin. However, some of the undiscovered accumulations could possibly benefit from application of WST. In addition, if the postulated source-rock system (shale oil) play existed and were developed, it would probably require application of hydraulic fracturing for permeability enhancement and production. Development would occur in the areas above the deep synclines where the Monterey is thermally mature with respect to oil.

4.5.2.9. Santa Maria and Partington Basins—Offshore

4.5.2.9.1. Geography and Geology

The Santa Maria Offshore Basin is a complexly faulted extensional structure, separated from the Santa Maria Onshore Basin by the Hosgri Fault Zone. The Offshore Basin extends westward to the Santa Lucia Bank and northward to the "San Martin Structural Discontinuity" of McCulloch (1987), which separates the Santa Maria and Partington basins (Figure 4-22).

Initial subsidence and sediment accumulation began in the Early Miocene as a result of extensional tectonics related to the development of the San Andreas transform fault, expressed by west-dipping, normally faulted basement blocks. The southern part of the central Santa Maria Basin has been drilled to Franciscan-type subduction complex basement rocks, including ophiolite sequences. In addition, certain wells are reported to have encountered basement rocks of Cretaceous age (Mayerson, 1997). Sub-basins bounded by normally faulted basement blocks were rapidly filled by volcanic, biogenic and siliciclastic rocks of the Lospe, Point Sal, Monterey, Sisquoc, Foxen, and Careaga Formations. These formations, which directly overlie basement rocks, are more than 3,050 m (10,000 ft) thick. In most areas, Paleogene strata are entirely absent. Compressional structures continue to develop today. As a result, the Neogene strata have been largely eroded from the tops of most active structures.

In Early Pliocene time, the regional tectonic regime changed from one of transtension (extension) to transpression (compression), resulting in uplift and structural inversion of the basin. Normal faults were reactivated and Miocene and earliest Pliocene strata were folded into antiformal structures that provide the traps for most petroleum in the Santa Maria Offshore.

Exploratory drilling in the central and southern parts of the Santa Maria Offshore began in 1964, with the drilling of an exploratory well northwest of Point Sal. Subsequent drilling found thirteen offshore fields in the Santa Maria Basin. Two of these fields, Point Arguello and Point Pedernales, were put on production, and the rest were shut in or abandoned. Oil is currently produced from Pliocene sandstones of the Sisquoc Formation, from various brecciated Neogene strata, particularly fractured quartz-phase Monterey, and from Paleogene sandstones (Mayerson, 1997).

The Partington Basin, which lies immediately north and northwest of the Santa Maria Offshore, is also bounded on the east by the Hosgri Fault Zone. The northern limit of the Partington Basin is taken to be the structural high of the Sur platform. Like the Santa Maria Offshore, the Partington Basin is underlain by westward-tilting basement fault blocks. However, unlike the Santa Maria, the Partington is largely undeformed by post-early-Miocene tectonics.

The Partington Basin has not been tested by drilling. Nevertheless, because of its geological similarity to the adjacent Santa Maria Offshore, the resources in both basins have generally been assessed together.

The principal source rocks for both the known and potential oil in Santa Maria Offshore and the postulated oil in the Partington Basin are inferred to be the organic-rich, phosphatic facies of the Monterey Formation, similar to those exposed in coastal outcrops (Isaacs, 1980; 1987). Migration pathways in the structurally complex basin are difficult to interpret, and other source rocks are a possibility. In particular the Paleogene sandstone reservoirs have been postulated, largely on the basis of structural considerations, (Mayerson, 1997) to possibly be sourced by as-yet-unidentified organic-rich Paleogene strata.

4.5.2.9.2. Resource Potential

Although the Santa Maria Offshore has been covered with dense seismic data, exploratory drilling remains sparse, and large volumes of yet-to-find and discovered but undeveloped petroleum is believed to be present in this basin. The BOEM/BSEE estimated in 1995 that 124 million m^3 (780 million barrels) of oil and about 21 billion m^3 (740 billion scf) of gas remain to be found and developed in the federal OCS of the Santa Maria and Partington basins (Dunkel, 2001); slightly higher estimates (176 million m^3 (1.11 million barrels) oil and 24 billion m^3 (840 billion scf) gas) were reported by Piper and Ojukwu (2014) for the 2011 BOEM assessment of this region. These resources are expected to be mainly (almost 90%) in fractured siliceous of quartz-phase Monterey reservoirs. The remaining resources are expected to be in sandstones of the Pliocene Sisquoc Formation, with the possibility of small quantities of oil and gas in pre-Miocene sandstones. The undiscovered resources are therefore considered to be quite similar to those that have already been found and developed in the Santa Maria Offshore.

4.5.2.9.3. Potential for Application of WST

The development model for the undiscovered and undeveloped resources of the Santa Maria Offshore and Partington basins calls for only limited, occasional, and incidental use of advanced well stimulation technology. This is because the quartz-phase Monterey reservoirs, which are expected to contain most of the undiscovered and undeveloped oil, are already highly fractured and brecciated (Hickman and Dunham, 1992) and little permeability enhancement is necessary for development. A more important technical issue for development of the remaining resources is the low gravity heavy oils that have been encountered in the known fields and that are to be expected in the remaining undiscovered accumulations. On the basis of geological evidence and on the history of exploration and discovery, the Santa Maria Offshore and Partington basins are estimated to contain more than 170 million m^3 (1.1 billion barrels) of undiscovered and undeveloped oil (Piper and Ojukwu, 2014), making it one of the most geologically prospective areas for new petroleum in North America. Although certain reservoirs in the undiscovered and undeveloped existing fields of the Santa Maria Offshore may be amenable to improved production rates as a result of hydraulic fracturing, well stimulation technology is expected to be incidental rather than fundamental to development.

4.5.2.10. Santa Barbara/Ventura Basin

4.5.2.10.1. Geography and Geology

The Santa Barbara/Ventura Basin is a structurally complex east-west trending synclinal trough bounded on the north and northeast by the Santa Ynez and San Gabriel faults

and on the south by the Santa Monica Mountains and Channel Islands. The west end of this basin is a poorly defined basement uplift called the Amberjack High (Dibblee, 1988; Keller, 1988; 1995; McCulloch, 1987; Nagle and Parker, 1971; Tennyson and Isaacs, 2001; Crain et al., 1985; Galloway, 1997). The Santa Barbara/Ventura Basin is a single, continuous structure; the onshore part is referred to as the Ventura Basin, while the offshore part is known as the Santa Barbara Basin (Figures 4-38 and 4-39).
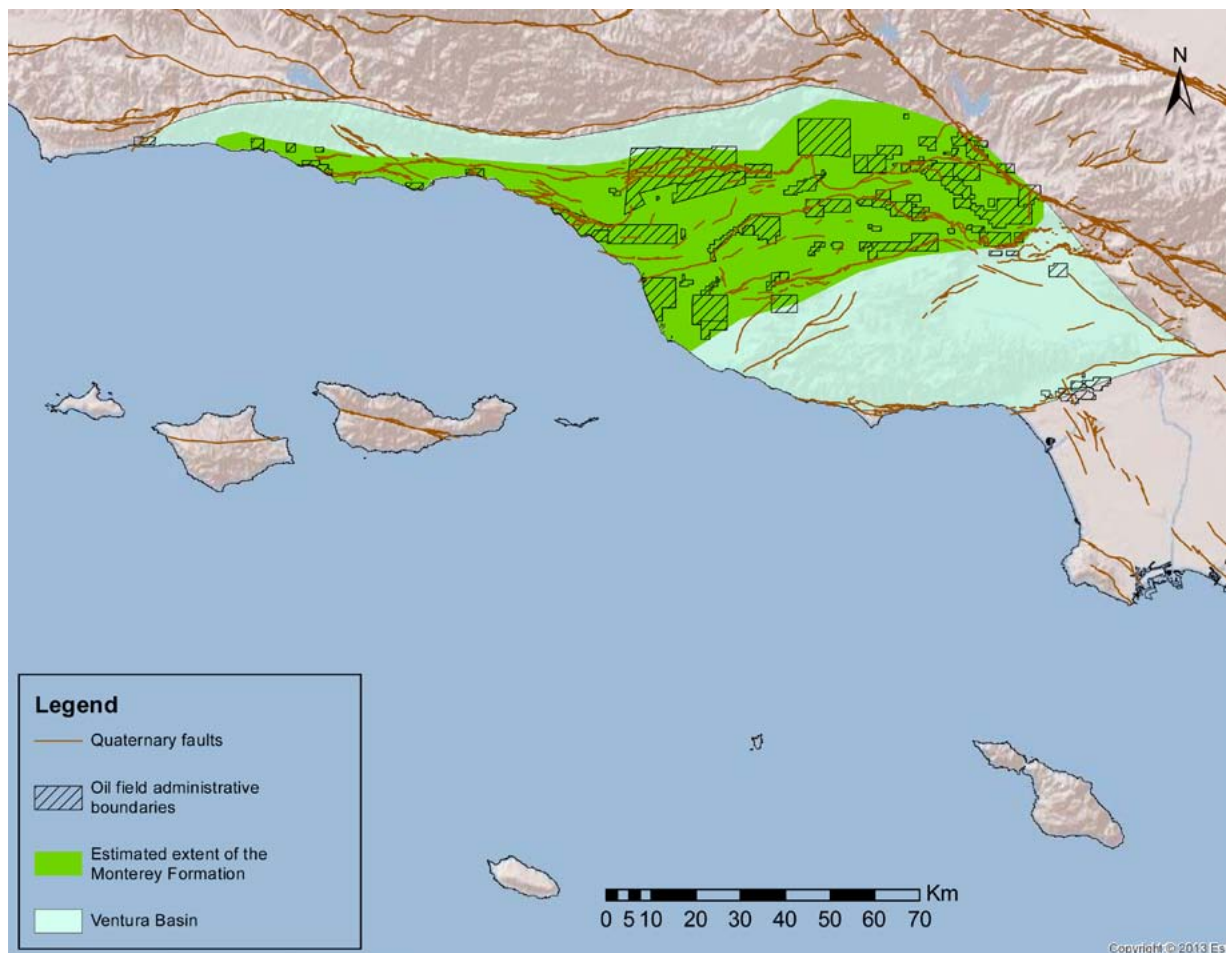
Figure 4-38. *The Ventura Basin and producing oil fields (Oil field data from DOGGR). Distribution of the Monterey (green) from Nagle and Parker (1971). No data were available to constrain the distribution of the active source rock for this basin.*
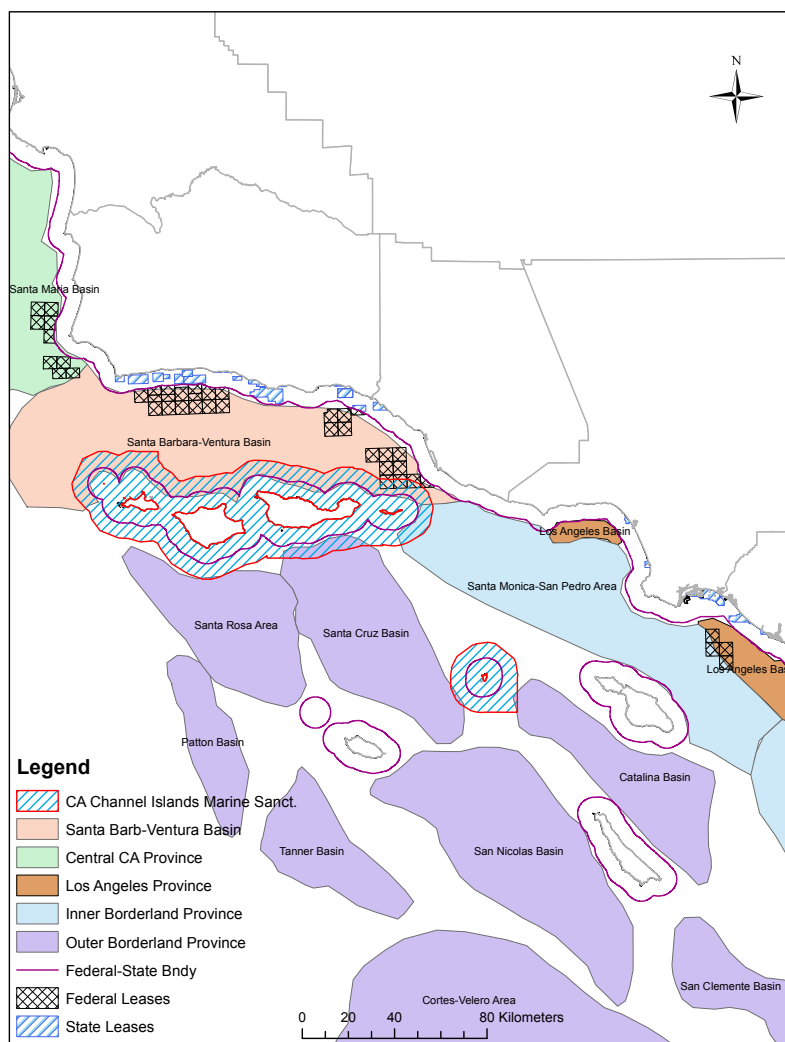
Figure 4-39. *Map of Southern Coastal California Offshore Basins (adapted from Dunkel and Piper, 1997).*

The Santa Barbara/Ventura Basin exhibits as much as 7,000 m (23,000 ft) of structural relief on the base of the Miocene section (Tennyson and Isaacs, 2001) and a succession of Upper Cretaceous to Quaternary sedimentary rocks as much as 11,000 m (36,000 ft) thick. In the primary depocenter, the Plio-Pleistocene strata are more than 6,100 m (20,000 ft) thick (Dibblee, 1988; Nagle and Parker, 1971).

This basin has a complex Neogene tectonic history. Prior to late early Miocene time, the present-day east-west trend was oriented north-south and located immediately west of Los Angeles Basin (Crouch and Suppe, 1993). Paleomagnetic data (Hornafius, 1985)

indicate that since then, the basin and the adjacent transverse ranges have rotated more than 90° (McCulloh and Beyer, 2004), accompanied by extensional deformation related to evolution of the transform margin between North America and the Pacific Plate. Since the Pliocene, intense compressional deformation has caused rapid differential uplift and subsidence responsible for thermal maturity of organic-rich source rocks and for the east-west trending reverse faults and folds that contain most of the known petroleum (Tennyson and Isaacs, 2001).

The principal source rocks for the Santa Barbara/Ventura Basin are the organic-rich and phosphatic facies of the Monterey (Isaacs and Rullkötter, 2001). However, the overlying Sisquoc Formation and the underlying Rincon shale may also be sources of hydrocarbons (Tennyson and Isaacs, 2001).

Ventura Basin oil was discovered onshore at Santa Paula in 1861. Since that time, approximately 155 additional petroleum accumulations have been identified, including nine gas fields, approximately 70 of which are larger than 0.16 million m^3 oil equivalent (1 million barrels of oil equivalent). The supergiant Rincon trend comprises three giant oil fields (>16 million m^3 (100 million barrels) of oil) (Ventura Avenue, San Miguelito, and Rincon) in a continuous structure that crosses the shoreline. Taken together, the three giant fields of the Rincon trend may contain more than 0.24 billion m^3 oil equivalent (1.5 billion barrels of oil equivalent) of recoverable petroleum (Keller, 1995). The most recent onshore discovery in the basin was Rincon Creek, found in 1982 (DOGGR, 1992).

The first offshore wells in North America, and perhaps in the world, were drilled in 1897 to extend the Summerland oil field (discovered in 1890) offshore (Rintoul, 1990). The last field found in California waters was Santa Clara, in 1971. Offshore exploration began in earnest after the World War II; the first federal lease was issued in 1966. Since that time at least 12 fields, including offshore areas of the Ventura Avenue-San Miguelito-Rincon trend, have been discovered offshore (Galloway, 1997). Other giant offshore fields in the basin include Hondo, Dos Cuadras, and Carpinteria. Most petroleum production is from Pliocene submarine-fan sandstones of the Pico and Repetto Formations, with additional production from Oligocene and lower Miocene sandstones of the Sespe and Vaqueros Formations (Figure 4-40). Production from fractured quartz-phase Monterey is limited to a few offshore fields, including South Elwood and Hondo (Tennyson and Isaacs, 2001).
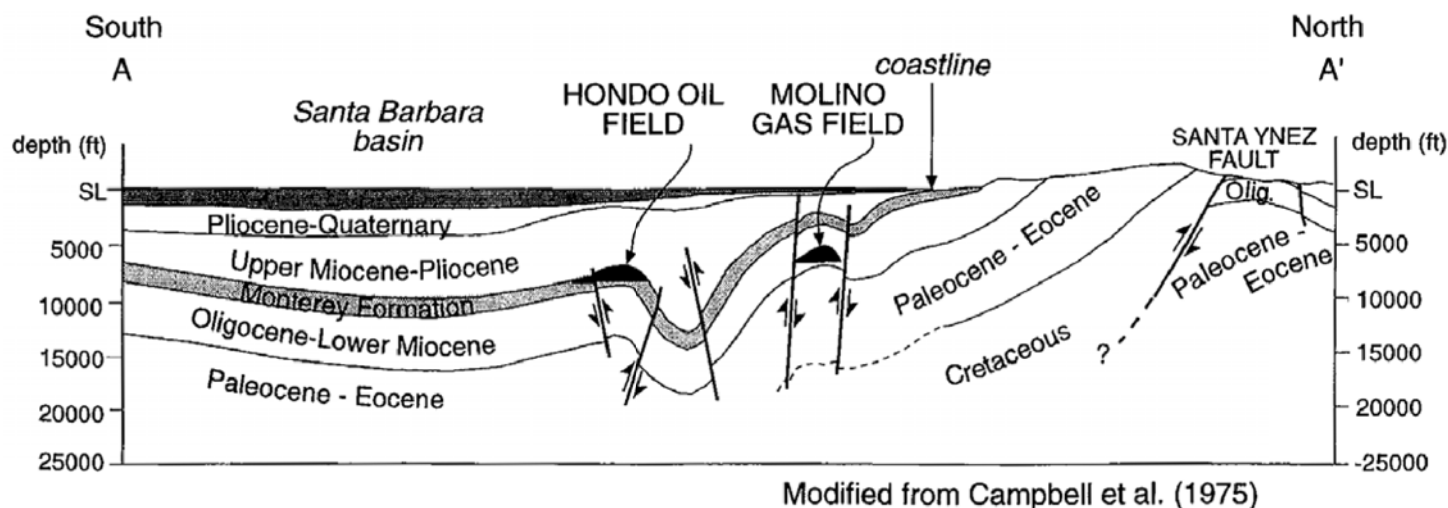
Figure 4-40. *NS cross section through the Santa Barbara Basin (Tennyson and Isaacs, 2001). Oil and gas fields are located in faulted anticlinal traps.*

4.5.2.10.2. Resource Potential

The USGS made the most recent assessment of onshore state waters areas of the Santa Barbara/Ventura Basin in 1995 (Gautier et al., 1995). At that time the mean volume of technically recoverable undiscovered oil was estimated to be about 170 million m^3 (1,060 million barrels) of oil, more than half of which was estimated to be beneath state waters offshore. Undiscovered technically recoverable gas resources of 54 billion m^3 (1.9 trillion scf) and 11 million m^3 (70 million barrels) of natural gas liquids were also estimated (Gautier et al., 1998).

The offshore federal OCS part of the Santa Barbara/Ventura Basin was last assessed in 2011 by BOEM (Piper and Ojukwu, 2014). Their mean estimate of undiscovered technically recoverable petroleum was 213 million m^3 (1.34 billion barrels) of oil and 78 billion m^3 (2.74 trillion scf) of natural gas. Like the offshore Santa Maria Basin to the north, the offshore Santa Barbara Basin is estimated to have a high potential for large volumes of additional oil reserves in conventional reservoirs. While occasional hydraulic fracturing can be expected in the development of conventional reservoirs offshore, it is not considered fundamental to development. On the other hand, the large volumes of known petroleum indicate the presence of an active and potent Monterey source rock that could, in principle, be developed as a low-permeability shale oil reservoir, which probably could only be developed by means of advanced drilling and stimulation technology.

4.5.2.10.3. Potential for Application of WST

Onshore

Because of the highly porous and permeable Pico and Repetto sandstone reservoirs, WST has not been widely employed in the Ventura Basin. A noteworthy exception to this, however, is at the Sespe oil field, in the northeastern edge of this basin, where production relies on hydraulic fracturing of low-permeability reservoirs for economically sustainable production. Therefore, it is considered likely that some of the undiscovered onshore accumulations could also benefit from application of WST.

Santa Barbara/Ventura is an extremely deep basin, with prolific Monterey source rocks. These organic-rich shales could, in principle, become targets for development of continuous-type source-rock system plays. However, in contrast with the Los Angeles Basin to the southeast, the Santa Barbara/Ventura Basin has a relatively low geothermal gradient (Jeffrey et al., 1991). As a result, any thermally mature source rock would only be present at great depths, making development more expensive and economically less feasible. However, if the postulated source-rock system (shale oil) play in the Monterey Formation existed and was developed, it would probably require the widespread application of hydraulic fracturing for permeability enhancement and production. Development would occur in the areas above the deep central trough, where the Monterey is thermally mature with respect to oil. The geography of thermally mature source rocks is not well constrained in the Santa Barbara/Ventura Basin and, in contrast to Santa Maria and adjacent Los Angeles, potential shale oil reservoirs could be present both onshore and offshore.

Offshore

The development model for the undiscovered and undeveloped resources of the offshore Santa Barbara Basin calls for only limited, occasional and incidental use of WST. This is because the Pico and Repetto submarine fan sandstones, which will probably contain most of the undiscovered and undeveloped oil offshore, typically do not require permeability enhancement. Similarly, fractured quartz-phase Monterey reservoirs that remain to be discovered or developed are expected to be highly fractured and therefore also need little permeability enhancement for development.

