Chapter One

Introduction

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1.1. Background

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. SB 4 stipulates that the independent study assess current and potential future well stimulation practices, including the likelihood that these 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 potential risks associated with current practices; and identify alternative practices that might limit these risks. This scientific assessment addresses well stimulation used in oil and gas production both on land and offshore in California.

Well stimulation enhances oil and gas production by making the reservoir rocks more permeable, thus allowing more oil or gas to flow to the well. The reports discuss three types of well stimulation as defined in SB 4 (Table 1.1-1 and Volume I, Chapter 2). The first type is "hydraulic fracturing." To create a hydraulic fracture, an operator increases the pressure of an injected fluid in an isolated section of a well until the surrounding rock breaks, or "fractures." Sand injected into these fractures props them open after the pressure is released. The second type is "acid fracturing," in which a high-pressure acidic fluid fractures the rock and etches the walls of the fractures, so they remain permeable after the pressure is released. The third type, "matrix acidizing," does not fracture the rock; instead, acid pumped into the well at relatively low pressure dissolves some of the rock and makes it more permeable. See Box 1.1-1 for a short history of oil and gas production in California.

This study is issued in three volumes. Volume I, issued in January 2015, describes how well stimulation technologies work, 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, issued in July 2015, discusses how well stimulation could affect water, atmosphere, seismic activity, wildlife and vegetation, and human health. Volume II

reviews available data, and identifies knowledge gaps and alternative practices that could avoid or mitigate these possible impacts. Volume III, this volume, presents case studies that assess environmental issues and qualitative risks for specific geographic regions. The Summary Report summarizes key findings, conclusions and recommendations of all three volumes.

Table 1.1-1. Well stimulation technologies included in Senate Bill 4 (SB 4).

Hydraulic Fracturing Stimulation Common feature: All treatments create sufficient pressure in the well to induce fractures in the reservoir.		
Proppant Fracturing: Uses proppant to retain fracture permeability		**Acid Fracturing:** Uses acid instead of proppant
Traditional Fracturing: Creates long, narrower hydraulic fractures deep into the formation for stimulating flow through lower-permeability reservoirs; proppant injected into fractures to retain fracture permeability	**Frac-Pack**: Creates short, wider hydraulic fractures near wells within higher-permeability reservoirs; objectives are bypassing regions near-the wellbore damaged by drilling and preventing sand from the reservoir entering the well	Similar to traditional fracturing, but uses acid instead of proppant to retain fracture permeability by etching, or "roughening" the fracture walls; only used in carbonate reservoirs

Acidizing Stimulation Common feature: All treatments use acid to dissolve materials impeding flow	
Matrix Acidizing: Dissolves material in the near-well region to make the reservoir rocks more permeable; typically only used for reservoirs that are already permeable enough to not require traditional or acid fracturing	
Sandstone Acidizing: Uses hydrofluoric acid in combination with other acids to dissolve minerals (silicates) that plug the pores of the reservoir; only used in reservoirs composed of sandstone or other siliceous rocks	**Carbonate Acidizing:** Uses hydrochloric acid (or acetic or formic acids) to dissolve carbonate minerals, such as those comprising limestone, and bypass rock near the wellbore damaged by drilling; only used in carbonate reservoirs

Volumes I, II and III of this report address issues that have very different amounts of available information and cover a wide range of topics and associated disciplines, which have well established but differing protocols for inquiry. In Volume I, available data and methods of statistics, engineering and geology allow the authors to present the factual basis of well stimulation in California. With a few exceptions, the existing data was sufficient to accurately identify the technologies used, analyze where and how often they are used, and evaluate where they are likely to be used in the future (see Volume I, Chapter 3).

The authors of Volume II faced the challenge of assessing and presenting the impacts of well stimulation. Since many impacts have never been thoroughly investigated, the authors drew on literature describing conditions and outcomes in other places, circumstantial evidence and expert judgment to catalog a complete list of potential impacts that may or may not occur in California. Volume II also identifies a set of concerning situations – "risk factors" (summarized in Appendix D of the Summary Report and Table 6.2-1 of Volume II) – that warrant a closer look and perhaps regulatory attention.

Box 1.1-1. History of Oil and Gas Production in California

California has some highest concentrations of oil in the world and oil and gas production remains a major California industry. Commercial production started in the middle of the 19th century from hand-dug pits and shallow wells. In 1929, at the peak of oil development in the Los Angeles Basin, California accounted for more than 22% of total world oil production (American Petroleum Institute, Basic Petroleum Data Book, Volume XIII, Number 2, 1993). California's oil production reached an all-time high of almost 64 million m^3 (400 million barrels) in 1985 and has generally declined since then. Today California is the third highest producing state, with about 6% of US production but less than 1% of global production. In 1960, almost as much oil was produced in California as was consumed, but by 2012 Californians produced only 32% of the oil they used (31.5 million m^3 or198 million barrels produced in the state out of a total of about 98.7 million m^3 or 621 million barrels consumed). Californian's mainly made up the shortfall of about 67.3 million m^3 (423 million barrels) mainly with oil delivered by tanker from Alaska, Saudi Arabia, Ecuador, Iraq, Colombia, and other countries.

Over the years, water flooding, gas injection, thermal recovery, hydraulic fracturing, and other techniques have been used to enhance oil and gas production as California fields mature. The diatomite reservoirs in the western San Joaquin Valley contain billions of barrels of oil in rocks that are not very permeable, and can only be produced with hydraulic fracturing—now accounting for about 20% of California oil and gas production (see Volume I, Chapter 3). Most of the natural gas produced in the state is a co-product of oil production, which is known as "associated" gas production. Most of this production occurs in the San Joaquin Valley, including reservoirs that use hydraulic fracturing.