4.5.2.11. Los Angeles Basin

4.5.2.11.1. Geography and Geology

The Los Angeles Basin is an active margin Neogene sedimentary basin having one of the world's highest concentrations of petroleum (Barbat, 1958; Yerkes et al., 1965; Biddle, 1991; Beyer, 1988b; 1995b) (Figure 4-41). The geological foundations of the Los Angeles Basin in southern California were laid during Cretaceous subduction and Late Cretaceous-to-Paleogene terrane accretion, but the Miocene rifting that opened the basin began

abruptly with basaltic volcanism at about 17.4 million years ago (Ma) (McCulloh and Beyer, 2004). Initial extension was followed by crustal detachment and > 90° of clockwise tectonic rotation of the transverse ranges, including the Santa Monica Mountains, which form the northern margin of the basin (Ingersoll and Rumelhart, 1999). In the wake of tectonic rotation (Figure 4-42), the nascent basin was more or less open to the nutrient-rich waters of the eastern Pacific but shielded from sediment influx. As a result, organic-carbon-rich sediments, which, after deep burial, would later serve as rich source rocks for the basin's oil, accumulated between 13.5 and about 8 Ma. These sediments are Monterey Formation - equivalent strata, including the Nodular Shale (Hoots et al., 1935) and the La Vida member of the Puente Formation.
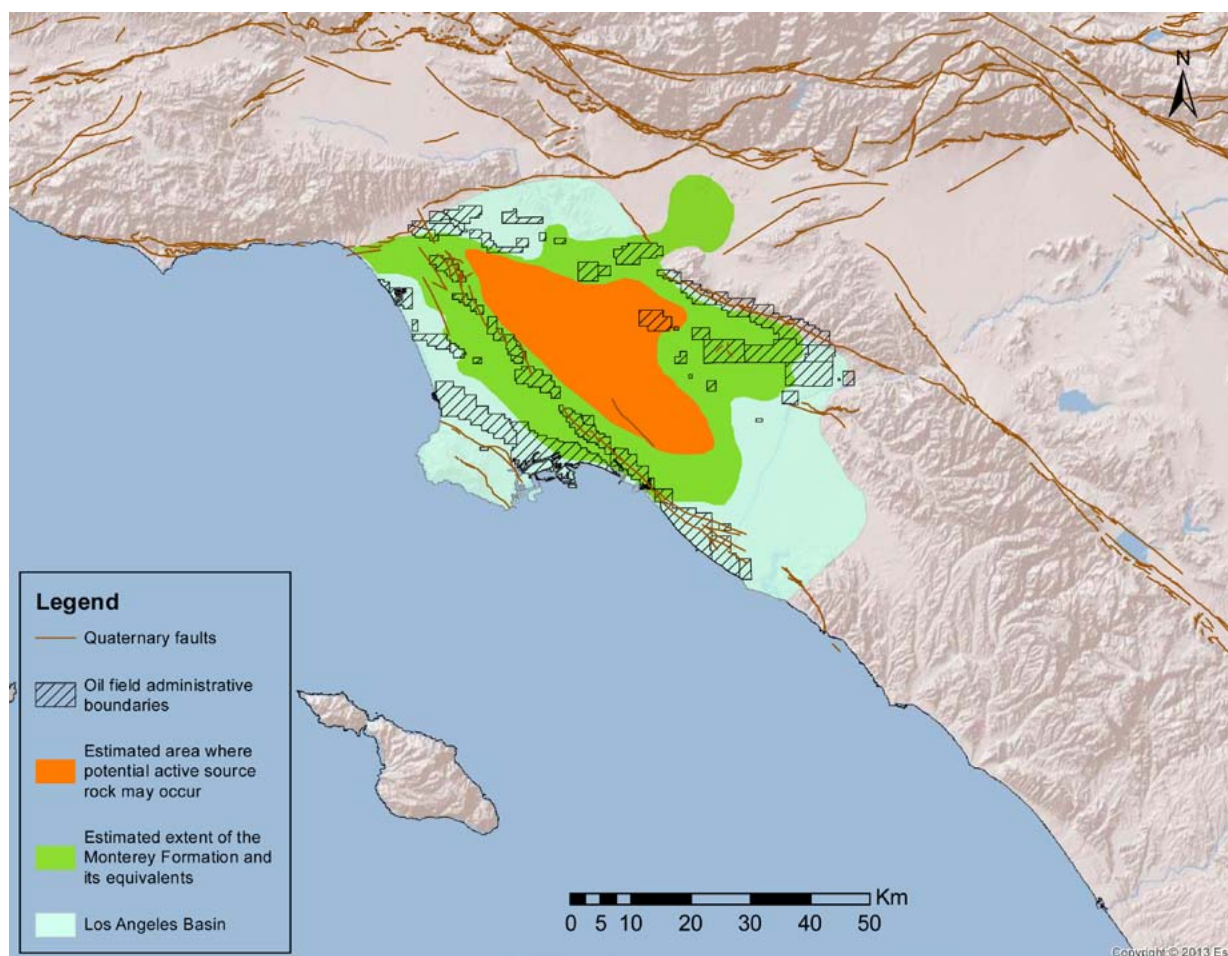
Figure 4-41. *Map of the Los Angeles Basin with outlines of producing oil fields. The orange shaded area depicts where deep source rocks within the oil window are located. Data from DOGGR, Wright (1991), and Gautier (2014).*
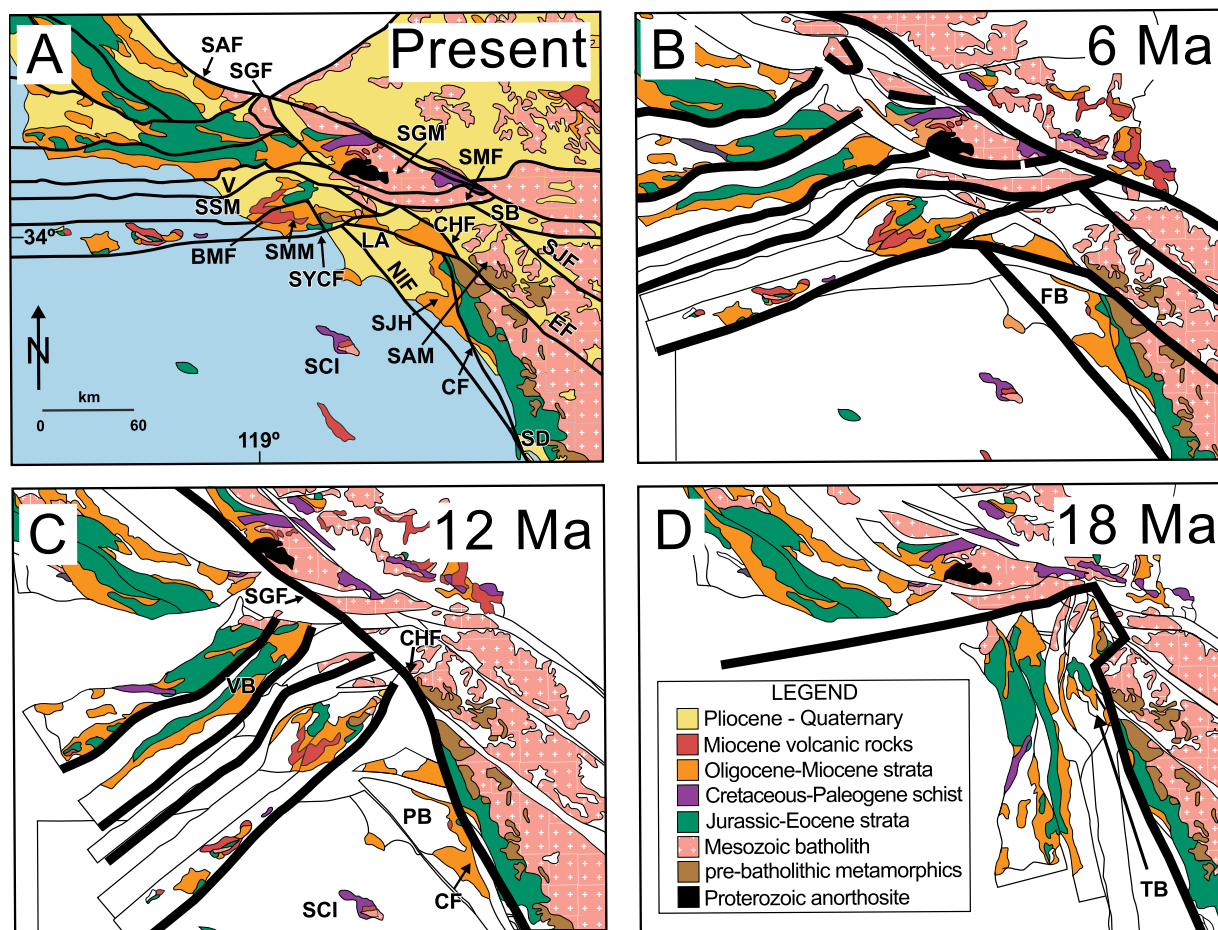
Figure 4-42. *Three-stage tectonic evolution of the Los Angeles Basin. A – Present day structural setting, B, C, D – Palinspastic reconstructions of basin at 6, 12, and 18 Ma (details described in Ingersoll and Rumelhart, 1999).*

The dominant feature of the Los Angeles Basin is the Central Syncline, a poorly understood north-northwest trending 72 km (45 mi) long trough within which organic-rich Miocene sediments have been buried to the oil window and beyond beneath thick submarine fan deposits (Wright, 1991). The Central Syncline is bordered on the north by east-west trending faults and the southern edge of the Santa Monica Mountains, on the east and northeast by *en echelon* folds and the Whittier Fault Zone, and on the southwest by the Newport-Inglewood Fault Zone and adjacent southwest structural shelf.

The many oil and gas seeps in and around the Los Angeles Basin suggest that petroleum is still being actively generated. Natural gas being lost through leaky seals accounts for the profound preference of oil over gas in the petroleum accumulations. Sandstones deposited

in slope-channel and basin-floor submarine fans of late Miocene to early Pliocene age (upper Mohnian, Delmontian, and "Repettian" stages) (Tsutsumi et al., 2001) are the main reservoir rocks (Redin, 1991). Although most of the major trapping structures were established during Miocene rifting, most of them have been modified and reversed during the tectonic compression of the past 5 million years; more than 95% of the known oil has been found in structural traps that were already forming by 6 Ma due to transpressional forces related to movement on the San Andreas transform and the opening of the Sea of Cortez (Ingersoll and Rumelhart, 1999).

Petroleum has been produced from 68 named fields, most of which are closely related to the Basin's principal structures (Wright, 1991): the Central Syncline, the Newport Inglewood Fault Zone (NIFZ), the Whittier Fault Zone (WFZ), the Santa Monica Fault Zone (SMFZ), and the Palos Verdes Fault Zone (PVFZ) (Figure 4-43). Principal oil accumulations ((>16 million m^3 >100 million barrels) of oil equivalent recoverable) with discovery year are: Wilmington-Belmont (1932), Huntington Beach (1920), Long Beach (1921), Santa Fe Springs (1919), Brea-Olinda (1880), Inglewood (1924), Dominguez (1923), Coyote West (1909), Torrance (1922), Seal Beach (1924), Richfield (1919), Montebello (1917), Beverly Hills East (1966), Coyote East (1911), Rosecrans (1924), and Yorba Linda (1930). These 15 principal accumulations, which account for about 91% of recoverable oil in the Los Angeles Basin, were discovered before 1933. The most recent significant discoveries occurred during the early to mid-1960s (Beverly Hills East, Las Cienegas (Jefferson area), Riviera, and San Vicente (Beyer, 1995b). One other large field, Beta Offshore, was found in Federal waters in 1976. Most of the known oil of the Los Angeles Basin has been found in structural traps that are not generally coincident with the areas below which petroleum source rocks are expected to be thermally mature (Figure 4-41).
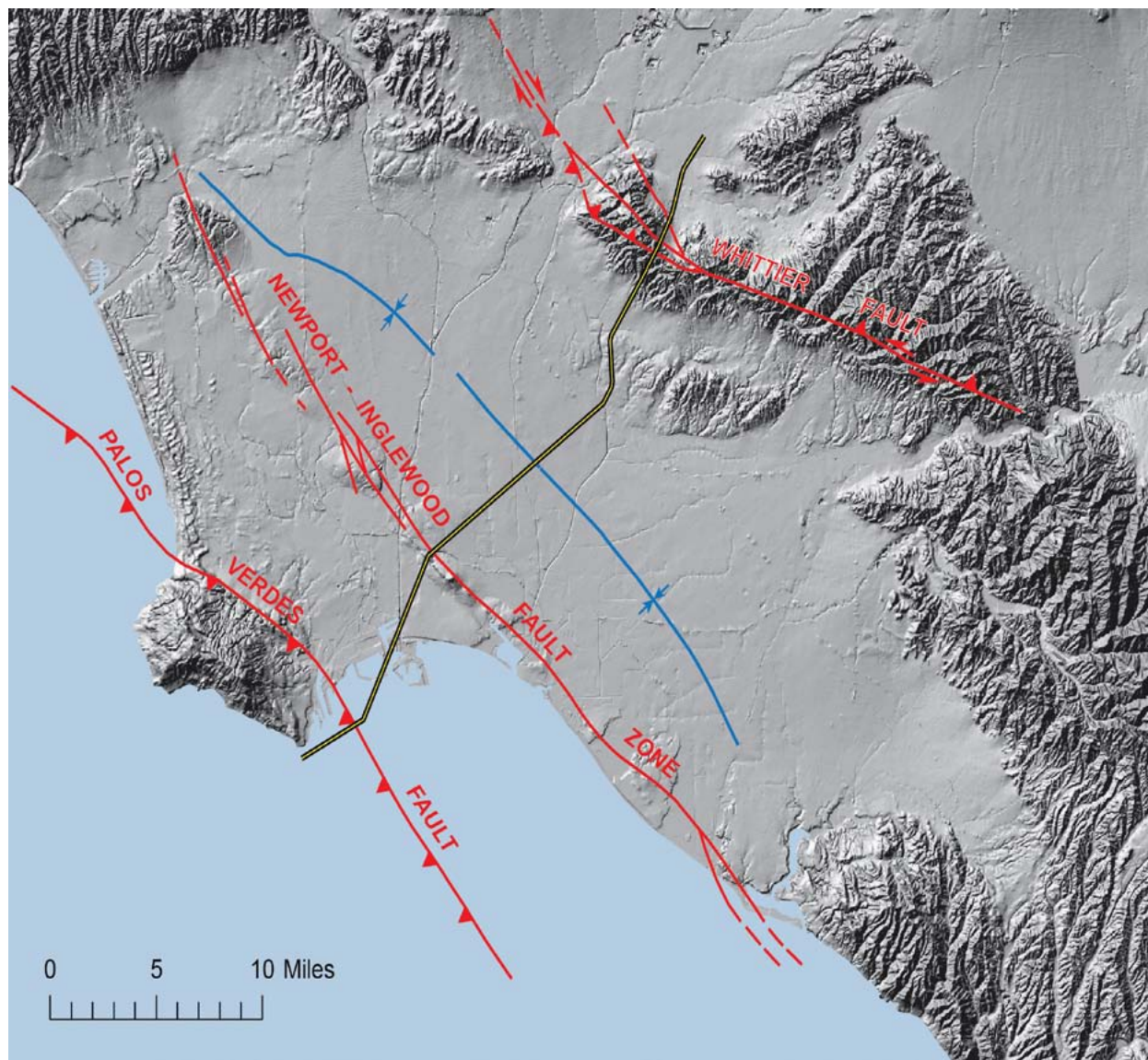
Figure 4-43. *Structural map of the Los Angeles Basin. Fault traces are depicted as red lines, and the Central Syncline appears as a blue syncline symbol. Shaded relief map from Zenon Valin, USGS.*

4.5.2.11.2. Resource Potential

In addition to the cumulative production and currently reported remaining reserves (DOGGR, 2010), the remaining resource potential of the Los Angeles Basin comprises three broad categories: 1) Undiscovered conventional oil fields, 2) Growth of reserves in existing fields, and 3) Development of unconventional resources.

4.5.2.11.3. Undiscovered Conventional Oil Fields

The last systematic assessment of undiscovered conventional resources in the Los Angeles Basin was done by the US Geological Survey and published in 1995 (Gautier et al., 1995). The mean undiscovered oil resource for the basin as whole, including the state waters but excluding the Federal Outer Continental Shelf, was estimated to be approximately 160 million m³ oil (980 million barrels) of oil (Gautier et al., 1998).

These undiscovered resources are distributed among seven confirmed conventional plays defined by USGS (Beyer, 1995b) (Figure 4-44): Santa Monica Fault System and Las Cienegas Fault and Block Play (mean estimate – 34 million m³ (214.2 million barrels) of oil) (http://certmapper.cr.usgs.gov/data/noga95/prov14/tabular/pr1401.pdf), Southwestern Shelf and Adjacent Offshore State Lands Play (mean estimate – 23 million m³ (142.8 million barrels) of oil) (http://certmapper.cr.usgs.gov/data/noga95/prov14/tabular/pr1402.pdf), Newport- Inglewood Deformation Zone and Southwest Flank of Central Syncline Play (mean estimate – 42 million m³ (264.9 million barrels) of oil) http://certmapper.cr.usgs.gov/data/noga95/prov14/tabular/pr1403.pdf), Whittier Fault Zone and Fullerton Embayment Play (mean estimate –14 million m³ (89.8 million barrels) of oil) (http://certmapper.cr.usgs.gov/data/noga95/prov14/tabular/pr1404.pdf), Northern Shelf and Northern Flank of Central Syncline Play (mean estimate – 17 million m³ (109.3 million barrels) of oil) (http://certmapper.cr.usgs.gov/data/noga95/prov14/tabular/pr1405.pdf), Anaheim Nose Play (mean estimate – 4.9 million m³ (30.8 million barrels) of oil) (http://certmapper.cr.usgs.gov/data/noga95/prov14/tabular/pr1406.pdf), Chino Marginal Basin, Puente and San Jose Hills, and San Gabriel Valley Marginal Basin Play (mean estimate – 2.9 million m³ (18.3 million barrels) of oil) (http://certmapper.cr.usgs.gov/data/noga95/prov14/tabular/pr1407.pdf).
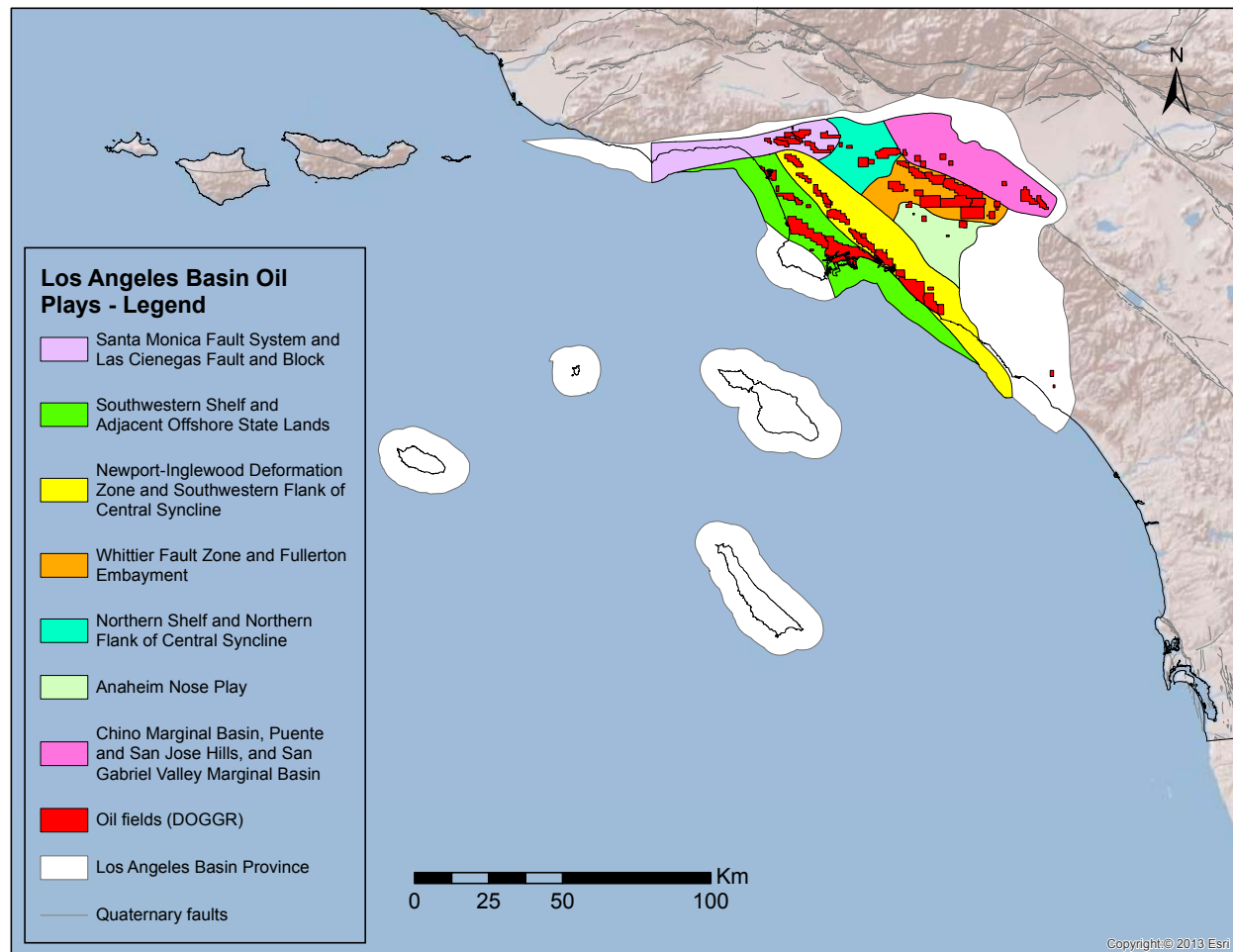
Figure 4-44. *Los Angeles Basin with seven conventional plays identified by USGS. Play outlines from USGS 1995 National Assessment of US Oil and Gas Resources http://certmapper.cr.usgs. gov/noga/broker1995.jsp?theServlet=NogaGISResultsServ&theProvince=14&thePage=gis*

Although a mean basin-level estimate of almost 160 million m³ (1 billion barrels) of oil (Gautier et al., 1998) would seem quite significant in many untested basins, in the Los Angeles Basin, where original oil in place probably exceeded 6.4 billion m³ (40 billion barrels) of oil, an estimated technically recoverable volume of less than 160 million m³ (1 billion barrels) probably represents the remaining residual small and hard-to-find accumulations that may not warrant much expensive exploration effort. These undiscovered accumulations are expected to share many of the geological features of the known field population. Therefore, if these small conventional fields were discovered, development practices would probably reflect updated versions of past development practices and typically not involve large-scale hydraulic fracturing or other WST.

4.5.2.11.4. Growth of Reserves in Existing Fields

Geologists and engineers familiar with the Los Angeles Basin believe that recovery efficiency is low in nearly every reservoir and that consistent application of best-practice technology could recover large volumes of additional oil. In order to evaluate the volumes of potentially recoverable oil remaining in existing fields of the Los Angeles Basin, the US Geological Survey assessed the 10 largest (by original oil in place) oil fields (Brea-Olinda, Dominguez Hills, Huntington Beach, Inglewood, Long Beach, Richfield, Santa Fe Springs, Seal Beach, Torrance, and Wilmington-Belmont) in the basin (Gautier et al., 2013). Production and reserves data for the study came from the California Division of Oil, Gas, and Geothermal Resources. The geology of each field was analyzed and the history of its engineering and development was reviewed. Probability distributions for original oil in place (OOIP) and maximum potential recovery efficiency (RE_{max}) were developed. The maximum recovery efficiency was evaluated on the basis of recovery efficiencies that have been modeled in engineering studies, achieved in similar reservoirs elsewhere, or indicated by laboratory results reported in technical literature. The resulting distributions of OOIP and RE_{max} were combined in a Monte Carlo simulation to estimate remaining recoverable oil.

The results of the USGS study suggest that between 0.25 and 0.89 billion m³ (1.4 and 5.6 billion barrels) of additional recoverable oil remain in the 10 analyzed fields, with a mean estimate of approximately 0.51 billion m³ (3.2 billion barrels). Recovery of these resources would require field redevelopment and unrestricted application of current best-practice technology, including improved imaging and widespread application of directional drilling, combined with extensive water, steam, and CO_2 floods.

Because the majority of petroleum reservoirs of the giant Los Angeles Basin fields are sandstones with high porosity and permeability, redevelopment of these fields would not generally require hydraulic fracturing as a common practice. However, low-permeability reservoirs are probably present in most of these large fields, and development of them could entail the local and limited application of hydraulic fracturing in conjunction with other technological applications.

In addition to the recoverable resources in the ten largest fields, recoverable oil probably also remains in many of the other 58 existing oil fields in the Los Angeles Basin. It's likely that some of the reservoirs are of low permeability. If so, then production of remaining resources in some of the smaller fields could benefit from limited application of small-volume hydraulic fracturing.

Generally unrestricted development or redevelopment, such as is assumed by the USGS study, is difficult to envision, given the highly urbanized condition of the Los Angeles Basin.

Large volumes of recoverable conventional oil remain in the Los Angeles Basin. While their development may be impeded by a number of factors, they could be produced in

time of need. These resources are probably more accessible than the unconventional resources postulated to also be present in the Los Angeles Basin.

4.5.2.11.5. Unconventional Resources

Given the large concentrations of petroleum in the Los Angeles Basin, it is certain that prolific organic-rich source rocks are present in the Basin and that they have been heated sufficiently for widespread petroleum generation. This circumstance is probably the basis for the published estimates of large quantities of recoverable "shale oil" in the Los Angeles Basin.

During the 1995 USGS national assessment, a potential play involving continuous-type resources in source rock systems and in adjacent related strata in the Los Angeles Basin was identified (Beyer, 1995b). Although the play was not quantitatively assessed at that time, its general resource potential and geological properties were described in some detail. The identification of this probable continuous type, unconventional, and hypothetical play, named the "Deep Overpressured Fractured Rocks of Central Syncline Play," was based largely on a single well in the Central Syncline (Figure 4-45), the deepest well in the basin, the American Petrofina Central Core Hole (APCCH) No. 1 well (sec. 4, T. 3 S., R. 13 W.). The APCCH encountered overpressured rocks and tested moderately high gravity oil below about 5,490 m (18,000 ft). The well bottomed in lowermost Delmontian (Late Miocene) strata at a measured depth of 6,466 m (21,215 ft) in the Central Syncline and therefore did not reach the presumed Monterey-equivalent source rock interval of Mohnian age. The Mohnian section has not been reached by drill in the Central Syncline. Based on inferred depth to basement (Yerkes et al., 1965) and projected thicknesses of upper Miocene rocks northeast and southwest of the Central Syncline, the lower Mohnian section is probably less than 910–2,130 m (3,000–7,000 ft) thick in the Syncline. The postulated conceptual unconventional reservoir is fractured rock within and immediately adjacent to the Mohnian source rock interval.
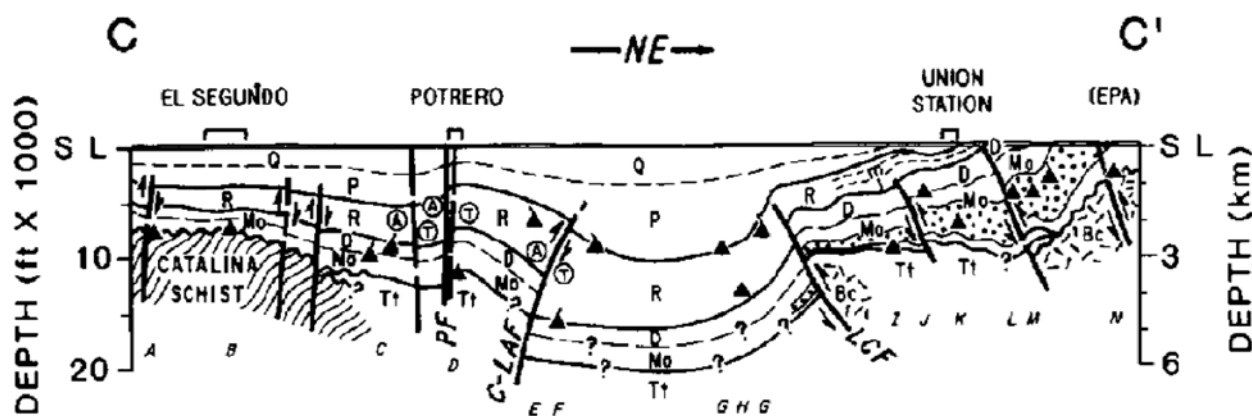
Figure 4-45. *Regional NE-SE cross section through the Los Angeles Basin, showing the Central Syncline (Wright, 1991).*

The potentially productive area of the play includes most of the Central Syncline and its deep flanks at depths below which the source rock interval has been heated sufficiently for maximum petroleum generation and formation of an overpressured condition. The deep southwestern flank of the Central Syncline was regarded at the time of the USGS assessment as the most favorable location for potentially productive continuous type low-permeability (light, tight) oil reservoirs.

The postulated fracturing of reservoir rocks is inferred to have been caused by fluid overpressuring during maturation of kerogen in the organic-rich shales. Late Miocene and early Pliocene extensional faulting and more recent north-south compression of the southwest flank of the Central Syncline could also contribute to fracturing. The compressional tectonics since the Pliocene may have locally enhanced fracturing along the deep syncline-bounding faults. This faulting also could have provided expulsion routes except where diagenetic alteration has kept seals intact. The presence of overpressuring in the APCCH well suggests that some seals remain intact. Many petroleum geochemists since Price (1994) have concluded that large amounts of generated hydrocarbons may remain in or near source rocks in basins where expulsion routes have not been provided by tectonism.

Potentially productive reservoirs are postulated to be fractured rocks of lower Mohnian or older age and the source rocks are believed to include some of the same lower Mohnian strata, thereby making the postulated play a source-rock system. Los Angeles Basin source rocks may be in less terrigenous parts of the lower Mohnian section, possibly analogous to the organic-rich basal unit ("nodular shale") on the southwestern shelf. The "nodular shale" is reported to occur northeast of the Newport-Inglewood zone of deformation in the Inglewood field (Wright, 1991). Vitrinite reflectance values are reported to be increasing rapidly toward the bottom of the American Petrofina Central Core Hole well where values >1.2% were observed (N.H. Bostick, 1994, personal comm.) Maturation of hydrocarbons probably began during early Pliocene time or earlier and continues today. Migration is not necessary for postulated source-rock system reservoirs

The postulated continuous-type play is unexplored except for American Petrofina Central Core Hole well, which confirmed the presence of hydrocarbons, but does not directly demonstrate the play, as its total depth is above the postulated play. The APCCH tested oil of 43 °API gravity with moderate to a high gas-oil ratio near total depth, prompting the USGS to postulate the existence of a "continuous-type" petroleum accumulation in the deepest parts of the Los Angeles Basin. Other, less deep, wells on the east flank of the Newport-Inglewood zone of deformation penetrated interbedded sandstone and shale with type II kerogen in the lower Mohnian section. Condensate or gas also is likely at the depths of this hypothetical play. Hydraulic fracturing has been applied to a number

of wells in the Inglewood oil field to enhance oil recovery (Cardno ENTRIX, 2012) and perhaps to test the concept of an unconventional source-rock system play in the Los Angeles Basin.

Because of the known organic richness of Luisian and lower Mohnian source rocks along the northeast and southwest margins of the Central Syncline, we infer that large amounts of hydrocarbons have been generated in the Central Syncline. However, the idea that large recoverable volumes of the generated petroleum remain trapped at great depth in suitable reservoir rocks is entirely hypothetical. Moreover, because of the postulated highly fractured condition of the potentially productive source rock intervals, the degree to which hydraulic fracturing would be needed for development of this hypothetical play also remains a subject of speculation. The presence of at least some recoverable oil in fractured reservoirs closely associated with source rocks in the deep Central Syncline has been demonstrated by the APCCH. These "shale oil" resources are beneath the central Los Angeles Basin, largely outside of the existing field boundaries. Testing their development potential would require drilling and production testing of deep wells specifically targeting the shale oil potential.

4.5.2.11.6. Potential for WST

Compared with most other highly petroliferous basins, the Los Angeles Basin is remarkable for the similarity and consistency of its productive reservoirs. The vast majority of petroleum has been and is being produced from highly porous and permeable sandstones deposited in the slope channels and basin-floor deposits of large submarine fans that accumulated in the basin between late Miocene and middle Pliocene time. The minor exception of production from outlier examples such as the schists and schist conglomerates on the western shelf and minor production low-permeability facies along the Whittier Fault Zone only reinforces the basic picture of homogeneity of reservoir quality across the Basin.

Beyond the issues of societal acceptance of production practice and land availability in an urban setting, the most important complications to additional production are the result of (1) loss of reservoir pressure due to haphazard development of the fields, (2) water breakthrough in major reservoirs leading to premature abandonment, and (3) technical problems related to production of low-gravity/high viscosity oil in a number of reservoirs.

The number of hydraulic fracture treatments that have been completed in the Los Angeles Basin is small compared with the widespread oil production and large production volumes. Even if large-scale and unrestricted additional production were permitted in the Basin, hydraulic fracturing would not be expected to be implemented in most cases. No doubt, as in the past, specific circumstances and certain reservoirs would warrant the use of hydraulic fracturing, but by and large, it would not be expected as a routine practice for conventional reservoirs.

An important exception that must be recognized is the possibility of production from the hypothetical recoverable unconventional petroleum resources that may or may not exist in and adjacent to the Central Syncline. If a source rock play were to be developed in the Los Angeles Basin, it would require the extensive deployment of WST.

4.5.2.12. Inner Borderland and Los Angeles Basin—Offshore

4.5.2.12.1. Geology and Geography

The offshore Los Angeles-Santa Monica Basin extends from Dana Point on the south to roughly Point Dume on the north (Figure 4-39). The Palos Verdes Peninsula (PVP) separates it into two geographically separate basins. South of the PVP the Palos Verdes Fault Zone marks the western margin of the basin and the Newport-Inglewood Fault Zone, which runs through state waters from San Pedro Bay to Dana Point, marks the eastern boundary. North of the PVP is Santa Monica Bay. This basin is the seaward extension of the Los Angeles Basin (Drewry, 1995; Drewry and Victor, 1995). The offshore area probably partly shares the thick, porous and permeable reservoir submarine fan sandstones of latest Miocene Puente Formation and the early Pliocene Repetto Formation that contain most of the known oil onshore.

Although a relatively dense grid of seismic data has been acquired in the offshore part of Los Angeles Basin, exploratory drilling has been restricted. Only two wildcat wells have been drilled in Santa Monica Bay and approximately 40 wells have been drilled in federal waters south of Palos Verdes. Some 50 wells have been drilled in state waters outside of the giant producing fields that extend seaward from onshore. Beta was the last large oil field discovered in the Los Angeles Basin in the federal waters south of Palos Verdes. The source rocks for oil accumulations in offshore Los Angeles Basin are presumed to be similar to those onshore; the extremely organic-rich and prolific Monterey-equivalent Nodular Shale probably underlies most areas at least north of the PVP.

4.5.2.12.2. Resource Potential

The BOEM estimate that around 140 million m^3 (0.89 billion barrels) of recoverable oil remain to be found in the offshore areas of Los Angeles-Santa Monica Basin (Piper and Ojukwu, 2014). As is the case onshore, submarine fan sandstones are the expected principal reservoirs for the undiscovered accumulations. As a result, WST is probably not essential for development. Although some hydraulic fracture stimulations have been used in various producing fields of western Los Angeles Basin, they are few compared to the large number of wells and the large resources of the Basin.

Seaward of the Los Angeles Basin, the Inner Borderland (IB) is bounded on the north by the Anacapa Ridge, which separates it from the Santa Barbara Basin to the northwest. It extends seaward to the Santa Cruz-Catalina Ridge on the west and southwest and

southeastward to the Oceanside-Capistrano Basin. BOEM defines three sub-basins within the IB: the Santa Monica Basin, the San Pedro Basin, and the San Pedro shelf (Drewry and Victor, 1997).

Like the onshore Los Angeles Basin, the geological properties of the Inner Borderland are the result of early to late Miocene extensional and rotational tectonics related to the opening of the basin in the wake of the rotation of the Transverse Ranges (Crouch and Suppe, 1993). Since the late Pliocene, the area has been subjected to northwest-trending right-lateral wrenching and transpressional compression that has reactivated and in many cases reversed earlier extensional structures.

In their most recent published resource assessment of the federal OCS (Piper and Ojukwu, 2014), the BOEM estimated that the Inner Borderland area, including the offshore Los Angeles Basin, contains about 312 million m^3 (1.96 billion barrels) of undiscovered technically recoverable oil and 61 billion m^3 (2.15 trillion scf) of technically recoverable conventional natural gas. This resource is probably distributed over a wide area, including the essentially unexplored Oceanside Basin to the south of the southernmost known occurrence of oil in the Los Angeles Basin. According to BOEM, while perhaps not as important in terms of resource potential as the Santa Barbara/Ventura and Santa Maria basins, a large quantity of undiscovered oil could remain to be found in the Inner Borderland. By analogy with the Beta offshore oil field, hydraulic fracturing would not necessarily fundamental to development.

4.5.2.12.3. Potential for Application of WST

The undiscovered resources of the Inner Borderland, including offshore Los Angeles, are expected to be found in sandstone reservoirs that exhibit relatively high permeability. The possibility of low-permeability reservoirs exists, of course, but given the logistical issues involved in offshore oil development, it is unlikely that a large-scale program that applies hydraulic fracturing technology would be employed. The most likely occurrence of so-called unconventional resources would be low-gravity, high-viscosity oils in conventional reservoirs. Whether such petroleum accumulations could be developed at all is conjectural, but in any case, their development would probably not entail application of WST.

4.5.2.13. Basins of the Outer Borderland

4.5.2.13.1. Geography and Geology

The Outer Borderland extends from the Channel Islands on the north southward to the US– Mexico maritime boundary (Figure 4-39). It is bounded on the west by the approximate base of the continental slope and on the east and northeast by the Santa Cruz-Santa Catalina Ridge, Santa Catalina Island, and the Thirty Mile Bank. Within the

Outer Borderland, at least eight sedimentary basins have been identified and mapped by the MMS and its successor organization the BOEM, which have been grouped into three main assessment areas, the Santa Cruz-Santa Rosa area, the San Nicolas Basin, and the Cortes-Valero-Long area (Victor, 1997; Piper and Ojukwu, 2014). Some of the basins contain significant thickness of sedimentary strata and are believed to have potential for undiscovered petroleum accumulations. In particular, the Santa Cruz Basin, to the south and southeast of Santa Cruz Island, the Santa Rosa Basin south of Santa Rosa Island, the San Nicolas Basin to the west of San Clemente Island, and the large Cortes-Velero-Long area, which extends from southwest of the San Nicolas Basin to the US–Mexico maritime boundary. Most other basins in the Outer Borderland area contain relatively thin successions of sedimentary strata and are therefore regarded by BOEM as having low resource potential.

The sedimentary basins of the Outer Borderland probably formed during the Miocene, when other southern California basins also came into existence as a result of the extensional tectonics during the initial development of the San Andreas transform fault system. Compared with the Inner Borderland, Santa Barbara/Ventura, or Santa Maria/ Partington basins, the Outer Borderland basins contain relatively thin successions of Neogene sedimentary strata. For this reason, the large area is considered to have relatively low resource potential.

4.5.2.13.2. Resource Potential

A relatively dense seismic grid has been acquired across the Outer Borderland, and so the basic structural configuration and sedimentary thickness are broadly understood, but not known in detail. Exploratory petroleum drilling has been extremely limited in the Outer Borderland, with only about ten total wells.

The MMS/BOEM has defined three broad geological settings that might contain undiscovered petroleum (Victor, 1997; Piper and Ojukwu, 2014). These are fractured, siliceous Monterey Formation reservoirs, Lower Miocene sandstone reservoirs and older, pre-Monterey sandstone reservoirs, including Paleogene and possibly Cretaceous age sandstones. All the plays in the Outer Borderland are hypothetical.

In its recently published 2011 assessment, the BOEM estimated that the Outer Borderland basins may contain 0.19 billion m^3 (1.2 billion barrels) of technically recoverable oil in conventional accumulations and 63 billion m^3 (2.24 trillion scf) of technically recoverable natural gas in conventional reservoirs (mean estimates from Piper and Ojukwu, 2014). While not nearly as prospective as the Inner Borderland, BOEM has estimated that large volumes of undiscovered oil may remain in the basins of the Outer Borderland.

4.5.2.13.3. Potential for Application of WST

The undiscovered resources of the Outer Borderland, if discovered, would either be conventional accumulations that would somehow warrant the development of platforms and wells, or would be oil accumulations in low-permeability and low volume reservoirs. In the unlikely case of the discovery of large conventional accumulations, WST would probably not be necessary as a widespread practice.

In the more likely event of the discovery of relatively small accumulations with or without low-permeability reservoirs, it is doubtful that such accumulations would warrant large-scale development in the remote offshore setting. For these reasons, the widespread application of WST in the Outer Borderland is considered to be extremely unlikely in any scenario.

4.6. US EIA 2011 Estimate of Monterey Shale Oil Potential

In 2011, the US EIA estimated that there are 2.4 billion m³ (15.4 billion barrels) of technically recoverable shale oil resources in the "Monterey/Santos" play in California. This estimate was based on an assumption that the potentially productive area of the play includes an area of 4,538 km² (1,752 mi²), developed with 16 wells per square mile (6.2 wells per km²), and each well recovering an average of 87,400 m³ (550,000 barrels) of oil. This postulated play area included parts of the San Joaquin, Los Angeles, Ventura, Santa Maria, Cuyama, and Salinas basins, and certain offshore regions. The potentially productive reservoirs were said to occur at depths of 2,440–4,270 m (8,000–14,000 ft), have thicknesses ranging from 305–915 m (1,000–3,000 ft), and have average porosity of 11% and average % total organic carbon (TOC) of 6.5% (US EIA, 2011).

The calculated total areas of estimated active (below the top (Ro > 0.6) and above the bottom (Ro < 1.2) of the oil window) Monterey (and Monterey equivalent) source rocks in the major onshore oil basins in California (as depicted in Figures 4-20, 4-31, 4-33, 4-36, and 4-41) (refer to map from each basin with Monterey source rock) are summarized in Table 4-4. The estimated areal extent of thermally mature Monterey Formation (4,532 km² (1,750 mi²)) represents a maximum estimate for the potentially productive shale oil play. This bounding estimate is similar to the active area of the Monterey/Santos shale play as reported by the US EIA (2011), which is 4,538 km² (1,752.1 mi²). Given that the onset of oil generation may begin at lower vitrinite reflectance levels in the Monterey (Walker et al., 1983; Petersen and Hickey, 1987), the extent of active oil generation may be greater, and this could extend the oil window to shallower depths.

Table 4-4. *Estimated extent of thermally mature Monterey Formation*

Basin	Area (km²)	Area (mi²)	References
Los Angeles	455	176	Wright, 1991; Gautier, 2014
San Joaquin (Antelope Shale)	1,309	505	Magoon et al., 2009
San Joaquin (McLure Shale)	2,309	892	Magoon et al., 2009
Santa Maria (Monterey Fm)	204	79	Tennyson and Isaacs, 2001; Sweetkind et al., 2010
Ventura (Monterey Fm)	Unconstrained		Nagle and Parker, 1971
Cuyama	33	13	Lillis, 1994; Sweetkind et al., 2013
Salinas	222	86	Durham, 1974; Menotti and Graham, 2012
Total	**4,532**	**1,750**	

The mean estimated ultimate recovery (EUR) per well assumed in the US EIA report (87,400 m³ (550,000 barrels)) significantly exceeds the observed long-term EUR of Monterey wells in conventional oil fields. Hughes (2013) conducted an extensive review of all oil wells in the San Joaquin and Santa Maria basins drilled since 1980 that produce from the Monterey Formation. For wells with a production history of at least 10 years, Hughes found that the average cumulative oil production of wells with vertical and directional completions was 20,200 and 15,400 m³ (127,000 and 97,000 barrels) from the San Joaquin Basin and 10,700 and 22,400 m³ (67,000 and 141,000 barrels) from the Santa Maria Basin (Figure 4-44). Based on these observed historical production rates, it is unlikely that the average recovery per well from Monterey source rocks will be as high as the average cumulative production of 400 m³ (550,000 barrels) assumed in the US EIA report. A 4- to 5-fold increase in average well productivity relative to current production in the conventional reservoirs would need to be achieved to meet the assumed levels for unconventional production in what is essentially an unproven resource.

The US EIA (2011) estimate of total recoverable oil from the Monterey source rock appears to be overstated, given that the assumed average oil recovery per well is significantly higher than historical production from wells in oil fields that have Monterey reservoir rocks. Due to a lack of operational experience, the potential recovery factor for this shale oil target is poorly constrained, but it is likely to be lower than what is currently obtained for Monterey-hosted oil reservoirs for a number of reasons, including expected lower permeability and porosity of the deeply buried source rocks. In addition, there is little information regarding the amounts of oil remaining in place in the deep (below oil window) portions of the Monterey. There is thus a significant oil retention/migration risk associated with this hypothetical play.
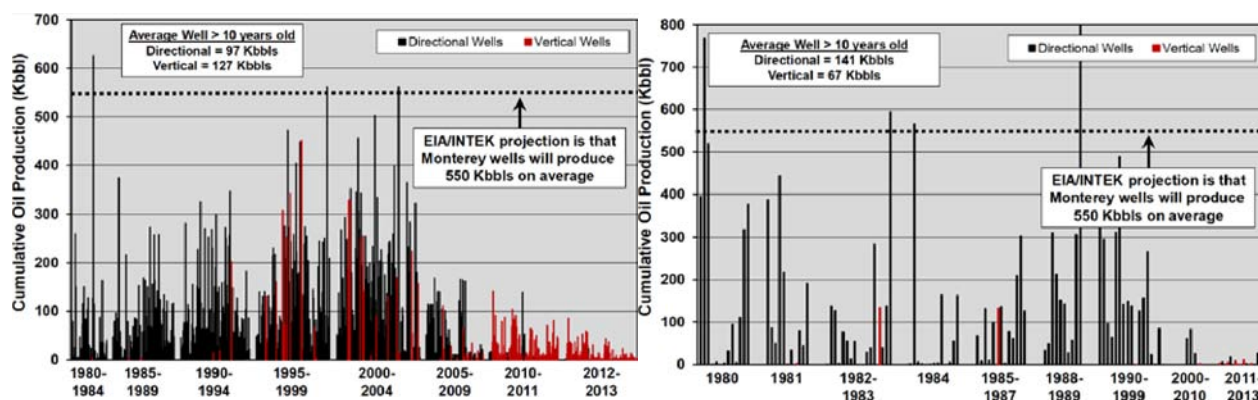
Figure 4-46. *Cumulative oil production grouped by year of first production, 1980 through June 2013. Left – Monterey wells from the San Joaquin Basin; Right – Monterey wells from the Santa Maria Basin. Figures from Hughes (2013) based on data obtained from the Drillinginfo production database. Dashed line denotes average cumulative well production assumed in US EIA/INTEK report.*

The thickness of the Monterey used in the INTEK model may also be overstated, as only a portion of the Monterey Formation has the elevated organic matter concentrations that would allow it to serve as a source rock. Well stimulation would likely be required to produce any remaining oil present in these source rocks, given their intrinsically low matrix permeabilities.