Volume III largely extends the method of inquiry used in Volume II to location-specific issues for offshore, the Monterey Formation Case Study, the Los Angeles Basin, and the San Joaquin Basin. The Offshore Case Study evaluates what we know and do not know about the use of stimulation technologies in that environment. The Monterey Case Study identifies the geographic locations (or "footprint") of the parts of the Monterey Formation that could contain producible oil and gas in "source rock," (see the Summary Report, Appendix E for a definition of source rock) and examines the implications if new production were to begin in those regions. Likewise, the San Joaquin Basin Case study evaluates likely future production with hydraulic fracturing and examines the implications of that production.

The first part of the Los Angeles Basin Case Study describes the geologic basis of oil production and its implications for future oil and gas production using technology such as hydraulic fracturing. The second part evaluates sparse information about public health implications of oil and gas development in a densely populated mega-city. This study compensates for the lack of data documenting adverse health outcomes by investigating information that suggests, but does not confirm with certainty, the risks to human health. The precepts of the field of public health include an emphasis on the anticipation of potential problems even though specific problems have not been observed or proven to create risk. In this way, the public health chapter of Volume II and the public health analysis for the Los Angeles Basin Case Study differ from other parts of this report. A major goal of public health research is to anticipate and avoid harm rather than to observe and allocate cause for harm.

The authors of this report hope this flexible and appropriate use of different (but well established) methods of inquiry under highly variable conditions of data availability and potential impacts serves useful to California.

1.2. CCST Committee Process

The California Council on Science and Technology (CCST) organized and led the study reported on here. Members of the CCST steering committee were appointed based on technical expertise and a balance of technical viewpoints. (Appendix B provides information about CCST's steering committee.) Under the guidance of the steering committee, Lawrence Berkeley National Laboratory (LBNL) and subcontractors (the science team) developed the findings based on the literature review and original technical data analyses. Appendix C provides information about the LBNL science team and subcontractors who authored Volumes I, II, and III of this report. The science team reviewed relevant literature and conducted original technical data analyses.

The science team studied each of the issues required by SB 4, and the science team and the steering committee collaborated to develop a series of conclusions and recommendations that are provided in this summary report. Both science team and steering committee members proposed draft conclusions and recommendations. These were modified based

on discussion within the steering committee along with continued consultation with the science team. Final responsibility for the conclusions and recommendations in this report lies with the steering committee. All steering committee members have agreed with these conclusions and recommendations. Any steering committee member could have written a dissenting opinion, but no one requested to do so.

SB 4 also required the participation of the California Environmental Protection Agency's Office of Environmental Health Hazard Assessment (OEHHA) in this study. OEHHA provided toxicity and other risk assessment information on many of the chemicals used in hydraulic fracturing, offered informal technical advice during the course of the study, and provided comments on drafts of Volumes II and III. OEHHA also organized a February 3, 2015 public workshop in Bakersfield in which representatives of CCST, LBNL, and subcontractors heard comments from attendees on the topics covered in the report.

This report has undergone extensive peer review. (Peer reviewers are listed in Appendix F, "California Council on Science and Technology Study Process"). Seventeen reviewers were chosen for their relevant technical expertise. More than 1,500 anonymous review comments were provided to the authors. The authors revised the report in response to peer review comments. In cases where the authors disagreed with the reviewer, the response to review included their reasons for disagreement. Report monitors then reviewed the response to review and when satisfied, approved the report.

1.3. The Four Case Studies

The case studies in this volume examine the impacts and issues that arise in four locations in California that are affected by well stimulation. Focus on a specific geography allows a more detailed examination of practices, impacts and potential risks specific to that region.

Offshore Case Study: Offshore production became controversial with the Santa Barbara oil spill in the 1970s, and subsequent policies severely limited development of the vast reserves that lie off the California coast. Concerns about hydraulic fracturing have exacerbated concerns about ocean contamination. The Offshore Case Study assembles available data describing stimulation practices offshore, the possible impacts on the ocean environment, and describes data gaps. The case study focuses on production in state and federal waters (those that are more than 5.6 km, or three nautical miles offshore). (Volume III, Chapter 2, Offshore Case Study).

Monterey Formation Case Study: The Energy Information Agency produced an estimate of shale-oil production potential in the source rocks of the Monterey Formation that caused concern about an imminent oil boom in California. A subsequent estimate downgraded the first by 96%; however, neither of these estimates have a strong basis in data (see Volume I). The Monterey Formation Case Study attempts to map the geographic locations where there is some possibility of deep, underlying source-rock shale oil that

could possibly be produced with stimulation technology and how these locations compare to current land use. In these locations, we also map the specific environmental and ecological issues that might cause concern if oil and gas development did occur and we provide some guidance about what it would take to get a more reliable estimate of the production potential for these rocks (Volume III, Chapter 3, Monterey Formation Case Study)

Los Angeles Basin Case Study: Los Angeles, a megacity with challenging air pollution problems, has giant, world-class oil fields within the city boundary. The development of these fields, contemporaneous with the growth of the city, has caused conflict for nearly a hundred years. Though oil production has been declining for years, there have been reports recently suggesting the possibility of additional large-scale oil production enabled by hydraulic fracturing. The Los Angeles Basin Case Study has two parts: The first part investigates the resource potential in the region in particular with regards to possible future production from deep source rocks. The second part examines air pollution in the valley caused by oil and gas development and the contribution to that air pollution made by stimulated wells. Although the oil and gas sector contributes a minor percentage of the total air pollution burden in the valley, the concentration of these air contaminants can be much larger near the wells that are a source of emissions. Exposure to toxic pollutants from production wells depends on how close people are to the wells. We look at the current proximity of population including vulnerable portions of the population to oil and gas development in general and to stimulated wells in particular. The future of oil production in the urban environment, including that enabled by well stimulation, has potential implications for human health. (Volume III, Chapter 4, Los Angeles Basin Case Study).