The US EIA Assumptions to the Annual Energy Outlook 2014 report (US EIA, 2014b) has revised the estimated unproved technically recoverable shale oil from the Monterey/Santos to a value of 95 million m^3 (0.6 billion barrels). This revision is based on new estimates of the potential area, the well density, and the production per well (Table 4-5). The biggest change in the new US EIA analysis results from a nine-fold reduction in the prospective area estimate; the projected well production rate is only 20% lower than that used in the INTEK model. The revised model has also assumed the use of wells with horizontal completions, thus resulting in fewer wells per square mile. Neither EIA report includes a description of how the values used in the calculations were derived, nor of the uncertainties associated with the input values. This study's review of the two EIA resource projections concludes that both estimates are highly uncertain.

Table 4-5. *Comparison of model parameters for 2011 US EIA/INTEK and 2014 US EIA estimates of unproved technically recoverable oil from Monterey/Santos play.*

Model Parameters	US EIA/INTEK (2011)	US EIA (2014)
Areal extent (mi^2)	1,752	192
Wells/mi^2	16	6.4
Production/well (Kbbl oil)	550	451
Total recoverable oil (Bbbl oil)	15.4	0.6

4.7. Data Quality and Data Gaps

In addition to the peer-reviewed literature listed in the references, Chapter 4 presents descriptions and interpretations that rely upon basic information that has been provided to the public by the California Division of Oil, Gas, and Geothermal Resources (DOGGR) for almost 100 years. These crucial data include production statistics, well records, well logs, field maps, and various reports, including a series of annual reports dating from the time of World War I that contain a wealth of information. The data and reports provided by DOGGR are relied upon by federal agencies for essentially all analyses of petroleum resources in California. They are also collected and included in the major commercial databases on which both the petroleum industry and government agencies depend for monitoring developments and trends in the industry. Such data are not consistently available from other oil and gas producing states. For this reason, the California data often serve as an analog research database from which to evaluate petroleum resources nationwide and globally. For decades, the basic DOGGR data have been reviewed and tracked by various researchers of the US Geological Survey, by certain commercial data providers, by analysts of the Energy Information Administration, and many others. To our knowledge, these users have found the drilling and production data to be internally consistent, reliable, and indispensable. It should be noted that the DOGGR data for petroleum resource characteristics and petroleum production discussed here are separate and distinct from the DOGGR data discussed in Chapter 3 concerning well stimulation activity.

The main data gaps for petroleum resource characterization in California exist where exploratory drilling is limited. These areas are primarily in the Santa Maria and Partington basins offshore, Inner Borderland and Los Angeles basins offshore, Outer Borderland basins offshore, and the Monterey and Kreyenhagen source rocks.

4.8. Findings and Conclusions Concerning the Potential for WST in California

California has a long history of oil and gas production. In spite of intensive development, large quantities of recoverable oil are believed to remain in the petroleum basins of California. Section 4.5 gives a detailed discussion of the oil and gas resource potential of the petroliferous basins of California. For each basin, the geography and geology of each basin is presented with an interpretation of the resource potential of the basin and the

likelihood of future application of WST. A summary of this assessment is given in Table 4-6, where the resource potential distinguishes undiscovered/undeveloped conventional accumulations, potential growth of reserves from further development of existing oil fields, and unconventional resources.

Most oil reservoirs in California require little or no WST because they have high natural permeability. For this reason, hydraulic fracturing has not been used for most past and present oil production in the Los Angeles Basin, in the offshore oil fields, and other areas. Because of their low permeability, the diatomite reservoirs in oil fields of the San Joaquin Basin are notable exceptions. Development of oil from diatomite reservoirs has been an important source of additions to reserves for decades. Diatomite reservoirs can only be effectively exploited by means of WST. Beyond the current production, the San Joaquin has high potential for additional oil production from the further development of diatomite reservoirs in several fields. This additional oil production can only be realized through the application of WST.

Most known oil, and in all likelihood most yet-to-be discovered and developed oil as well, was generated through the thermal alteration of organic matter in the Monterey Formation. In short, the Monterey is a prolific petroleum source rock. Recent direct production of oil from source rocks (so-called shale oil) in other parts of the country have drawn attention to the possibility of producing oil directly from the Monterey source rocks as well. Although no such production has yet been demonstrated, the possibility exists for "source-rock system (shale oil) plays" in the deeper parts of a number of California basins, including the San Joaquin, Los Angeles, Ventura, Santa Maria, and Salinas basins. If these postulated resources exist and could be developed, their production would probably entail the widespread application of WST in hundreds or thousands of new wells.

However, geological complexities make the Monterey source rocks strikingly different from the shale oil reservoirs being produced elsewhere in the United States. For this reason, the techniques and technologies successfully employed in Texas, North Dakota, Pennsylvania and elsewhere cannot be simply copied for development of the Monterey (e.g., El Shaari et al., 2011). The extent to which shale oil development can occur in California remains fundamentally uncertain. This has resulted in highly variable resource estimates by the EIA (2011; 2014b) because the information and understanding necessary to develop a meaningful forecast, or even a suite of scenarios about possible recoverable unconventional oil in the Monterey shale, are not available. This uncertainty concerns the geological uncertainties related to the highly variable source rock lithologies, complex structural history, and the extent of post-expulsion oil retention of the petroleum source rocks. The situation is exacerbated by the limited amount of exploratory drilling that has been directed at testing the concept of shale oil production in California. Systematic exploratory drilling and production testing is the only effective way to reduce this uncertainty. The source rock intervals of the San Joaquin Basin are the most likely candidates for high-volume shale oil production. A program of exploratory drilling

and production testing in the depocenters of the San Joaquin, where Monterey and Kreyenhagen source rocks are thermally mature, is the most efficient route for reducing the uncertainties. Based on the current state of knowledge, it seems unlikely that WST as practiced in Texas, North Dakota and Pennsylvania will become widespread in California in the near future. WST will continue to be important role for oil fields in the San Joaquin Basin, such as South Belridge, where oil recovery from diatomite reservoirs is facilitated through the use of WST.

Large quantities of natural gas are produced in California. Natural gas produced in the Sacramento Basin is mainly non-associated gas. Non-associated gas fields also have been found in the San Joaquin, Eel River, and other basins, both onshore and offshore. Associated and dissolved natural gas is produced from various oil fields. This production has not involved the widespread use of WST. Conventional reservoirs of the Sacramento Basin exhibit few of the features of true basin-centered accumulations, such as regional water expulsion, abnormal fluid pressures resulting from hydrocarbon generation, and absence of hydrocarbon-water contacts. It is therefore considered unlikely that a basin-center gas accumulation exists in the Sacramento Basin, at least at the depths that have been explored so far. More generally, large-scale development of unconventional natural gas resources such as shale gas, basin-center "tight gas," and coalbed methane is geologically unlikely in California.

North coastal basins and outer borderland basins offshore Southern California are expected to have relatively small accumulations that would not warrant widespread application of well stimulation technology. Other potentially more significant undiscovered or undeveloped conventional accumulations are expected to be present along the central and southern California coast. By analogy with currently producing offshore fields, the development of new offshore fields are likely to only involve the occasional use of WST for their development. This is because the formations where oil is likely to be found typically do not require permeability enhancement. The development of these resources would take priority over any low-permeability plays requiring routine well stimulation. Therefore, if expansion of offshore oil production along California's coast is allowed in the future, this production would not likely require WST.

Table 4-6. *Resources and prospective application of WST to California basins discussed in chapter 4*

Basin	Known Petroleum (Cumulative Production + Reserves)			Undiscovered/Undeveloped Conventional Resources		Growth of Reserves in Existing Fields		Continuous Resources (Unconventional)	
	Reservoirs	Volume	WST Conducted	Resource Potential	WST Required	Resource Potential	WST Required	Resource Potential	WST Required
Onshore Basins									
Bitterwater	Conventional	Minor	No	Low	Limited	NA	NA	Low	NA
Cuyama	Conventional	Large	No (?)	Moderate	Limited	NA	NA	Possible	Yes
Eel River Onshore gas	Conventional	Minor	No	Low	Limited	NA	NA	Low	NA
La Honda	Conventional	Minor	No	Moderate	Limited	NA	NA	Low	NA
Los Angeles*	Conventional	Very large	Yes	Large	Limited	Very large	Limited	Possible	Yes
Pescadero	None	None	NA	Low	Limited	NA	NA	Low	NA
Sacramento gas	Conventional	Very Large	Limited	Moderate	Limited	NA	NA	Low	NA
Salinas	Conventional	Large	No	Moderate	Limited	Moderate	Limited	Possible	Yes
San Joaquin	Conventional	Very large	Yes**	Large	Limited	Very large	Yes**	Possible	Yes
Santa Maria Onshore	Conventional	Very Large	Limited	Moderate	Limited	NA	NA	Possible	Yes
Sargent-Hollister	Conventional	Minor	No	Low	Limited	NA	NA	Low	NA
Ventura	Conventional	Very large	Yes	Large	Limited	Large	Yes	Possible	Yes
Offshore Basins									
Año Nuevo, Bodega, Point Arena***	None	None	NA	Very Large	Limited	NA	NA	Low	NA
Cordell****	NA	NA	NA	NA	NA	NA	NA	NA	NA
Inner Borderland	Conventional	Large	Limited	Very Large	Limited	NA	NA	Low	NA
Outer Borderland	None	None	NA	Very Large	Limited	NA	NA	Low	NA
Eel River Offshore gas	None	None	NA	Moderate	Limited	NA	NA	Low	NA
Partington	Conventional	None	NA	Very Large	Limited	NA	NA	Low	NA
Santa Barbara	Conventional	Very Large	Limited	Very Large	Limited	NA	NA	Low	NA
Santa Lucia****	NA	NA	NA	NA	NA	NA	NA	NA	NA
Santa Maria Offshore	Conventional	Very Large	Limited	Very Large	Limited	NA	NA	Low	NA

*Includes state waters; **Mainly in diatomite reservoir; ***Basin resources considered together by BOEM; ****Basin shown on Figure 4-22 but not considered in Chapter 4

Known petroleum: Minor = Producing fields; Large = one giant field (>100MMBOE); Very Large = Multiple giant fields

Undiscovered/undeveloped: Low = <50MMBOE; Moderate = 50-500MMBOE; Large=>500MMBOE; Very Large >1BBOE

Growth of reserves in existing fields: Low = <50MMBOE; Moderate = 50-500MMBOE; Large=>500MMBOE; Very Large >1BBOE

Continuous Resources (Unconventional): Possible = Geology and location may permit development with existing technology and economics; Low = Not currently feasible

MMBOE = Million barrels of oil equivalent oil, gas, and natural gas liquids; BBOE = Billion barrels of oil equivalent oil, gas, and natural gas liquids; 1BOE ~ 1barrel of oil or 6000 standard cubic feet of natural gas; 1US Barrel ~ 0.159 cubic meters; NA = not applicable; Giant field >100MMBOE oil, gas, and/or natural gas liquids; All listed resources are considered to be recoverable with existing technology; Low = low potential; Possible = a chance of volumetrically significant resources

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Chapter Five

Future Work

In response to Senate Bill 4 (SB 4), the California Council on Science and Technology (CCST) and Lawrence Berkeley National Laboratory (LBNL) are conducting an independent scientific study of well stimulation technologies in the state to assess current and potential future practices, evaluate the impacts of well stimulation technologies and related data gaps, analyze risks associated with current practices, and identify alternative practices that might limit these risks. The study findings are issued in three report volumes. This document, Volume I, provides the factual basis for the upcoming Volumes II and III. Chapter 2 in Volume I comprises a general description of well stimulation technologies as applied in oil and gas production for both onshore and offshore locations, including well drilling, well construction, and well completion, with an emphasis on aspects of these activities that affect well stimulation treatments. Chapter 3 provides a review of historical and current well stimulation in California, for onshore and offshore oil production and gas production, and Chapter 4 details the oil and gas provinces of California and assesses the probability of expanded or new production using well stimulation technologies in each. The basic assessment conducted in Volume I will be used in upcoming Volumes II and III to evaluate the potential impacts of current and future well stimulation in California. Volume II, entitled "Generic and Potential Environmental Impacts of Well Stimulation Technologies," assesses such impacts with respect to water, air quality, and greenhouse gas emissions, as well as induced seismicity, ecology, traffic, and noise. Volume III, entitled "Case Studies with Selected Evaluations of Environmental and Public Health Risk," presents case studies to evaluate environmental issues and qualitative hazards specific to geographically focused scenarios. Volumes II and III will be issued June 30, 2015.

5.1. Assessment of Environmental Impacts in Volume II

Volume II describes the various pathways and mechanisms that lead to environmental impacts in a general sense—with respect to water, air quality, and greenhouse gas emissions, as well as induced seismicity, ecology, traffic, and noise—and specifically assesses the available data and literature on these impacts in California. Analysis and discussion of current and potential future impacts then leads into development of a hazard matrix, as a starting point to a hazard assessment and risk analysis for human populations addressing occupational and community exposures to chemical/physical stressors associated with well stimulation treatments. Volume II also includes a discussion of methods that facilitate safe and effective well stimulation, summarized from the scientific literature as well as government and industry/trade association publications.

5.2. Case Studies in Volume III

Volume III presents case studies to assess environmental issues and qualitative hazards specific to selected locations. Case studies are geographically focused cases, based on findings in Volumes I and II. The case studies are focused on key issues specific to a regional setting involving current or potential well stimulation activities, which are evaluated and discussed. Each case study starts with a description of the geologic and technical basis for well stimulation in the region, and then assesses key issues and selected impacts for current and/or potential future operations. Four likely case studies have been identified: (1) the San Joaquin Basin, where the vast majority of well stimulation takes place now and likely will continue in the future; (2) the Los Angeles Basin, where oil production coincides with a major urban environment, (3) an assessment of current practices of well stimulation offshore, and (4) a Monterey Shale development case study which assumes production enabled by well stimulation from Monterey Shale source rock could take place in the future. In each case study, important data gaps will be identified and qualitative risk assessments will be conducted.

Senate Bill 4 Language Mandating the Independent Scientific Study on Well Stimulation Treatments

The following is the language from Senate Bill 4 (Pavley, Statutes of 2013) that required the independent scientific study on well stimulation treatments, of which this volume comprises the first installment.

3160. (a) On or before January 1, 2015, the Secretary of the Natural Resources Agency shall cause to be conducted, and completed, an independent scientific study on well stimulation treatments, including, but not limited to, hydraulic fracturing and acid well stimulation treatments. The scientific study shall evaluate the hazards and risks and potential hazards and risks that well stimulation treatments pose to natural resources and public, occupational, and environmental health and safety. The scientific study shall do all of the following:

1. Follow the well-established standard protocols of the scientific profession, including, but not limited to, the use of recognized experts, peer review, and publication.

2. Identify areas with existing and potential conventional and unconventional oil and gas reserves where well stimulation treatments are likely to spur or enable oil and gas exploration and production.

3. (A) Evaluate all aspects and effects of well stimulation treatments, including, but not limited to, the well stimulation treatment, additive and water transportation to and from the well site, mixing and handling of the well stimulation treatment fluids and additives onsite, the use and potential for use of nontoxic additives and the use or reuse of treated or produced water in well stimulation treatment fluids, flowback fluids and handling, treatment, and disposal of flowback fluids and other materials, if any, generated by the treatment. Specifically, the potential for the use of recycled water in well stimulation treatments, including appropriate water quality requirements and available treatment technologies, shall be evaluated. Well stimulation treatments include, but are not limited to, hydraulic fracturing and acid well stimulation treatments.

(B) Review and evaluate acid matrix stimulation treatments, including the range of acid volumes applied per treated foot and total acid volumes used in treatments, types of acids, acid concentration, and other chemicals used in the treatments.

4. Consider, at a minimum, atmospheric emissions, including potential greenhouse gas emissions, the potential degradation of air quality, potential impacts on wildlife, native plants, and habitat, including habitat fragmentation, potential water and surface contamination, potential noise pollution, induced seismicity, and the ultimate disposition, transport, transformation, and toxicology of well stimulation treatments, including acid well stimulation fluids, hydraulic fracturing fluids, and waste hydraulic fracturing fluids and acid well stimulation in the environment.

5. Identify and evaluate the geologic features present in the vicinity of a well, including the well bore, that should be taken into consideration in the design of a proposed well stimulation treatment.

6. Include a hazard assessment and risk analysis addressing occupational and environmental exposures to well stimulation treatments, including hydraulic fracturing treatments, hydraulic fracturing treatment-related processes, acid well stimulation treatments, acid well stimulation treatment-related processes, and the corresponding impacts on public health and safety with the participation of the Office of Environmental Health Hazard Assessment.

7. Clearly identify where additional information is necessary to inform and improve the analyses.

Appendix B

CCST Steering Committee Members

CCST Steering Committee Members

Full curricula vitae for Steering Committee members are available upon request. Please contact California Council on Science and Technology (916)-492-0096.

Jane Long, Ph.D.

Principal Associate Director at Large, Lawrence Livermore National Laboratory, Retired

Dr. Long recently retired from Lawrence Livermore National Laboratory where she was the Principal Associate Director at Large, Fellow in the LLNL Center for Global Strategic Research and the Associate Director for Energy and Environment. She is currently a senior contributing scientist for the Environmental Defense Fund, Visiting Researcher at UC Berkeley, Co-chair of the Task Force on Geoengineering for the Bipartisan Policy Center and chairman of the California Council on Science and Technology's California's Energy Future committee. Her current work involves strategies for dealing with climate change including reinvention of the energy system, geoengineering and adaptation. Dr. Long was the Dean of the Mackay School of Mines, University of Nevada, Reno and Department Chair for the Energy Resources Technology and the Environmental Research Departments at Lawrence Berkeley National Lab. She holds a bachelor's degree in engineering from Brown University and Masters and PhD from U. C. Berkeley. Dr. Long is a fellow of the American Association for the Advancement of Science and was named Alum of the Year in 2012 by the Brown University School of Engineering. Dr. Long is an Associate of the National Academies of Science (NAS) and a Senior Fellow and council member of the California Council on Science and Technology (CCST) and the Breakthrough Institute. She serves on the board of directors for the Clean Air Task Force and the Center for Sustainable Shale Development.

Roger Aines, Ph.D.

Senior Scientist, Atmospheric, Earth, and Energy Division and Carbon Fuel Cycle Program Leader E Programs, Global Security, Lawrence Livermore National Laboratory

Roger Aines leads the development of carbon management technologies at Lawrence Livermore National Laboratory, working since 1984 in US national laboratory system. Dr. Aines's work has spanned nuclear waste disposal, environmental remediation, applying stochastic methods to inversion and data fusion, managing carbon emissions and sequestration monitoring and verification methods. Aines takes an integrated view of the energy, climate, and environmental aspects of carbon-based fuel production and use. His current focus is on efficient ways to remove carbon dioxide from the atmosphere and safer methods for producing environmentally clean fuel. He holds 13 patents and has authored more than 100 publications. Aines holds a Bachelor of Arts degree in Chemistry from Carleton College, and Doctor of Philosophy in geochemistry from the California Institute of Technology.

Jens Birkholzer, Ph.D.

Deputy Director, Earth Sciences Division, Lawrence Berkeley National Laboratory

Dr. Birkholzer joined Lawrence Berkeley National Laboratory in 1994 as a post-doctoral fellow and has since been promoted to the second-highest scientist rank at this research facility. He currently serves as the deputy director of the Earth Sciences Division and as the program lead for the nuclear waste program, and also leads a research group working on environmental impacts related to geologic carbon sequestration and other subsurface activities. His area of expertise is subsurface hydrology with emphasis on understanding and modeling coupled fluid, gas, solute and heat transport in complex subsurface systems, such as heterogeneous sediments or fractured rock. His recent research was mostly in the context of risk/performance assessment, e.g., for geologic disposal of radioactive wastes and for geologic CO_2 storage. Dr. Birkholzer has authored about 90 peer-reviewed journal articles and book chapters, and has over 230 conference publications and abstracts.

Brian Cypher, Ph.D.

Associate Director, Endangered Species Recovery Program, California State University-Stanislaus

Dr. Cypher received a PhD in Zoology from Southern Illinois University in 1991. Since 1990, he has been engaged in ecological research and conservation efforts on a variety of animal and plant species and their habitats. Much of this work has occurred in the San Joaquin Valley in central California and has involved extensive evaluations of the effects of hydrocarbon production and energy development on ecological processes and individual species. The information generated has been presented in numerous reports and publications, which have contributed to the development of conservation strategies and best-management practices that help mitigate environmental impacts from energy development activities.

Donald L. Gautier, Ph.D.

Consulting Petroleum Geologist, DonGautier L.L.C.

With a career spanning almost four decades, Dr. Donald L. Gautier is an internationally recognized leader and author in the theory and practice of petroleum resource analysis. As a principal architect of modern USGS assessment methodology, Gautier's accomplishments include leadership of the first comprehensive evaluation of undiscovered oil and gas resources north of the Arctic Circle, the first national assessment of United States petroleum resources to be fully documented in a digital environment, and the first development of performance-based methodology for assessment of unconventional petroleum resources such as shale gas or light, tight oil. He was lead scientist for the San Joaquin Basin and Los Angeles Basin Resource Assessment projects. His recent work has focused on the analysis of growth of reserves in existing fields and on the development of probabilistic resource/cost functions. Gautier is the author of more than 200 technical publications, most of which concern the evaluation of undiscovered and undeveloped petroleum resources. He holds a Ph.D. in geology from the University of Colorado.

Peter H. Gleick, Ph.D.

President, Pacific Institute

Dr. Peter H. Gleick is an internationally recognized environmental scientist and co-founder of the Pacific Institute in Oakland, California. His research addresses the critical connections between water and human health, the hydrologic impacts of climate change, sustainable water use, privatization and globalization, and international security and

conflicts over water resources. Dr. Gleick was named a MacArthur "genius" Fellow in October 2003 for his work on water, climate, and security. In 2006 Dr. Gleick was elected to the U.S. National Academy of Sciences, Washington, D.C. Dr. Gleick's work has redefined water from the realm of engineers to the world of social justice, sustainability, human rights, and integrated thinking. His influence on the field of water has been long and deep: he developed one of the earliest assessments of the impacts of climate change on water resources, defined and explored the links between water and international security and local conflict, and developed a comprehensive argument in favor of basic human needs for water and the human right to water – work that has been used by the UN and in human rights court cases. He pioneered the concept of the "soft path for water," developed the idea of "peak water," and has written about the need for a "local water movement." Dr. Gleick received a B.S. in Engineering and Applied Science from Yale University and an M.S. and Ph.D. from the Energy and Resources Group of the University of California, Berkeley. He serves on the boards of numerous journals and organizations, and is the author of many scientific papers and ten books, including Bottled & Sold: The Story Behind Our Obsession with Bottled Water and the biennial water report, The World's Water, published by Island Press (Washington, D.C.).

A. Daniel Hill, Ph.D.

Department Head, Professor and holder of the Noble Chair, Petroleum Engineering Department at Texas A&M University

Dr. A. D. Hill is Professor, holder of the Noble Endowed Chair, and Department Head of Petroleum Engineering at Texas A&M University. Previously, he taught for twenty-two years at The University of Texas at Austin after spending five years in industry. He holds a B. S. degree from Texas A&M University and M. S. and Ph. D. degrees from The University of Texas at Austin, all in chemical engineering. He is the author of the Society of Petroleum Engineering (SPE) monograph, Production Logging: Theoretical and Interpretive Elements, co-author of the textbook, Petroleum Production Systems (1st and 2nd editions), co-author of an SPE book, Multilateral Wells, and author of over 170 technical papers and five patents. He has been a Society of Petroleum Engineers (SPE) Distinguished Lecturer, has served on numerous SPE committees and was founding chairman of the Austin SPE Section. He was named a Distinguished Member of SPE in 1999 and received the SPE Production and Operations Award in 2008. In 2012, he was one of the two inaugural winners of the SPE Pipeline Award, which recognizes faculty, who have fostered petroleum engineering Ph.Ds. to enter academia. He currently serves on the SPE Editorial Review Committee, the SPE Global Training Committee, and the SPE Hydraulic Fracturing Technology Conference Program Committee. Professor Hill is an expert in the areas of production engineering, well completions, well stimulation, production logging, and complex well performance (horizontal and multilateral wells), and has presented lectures and courses and consulted on these topics throughout the world.

Larry Lake, Ph.D.

Professor, Department of Petroleum and Geosystems Engineering, University of Texas, Austin

Larry W. Lake is a professor of the Department of Petroleum and Geosystems Engineering at The University of Texas at Austin and director of the Center for Petroleum Asset Risk Management. He holds B.S.E and Ph.D. degrees in Chemical Engineering from Arizona State University and Rice University. Dr. Lake has published widely; he is the author or co-author of more than 100 technical papers, the editor of 3 bound volumes and author or co-author of four textbooks. He has been teaching at UT for 34 years before which he worked for Shell Development Company in Houston, Texas. He was chairman of the PGE department twice, from 1989 to 1997 and from 2008- 1010. He formerly held the Shell Distinguished Chair and the W.A. (Tex) Moncrief, Jr. Centennial Endowed Chair in Petroleum Engineering. He currently holds the W.A. (Monty) Moncrief Centennial Chair in Petroleum Engineering. Dr. Lake has served on the Board of Directors for the Society of Petroleum Engineers (SPE) as well as on several of its committees; he has twice been an SPE distinguished lecturer. Dr. Lake is a member of the US National Academy of Engineers and won the 1996 Anthony F. Lucas Gold Medal of the SPE. He won the 1999 Dad's Award for excellence in teaching undergraduates at The University of Texas and the 1999 Hocott Award in the College of Engineering for excellence in research. He also is a member of the 2001 Engineering Dream Team awarded by the Texas Society of Professional Engineers. He is an SPE Honorary Member.

Tom McKone, Ph.D.

Deputy for Research Programs in the Energy Analysis and Environmental Impacts Department, Lawrence Berkeley National Laboratory (LBNL)

Thomas E. McKone, is a senior staff scientist and Deputy for Research Programs in the Energy Analysis and Environmental Impacts Department at the Lawrence Berkeley National Laboratory (LBNL) and Professor of Environmental Health Sciences at the University of California, Berkeley School of Public Health. At LNBL he leads the Sustainable Energy Systems Group. His research focuses on the development, use, and evaluation of models and data for human-health and ecological risk assessments and the health and environmental impacts of energy, industrial, and agricultural systems. Outside of Berkeley, he has served six years on the EPA Science Advisory Board, has been a member of more than a dozen National Academy of Sciences (NAS) committees including the Board on Environmental Studies and Toxicology, and has been on consultant committees for the Organization for Economic Cooperation and Development (OECD), the World Health Organization, the International Atomic Energy Agency, and the Food and Agriculture Organization. McKone is a Fellow of the Society of Risk Analysis and has

received two major awards from the International Society of Exposure Analysis—one for lifetime achievement in exposure science research and one for research that has impacted major international and national environmental policies.

William A. Minner, P.E.

Principal Consultant, StrataGen, Inc.

Minner is a principal consultant with StrataGen, Inc., a petroleum engineering consulting firm with a focus on hydraulic fracture well stimulation treatments. After receiving B.S. and M.S. degrees in mechanical engineering with a petroleum option from the University of California, Berkeley, Minner joined Unocal in 1980, and began to focus on hydraulic fracturing well stimulation in 1985. In 1995, he opened an office for Pinnacle Technologies in Bakersfield. Pinnacle's focus was on the development and commercialization of hydraulic fracture mapping technologies; His role was engineering consulting, using fracture diagnostics and mapping to assist clients with hydraulic fracture engineering design, execution, and analysis. His engineering consulting role continued after the fracture mapping business was sold in 2008, and the name was changed to StrataGen. Minner is a registered Petroleum Engineer in California, and received a Society of Petroleum Engineers Production and Operations Award in 2011 for his contribution to technical progress and interchange. He has authored or coauthored 21 industry technical papers on hydraulic fracturing.

Amy Myers Jaffe

Executive Director, Energy and Sustainability, UC Davis

Amy Myers Jaffe is a leading expert on global energy policy, geopolitical risk, and energy and sustainability. Jaffe serves as executive director for Energy and Sustainability at University of California, Davis with a joint appointment to the Graduate School of Management and Institute of Transportation Studies (ITS). At ITS-Davis, Jaffe heads the fossil fuel component of Next STEPS (Sustainable Transportation Energy Pathways). She is associate editor (North America) for the academic journal, Energy Strategy Reviews. Prior to joining UC Davis, Jaffe served as director of the Energy Forum and Wallace S. Wilson Fellow in Energy Studies at Rice University's James A. Baker III Institute for Public Policy. Jaffe's research focuses on oil and natural gas geopolitics, strategic energy policy, corporate investment strategies in the energy sector, and energy economics. She was formerly senior editor and Middle East analyst for Petroleum Intelligence Weekly. Jaffe is widely published, including as co-author of "Oil, Dollars, Debt and Crises: The Global Curse of Black Gold" (Cambridge University Press, January 2010 with Mahmoud El-Gamal). She served as co-editor of "Energy in the Caspian Region: Present and Future"

(Palgrave, 2002) and "Natural Gas and Geopolitics: From 1970 to 2040" (Cambridge University Press, 2006). Jaffe was the honoree for Esquire's annual 100 Best and Brightest in the contribution to society category (2005) and Elle Magazine's Women for the Environment (2006) and holds the excellence in writing prize from the International Association for Energy Economics (1994).

Seth B. Shonkoff, Ph.D., MPH

Executive Director, Physicians Scientists & Engineers for Healthy Energy

Dr. Shonkoff is the executive director of the energy science and policy organization, Physicians Scientists & Engineers for Healthy Energy (PSE), and a visiting scholar in the Department of Environmental Science, Policy and Management at UC Berkeley. An environmental and public health scientist by training, he has many years of experience in water, air, climate, and population health research. Dr. Shonkoff completed his PhD in the Department of Environmental Science, Policy, and Management and his MPH in epidemiology at the School of Public Health from the University of California, Berkeley. He is a contributing author to Chapter 11, Human Health: Impacts, Adaptation, and Co-Benefits the Intergovernmental Panel on Climate Change (IPCC) Fifth Assessment report (AR5). He has worked and published on topics related to air and water quality and the environmental and public health dimensions of energy choices and climate change from scientific and policy perspectives. Dr. Shonkoff has also researched interaction between the climate and human health dimensions of shorter-live climate forcing emissions (i.e., ozone, black carbon, sulphate particles, etc.) and on the development of more effective anthropogenic climate change mitigation policies that generate socioeconomic and health co-benefits. Dr. Shonkoff's current work focuses on the human health, environmental and climate dimensions of oil and gas development in the United States and abroad.

Dan Tormey, Ph. D., P.G.

Principal, ENVIRON International Corporation

Dr. Daniel Tormey is an expert in energy and water and conducts environmental reviews for both government and industry. He works with the environmental aspects of all types of energy development, with an emphasis on oil and gas, including hydraulic fracturing and produced water management, pipelines, LNG terminals, refineries and retail facilities. Dr. Tormey was the principal investigator for the peer-reviewed, publicly-available, Hydraulic Fracturing Study at the Baldwin Hills of southern California, on behalf of the County of Los Angeles and the field operator, PXP. He conducts projects in sediment transport,

hydrology, water supply, water quality, and groundwater-surfacewater interaction. He has been project manager or technical lead for over two hundred projects requiring fate and transport analysis of chemicals in the environment. He has a Ph.D. in Geology and Geochemistry from MIT, and a B.S. in Civil Engineering and Geology from Stanford. He is a Principal at ENVIRON International Corporation; was named by the National Academy of Sciences to the Science Advisory Board for Giant Sequoia National Monument; is a Distinguished Lecturer for the Society of Petroleum Engineers; is on the review committee on behalf of IUCN for the UNESCO World Heritage Site List; is volcanologist for Cruz del Sur, an emergency response and contingency planning organization in Chile; was an Executive in Residence at California Polytechnic University San Luis Obispo; and is a Professional Geologist in California. He has worked throughout the USA, Australia, Indonesia, Italy, Chile, Ecuador, Colombia, Venezuela, Brazil, Senegal, South Africa, Armenia and the Republic of Georgia.

Sam Traina, Ph.D.

Vice Chancellor of Research, University of California, Merced

Dr. Traina is the Vice Chancellor for Research and Economic Development at the University of California, Merced where he holds the Falasco Chair in Earth Sciences and Geology. He serves as a Board Member of the California Council of Science and Technology. Prior to joining UC Merced in 2002 as a Founding Faculty member and the Founding Director of the Sierra Nevada Research Institute, Dr. Traina was a faculty member for 17 years at the Ohio State University, with concomitant appointments in the School of Natural Resources and the Environment, the department of Earth Science and Geology, Civil and Environmental Engineering, Microbiology and Chemistry. He has served on the National Research Council's Standing Committee on Earth Resources. In 1997-1998 he held the Cox Visiting Professorship in the School of Earth Sciences at Stanford University. Dr. Traina's past and current research has dealt with the fate, transformation and transport of contaminants in the soils and natural waters with an emphasis on radionuclides, heavy metals, and mining wastes. Dr. Traina holds a B.S. In soil resource management and Ph.D. in soil chemistry. He is a fellow of the Soil Science Society of American and of the American Association for the Advancement of Science as well as a recipient of the Clay Scientist Award of the Clay Minerals Society.

Disclosure of Conflict of Interest: Prof. Dan Hill

In accordance with the practice of the California Council on Science and Technology (CCST), CCST makes best efforts to ensure that no individual appointed to serve on a committee has a conflict of interest that is relevant to the functions to be performed, unless such conflict is promptly and publicly disclosed and CCST determines that the conflict is unavoidable. A conflict of interest refers to an interest, ordinarily financial, of an individual that could be directly affected by the work of the committee. An objective

determination is made for each provisionally appointed committee member whether or not a conflict of interest exists given the facts of the individual's financial and other interests, and the task being undertaken by the committee. A determination of a conflict of interest for an individual is not an assessment of that individual's actual behavior or character or ability to act objectively despite the conflicting interest.

We have concluded that for this committee to accomplish the tasks for which it was established, its membership must include among others, individuals with research and expertise in the area of acid treatments for petroleum wells who have studied oil and gas industry operations in the United States and are internationally recognized for this expertise. Acid treatment is of particular public concern in California and is the subject of regulation under SB4.

To meet the need for this expertise and experience, Dr. Dan Hill is proposed for appointment to the committee, even though we have concluded that he has a conflict of interest because of investments he holds and research services provided by his employer.

As his biographical summary makes clear, Dr. Hill is a recognized expert in petroleum reservoir engineering with many publications to wit. He is also known as one of the world's key experts in acid treatment.

After an extensive search, we have been unable to find another individual with the equivalent combination of expertise in acid treatment as Dr. Hill, who does not have a similar conflict of interest. Therefore, we have concluded that this potential conflict is unavoidable.

Disclosure of Conflict of Interest: William Minner

In accordance with the practice of the California Council on Science and Technology (CCST), CCST makes best efforts to ensure that no individual appointed to serve on a committee has a conflict of interest that is relevant to the functions to be performed, unless such conflict is promptly and publicly disclosed and CCST determines that the conflict is unavoidable. A conflict of interest refers to an interest, ordinarily financial, of an individual that could be directly affected by the work of the committee. An objective determination is made for each provisionally appointed committee member whether or not a conflict of interest exists given the facts of the individual's financial and other interests, and the task being undertaken by the committee. A determination of a conflict of interest for an individual is not an assessment of that individual's actual behavior or character or ability to act objectively despite the conflicting interest.

We have concluded that for this committee to accomplish the tasks for which it was established its membership must include, among others, individuals with direct experience in the area of well stimulation practice, specifically in California.   Well stimulation is of particular public concern in California and is the subject of regulation under SB4. The practice in California is significantly different than in other states so we require someone

with direct experience in the state.

To meet the need for this expertise and experience, William Minner is proposed for appointment to the committee even though we have concluded that he has a conflict of interest because of investments he holds and research services provided by his employer.

As his biographical summary makes clear, William Minner is a recognized expert in petroleum reservoir stimulation with a long history of practice in California as well as around the world. He is one of the most recognized experts in California well stimulation design and execution.

After an extensive search, we have been unable to find another individual with the equivalent combination of expertise as William Minner, who does not have a similar conflict of interest. Therefore, we have concluded that this potential conflict is unavoidable.

Report Author Biosketches

- **Jens Birkholzer**, Lawrence Berkeley National Laboratory

- **Patrick F. Dobson**, Lawrence Berkeley National Laboratory

- **Laura Feinstein**, California Council on Science and Technology (CCST)

- **Donald Gautier**

- **Matthew Heberger**, Pacific Institute

- **James E. Houseworth**, Lawrence Berkeley National Laboratory

- **Preston D. Jordan**, Lawrence Berkeley National Laboratory

- **Jane Long**, California Council on Science and Technology (CCST)

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Jens T. Birkholzer

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Education

1982-1985	University of Technology, Aachen. B.Sc. in Civil Engineering, 1985.
1985-1988	University of Technology, Aachen. M.Sc. in Water Resources, Hydraulic Engineering, Soil and Rock Mechanics, 1988.
1989-1994	University of Technology, Aachen. Ph.D. in Subsurface Hydrology, 1994.

Research and Professional Experience

Dr. Birkholzer joined LBNL in 1994 as a post-doctoral fellow and has since been promoted to the second-highest scientist rank at this research facility. He currently serves as the deputy director of the Earth Sciences Division and as the program lead for the nuclear waste program, and also leads a research group working on environmental impacts related to geologic carbon sequestration and other subsurface activities. His area of expertise is subsurface hydrology with emphasis on understanding and modeling coupled fluid, gas, solute and heat transport in complex subsurface systems, such as heterogeneous sediments or fractured rock. His recent research was mostly in the context of risk/performance assessment, e.g., for geologic disposal of radioactive wastes and for geologic CO_2 storage. Dr. Birkholzer has authored about 90 peer-reviewed journal articles and book chapters, and has over 230 conference publications and abstracts.

Current and past Positions

Since 2014	Deputy Director, Earth Sciences Division, Lawrence Berkeley National Laboratory (LBNL)
Since 2008	Program Lead, Nuclear Energy and Waste, Earth Sciences Division, LBNL
Since 2001	Staff Scientist and Group Leader, Earth Sciences Division, LBNL
1999 - 2001	Chief Engineer and Project Manager, Construction of the New International Airport in Dusseldorf, HOCHTIEF AG, Germany
1994 - 1998	Geological Scientist, Earth Sciences Division, LBNL

1989 - 1994	Research Associate (since 1993 Group Leader), Institute of Hydraulic Engineering and Water Resources Management (IWW), University of Technology, Aachen, Germany

Honors and Awards:

2012	Director's Award for Exceptional Achievement (TOUGH codes), by LBNL
2007, 1997	Outstanding Performance Award, by LBNL
1995 - 1996	Postdoctoral fellowship granted by the Humboldt-Stiftung
1995	Friedrich-Wilhelm Award for Summa Cum Laude Ph.D. Thesis
1995	Borchers Award for Summa Cum Laude Ph.D. Thesis
1994 - 1995	Postdoctoral fellowship granted by the DAAD
1989	Research-fellowship granted by the DAAD
1989	Springorum Award for Summa Cum Laude M.Sc.
1989	Hünnebeck Award for best Master Thesis
since 1986	Studienstiftung des Deutschen Volkes

Patrick F. Dobson

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Education

1977-1981	Williams College, Williamstown, MA, BA in Geology (magna cum laude)
1981-1984	Stanford University, Stanford, CA, M.S. in Geology
1984-1986	Stanford University, Stanford, CA, Ph.D. in Geology

Research and Professional Experience

Dr. Dobson has been a research scientist in the Earth Sciences Division of LBNL since 2000. His expertise is in the study of water-rock interaction related to geothermal systems and high-level radioactive waste repositories. His most recent work has focused on radioactive waste disposal in shales, use of He isotopes in characterization of geothermal systems, and developing methodologies for assessing geothermal resources.

Current and Past Positions

2010-present	Career Geological Staff Scientist, Earth Sciences Division, Lawrence Berkeley National Laboratory, Berkeley, CA
2007-2009	Deputy Program Manager, Geosciences Program, Office of Basic Energy Sciences, US Department of Energy, Germantown, MD (on detail from LBNL)
2003-2010	Career Geological Research Scientist, Earth Sciences Division, Lawrence Berkeley National Laboratory, Berkeley, CA
2000-2003	Geological Scientist, Earth Sciences Division, Lawrence Berkeley National Laboratory, Berkeley, CA
1999-2001	Consultant, Empresa Nacional del Petroleo (ENAP), Santiago, Chile
1998-1999	Advising Geologist, Unocal Geothermal and Power Operations, Unocal Corporation, Santa Rosa, CA
1994-1998	Senior Geologist, Unocal Geothermal and Power Operations, Unocal

Corporation, Santa Rosa, CA

| 1989-1994 | Research Geologist, Unocal Science and Technology Division, Unocal Corporation, Brea, CA |

1989   Postdoctoral Research Fellow, Department of Geological Sciences, University of California, Santa Barbara, CA

1986-1989   Postdoctoral Research Fellow, Division of Geological and Planetary Sciences, California Institute of Technology, Pasadena, CA

Honors and Awards

2012   Geothermal Special Achievement Award, Geothermal Resources Council

2012   Fulbright Specialist Grant in Environmental Science, University of Chile

2009   Outstanding Contributions in Geosciences Research Award, DOE BES

2002, 2006   SPOT Awards (3), Lawrence Berkeley National Laboratory

1995, 1998   Special Recognition Awards (3), Unocal Corporation

1992   Fred L. Hartley Research Center Creativity Award, Unocal Corporation

Laura C. Feinstein

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Education

1994-1998   University of California at Berkeley, Berkeley, CA. B.A. in Anthropology, 1998.

2006-2012   University of California at Davis, Davis, CA. Ph.D. in Ecology, 2012.

Research and Professional Experience

Dr. Feinstein has worked for the California Council on Science and Technology (CCST) since January 2014. She previously served as a CCST Science and Technology Fellow with the California Senate Committee on Environmental Quality. Her graduate student research focused on the ecology and genetics of an invasive plant species in the San Francisco Bay's tidal wetlands. She has worked on a diverse array of ecological problems, including restoration of coastal marshes, biogeochemical cycles in redwood forests, and the genetics of adaptation. Laura has published and presented at numerous conferences on ecological genetics and tidal wetland plant communities.

Current and past Positions

Since 2014   Project Manager, Well Stimulation Technology in California, California Council on Science and Technology (CCST)

Since 2012   Postdoctoral researcher, restoration of San Francisco Bay tidal marshes, U.C. Davis

2012-2013   CCST Science and Technology Policy Fellow with the California Senate Committee on Environmental Quality

2006 - 2012   Ph.D. student, U.C. Davis

Honors and Awards

2007   CALFED Bay-Delta Science Fellow

2006   National Science Foundation Integrative Graduate Education and Research Traineeship on Invasive Species Research Award

2006   California Native Plant Society Research Award

Donald Gautier

Consulting Geologist
University of Adelaide (Adjunct Professor); U.S. Geological Survey (Scientist Emeritus)

Research: During a career spanning almost four decades I have conducted basic and applied research to address problems of petroleum geology and resource analysis. An extensive publication record and a global reputation for excellence in speaking, writing and teaching document this body of work.

My research has contributed to significant advancements, which include: (1) the first comprehensive evaluation of undiscovered oil and gas resources north of the Arctic Circle (Gautier and others 2009; Gautier and others 2011), (2) the first assessment of United States petroleum resources to be fully documented in a digital environment (Gautier and others 1995a; Gautier and others 1995b), (3) quantification of the relationship between porosity and time-temperature exposure in quartz-rich sandstones (Schmoker and Gautier 1988; Gautier and Schmoker 1989), and (4) the linkage of authigenic mineral precipitation in fine-grained sediments to the microbial geochemistry of early diagenetic environments (Gautier 1982; Gautier and Claypool 1984).

Recent work has focused on the quantitative evaluation of unconventional resources, the analysis of reserve growth in existing fields, and the development of probabilistic resource/cost analysis techniques to support interdisciplinary resource decisions.

Teaching: For the last ten years, my teaching has emphasized intensive graduate or professional-level training for university, government, and industrial groups. Courses and workshops have addressed the geology of unconventional resources, resource evaluation, quantitative assessment methodology, and geopolitical and economic issues related to the global distribution and quality of petroleum resources. Recent course offerings have included: Geology and Assessment of Unconventional Reservoirs, Play Assessment Methodology, and Integration of Resource Geology and Microeconomics

Outreach and Public Service: Lots of my time goes to providing information and guidance to governmental and non-profit organizations such as the California Division of Oil, Gas, and Geothermal Resources, California Council on Science and Technology, Central Intelligence Agency, EuroGeoSurveys, United States Coast Guard, U.S. Department of State, Energy Information Administration, International Energy Agency, Geological Survey of Denmark and Greenland, National Intelligence Council, The Nature Conservancy, Norwegian Petroleum Directorate, Massachusetts Institute of Technology, University of California, and the World Bank.