San Joaquin Basin Case Study: The San Joaquin Basin produces most of the oil and gas in California and is home to 96% of the stimulation treatments. The valley is also a major center of industrial agriculture and suffers from chronic air pollution and water shortage. The San Joaquin Basin Case Study examines the likely future of well stimulation and the potential risks posed by this practice to water, air and human health (Volume III, Chapter 5, San Joaquin Basin Case Study).

One other case study was initially considered but not developed. Most of our focus has been on oil production and gas production associated with oil production. However, northern California does have “un-associated” or “dry” gas production. We found very little evidence to support a new major dry gas play that would require well stimulation or any evidence supporting extensive use of well stimulation in current dry gas production, so there seemed little point in pursuing a northern California gas case study.

These case studies integrate what we learned about stimulation practices in Volume I with generalized potential impacts evaluated in Volume II and focus on more detailed locally specific issues. Each case study is different and depends entirely on apparent issues for each location. Each might well be revisited in the future as more data is collected and as the practice in industry changes.

1.4. Data and Literature Used in the Report

This assessment reviews and analyzes both existing data and scientific literature, with preference given to findings presented in the peer-reviewed scientific literature. The study included both voluntary and mandatory reporting of stimulation data, 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. Finally, the California Council on Science and Technology solicited and reviewed nominations of literature from the public, employing specific criteria for material as described in Appendix E, "Review of Information Sources." The science team did not collect any new data, but did do original analysis of available data.

1.4.1. Data on Well Stimulation Statistics and Stimulation Chemistry

A comprehensive understanding of well stimulation in the state requires complete and accurate reporting, as directed by SB 4, and sufficient time for a representative number and type of operations to be reported. The analyses summarized in this report assess less than one year of well stimulation data reported under mandatory reporting starting on January 1, 2014. Mandatory reporting under SB 4 includes data submittals to FracFocus, a website created by petroleum industry groups to disclose information about drilling and chemical use in hydraulic fracturing, as well as submission of this and additional information to the California Division of Oil, Gas and Geothermal Resources (DOGGR), which provides access through its website. Other sources of data collected under mandatory reporting include data from the South Coast Air Quality Management District (SCAQMD) since June 2013 and from the Central Valley Regional Water Quality Control Board (CVRWQCB) for 2012 and 2013. The SCAQMD and CVRWQCB data are limited to the Los Angeles Air Basin and the Central Valley Region, respectively. Voluntary data on hydraulic fracturing operations have been available for longer time periods going back several years, but remain incomplete and are not fully verifiable. Voluntary sources include information submitted to FracFocus, between 2011 and 2013, and well construction histories provided to and available from DOGGR going back many years. We estimate more than half of hydraulic fracturing operations in California are recorded in these histories. The content of each record varies from as little as just an indication a hydraulic fracturing operation occurred to as much as the times, flow rates, stages, fluid type, injection pressures, and proppant loading schedule for the operation. In all cases, analyses summarized in this report only assess data available prior to 2015, and prior to July 2014 for many of the data sets considered starting in Volume I.

The conclusions about hydraulic fracturing onshore derived in this report are supported by information from voluntary and mandatory reported data, scientific literature, government reports, and other sources such as patents and industrial literature which give largely consistent results, indicating that we can have reasonable confidence in the quality and consistency of the data collected before and since mandatory reporting began despite

the limitations in the data. Consequently, the authors think the report conclusions about hydraulic fracturing are generally accurate and representative of well stimulation activities in the state. Additional data in the future might change some of the quantitative findings in the report, but it is unlikely these will fundamentally alter the report findings about the current and likely future use of well stimulation in California.

We consider the available information on the geology of conventional resources in California and the potential for future use of well stimulation in reservoirs of the state to be of high quality. In contrast, current estimates on the recoverable shale-oil resources in the deep Monterey source rock are highly uncertain.

1.4.2. Information and Data on Well Stimulation Impacts

The SB 4 completion reports contain reliable data on stimulation statistics and provide a basis for assessment of certain potential environmental and health impacts, such as the quantity of fresh water for hydraulic fracturing or the fracturing depth in the vicinity of groundwater resources. For many other impacts, however, only incomplete information and data exist, and questions remain that require additional research and data collection. For example, few scientific studies of health and environmental impacts of well stimulation have been done to date, and the ones that have been done address other parts of the country, where practices differ significantly from present-day practices in California. Generally, environmental baseline data has not been collected in the vicinity of stimulation sites before stimulation. The lack of baseline data makes it difficult to know if the process of stimulation has changed groundwater chemistry or habitat, or how likely any potential impacts might be. No records of contamination of protected water by hydraulic fracturing fluids in California exist, but few if any targeted studies have been conducted to look for such contamination. Data describing the quality of groundwater near hydraulic fracturing sites are not universally available. The requirement for groundwater monitoring in SB 4 addresses this issue by requiring groundwater monitoring when protected water is present. Applications for hydraulic fracturing operations that have no nearby protected groundwater have been exempted from groundwater monitoring. Thus, the requirements and exemptions provide some information about the quality of water near proposed hydraulic fracturing sites.

A complete analysis of the risks posed by well stimulation (primarily hydraulic fracturing) to water contamination, air pollution, earthquakes, wildlife, plants, and human health requires much more data than that available. However, the study authors were able to draw on their technical knowledge, data from other places, and consideration of the specific conditions in California to identify conditions in California that deserve more attention and make recommendations for additional data collection, increased regulation, or other mitigating measures. These conditions, or “risk factors” have become the subjects of the conclusions and recommendations under the heading of “Impacts.” Appendix D of the Summary Report also provides a summary of risk issues in a tabular form.

1.4.3. Data for Case Studies

The data sources used to construct the case studies is largely the same as the sources above with the same limitations on the length and accuracy of records and data gaps. We describe the limitations of the data throughout the volume in order to transparently qualify the accuracy of the conclusions.

1.5. Conclusions and Recommendations of Volume III

The following conclusions and recommendations are numbered to correspond to the full set of conclusions and recommendations as given in the Summary Report, but only those conclusions and recommendations that derive from this volume are given below. This is the reason that the conclusions and recommendations are not numbered sequentially starting with number 1. However, for the sake of consistency, some conclusions include information from other volumes as noted.

Offshore Case Study:

Conclusion 1.5. Record keeping for hydraulic fracturing and acid stimulation in federal waters does not meet state standards.

Current record-keeping practice on stimulations in federal waters (from platforms more than 5.6 km, or three nautical miles offshore) does not meet the standards set by the pending SB 4 well treatment regulations and does not allow an assessment of the level of activity or composition of hydraulic fracturing chemicals being discharged in the ocean. The U.S. Environmental Protection Agency's (U.S. EPA) National Pollutant Discharge Elimination System (NPDES) permits that regulate discharge from offshore platforms do not effectively address hydraulic fracturing fluids. The limited publicly available records disclose only a few stimulations per year.

The federal government does not maintain a website or other public portal with data on the use of hydraulic fracturing from platforms in federal waters (federal waters are more than 5.6 km or three nautical miles, from the coast) except for data that has been requested through the Federal Freedom of Information Act (FOIA). The FOIA records include about one hydraulic fracturing operation per year out of the 200 wells installed from 1992 through 2013, all but one of these operations were in the Santa Barbara-Ventura Basin (Volume I, Chapter 3). Through NPDES, EPA permits offshore facilities in federal waters to discharge recovered hydraulic fracturing fluids mixed with produced water to the ocean, subject to constraints on contaminant concentrations. However, the constraints do not include limits on hydraulic fracturing chemicals. EPA requires sampling of produced water discharge and testing these samples through a "whole effluent toxicity" or "WET" test that provides an integrated assessment of the toxicity of the effluent. However, these tests do not occur in coordination with any hydraulic fracturing operation, so they are likely to miss any impacts that hydraulic fracturing chemicals might cause.

Recommendation 1.2. Improve reporting of hydraulic fracturing and acid stimulation data in federal waters.

The State of California should request that the federal government improve data collection and record keeping concerning well stimulation conducted in federal waters to at least match the requirements of SB 4. The U.S. EPA should conduct an assessment of ocean discharge and, based on these results, consider if alternatives to ocean disposal for well stimulation fluid returns are necessary (Volume III, Chapter 2 [Offshore Case Study]).

Monterey Formation Case Study:

Conclusion 2.2. Oil resource assessment and future use of hydraulic fracturing and acid stimulation in the Monterey Formation[1] of California remain uncertain.

In 2011, the U.S. Energy Information Administration (EIA) estimated that 2.4 billion m^3 (15 billion barrels) of recoverable shale-oil resources existed in Monterey source rock. This caused concern about the potential environmental impacts of widespread shale-oil development in California using hydraulic fracturing. In 2014 the EIA downgraded the 2011 estimate by 96%. This study reviewed both EIA estimates and concluded that neither one can be considered reliable. Any potential for production in the Monterey Formation would be confined to those parts of the formation in the "oil window," that is, where Monterey Formation rocks have experienced the temperatures and pressures required to form oil. The surface footprint of this subset of the Monterey Formation expands existing regions of oil and gas production rather than opening up entirely new oil and gas producing regions. Significant unconventional gas resources (such as those of the Appalachian Basin Marcellus Shale or the Fort Worth Basin Barnett Formation which have been produced with large-scale hydraulic fracturing operations) probably do not exist in California.

In 2011, the EIA reported that more than 2.4 billion m^3 (15 billion barrels) of oil could be recovered from the "Monterey/Santos[2] (source rock) Play" across the state, presumably by means of hydraulic fracturing or acid stimulation. At the time, this estimate exceeded the estimated recoverable oil volume from source rock for the entire rest of the country. The EIA's projection, combined with widespread production using hydraulic fracturing of petroleum source rocks in North Dakota, Texas, and elsewhere, led to speculation and concern that similar development might be in the offing for California. Many Californians became concerned that California could experience a "boom-town" surge

1. The Summary Report, Appendix G provides an explanation of the terms Monterey Formation and Monterey Source Rock.
2. The 2011 and 2014 EIA assessments both use the term "Monterey/Santos" in describing the shale oil play in California. The "Santos" appears to be an erroneous reference to the Saltos shale of the Cuyama basin. Geochemical studies have not identified the Saltos shale as a significant source of hydrocarbons, so it is likely that the Monterey is the dominant source rock considered in the EIA evaluation.

in oil production, i.e., activity in regions of the state that have not yet experienced oil production, unacceptable water use in a water-short state, water contamination, and health impacts. While no significant source-rock production has yet occurred in the state, future technical innovations might facilitate such development. A second EIA report, released in 2014, reduced the estimate of recoverable oil in Monterey source rocks to 0.1 billion m^3 (0.6 billion barrels). Figure 1.5-1 shows both these estimates. However, EIA provided little documentation to support either estimate. Consequently, neither of these estimates can be scientifically evaluated, and they do little to constrain the range of possible source rock oil resources in the Monterey Formation.