Professional societies seek me out as a meeting convener, technical session chair, short course teacher, expert panelist and speaker. I have enjoyed contributing my expertise to the World Petroleum Congress, the International Geological Congress, the American

Association of Petroleum Geologists, the European Association of Geoscientists and Engineers, the Geological Society of London, and many other organizations.

The international press and scientific journalists regard me as a trusted source of objective information on issues of global petroleum resources and their development. I routinely grant print, radio, and television interviews to organizations such as the BBC, CBC, CNN, National Geographic, the New York Times, PBS, Der Spiegel, Science Magazine, and the Wall Street Journal.

Matthew G. Heberger

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Education

1992–1996   Cornell University, Ithaca, New York. B.S. in Agricultural and Biological Engineering, 1996.

2001–2003   Tufts University, Medford, Massachusetts. M.S. in Water Resources Engineering, 2003.

Research and Professional Experience

Mr. Heberger has been a research associate in the Water Program of the Pacific Institute since 2007. He is a water resource engineer and hydrologist specializing in hydraulic, hydrologic, and water quality analyses and modeling, the nexus between water and energy, and impacts of climate change on water resources. Prior to joining the institute Mr. Heberger worked as a consulting engineer at the consulting firm of Camp, Dresser, and McKee (CDM) where he was responsible for building and calibrating rainfall-runoff, hydraulic and water quality models for major waterways across the US.

Current and past Positions

Since 2007   Research Associate, Pacific Institute, Oakland, California

2003 – 2007   Water Resources Engineer, Camp Dresser & McKee,
Cambridge, Massachusetts

2001 – 2003   Research Assistant, Department of Civil and Environmental Engineering,
Tufts University, Medford, Massachusetts

1999 – 2001   Coordinator, International Network on Participatory Irrigation
Management, Washington, DC

1996 – 1998   Water and Sanitation Extension Agent, United States Peace Corps, Mali,
West Africa

Honors and Awards:

2007   Registered Professional Engineer, Commonwealth of Massachusetts

2004   Certified Floodplain Manager, Association of State Floodplain Managers

James E. Houseworth

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Education

1973-1977	California Institute of Technology, Pasadena, CA. B.S. in Environmental Engineering, 1977.
1977-1978	California Institute of Technology, Pasadena, CA. M.S. in Environmental Engineering, 1978.
1979-1984	California Institute of Technology, Pasadena, CA. Ph.D. in Environmental Engineering, 1984.

Research and Professional Experience

Dr. Houseworth has been a program manager in the Earth Sciences Division of Lawrence Berkeley National Laboratory (LBNL) since 2000. His expertise is in single and multiphase flow and solute transport in porous and fractured geologic media and has worked on applications to petroleum recovery, nuclear waste disposal, and geologic CO_2 sequestration. His most recent work has centered on nuclear waste disposal in argillaceous rock, CO_2/brine leakage from geologic storage reservoirs, and risk assessments of petroleum recovery operations. Dr. Houseworth has authored over 30 peer-reviewed journal articles and conference publications.

Current and Past Positions

Since 2000	Program Manager, Earth Sciences Division, Lawrence Berkeley National Laboratory (LBNL)
1997 – 2000	Technical Systems Manager II, Duke Engineering and Services, Las Vegas, Nevada
1992 – 1997	Senior Staff Consultant, INTERA Inc., Las Vegas, Nevada
1984 – 1992	Research Engineer, Chevron Oil Field Research Company, La Habra, California
1979 – 1980	Engineer, Bechtel Inc., San Francisco, California

Honors and Awards

2012   Director's Award for Exceptional Achievement (TOUGH codes), by LBNL

2007, 2006   Outstanding Performance Award, by LBNL

1984   Ph.D. thesis - Richard Bruce Chapman Memorial Award

Preston D. Jordan

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Education

1982-1987   University of California, Berkeley, B.A., Geology, 1988

1996-1997   University of California, Berkeley, M.S. in Eng. Sci., Geotechnical
                     Engineering, 1997

Licenses: California Professional Geologist (since 1998)
                     California Certified Hydrogeologist (since 2007)
                     California Certified Engineering Geologist (since 2012)

Research Interests

Mr. Jordan has been a geologist in the Earth Sciences Division at Lawrence Berkeley
National Laboratory (LBNL) since 1990. His research over the last eight years has focused
primarily on the risk of geologic carbon storage, with a focus on assessing leakage risk.
His work on a risk assessment of one of the few industrial-scale geologic carbon storage
projects in the world led the operator to reduce the injection pressure. Mr. Jordan has co-
authored over 15 peer-reviewed journal articles and conference papers.

Professional Experience

Since 1990   Staff Research Associate currently (after five promotions), Earth Science
                     Division, Lawrence Berkeley National Laboratory

1988-1989   Staff Geologist, Harlan Tait Associates, San Francisco

1988   Field Geologist, Department of Geology and Geophysics, University of
                     California, Berkeley

1987   Assistant Field Geologist, Department of Geology and Geophysics,
                     University of California, Berkeley

Honors and Awards

2010   Outstanding Performance Award, by LBNL

1987   USGS/NAGT program nominee, by University of California, Berkeley

Dr. Jane C. S. Long

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Dr. Long currently focuses on strategic approaches to the climate change problem. She has led efforts to define energy systems with radical emission cuts that can feasibly be built by mid century. In recognition that the outcomes of climate change might become extremely severe, she leads a national effort to begin research on intentional modification of the climate: geoengineering. Dr. Long also works to bring a factual basis to the debate about hydraulic fracturing and to develop standards for safe practice.

Dr. Long recently retired from Lawrence Livermore National Laboratory as Principal Associate Director at Large. Her leadership was focused on insuring that energy research was coordinated with climate research and the directorate she led was not just describing the climate problem, but developing solutions to this problem. Outside of the Lab, she was co-chair of the Task Force on Geoengineering for the Bipartisan Policy Center that issued a report recommending that the US begin research on this topic. She led the effort to propose concrete steps the government can take to start research that will be featured in an upcoming "Comment" piece in Nature. These steps recommend governance appropriate for this controversial topic, including review of scientific and social merit, risk assessment, transparency and vested interests management and legal constructs.

She is chairman of the California Council on Science and Technology's California's Energy Future committee, which produced a series of reports designed to show if and how California could reduce emissions by 80% by 2050. These reports contained a methodology – a four-step process -- for thinking about this problem that has had influence well beyond the California borders. Many advocates or plans for a new energy system do not take feasibility into account and they often use questionable accounting in counting emissions. The methodology contained in these reports explicitly assesses feasibility and presents an accounting framework for ensuring emission reductions are all counted and counted once. Dr. Long wrote the summary report in language understandable by policy makers and this report is cited frequently and she has presented the material in many places throughout the country.

She is now on the board of the Center for Sustainable Shale Gas Development in Pennsylvania which is an organization formed to provide voluntary environmental certification for hydraulic fracturing operators. On this board she has worked to help develop a standard for wastewater treatment and disposal, perhaps the most difficult environmental problem associated with hydraulic fracturing. She is the lead for a legislatively mandated study of hydraulic fracturing in the state of California. This multimillion dollar assessment includes a large team of scientists. In this role, she has served as the bridge between science and policy by working with scientists to tailor highly

technical assessments to the public concerns and to communicate both issues that are usually not discussed but are important and identify issues that are often discussed, but in reality not important.

As the Dean of the Mackay School of Mines, Dr. Long started the Director of the Great Basin Center for Geothermal Energy and through her initiative, the state instituted the Task Force on Renewable Energy and Energy Conservation, which was the first time Nevada had a state body devoted to promoting these technologies. She also initiated the Mining Life-Cycle Center designed to act like an extension service in promoting sustainable practice to the mining industry.. Dr. Long also worked at Lawrence Berkeley National Laboratory leading teams to clean up environmental contamination, develop geothermal energy, and store nuclear waste.

Appendix D

Glossary

Acid fracturing – a form of hydraulic fracture stimulation of a formation performed by injecting the acid over the parting pressure of the rock and using the acid to etch channels in the fracture face.

Androgens – steroid hormones that promote the development and maintenance of male characteristics of the body.

Anti-androgens – a substance that can prevent the full expression of androgen.

Anti-estrogens – a substance that can prevent the full expression of estrogen.

Aquifer – a zone of saturated rock or soil through which water can easily move.

Bactericide – a product that kills bacteria in the water or on the surface of the pipe.

Basement faults – faults that occur in the undifferentiated assemblage of rock underlying the oldest stratified rocks in any region.

Basement rock – the undifferentiated assemblage of rock underlying the oldest stratified rocks in any region.

Bedding planes – surfaces that separate sedimentary layers in a rock. The beds are distinguished from each other by grain size and composition, such as in shale and sandstone. Subtle changes, such as beds richer in iron-oxide, help distinguish bedding. Most beds are deposited essentially horizontally.

Biogenic methane – methane produced as a direct consequence of bacterial activity.

Biomarkers – complex molecular fossils used to correlate crude oil and petroleum source rocks, provide information on the type of organic matter, and characterize the thermal maturity.

Borehole cuttings – the small chips and fines generated by drilling through a formation with a drill bit. Most of the cuttings are removed from the drilling mud as the fluid pass through the solids control equipment (e.g., shakers, screens, cyclones, etc.,) at the surface.

Brittle – a rock characteristic that implies mechanical failure in the form of a fracture created with little or no plastic deformation.

BTEX (benzene, toluene, ethylbenzene, and xylene) – volatile aromatic compounds typically found in petroleum products such as gasoline and diesel fuel.

Buffer – a chemical used to maintain the pH of a solution within a limited range.

Cations – positively charged ions.

Chemical Abstracts Service (CAS) number – a unique numeric identifier, designates only one substance, has no chemical significance, and is a link to a wealth of information about a specific chemical substance within the CAS registry.

Chimneys – vertically oriented geological structures that may have circular or subcircular in planform if associated with faults or may be more disperse laterally if not associated with faults. Chimneys form from gas migration processes and are often found in association with mud volcanoes.

Class II wells – used for injection/disposal of fluids associated with oil and natural gas production. Most of the injected fluid is salt water (brine), which is brought to the surface in the process of producing (extracting) oil and gas. In addition, brine and other fluids are injected to enhance (improve) oil and gas production.

Clay stabilizer – a chemical additive used to prevent clay destabilization that results in clay migration or swelling caused by a reaction to an aqueous fluid.

Conductor casing – generally, the first string of casing in a well. It may be lowered into a hole drilled into the formations near the surface and cemented in place, or it may be driven into the ground by a special pile driver. Its purpose is to prevent the soft formations near the surface from caving in and to conduct drilling mud from the bottom of the hole to the surface when drilling starts.

Conventional reservoir – reservoirs that may be produced commercially without altering the reservoir permeability or associated hydrocarbon viscosity.

Corrosion inhibitor – a chemical or mixture of chemicals that prevents or reduces corrosion.

Coulomb criterion – a criterion for rock failure as a function of the normal and shear stress conditions.

Cross-link gel fracturing fluid – is generally an aqueous fluid containing a gelling agent like guar or xanthan and a crosslinker. It has even greater viscosity than a gel fracturing fluid.

Crosslinker – A substance that promotes or regulates intermolecular covalent bonding between polymer chains, linking them together to create a larger structure.

Diagenetic –physical and chemical changes that affect sedimentary deposits during burial and may culminate in lithification, i.e., turning sediment into solid rock.

Diagenetic trap – a trap formed as a result of diagenetic alteration of rocks within a sedimentary basin, resulting in decreased permeability.

Diatomite – a fine, soft, siliceous sedimentary rock composed chiefly of the silica-rich remains of diatoms.

Dip – A measure of the angle between the flat horizon and the slope of a sedimentary layer, fault plane, metamorphic foliation, or other geologic structure.

Directional drilling – drilling the wellbore in a planned angle of deviation or trajectory other than vertical.

Dissolved Organic Carbon (DOC) – mass of organic carbon from a measured water sample that is dissolved or colloidal that can pass through a filter, typically a 0.4 to 0.7 micron filter

Dolomites – carbonate rocks made up of dolomite (CaMg(CaCO3)2).

Downdip – located down the dip of a sloping planar surface.

Drilling mud – the fluid, water, oil or gas based, circulated through the wellbore during rotary drilling and workover operations that is used to establish well control, transport cuttings to the surface, provide fluid loss control, lubricate the string and cool the bottom hole assembly.

Ductile – a rock characteristic that implies mechanical failure in the form of a fracture created with a large amount of plastic deformation.

Earthquake magnitude – a measure of the amount of energy released during an earthquake, such as the Richter scale.

Effective stress – the total stress minus the pore pressure.

Endocrine-disrupting compounds – chemicals that may interfere with the body's endocrine system and produce adverse developmental, reproductive, neurological, and immune effects in both humans and wildlife.

EPA maximum contaminant level (MCL) – threshold concentration of a contaminant above which water is not suitable for drinking.

Epicenter – a point, directly above the true center of disturbance at the earth's surface, from which the shock waves of an earthquake apparently radiate.

Estrogens – steroid hormones that promote the development and maintenance of female characteristics of the body.

Evaporative emissions – hydrocarbons released into the atmosphere through evaporation from equipment or storage facilities.

Fault – a fracture in the Earth in which one side has moved relative to the other.

Flaring – the combustion of unwanted gases produced by an oil well.

Flowback – fracturing fluid, perhaps mixed with formation water and traces of hydrocarbon, that flows back to the surface after the completion of hydraulic fracturing.

Foaming agent – a material that facilitates formation of foam.

Formation – a body of rock of considerable extent with distinctive characteristics that allow geologists to map, describe, and name it.

Fracture aperture – the distance between fracture faces.

Fracture height – the vertical extent of a fracture.

Fracture length – the horizontal extent of a fracture.

Fracture propagation – enlargement or extension of a crack in a solid material.

Friction reducer – a material, usually a polymer that reduces the friction of flowing fluid in a conduit.

Fugitive emissions – emissions of gases or vapors due to leaks and other unintended or irregular releases.

Gel fracturing fluid – is generally an aqueous fluid containing a gelling agent like guar or xanthan. It has an enhanced viscosity relative to slickwater fracturing fluids.

Globally Harmonized System of Classification and Labeling of Chemicals (GHS) – a worldwide initiative to promote standard criteria for classifying chemicals according to their health, physical and environmental hazards.

Greenhouse gas emissions (GHG) – emissions of gases such as CO_2 and methane that trap heat in the atmosphere.

Horizontal drilling – a well drilled in a manner to reach an angle of 90 degrees relative to a level plane at its departure point at the surface. In practice, the horizontal section of most horizontal wells varies by several degrees.

Hybrid fracturing – hydraulic fracturing that utilizes more than one type of fracturing fluid for a given stage.

Hydraulic diffusivity coefficient – the ratio of the hydraulic conductivity to the volume of water that a unit volume of saturated soil or rock releases from storage per unit decline in hydraulic head. It is a parameter that combines transmission characteristics and the storage properties of a porous medium.

Hydraulic fracturing – an operation in which a specially blended liquid is pumped down a well and into a formation under pressure high enough to cause the formation to crack open, forming passages through which oil can flow into the wellbore.

Hydrostatic pressure – the pore pressure that results from the static weight of pore fluid above the point of interest.

Induced seismicity – earthquakes caused by human activities.

Intercalated turbiditic sandstones – sandstones deposited from a turbidity current (an underwater current flowing downslope owing to the weight of sediment it carries) that are alternately layered between other rock types.

Intermediate casing – the casing set in a well after the surface casing but before production casing to keep the hole from caving and to seal off formations.

Iron control agent – a chemical that controls the precipitation of iron from solution.

Kelly – the heavy square or hexagonal steel member suspended from the swivel through the rotary table and connected to the topmost joint of drill pipe to turn the drill stem as the rotary table turns.

Kerogen – solid, insoluble organic material in shale and other sedimentary rock that yields oil and/or gas upon heating.

Lithology – the physical characteristics (e.g., mineral content, grain size, texture and color) of a rock or stratigraphic unit.

Matrix acidizing – use of a mineral acid (typically hydrochloric acid (HCl) or HCl in combination with hydrofluoric acid (HF)) or an organic acid (typically acetic or formic) to remove damage or stimulate the permeability of a formation.

Maturation – the chemical transformation of kerogen into petroleum fluids.

Median lethal dose (LD50) – the dose required to kill half the members of a tested population after a specified test duration.

Microearthquakes – an earthquake of low intensity with a magnitude of 2 or less on the Richter scale.

Microscanner log – a geophysical measurement record from a downhole instrument that consists of four orthogonal imaging pads containing microelectrodes in direct contact with the borehole wall. It is used for mapping of bedding planes, fractures, faults, foliations, and other formation structures and dip determination.

Microseismic monitoring – a method of tracking a fracture by listening for the sounds of shear fracturing in the formation during the hydraulic fracturing process.

Migrated oil – oil that has moved from source rock to reservoir rock.

Miocene – the geologic time ranging from about 23 to 5.3 million years ago.

MODFLOW – the USGS's three-dimensional (3D) finite-difference groundwater model.

Multi-stage hydraulic fracturing – is where hydraulic fracturing is conducted repeatedly in isolated segments along the length of the well's production interval.

Nanoparticles – a microscopic particle of matter that is measured on the nanoscale, usually less than 100 nanometers.

Normal stress – the internal forces per unit area that are exerted in a material object and are also perpendicular to the selected area.

Oil window – the temperature and pressure ranges under which the organic matter in organic-rich sedimentary rocks is transformed into petroleum fluids.

Opening mode fractures – a fracture that opens in response to tensile stress, i.e., a stress that acts to pull a material object apart.

Organic shales – organic-rich shales.

Overburden – the rock layers lying above a point of interest in the subsurface.

Oxides of nitrogen (NOx) – consist of nitric oxide (NO), nitrogen dioxide (NO2) and nitrous oxide (N2O).

Ozone precursors – chemical compounds, such as carbon monoxide, methane, non-methane hydrocarbons, and nitrogen oxides, which in the presence of solar radiation react with other chemical compounds to form ozone.

Particulate matter (PM) and PM2.5 – a complex mixture of extremely small particles and liquid droplets. PM2.5 consist of particles less than 2.5 microns in diameter.

Permeability – The ability of a rock or other material to allow fluid flow through its interconnected spaces.

pH adjuster – chemical agents to reduce, or to increase, the acidity of a solution.

Phosphatic shales – phosphate-rich shales.

Pipes – vertically-oriented geologic structures commonly circular or subcircular in planform that may have formed as a result of hydrothermal activity, overpressure, or dissolution processes.

Play – hydrocarbon reservoirs within the same region that have common sourcing and trapping mechanisms.

Pore pressure – the normal stress exerted by pore fluids on the porous medium.

Poromechanical effects – phenomena that occur in porous materials whose mechanical behavior is significantly influenced by the pore fluid.

Portland cement – a general class of hydraulic cements (cements that can harden under water) usually made by burning a mixture of limestone and clay in a kiln and pulverizing into a powder.

Precipitate – a solid substance formed from a liquid solution during a chemical process.

Produced water – water, ranging from fresh to salty, produced with the hydrocarbons as a result of pressure drawdown and flow through the petroleum reservoir.

Production casing – the last string of casing set in a well that straddles and isolates the producing interval, inside of which is usually suspended a tubing string.

Production liner – similar to casing pipe but does not extend back to the ground surface. Liners may or may not be cemented.

Propagation of water front – the movement of a constant water saturation level through a porous medium.

Proppant – well sorted and consistently sized sand or man-made materials that are injected with the fracturing fluid to hold the fracture faces apart after pressure is released.

Quaternary fault – a fault that formed sometime between the present and about 2.6 million years ago.

Radiogenic material – material produced by radioactive decay.

Redox conditions – a quantitative description of the environment in question with respect to be oxidizing or reducing.

Reservoir – a subsurface accumulation of hydrocarbon fluids that resides in rock pores and fractures.

Scale inhibitor – a chemical that prevents scale from forming in scale mineral saturated produced waters.

Sedimentary basin – a depression in the Earth's surface that collects sediment.

Seismic hazard – a phenomenon such as ground shaking, fault rupture, or soil liquefaction that is generated by an earthquake.

Seismic moment – a measure of the size of an earthquake based on the area of fault rupture, the average amount of slip, and the force that was required to overcome the friction sticking the rocks together that were offset by faulting.

Seismometer – an instrument for measuring the direction, intensity, and duration of earthquakes by measuring the actual movement of the ground.

Seismometer array – numerous seismometers placed at discrete points in a well-defined configuration.

Semi-volatile organic compounds (SVOC) – organic compound which has a boiling point higher than water and which may vaporize when exposed to temperatures above room temperature.

Shale – sedimentary rock derived from mud and commonly finely laminated (bedded). Particles in shale are commonly clay minerals mixed with tiny grains of quartz eroded from pre-existing rocks.

Shear failure – brittle or ductile damage that results from shear stress of sufficient magnitude.

Shear stress – the internal forces per unit area that are exerted in a material object and are also tangential to the selected area.

Siliceous – a rock rich in a silica phase, such as opal, cristobalite, or quartz.

Siliceous shales – silica-rich shales.

Slickwater fracturing fluid - a water base fracturing fluid with only a very small amount of a polymer added to give friction reduction benefit.

Solvent - a substance that will dissolve a solid. In the oil field, oil based solvents may range from xylene for asphaltenes and sludges, to kerosene and diesel/xylene mixtures for paraffins.

Source rock – a rock rich in organic matter from the original sediment deposition that can generate petroleum fluids under certain temperature and pressure conditions.

Specific conductance – the measure of a material to conduct an electric current.

Stable isotopes – two or more forms of a chemical element having different numbers of neutrons that do not have any measurable radioactive decay.

Static fractures – fractures that are not changing over time.

Steam cycling – a form of steam injection in which injection and production take place in the same well, which is accomplished by alternating steam injection with oil production.

Steam injection – a thermally-enhanced oil recovery method in which steam is forced into the reservoir by applying pressure; the thermal energy of the steam heats the reservoir which reduces the viscosity of heavy oil that are usually the target of thermal oil recovery methods.

Storage coefficient – the volume of water released from storage per unit surface area of a confined aquifer per unit decline in hydraulic head.

Stratigraphic trap – a trap formed as a result of variations in porosity and permeability of the stratigraphic sequence.

Stratigraphic zone – a body of strata that is distinguished on the basis of lithology, fossil content, age, or other rock property.

Stress – the internal forces per unit area that are exerted in a material object.

Strike – is a geometrical characteristic of a planar geologic surface and is defined by the line of intersection between the geologic surface and a horizontal plane.