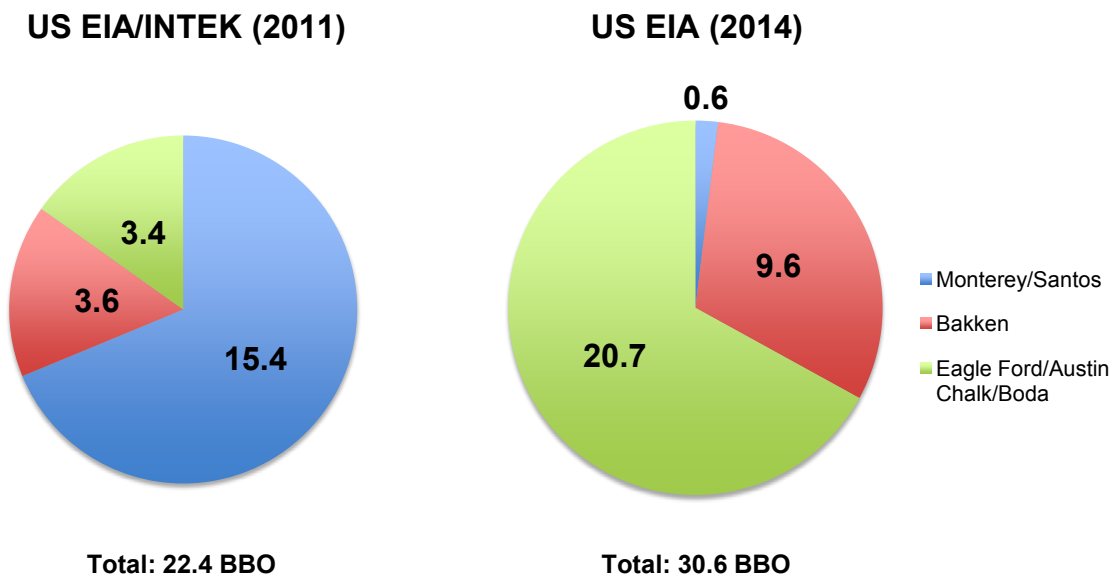

Figure 1.5-1. The Energy Information Administration 2011 and 2014 estimates of the potential of recoverable oil in source rock in the United States. The 2011 estimate for the Monterey/Santos is more than 2.4 billion m^3 (15 billion barrels), whereas the 2014 estimate decreases the Monterey estimate to about 4 % of the earlier estimate while increasing the total U.S. estimate by 30% (figure modified from Volume III, Chapter 1).

The footprint of the oil and gas window of the Monterey Formation primarily expands the regions that currently produce oil and gas. No part of this footprint is more than ~20 km (12 miles) from existing production. Any potential future development of Monterey Formation source rocks would likely involve hydraulic fracturing or acid stimulation and would occur in the vicinity of current oil and gas producing regions with their existing infrastructure and economy (Figure 1.5-2) (Volume III, Chapter 3 [Monterey Formation Case Study]).

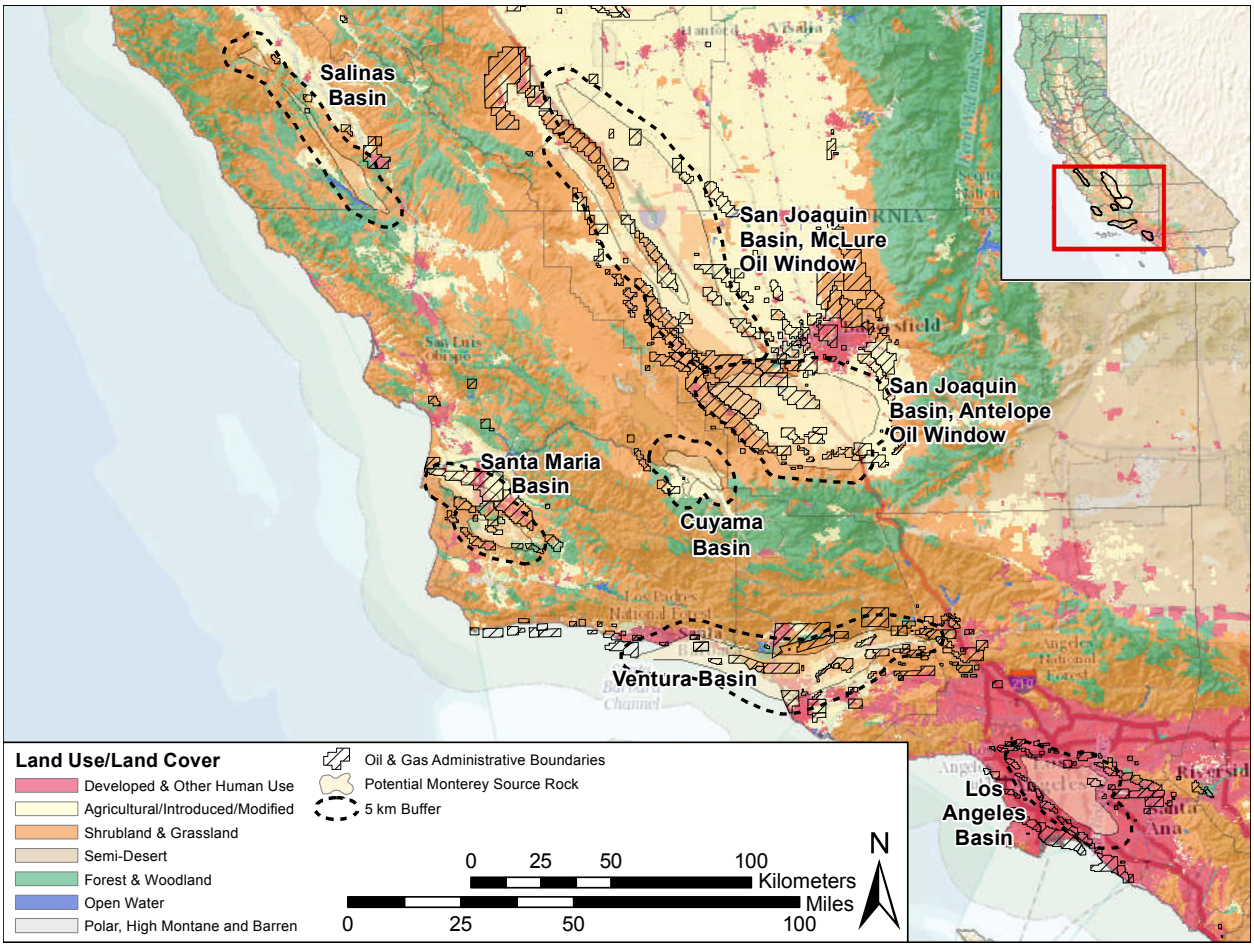

Figure 1.5-2. The approximate geographic footprint of those parts of the Monterey Formation in the oil and gas window (i.e. those parts that might be actively generating oil and gas) mapped along with current land use. Black hatching indicates the locations of existing oil fields. Thin black lines mark the footprint of the Monterey source rock oil window and dashed black lines mark a ~5 km (three-mile) buffer to include uncertainty in the actual extent. Note that the boundaries of the Monterey source rock window are in the vicinity of existing oil and gas fields, but cover a larger area (Figure modified from Volume III, Chapter 3 [Monterey Formation Case Study]).

The geological conditions in California do not likely include basin-wide gas accumulations. The Sacramento Basin, which contains the majority of dry gas reservoirs, does not exhibit the geological features of the Marcellus or Barnett Formations, or the Uinta-Piceance Basin, that would result in significant gas accumulations—at least at the depths that have been explored so far (Volume I, Chapter 4).

Recommendation 2.1. Assess the oil resource potential of the Monterey Formation.

The state should request a comprehensive, science-based and peer-reviewed assessment of source-rock ("shale") oil resources in California and the technologies that might be used to produce them. The state could request such an assessment from the U.S. Geological Survey (USGS), for example.

Recommendation 2.2. Keep track of exploration in the Monterey Formation.

As expansive production in the Monterey Formation remains possible, DOGGR should track well permits for future drilling in the "oil window" of the Monterey source rocks (and other extensive source rocks, such as the Kreyenhagen) and be able to report increased activity (Volume I, Chapter 4; Volume III, Chapter 3 [Monterey Formation Case Study]).

Los Angeles Basin Case Study:

Conclusion 6.3. Emissions concentrated near all oil and gas production could present health hazards to nearby communities in California.

Many of the constituents used in and emitted by oil and gas development can damage health, and place disproportionate risks on sensitive populations, including children, pregnant women, the elderly, and those with pre-existing respiratory and cardiovascular conditions. Health risks near oil and gas wells may be independent of whether wells in production have undergone hydraulic fracturing or not. Consequently, a full understanding of health risks caused by proximity to production wells will require studying all types of productions wells, not just those that have undergone hydraulic fracturing. Oil and gas development poses more elevated health risks when conducted in areas of high population density, such as the Los Angeles Basin, because it results in larger population exposures to toxic air contaminants.

California has large developed oil reserves located in densely populated areas. For example, the Los Angeles Basin reservoirs, which have the highest concentrations of oil in the world, exist within the global megacity of Los Angeles. Approximately half a million people live, and large numbers of schools, elderly facilities, and daycare facilities exist, within one mile of a stimulated well, and many more live near oil and gas development of all types (Figure 1.5-3). The closer citizens are to these industrial facilities, the higher their potential exposure to toxic air emissions and higher risk of associated health effects. Production enabled by well stimulation accounts for a fraction of these emissions.

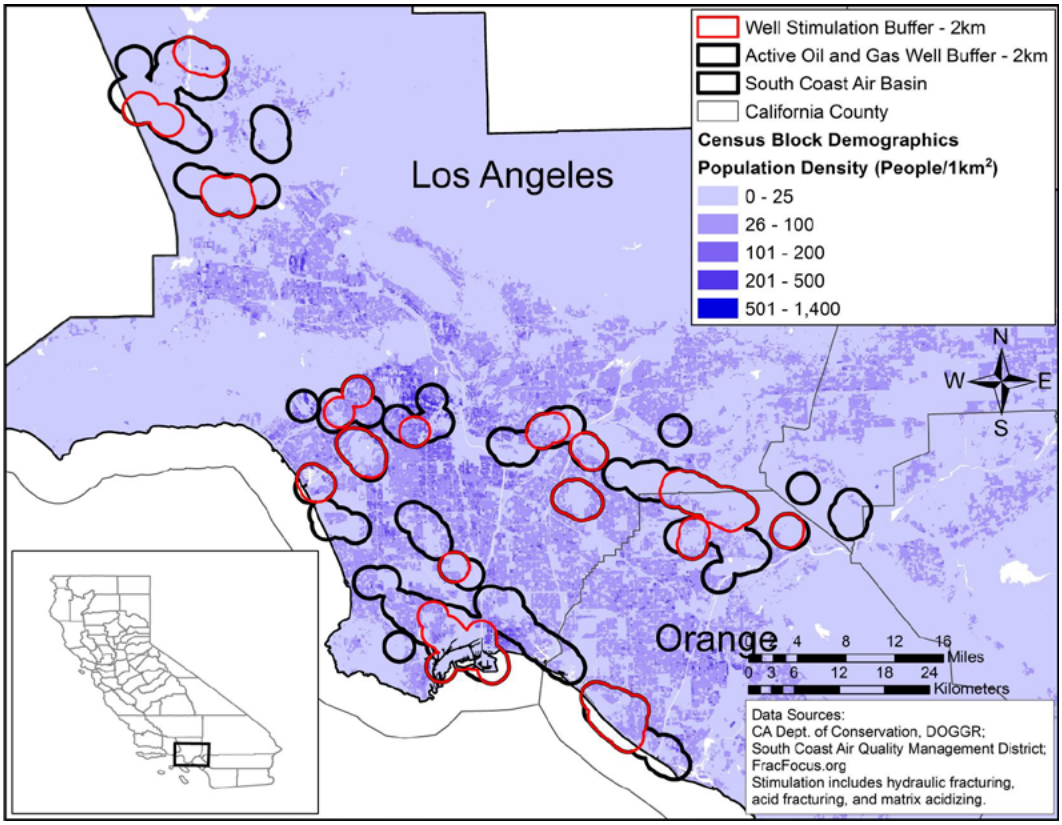

Figure 1.5-3. Population density within 2,000 m (6,562 ft) of currently active oil production wells and currently active wells that have been stimulated (figure from Volume III, Chapter 4 [Los Angeles Basin Case Study]).