Structural features – geologic features that result from tectonic, diapiric, gravitational and compactional processes.

Structural trap – a trap formed as a result of faulting or folding of the rock.

Supercritical CO_2 – a fluid state of carbon dioxide which displays characteristics of both liquid and gas that occurs at conditions above its critical temperature and critical pressure.

Surface casing – the casing following the conductor casing in a well that protects fresh water aquifers from contact with fluids moving through the well. It is always cemented across the water zone and the cement usually extends to the surface.

Surfactant – a chemical that is attracted to the surface of a fluid and modifies the properties such as surface tension.

Tectonic features – features that are a result of forces or conditions within the earth that cause movements of the crust.

Tectonic stress – stress that results from forces or conditions within the earth that cause movements of the crust.

Televiewer log – a record of the amplitude of high-frequency acoustic pulses reflected by the borehole wall; provides location and orientation of bedding, fractures, and cavities.

Thermogenic methane – methane created by the thermal decomposition of buried organic material.

Tiltmeter – an instrument used to measure slight changes in the inclination of the earth's surface resulting from subsidence or uplift, usually in connection with volcanology and earthquake seismology.

Total dissolved solids (TDS) – total amount of all inorganic and organic substances – including minerals, salts, metals, cations or anions – that are dissolved within a volume of water.

Total Organic Carbon (TOC) – total mass of organic carbon from a measured sample.

Total Suspended Solids (TSS) - total mass retained on a filter per unit volume of water, typically a 0.4 to 0.7 micron filter.

Toxicity – the degree to which a substance can harm humans or other living organisms.

Trace metals – metals that do not affect chemical or physical properties of the system as a whole to any significant extent, and have ideal solution behavior characteristic of very high dilution.

Trap – a configuration of geologic layers and/or structures that has a very low permeability and is suitable for blocking the upward movement of buoyant hydrocarbons.

Turbidity – the measure of relative clarity of a liquid. It is an optical characteristic of water and is an expression of the amount of light that is scattered by material in the water when a light is shined through the water sample.

Unconventional reservoir – oil and gas resources whose porosity, permeability, fluid trapping mechanism, or other characteristics differ from conventional sandstone and carbonate reservoirs, such as shale gas, shale oil, heavy and viscous oil, gas hydrates, tight gas, and coal bed methane resources.

Updip – located up the dip of a sloping planar surface.

Viscosity – a measurement of a fluid's internal resistance to flow, expressed as the ratio of shear stress to shear rate.

Vitrinite – a type of woody kerogen that is used to measure source rock maturity.

Vitrinite reflectance – a measure of source rock maturity based on the reflectance of vitrinite, measured as % Ro. The onset of oil generation typically occurs at around Ro = 0.6%, with gas formation occurring when Ro = 1.2 %.

Volatile organic compounds (VOC) –organic chemicals whose composition makes it possible for them to evaporate under normal indoor atmospheric conditions of temperature and pressure.

Water flooding – purposely injecting water below and/or into the reservoir to drive the oil towards the producing wellbore.

Well completion – the activities and methods of preparing a well for the production of oil and gas or for other purposes, such as injection; the method by which one or more flow paths for hydrocarbons are established between the reservoir and the surface.

Well stimulation technology – refers to well stimulation methods of hydraulic fracturing, acid fracturing, and matrix acidizing.

Zonal isolation – the exclusion of fluids such as water or gas in one zone from mixing with fluids in another zone along pathways outside of a well casing, accomplished through cement that seals the rock to the casing.

Appendix E

Review of Information Sources

For this report, authors of the report reviewed many sources of public information, including some that are not easily accessible to all citizens, such as fee-based scientific journals. If a member of the public wishes to view a document referenced in the report, they may visit California Council on Science and Technology at 1130 K Street, Suite 280, Sacramento, CA 95814-3965. We cannot duplicate or electronically transmit copyright documents. Please make arrangements in advance by contacting CCST at (916) 492-0996.

CCST issued a request for public submissions of literature by July 15, 2014. All literature submitted by the deadline is listed below in the Bibliography of Submitted Literature. Our scientists reviewed the submissions and cited a given reference in the report if it met all three of the following criteria:

1. Fit into one of the five categories of admissible literature (described in a-e below).

   a. Published, peer-reviewed scientific papers.

   b. Government data and reports.

   c. Academic studies that are reviewed through a university process, textbooks, and papers from technical conferences.

   d. Studies generated by non-government organizations that are based on data, and draw traceable conclusions clearly supported by the data.

   e. Voluntary reporting from industry. This data is cited with the caveat that, as voluntary, there is no quality control on the accuracy or completeness of the data.

2. Was relevant to the scope of the report.

3. Added substantive information to the report.

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Appendix F

California Council On Science And Technology Study Process

The reports of the California Council on Science and Technology (CCST) are viewed as being valuable and credible because of the institution's reputation for providing independent, objective, and nonpartisan advice with high standards of scientific and technical quality. Checks and balances are applied at every step in the study process to protect the integrity of the reports and to maintain public confidence in them.

Study Process Overview—Ensuring Independent, Objective Advice

For over 25 years, CCST has been advising California on issues of science and technology by leveraging exceptional talent and expertise.

CCST can enlist the state's foremost scientists, engineers, health professionals, and other experts to address the scientific and technical aspects of society's most pressing problems.

CCST studies are funded by state agencies, foundations and other private sponsors. CCST provides independent advice; external sponsors have no control over the conduct of a study once the statement of task and budget are finalized. Study committees gather information from many sources in public and private meetings but they carry out their deliberations in private in order to avoid political, special interest, and sponsor influence.

Stage 1: Defining the Study

Before the committee selection process begins, CCST staff and members work with sponsors to determine the specific set of questions to be addressed by the study in a formal "statement of task," as well as the duration and cost of the study. The statement of task defines and bounds the scope of the study, and it serves as the basis for determining the expertise and the balance of perspectives needed on the committee.

The statement of task, work plan, and budget must be approved by CCST's Board chair. This review often results in changes to the proposed task and work plan. On occasion, it results in turning down studies that CCST believes are inappropriately framed or not within its purview.

Stage 2: Committee Selection and Approval

Selection of appropriate committee members, individually and collectively, is essential for the success of a study. All committee members serve as individual experts, not as representatives of organizations or interest groups. Each member is expected to contribute to the project on the basis of his or her own expertise and good judgment. A committee is not finally approved until a thorough balance and conflict-of-interest discussion is held, and any issues raised in that discussion are investigated and addressed. Members of a committee are anonymous until this process is completed.

Careful steps are taken to convene committees that meet the following criteria:

An appropriate range of expertise for the task. The committee must include experts with the specific expertise and experience needed to address the study's statement of task. A major strength of CCST is the ability to bring together recognized experts from diverse disciplines and backgrounds who might not otherwise collaborate. These diverse groups are encouraged to conceive new ways of thinking about a problem.

A balance of perspectives. Having the right expertise is not sufficient for success. It is also essential to evaluate the overall composition of the committee in terms of different experiences and perspectives. The goal is to ensure that the relevant points of view are, in CCST's judgment, reasonably balanced so that the committee can carry out its charge objectively and credibly.

Screened for conflicts of interest. All provisional committee members are screened in writing and in a confidential group discussion about possible conflicts of interest. For this purpose, a "conflict of interest" means any financial or other interest which conflicts with the service of the individual because it could significantly impair the individual's objectivity or could create an unfair competitive advantage for any person or organization. The term "conflict of interest" means something more than individual bias. There must be an interest, ordinarily financial, which could be directly affected by the work of the committee. Except for those rare situations in which CCST determines that a conflict of interest is unavoidable and promptly and publicly disclose the conflict of interest, no individual can be appointed to serve (or continue to serve) on a committee of the institution used in the development of reports if the individual has a conflict of interest that is relevant to the functions to be performed.

Point of View is different from Conflict of Interest. A point of view or bias is not necessarily a conflict of interest. Committee members are expected to have points of view, and CCST attempts to balance these points of view in a way deemed appropriate for the task. Committee members are asked to consider respectfully the viewpoints of other

members, to reflect their own views rather than be a representative of any organization, and to base their scientific findings and conclusions on the evidence. Each committee member has the right to issue a dissenting opinion to the report if he or she disagrees with the consensus of the other members.

Other considerations. Membership in CCST and previous involvement in CCST studies are taken into account in committee selection. The inclusion of women, minorities, and young professionals are additional considerations.

Specific steps in the committee selection and approval process are as follows:

Staff solicit an extensive number of suggestions for potential committee members from a wide range of sources, then recommend a slate of nominees. Nominees are reviewed and approved at several levels within CCST. A provisional slate is then approved by CCST's Board. The provisional committee members complete background information and conflict-of-interest disclosure forms. The committee balance and conflict-of-interest discussion is held at the first committee meeting. Any conflicts of interest or issues of committee balance and expertise are investigated; changes to the committee are proposed and finalized. Committee is formally approved. Committee members continue to be screened for conflict of interest throughout the life of the committee.

Stage 3: Committee Meetings, Information Gathering, Deliberations, and Drafting the Report

Study committees typically gather information through:

1. meetings;

2. submission of information by outside parties;

3. reviews of the scientific literature; and

4. investigations by the committee members and staff.

In all cases, efforts are made to solicit input from individuals who have been directly involved in, or who have special knowledge of, the problem under consideration.

The committee deliberates in meetings closed to the public in order to develop draft findings and recommendations free from outside influences. The public is provided with brief summaries of these meetings that include the list of committee members present. All analyses and drafts of the report remain confidential.

Stage 4: Report Review

As a final check on the quality and objectivity of the study, all CCST reports whether products of studies, summaries of workshop proceedings, or other documents must undergo a rigorous, independent external review by experts whose comments are provided anonymously to the committee members. CCST recruits independent experts with a range of views and perspectives to review and comment on the draft report prepared by the committee.

The review process is structured to ensure that each report addresses its approved study charge and does not go beyond it, that the findings are supported by the scientific evidence and arguments presented, that the exposition and organization are effective, and that the report is impartial and objective.

Each committee must respond to, but need not agree with, reviewer comments in a detailed "response to review" that is examined by one or two independent report review "monitors" responsible for ensuring that the report review criteria have been satisfied. While feedback from the peer reviewers and report monitors is reflected in the report, neither group approved the final report before publication. The steering committee and CCST take sole responsibility for the content of the report. After all committee members and appropriate CCST officials have signed off on the final report, it is transmitted to the sponsor of the study and is released to the public. Sponsors are not given an opportunity to suggest changes in reports. All reviewer comments remain confidential. The names and affiliations of the report reviewers are made public when the report is released.

The report steering committee wishes to thank the oversight committee and the peer reviewers for many thoughtful comments that improved this manuscript.

Oversight committee co-chairs:

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Appendix G

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Chapter 2 Acknowledgements

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Chapter 4 Acknowledgements

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Horizontal Well Drilling History in CA

In California, horizontal wells are used with and without well stimulation. This appendix discusses the historic application of horizontal wells without well stimulation, followed by an assessment of recent horizontal well installation activity. Historic and recent stimulation of horizontal wells is discussed in Section 3.2 regarding hydraulic fracturing. The following is a review of the use of horizontal wells in California.

Historical Horizontal Well Utilization

The first horizontal-well-drilling technology was developed in the 1920s, but the development of the technology led to limited use until the mid-1980s, followed by a rapid increase through the 1990s, when they became common (Ellis et al., 2000). Many thousands of horizontal wells had been installed in the United States by the mid-1990s (Joshi and Ding, 1996).

Modern methods of horizontal well drilling, as described in Section 2.2.2, have a number of applications in oil production (Ellis et al., 2000); in the shale oil and gas basins elsewhere in the country, their use is principally to allow production from relatively thin, impermeable shales. However, in California, the applications are more varied. They can have greater contact area with the petroleum-containing reservoir in near-horizontal layered geologic systems. Horizontal wells can also more readily intersect more natural fractures in the reservoir that may conduct oil, owing not only to their intersecting more of the reservoir than a vertical well, but also because fractures are typically perpendicular to rock strata, and so are nearly vertical in near-horizontal strata.

Horizontal wells can parallel water-oil or oil-gas contacts, and so can be positioned along their length to produce more oil, without drawing in water or gas, than is possible from a vertical well. Due to their orientation parallel to geologic strata, horizontal wells can improve sweep efficiency during secondary or tertiary oil recovery, which involves the injection of other fluids, such as steam, to mobilize oil to a production well. A horizontal well also provides for more uniform injection to a particular stratum. On the production side, a horizontal well provides a more thorough interception of the oil mobilized by the injection. Vertical wells are more readily bypassed by mobilized oil due to variation in the permeability of the reservoir rock. Similar to being better positioned to intercept oil mobilized by injection, horizontal wells are also better positioned to intercept oil draining by gravity through a reservoir.

An example of a thin reservoir development in California is the installation of a horizontal well in a Stevens Sand layer of the Yowlumne field in the southern San Joaquin Basin, which was a layer too thin to be developed economically using vertical wells. It was completed in 1991 at a true depth of over 3,400 m (11,200 ft) with a 687 m (2,252 ft) lateral. The well tripled the production rate from the previous vertical wells in the reservoir (Marino and Shultz, 1992).

The use of horizontal wells to improve the efficiency of steam injection for oil recovery began in the early 1990s. Steam injection reduces the viscosity of oil, allowing it to flow more readily to production wells. For example, in 1990 and 1991, three horizontal wells were installed by Shell Western Exploration and Production in 45° dipping (tilted) units with a long history of steam injection in the Midway Sunset field in the San Joaquin Basin. Two of the wells were installed with 121 m (400 ft) sloping laterals. These wells produced two to three times more oil as nearby vertical wells, but cost two to three times more, and so did not provide an economic benefit. The third well, with a longer horizontal lateral of 213 m (700 ft), produced six times more oil than nearby vertical wells and so was more economically successful (Carpenter and Dazet, 1992).

Shell Western Exploration and Production also installed horizontal wells in a shallow, tilted (dipping) geologic bed in the Coalinga field in the San Joaquin Basin in the early 1990s. Steam injection with oil production via vertical wells started in this zone in the late 1980s. The horizontal wells were installed in the same reservoir but deeper along the tilted bed. The wells were initially operated with steam cycling. This process entails injecting steam for a period, then closing the well to let the steam continue to heat the oil and reservoir, then opening the well and producing oil. However, the increase in production resulting from steam cycling was lower than expected. Vertical wells for continuous steam injection were subsequently installed shallower along the tilted bed from the horizontal wells. This resulted in a large sustained production rate that justified the horizontal wells, which led to considering further opportunities for installing horizontal wells in the Coalinga field (Huff, 1995).

By the late 1990s, horizontal well installation projects for production of shallow oil, using vertical steam injectors, involved tens of wells each. Nearly 100 horizontal wells were installed in shallow sands containing heavy (viscous) oil in the Cymric and McKittrick fields in the San Joaquin Basin from the late 1990s to early 2000s. These wells were installed in association with vertical wells that injected steam to reduce the viscosity of the oil by heating, allowing it to flow to the horizontal wells. The wells were installed in phases, allowing optimization with each phase that reduced the cost per well by 45% by the last phase (Cline and Basham, 2002). By the late 2000s and early 2010s, drilling programs in reservoirs with steam injection included as many as hundreds of wells. For instance, over 400 horizontal wells were installed in the Kern River field in the San Joaquin Basin between 2007 and 2013, targeting zones identified with low oil recovery to date. These wells provided a quarter of the field's daily production (McNaboe and Shotts, 2013).

The third application of horizontal wells in California is for more efficient production of oil by gravity drainage. A prominent example of this is the installation of horizontal wells in a steeply dipping (60° from horizontal) sandstone reservoir in the Elk Hills field by Bechtel Petroleum Operations. Pressure in the formation was maintained by injecting natural gas updip in the reservoir. The position of the gas-oil contact moved deeper as oil production proceeded. Production from vertical wells in the oil zone was reduced to limit the amount of overlying gas they drew in, which then had to be re-injected. The wells were also reconfigured periodically to move the top of the interval from which they produced to greater depths (Mut et al., 1996).

The first horizontal well was installed in this steeply dipping sandstone reservoir in the Elk Hills field in 1988; the second in 1990. The wells' laterals (horizontal sections) were installed 12 m (40 ft) above the oil-water contact and about 76 m (250 ft) downdip of the gas-oil contact. This allowed production rates multiple times that from the adjacent vertical wells without drawing in the overlying gas or water from below. Production was also more constant over time compared to the typically declining rates from the vertical wells (Gangle et al., 1991); production from one of the first two wells remained constant for at least five years (Gangle et al., 1991). Given the successful production from these wells, another 16 had been installed by early 1995 (Mut et al., 1996).

Recent Horizontal Well Installation

The GIS data files made available by DOGGR with attributes of oil, gas, and geothermal wells in California (DOGGR, 2014a) include the county and field in which the well is located, the date drilling was initiated, and whether the well was vertical (listed as "not directional" in the file), directional, horizontal, or had an unknown path. Review of a sample of recent well records available from DOGGR for directionally drilled wells indicates they are typically near-vertical in the reservoir, with the directional drilling employed primarily to offset (shift) where the well encounters the reservoir relative to the point from which it is drilled. This is typical if the locations suitable for drilling are smaller than the extent of its oil resource.

Table H-1 shows the number of wells with a commencement date in 2012 or 2013 in DOGGR's GIS well data file and the number of these listed as horizontal. The percentage of all wells that are horizontal is relatively small. A higher percentage of these are in Kern County than wells in general.

A small percentage of recently installed wells in California are horizontal. All but three of these wells, more than 99% of the total, were installed in pre-existing fields as defined by DOGGR. The three outside pre-existing fields were in Kern County. The vast majority of all horizontal wells were installed are in Kern County. Outside of Kern County, 11 horizontal wells were installed in Fresno County, all in the Coalinga field; and nine in Monterey County, all in the San Ardo field. Three fields in Ventura County and two fields in Los Angeles County each had one or two horizontal wells installed.

Table H-1. *Number of all wells and horizontal wells whose installation was listed as commencing in 2012 and 2013 (DOGGR, 2014b).*

	All wells					Horizontal wells			
		With path type							
#	In California		In Kern County		#	% of wells with path type	% in Kern County	% in pre-existing fields
	#	%	#	%				
5,143	4,384	85	4,297	84	308	7	92	99

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Procedure for Searching Well Records for Indications of Hydraulic Fracturing

Well records are publicly available from the California Department of Oil, Gas, and Geothermal Resources (DOGGR) in the form of scans without searchable text (DOGGR, undated a). Through application of optical character recognition software, DOGGR provided versions of scanned records with searchable text for wells with first production or injection after 2001 (Bill Winkler, DOGGR, personnel communication).

Due to the large number of wells in Kern County, a sample of records was chosen for application of character recognition and subsequent searching. To define the sample proportion, the proportion of all records indicating hydraulic fracturing was presumed to be 20%. Given this presumption, the sample proportion for Kern County was selected to provide 95% confidence that the estimated proportion was within 2% of the actual proportion, using a finite population correction factor.

For some other counties, such as Fresno, digital records were available for all the wells. For the remaining counties, digital records were not available for all wells. Like for Kern County, this resulted in searching a sample of records for these counties. For some of them, such as Los Angeles and Orange counties, the proportion of wells with previously available digitized records was too small to provide a sufficiently constrained estimate of the proportion of wells hydraulically fractured. DOGGR scanned and provided additional records for these counties.

Searching the well record set provided by DOGGR resulted in data regarding the number of wells hydraulically fractured over time. Records potentially indicating that a well was hydraulically fractured were identified using the search term "frac ". The space after the term avoided occurrences of the term "fracture", which appears in the template information on some forms, and consequently the term is not correlated with wells that have been hydraulically fractured.

Records containing "frac " were reviewed to determine if hydraulic fracturing indeed occurred. The term "frac " was found to correctly identify more records of hydraulic fracturing than other potential terms, such as "fracture", "stimulation", "stage", and "frack." The few records containing the latter term also all included the term "frac ".

For Kern County, 90% of all the well records containing the term "frac " were confirmed as indicating hydraulic fracturing had occurred. In the other 10% of records, the term was used for other purposes, such as to describe geologic materials or to refer to the fracture gradient (the minimum fluid pressure per depth that will fracture the rock in a particular location). For the rest of the state, 63% of the records containing "frac " were confirmed as indicating hydraulic fracturing had taken place, and the term was used for other purposes in the other 37% of records. These percentages are based on weighting the result for each county by the estimated number of records containing "frac " in that county. For individual counties with at least five records containing "frac ", the percentage confirmed as indicating hydraulic fracturing ranged from 13% (Santa Barbara County) to 73% (Solano County).

In some records, the term "frac " was found to also indicate a Frac-Pack was completed. As described previously, placement of a Frac-Pack occurs above the fracturing pressure, and results in a fracture (the "frac ") propagated from the well filled with introduced granular material (the "pack"). The purpose of a Frac-Pack is to bypass formation damage resulting from drilling and/or control production of granular material from the formation.

"HRGP," standing for "high rate gravel pack," was identified in records for a number of wells in Los Angeles County. This is an alternate term for a Frac-Pack. The Los Angeles County records were searched for this term with the result that 16 in addition to those containing the term "frac " were identified. Review confirmed each of these records indicated a fracturing operation had occurred. All the records regarded wells in the Inglewood field. Subsequently, all of the well records were searched for "HRGP." Only one additional record not also containing the term "frac " was identified. This regarded a well in Kern County.

For records indicating hydraulic fracturing occurred, the operation was assigned to the date of the well's first production, or first injection if first production was not available. For hydraulically fractured wells with first production and injection, the fracturing date in almost all the records is closer to the first production date.

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DOGGR (Division of Oil, Gas and Geothermal Resources) (undateda). OWRS – Search Oil and Gas Well Records. Available at http://owr.conservation.ca.gov/WellSearch/WellSearch.aspx

Number of Well Records Searched for Indication of Hydraulic Fracturing

The following tables list the number of well first produced or injected from 2002 through September 2013, the number and % of these wells whose records were searched for reports of hydraulic fracturing (HF), and the number and percent of records that contained reports of hydraulic fracturing. The first table lists basins and the second counties with at least one well with first production or injection during this time period.

Table K-1 lists the estimated number of well records indicating hydraulic fracturing by sedimentary basin. Table K-2 lists the estimated number of well records indicating hydraulic fracturing by county.