Studies from outside of California indicate that, from a public health perspective, the most significant exposures to toxic air contaminants such as benzene, aliphatic hydrocarbons and hydrogen sulfide occur within 800 m (one-half mile) from active oil and gas development. These risks depend on local conditions and the type of petroleum being produced. California impacts may be significantly different, but have not been measured.

Recommendation 6.3. Assess public health near oil and gas production.

Conduct studies in California to assess public health as a function of proximity to all oil and gas development, not just stimulated wells, and develop policies such as science-based surface setbacks, to limit exposures (Volume II, Chapter 6; Volume III, Chapters 4 and 5 [Los Angeles Basin and San Joaquin Basin Case Studies]).

San Joaquin Basin Case Study:

Conclusion 2.1. Future use of hydraulic fracturing in California will likely resemble current use.

Future use of hydraulic fracturing will most likely expand production in and near existing oil fields in the San Joaquin Basin that currently require hydraulic fracturing.

The vast majority of hydraulic fracturing in the state takes place in the San Joaquin Basin in reservoirs that require this technology for economic production. A significant amount of oil remains in these reservoirs. Future additional development in these reservoirs would likely continue to use hydraulic fracturing (Volume I, Chapter 4; Volume III, Chapter 5 [San Joaquin Basin Case Study]). Figure 1.5-4 shows an example of how hydraulic-fracture-enabled production has expanded in the Cahn pool of the Lost Hills field in the San Joaquin Basin over time.

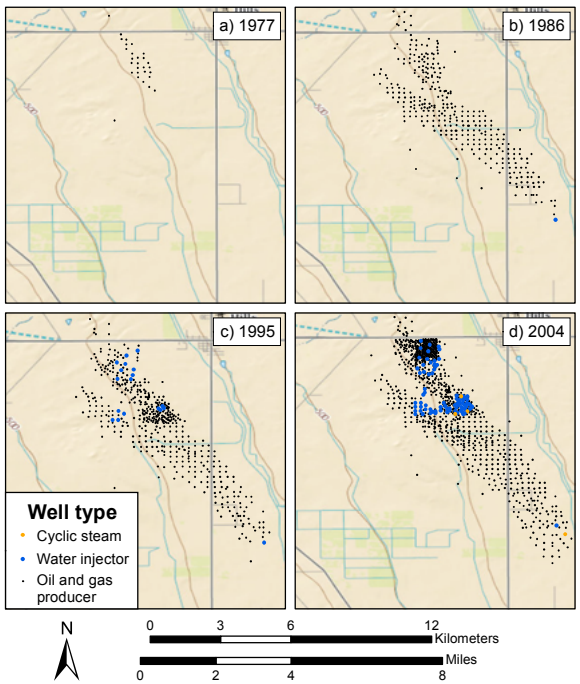

Figure 1.5-4. Growth in the number of wells operating over time in the Cahn pool in the Lost Hills field, one of the two pools in the field where hydraulic fracturing enables production. Data indicate that operators use hydraulic fracturing in almost all to all production wells in this field. Future growth in production would likely follow a similar pattern. The digital data on this field extends back to 1977. The primary well pattern reached nearly its full extent in 1986. By 1995, operators started infill drilling and by 2004, they were deploying water flooding (from Volume III, Chapter 5 [San Joaquin Basin Case Study]).

Conclusion 4.1. Produced water disposed of in percolation pits could contain hydraulic fracturing chemicals.

Based on publicly available data, operators disposed of some produced water from stimulated wells in Kern County in percolation pits. The effluent has not been tested to determine if there is a measureable concentration of hydraulic fracturing chemical constituents. If these chemicals were present, the potential impacts to groundwater, human health, wildlife, and vegetation would be extremely difficult to predict, because there are so many possible chemicals, and the environmental profiles of many of them are unmeasured.

A commonly reported disposal method for produced water from stimulated wells in California is by evaporation and percolation in percolation surface impoundments, also referred to as percolation pits, as shown in Figure 1.5-5. Information from 2011 to 2014 indicates that operators dispose of some 40-60% of the produced water from hydraulically fractured wells in percolation pits during the first full month of production after stimulation. The range in estimated proportion stems from uncertainties about which wells were stimulated prior to mandatory reporting. Produced water from these wells may contain hazardous chemicals from hydraulic fracturing treatments, as well as reaction byproducts of those chemicals. We do not know how long hydraulic fracturing chemicals persist in produced water or at what concentrations or how these change in time, which means that hazardous levels of contaminants in produced water disposed into pits cannot be ruled out.

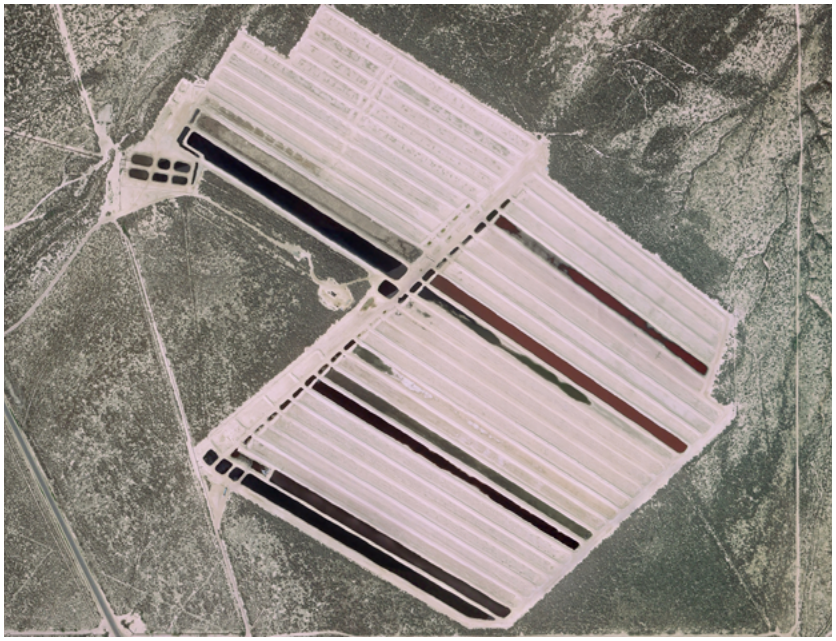

Figure 1.5-5. Percolation pits in Kern County used for produced water disposal (figure modified from Volume II, Chapter 1). Image courtesy of Google Earth.