Table J-1. *Total number of well records, and total number and percent of well records identified as indicating hydraulic fracturing by basin and for the state for wells with first production or injection from 2002 to 2013.*

Basin	2002-2006					2007-2011					2012-2013				
	New wells	Searched		HF recorded		New wells	Searched		HF recorded		New wells	Searched		HF recorded	
		#	%	#	%		#	%	#	%		#	%	#	%
Cuyama	21	2	10%	0	0%	11	1	9%	0	0%	1	0	0%	-	-
Eel River	9	9	100%	0	0%	2	2	100%	0	0%	0	-	-	-	-
Hollister-Sargent	0	-	-	-	-	8	4	50%	0	0%	0	-	-	-	-
Los Angeles	661	528	80%	153	29%	639	503	79%	75	15%	428	331	77%	32	10%
onshore	457	341	75%	106	31%	431	317	74%	34	11%	246	176	72%	14	8%
offshore	204	187	92%	47	25%	208	186	89%	41	22%	182	155	85%	18	12%
Sacramento	458	455	99%	15	3%	545	534	98%	59	11%	28	22	79%	0	0%
Salinas	156	18	12%	3	17%	405	121	30%	0	0%	118	7	6%	0	0%
San Joaquin	13,355	2,318	17%	591	25%	13,372	2,377	18%	523	22%	5,681	1,266	22%	372	29%
Santa Barbara-Ventura	130	126	97%	12	10%	347	339	98%	65	19%	154	149	97%	28	19%
Santa Maria	126	126	100%	12	10%	344	337	98%	65	19%	147	142	97%	28	20%
Santa Barbara-Ventura	4	0	0%	-	-	3	2	67%	0	0%	7	7	100%	0	0%
California	14,865	3,490	23%	775	22%	15,520	4,012	26%	724	18%	6,543	1,814	28%	432	24%

Table J-2. *Total number of well records, and total number and percent of well records identified as indicating hydraulic fracturing by county and for the state for wells with first production or injection from 2002 to 2013.*

County	2002-2006					2007-2011					2012-2013				
	New wells	Searched		HF recorded		New wells	Searched		HF recorded		New wells	Searched		HF recorded	
		#	%	#	%		#	%	#	%		#	%	#	%
Alameda	1	1	100%	0	0%	0	0	-	0	-	0	0	-	0	-
Butte	6	6	100%	0	0%	9	7	78%	0	0%	0	0	-	0	-
Colusa	61	61	100%	1	2%	114	109	96%	10	9%	16	10	63%	0	0%
Contra Costa	5	5	100%	1	20%	8	8	100%	0	0%	0	0	-	0	-
Fresno	463	463	100%	2	0%	664	664	100%	4	1%	166	166	100%	3	2%
Glenn	63	63	100%	2	3%	125	124	99%	11	9%	4	4	100%	0	0%
Humboldt	9	9	100%	0	0%	2	2	100%	0	0%	0	0	-	0	-
Kern	12,821	1,785	14%	589	33%	12,655	1,663	13%	516	31%	5,506	1,093	20%	369	34%
Kings	11	11	100%	0	0%	10	10	100%	2	20%	3	2	67%	0	0%
Los Angeles	697	588	84%	157	27%	659	549	83%	64	12%	434	341	79%	26	8%
Madera	7	7	100%	0	0%	16	16	100%	0	0%	1	1	100%	0	0%
Merced	1	1	100%	0	0%	1	1	100%	0	0%	0	0	-	0	-
Monterey	156	18	12%	3	17%	405	121	30%	0	0%	118	7	6%	0	0%
Orange	50	26	52%	2	8%	56	30	54%	13	43%	18	14	78%	6	43%
Sacramento	73	72	99%	6	8%	46	45	98%	4	9%	5	5	100%	0	0%
San Benito	1	1	100%	0	0%	1	1	100%	0	0%	0	0	-	0	-
San Joaquin	43	43	100%	0	0%	13	11	85%	1	9%	3	3	100%	0	0%
San Luis Obispo	45	17	38%	0	0%	17	6	35%	0	0%	20	0	0%	-	-
Santa Barbara	55	18	33%	1	6%	185	125	68%	2	2%	113	38	34%	0	0%
Santa Clara	0	0	-	0	-	7	3	43%	0	0%	0	0	-	0	-
Solano	72	71	99%	4	6%	53	53	100%	10	19%	1	1	100%	0	0%
Stanislaus	2	2	100%	0	0%	0	0	-	0	-	0	0	-	0	-
Sutter	66	66	100%	1	2%	161	161	100%	24	15%	0	0	-	0	-
Tehama	77	77	100%	0	0%	19	19	100%	0	0%	2	2	100%	0	0%
Tulare	7	7	100%	0	0%	13	12	92%	0	0%	2	1	50%	0	0%
Ventura	40	40	100%	6	15%	271	264	97%	63	24%	130	125	96%	28	22%
Yolo	32	31	97%	0	0%	10	8	80%	0	0%	1	1	100%	0	0%
Yuba	1	1	100%	0	0%	0	0	-	0	-	0	0	-	0	-
California	14,865	3,490	23%	775	22%	15,520	4,012	26%	724	18%	6,543	1,814	28%	432	24%

Estimated Number of Well Records Indicating Hydraulic Fracturing By Geographic Area

Table K-1 lists the estimated number of well records indicating hydraulic fracturing by sedimentary basin. Table K-2 lists the estimated number of well records indicating hydraulic fracturing by county.

For geographic areas with more than zero wells fractured during a time period, the 95% confidence bounds were calculated using a logit transform. For geographic areas with zero wells fractured during a time period, the 95% confidence bounds were calculated using the rule of three. The positive confidence increment was taken as the theoretical maximum if it were less than either the logit or rule of three results. The theoretical maximum is calculated by assuming all the wells with unavailable records were fractured.

Table K-1. *Annual average number of wells with first production or injection from 2002 to 2013 by basin. Estimated annual average rate of wells fractured, percent of all wells fractured, and 95% confidence interval (CI) for the fracturing rate based on searching well records. No fracturing rate is shown if less than one eighth of the well records were available for searching. "NA" for the percentage fractured indicates no wells had first injection or production in the time period. No CI is shown if no rate was estimated or all the well records were searched. Analysis of more recent data from various sources indicates actual hydraulic fracturing rates may be up to twice as high.*

Basin	2002-2006				2007-2011				2012-2013			
	New wells	Frac. wells	% frac	95% CI	New wells	Frac. wells	% frac	95% CI	New wells	Frac. wells	% frac	95% CI
Cuyama	4.2	-	-	-	2.2	-	-	-	0.6	-	-	-
Eel River	1.8	0.0	0%	-	0.4	0.0	0%	-	0.0	0.0	NA	-
Hollister-Sargent	0.0	0.0	NA	-	1.6	0.0	0%	0.0-0.2	0.0	0.0	NA	-
Sonoma-Livermore	0.2	0.0	0%	-	0.0	0.0	NA	-	0.0	0.0	NA	-
Los Angeles	132	38.3	29%	36.0-40.6	128	19	15%	17.3-21.0	245	23.6	10%	20.2-27.6
onshore	91.4	28.4	31%	26.2-30.7	86.2	9.2	11%	7.8-10.9	140.6	11.2	8%	8.5-14.6
offshore	40.8	10.3	25%	9.5-11.0	41.6	9.2	22%	8.4-10.0	104.0	12.1	12%	10.3-14.3
Sacramento	91.6	3.0	3%	-	109	11.9	11%	11.9-11.9	16.0	0.0	0%	0.0-0.1
Salinas	31.2	-	-	-	81.0	0.0	0%	0.0-0.0	67.4	-	-	-
San Joaquin	2,671	847	32%	795-899	2,674	787	29%	735-841	3,246	1,064	33%	986-1,146
Santa Maria	15	0.5	3%	0.2-2.0	36.8	0.6	2%	0.4-1.2	74.3	0.0	0%	0.0-0.0
Santa Barbara-Ventura	26.0	2.5	10%	2.4-2.7	69.4	13.3	19%	13.0-13.8	88.0	16.5	19%	16.0-17.6
California	2,973	895	30%	837-961	3,104	832	27%	778-891	3,739	1,104	30%	1,022-1,192

Table K-2. *Annual average number of wells with first production or injection from 2002 to 2013 by county. Estimated annual average rate, percent, and 95% confidence interval (CI) for the rate of wells fractured based on searching well records. No fracturing rate is shown if less than one eighth of the well records were available for searching. NA" for the percentage fractured indicates no wells had first injection or production in the time period. No CI is shown if no rate was estimated or all the well records were searched. Analysis of more recent data from various sources indicates actual rates may be up to twice as high.*

County	2002-2006				2007-2011				2012-2013			
	New wells	Frac. wells	% frac.	95% CI	New wells	Frac. wells	% frac.	95% CI	New wells	Frac. wells	% frac.	95% CI
Alameda	0.2	0.0	0%	-	0.0	0.0	NA	-	0.0	0.0	NA	-
Butte	1.2	0.0	0%	-	1.8	0.0	0%	0.0-0.1	0.0	0.0	NA	-
Colusa	12	0.2	2%	-	22.8	2.1	9%	2.0-2.4	9.1	0.0	0%	0.0-0.2
Contra Costa	1.0	0.2	20%	-	1.6	0.0	0%	-	0.0	0.0	NA	-
Fresno	92.6	0.4	0%	-	133	0.8	1%	-	94.9	1.7	2%	1.7-1.7
Kern	2,564	846	33%	795-899	2,531	785	31%	734-839	3,146	1,062	34%	985-1,143
Kings	2.2	0.0	0%	-	2.0	0.4	20%	0.4-0.4	1.7	0.0	0%	0.0-0.6
Los Angeles	139	37.2	27%	35.3-39.2	132	15.4	12%	14.0-16.9	248	18.9	8%	15.9-22.4
Madera	1.4	0.0	0%	-	3.2	0.0	0%	-	0.6	0.0	0%	-
Merced	0.2	0.0	0%	-	0.2	0.0	0%	-	0.0	0.0	NA	-
Monterey	31.2	-	-	-	81.0	0.0	0%	-	67.4	-	-	-
Orange	10	0.8	8%	0.4-1.9	11.2	4.9	43%	3.5-6.3	10	4.4	43%	3.4-5.7
Sacramento	15	1.2	8%	1.2-1.3	9	0.8	9%	0.8-0.9	2.9	0.0	0%	-
San Benito	0.2	0.0	0%	-	0.2	0.0	0%	-	0.0	0.0	NA	-
San Joaquin	8.6	0.0	0%	-	2.6	0.2	9%	0.2-0.5	1.7	0.0	0%	-
San Luis Obispo	9.0	0.0	0%	-	3.4	0.0	0%	0.0-0.1	11.4	-	-	-
Santa Barbara	11	0.6	6%	0.2-2.8	37.0	0.6	2%	0.4-1.3	64.6	0.0	0%	-
Santa Clara	0.0	0.0	NA	-	1.4	0.0	0%	0.0-0.2	0.0	0.0	NA	-
Solano	14	0.8	6%	0.8-0.9	11	2.0	19%	2.0-2.0	0.6	0.0	0%	-
Stanislaus	0.4	0.0	0%	-	0.0	0.0	NA	-	0.0	0.0	NA	-
Sutter	13	0.2	2%	-	32.2	4.8	15%	4.8-4.8	0.0	0.0	NA	-
Tehama	15	0.0	0%	-	3.8	0.0	0%	-	1.1	0.0	0%	-
Tulare	1.4	0.0	0%	-	2.6	0.0	0%	0.0-0.1	1.1	0.0	0%	0.0-0.6
Ventura	8.0	1.2	15%	-	54.2	12.9	24%	12.6-13.4	74.3	16.6	22%	16.0-17.7
Yolo	6.4	0.0	0%	-	2.0	0.0	0%	0.0-0.1	0.6	0.0	0%	-
Yuba	0.2	0.0	0%	-	0.0	0.0	NA	-	0.0	0.0	NA	-
California	2,973	895	30%	837-961	3,104	832	27%	778-891	3,739	1,104	30%	1,022-1,192

Appendix L

Well-Record Result Data Set

The data listing the API number for the wells considered in the well record search are provided in both Excel and tab-delimited text format. These wells have a first production date between 2002 and near the end of 2013, or a first injection date if no first production date, which is also listed, along with the basin, county, field, and area where that well is located, and the pool it was open to on that date. Whether the record for a well was searched, if the record indicated hydraulic fracturing occurred, and if the hydraulic fracturing consisted of a frac-pack is also listed.

The first production and injection date source file provided by the California Department of Oil, Gas, and Geothermal Resources has more than one record for some wells. The start dates are specific to the combination of a well and pool, so if a well is recompleted in a new pool it will have an additional start date. The data in this appendix include only the first occurrence of a well's production and injection dates, and the pool for that date. The full data can be found at http://ccst.us/publications/WST.

Appendix M

Integrated hydraulic fracturing data set regarding occurrence, location, date, and depth

Data regarding the occurrence, location, date and depth of hydraulic fracturing was integrated from the following data sources:

1. Well stimulation disclosures to the California Division of Oil, Gas, and Geothermal Resources (DOGGR),

2. South Coast Air Quality Management District (SCAQMD) well work data,

3. FracFocus,

4. FracFocus data compiled by SkyTruth,

5. Well record search results combined with first production or injection date (described above),

6. Central Valley Regional Water Quality Control Board (CVRWQCB) well work data, and

7. DOGGR geographic information system (GIS) well layer.

Each of these sources is described in the section 3.5 of the associated report. The data are provided in both Excel and tab-delimited text formats. The tables include all the data from all the sources. The first columns contain the most accurate version of each datum from among all the sources in the authors' judgment and a code indicating the source of that datum. The data source codes are as follows:

AW = DOGGR's AllWells GIS layer
CR = Hydraulic fracturing disclosures (completion reports) provided to DOGGR
CV = CVRWQCB data set
FF = FracFocus
FI = First injection
FP = First production
SC = SCAQMD data set
WR = Well record search

Some of the data sources contain more than one record for a well, such as DOGGR's AllWells GIS layer. This appendix lists the data from the first record for each well with regard to occurrence and location, and the minimum value for date and depth. The full data can be found at http://ccst.us/publications/WST.

Appendix N

Pools with Production Predominantly Facilitated By Hydraulic Fracturing

This appendix contains two lists of pools for which more than half the wells starting production from 2002 through late 2013 are estimated to be hydraulically fractured. The first list ("non-GS") regards oil and gas production pools. The second list ("GS") regards gas storage pools. The lists provide the following for each pool:

- The number of wells entering production during the time period

- The number of these wells for which records were received

- The fraction of wells with records received

- The number of records indicating hydraulic fracturing

- The fraction of records indicating hydraulic fracturing

- The fraction of such records adjusted for underreporting,

- Oil, gas, and water production from 2002 through May 2014

- The oil, gas, and water production multiplied by the fraction of records indicating hydraulic fracturing adjusted for underreporting

- Average oil and gas production per well per day

- The gas-oil ratio

The underreporting adjustment was made by taking the minimum of one or 1.63 times the fraction of records indicating hydraulic fracturing. The underreporting adjustment factor is equal to 150, which is the estimated average number of well fractured per month statewide, divided by 92, which is the estimated average number of records indicating fracturing statewide (shown on Figure 3-10 and discussed in related text).

The oil, gas, and water production were summed from sum by pool data available through the California Department of Oil, Gas, and Geothermal Resources online production and injection portal (http://opi.consrv.ca.gov/opi/opi.dll). The full data can be found at http://ccst.us/publications/WST.

Appendix O

Water Volume Per Stimulation Event

The available data regarding the volume of water used per stimulation were aggregated from FracFocus, CVRWQCB well work, SCAQMD well work, and the well stimulation disclosures. For some wells, multiple values were available. If the volume was different and the dates sufficiently different, these were judged to be refracturing operations and were included. If the volume or date was the same, these were judged to be two records regarding the same operation. Judgment was used in selecting which data to include. The full data can be found at http://ccst.us/publications/WST.

Appendix P

California Oil Fields and Source Rocks

This appendix provides support for the fraction of known oil reservoirs in California that have source rocks in the Monterey Formation. The table below lists large California oil fields along with the associated basin, discovery date, cumulative production, reserves, source rock name, source rock age, source rock status relative to the Monterey Formation, and indicates the references for the information.

Field Name	Basin	Discovered	Cum Prod	Reserves	Known oil	SourceRock Name	SR Age	Monterey-equivalent	Reference
Midway-Sunset	San Joaquin	1894	2,981	498	3,479	Antelope Sh	Miocene	Yes	1
Wilmington	Los Angeles	1932	2,701	283	2,984	Nodular Sh	Miocene	Yes	2,3
Kern River	San Joaquin	1899	2,064	569	2,633	Antelope Sh	Miocene	Yes	1
Belridge South	San Joaquin	1911	1,564	483	2,047	McLure Sh	Miocene	Yes	1
Elk Hills	San Joaquin	1911	1,330	62	1,392	Antelope Sh	Miocene	Yes	1
Huntington Beach	Los Angeles	1920	1,133	32	1,165			Yes	2,3
Ventura	Santa Barbara-Ventura	1919	999	106	1,105	Monterey Formation	Miocene	Yes	5
Long Beach	Los Angeles	1921	944	2	946	Nodular Sh	Miocene	Yes	2,3
Coalinga	San Joaquin	1890	929	89	1,018	Kreyenhagen Sh	Eocene	No	1
Buena Vista	San Joaquin	1909	670	5	675	Antelope Sh	Miocene	Yes	1
Santa Fe Springs	Los Angeles	1919	629	5	634	Miocene Undifferentiated	Miocene	Yes	2,3
Cymric	San Joaquin	1909	515	79	594	McLure Sh		Yes	1
Coalinga East Ext	San Joaquin	1938	504	0	504	Kreyenhagen Sh	Eocene	No	1
San Ardo	Salinas	1947	498	35	533	Monterey Formation	Miocene	Yes	7
Kettleman North Dome	San Joaquin	1928	459	2	461	Kreyenhagen Sh, Tumey Sh	Eocene	No	1
Brea-Olinda	Los Angeles	1880	413	18	431	Miocene Undifferentiated	Miocene	Yes	2,3
Lost Hills	San Joaquin	1910	403	124	527	McLure Sh	Miocene	Yes	1
Inglewood	Los Angeles	1924	399	30	429	Miocene Undifferentiated	Miocene	Yes	2,3
McKittrick	San Joaquin	1896	311	14	325	Kreyenhagen Sh?	Eocene	No	1
Cat Canyon	Cat Canyon	1908	303	2	305	Monterey Formation	Miocene	Yes	8

Field Name	Basin	Discovered	Cum Prod	Reserves	Known oil	SourceRock Name	SR Age	Monterey-equivalent	Reference
Mount Poso	San Joaquin	1926	300	6	306	Antelope Sh	Miocene	Yes	1
Hondo Offshore	Santa Barbara-Ventura	1969	286	31	317	Monterey Formation	Miocene	Yes	8
Dominguez	Los Angeles	1923	274	52	326	Nodular Shale	Miocene	Yes	2,3
Dos Cuadras	Santa Barbara-Ventura	1968	263	2	265	Monterey Formation	Miocene	Yes	8
Coyote West	Los Angeles	1909	253	0	253			Yes	2,3
Torrance	Los Angeles	1922	226	5	231	Nodular Sh	Miocene	Yes	2,3
Cuyama South	Cuyama	1949	255	4	259	Vacqueros	Oligocene	No	4
Seal Beach	Los Angeles	1924	215	6	221	Nodular Sh	Miocene	Yes	2,3
Kern Front	San Joaquin	1912	215	18	233	Antelope Sh	Miocene	Yes	1
Santa Maria Valley	Santa Maria	1934	207	1	208	Monterey Formation	Miocene	Yes	
Montebello	Los Angeles	1917	205	6	211	Undifferentiated Miocene shales	Miocene	Yes	2,3
Richfield	Los Angeles	1919	203	3	206	Undifferentiated Miocene shales	Miocene	Yes	2,3
Orcutt	Santa Maria	1901	181	12	193	Monterey Formation	Miocene	Yes	8
Point Arguello Offshore	Santa Maria	1981	179	29	208	Monterey Formation	Miocene	Yes	6
Coles Levee North	San Joaquin	1938	165	1	166	Antelope Sh	Miocene	Yes	1
Rincon	Santa Barbara-Ventura	1927	163	3	166	Monterey Formation	Miocene	Yes	5
South Mountain	Santa Barbara-Ventura	1916	159	6	165	Monterey Formation	Miocene	Yes	
Edison	San Joaquin	1928	150	6	156	Antelope Sh	Miocene	Yes	1
Beverly Hills	Los Angeles	1900	150	9	159			Yes	2,3
Belridge North	San Joaquin	1912	147	17	164	Kreyenhagen Sh?	Eocene	No	1
Pescado Offshore	Santa Barbara-Ventura	1970	132	15	147	Monterey Formation	Miocene	Yes	8
Fruitvale	San Joaquin	1928	126	9	135	Antelope Sh	Miocene	Yes	1
Rio Bravo	San Joaquin	1937	118	1	119	Antelope Sh	Miocene	Yes	1
San Miguelito	Santa Barbara-Ventura	1931	118	7	125	Monterey Formation	Miocene	Yes	5
Coyote East	Los Angeles	1909	116	4	120			Yes	2,3
Greeley	San Joaquin	1936	116	1	117	Antelope Sh	Miocene	Yes	1
Round Mountain	San Joaquin	1947	115	7	122	Antelope Sh	Miocene	Yes	1
Yowlumne	San Joaquin	1974	111	2	113	Antelope Sh	Miocene	Yes	1
Carpinteria Off-shore	Santa Barbara-Ventura	1966	107	2	109	Monterey Formation	Miocene	Yes	8

Field Name	Basin	Discovered	Cum Prod	Reserves	Known oil	SourceRock Name	SR Age	Monterey-equivalent	Reference
Elwood	Santa Barbara-Ventura	1928	106	0	106	Monterey Formation	Miocene	Yes	8
Beta Offshore	Los Angeles	1976	91	16	107	Undifferentiated Miocene shale	Miocene	Yes	2,3
Point Pedernales Offshore	Santa Maria	1983	86	20	106	Monterey Formation	Miocene	Yes	8

Discovery date, cumulative production and reserves from CDOGGR AR 2009

Known oil is the sum of cumulative production and reserves, all in millions of barrels.

If field known oil is assigned to likely principal reservoir oil source rock non-Monterey is about 9.74% of total oil in fields larger than 100 MMBO

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Appendix Q

Unit Conversion Table

1	Barrel	=	0.158987	Cubic Meters (m^3)
1	Cubic Foot (ft^3)	=	0.02831685	Cubic Meters (m^3)
1	Cubic Mile (mi^3)	=	4.16818	Cubic Kilometers (km^3)
1	Foot (ft)	=	0.3048	Meters (m)
1	Inch (in)	=	2.54	Centimeters (cm)
1	Gallon (gal)	=	0.00378541	Cubic Meters (m^3)
1	Acre-foot	=	1,233.4	Cubic Meters (m^3)
1	Miles (mi)	=	1.609344	Kilometers (km)
1	Square Mile (mi^2)	=	2.589988	Square Kilometers (km^2)
1	Nautical Mile	=	1.852	Kilometers (km)
1	Millidarcy (md)	=	9.87 x 10-16	Square meters (m^2)
1	Pound per Square Inch (psi)	=	6.89476 x 10-6	Gigapascals (GPa)

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