The primary intent of percolation pits is to percolate water into the ground. This practice provides a potential direct pathway to transport produced water constituents, including returned hydraulic fracturing fluids, into groundwater aquifers. Groundwater contaminated in this way could subsequently intercept rivers, streams, and surface water resources. Contaminated water used by plants (including food crops), humans, fish, and wildlife could introduce contaminants into the food chain. Some states, including Kentucky, Texas and Ohio, have phased out the use of percolation pits for produced water disposal, because their use has demonstrably contaminated groundwater.

Operators have reported disposal of produced water in percolation pits in several California counties (e.g., Fresno, Monterey, and Tulare counties). However, records from 2011 to mid-2014 show that percolation pits received produced water from hydraulically fractured wells only in Kern County. Specifically, wells in the Elk Hills, South Belridge, North Belridge, Lost Hills, and Buena Vista fields were hydraulically fractured, and these fields disposed of produced water to percolation pits in the region under the jurisdiction of the CVRWQCB. An estimated 36% of percolation pits in the Central Valley operate without necessary permits from the CVRWQCB.

The data reported to DOGGR may contain errors on disposition of produced water. For example, DOGGR's production database shows that, during the past few years, one operator discharged produced water to percolation pits at Lost Hills, yet CVRWQCB ordered the closure of percolation pits at Lost Hills in 2009.[3]

Data collected pursuant to the recent Senate Bill 1281 (SB 1281) will shed light on the disposition of produced water and locations of percolation pits statewide. With the data available as of the writing of this report, we cannot rule out that some produced water from hydraulically fractured wells at other fields went to percolation pits and that this water might have contained chemicals used in hydraulic fracturing. Figure 1.5-6 shows that many of these pits overlie protected groundwater. The pending well stimulation regulations, effective July 1, 2015, disallow fluid produced from a stimulated well from being placed in percolation pits.[4]

3. Order R5-2013-0056, Waste Discharge Requirements for Chevron USA, Inc., Central Valley Regional Water Quality Control Board.

4. Title 14 California Code of Regulations, Section 1786(a)(4)

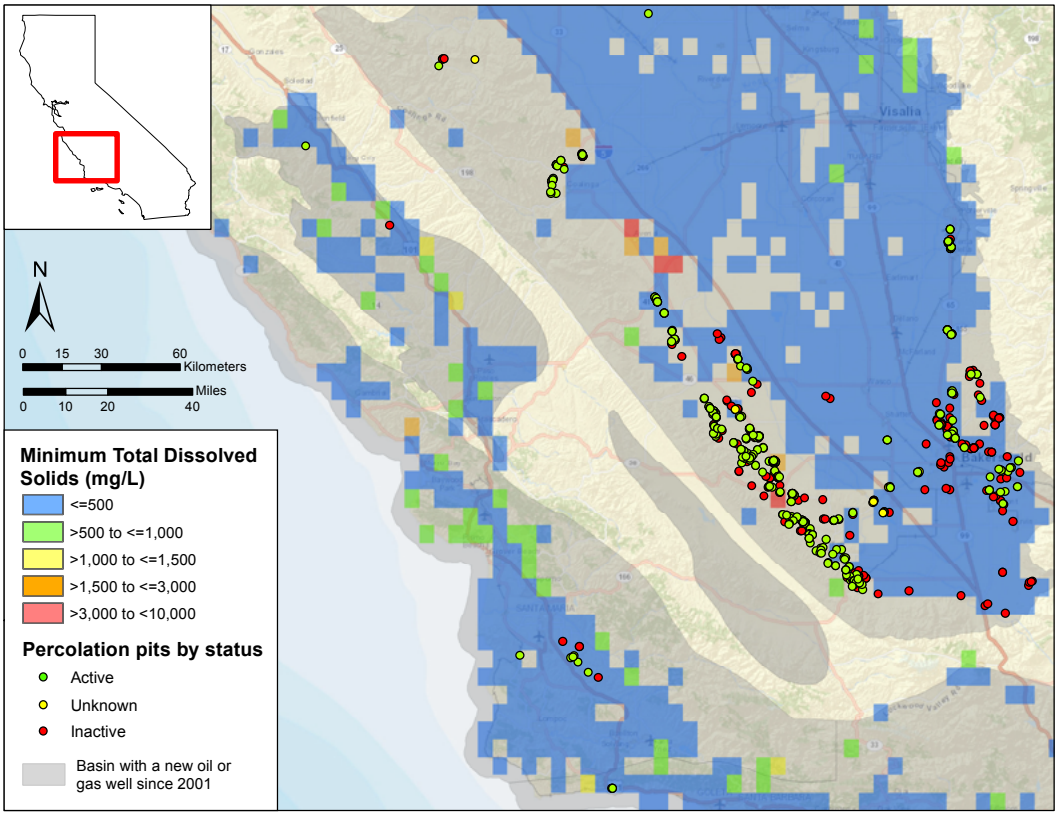

Figure 1.5-6. Location of percolation pits in the Central Valley and Central Coast used for produced water disposal and the location of groundwater of varying quality showing that many percolation pits are located in regions that have potentially protected groundwater shown in color (figure from Volume II, Chapter 2).

Recommendation 4.1. Ensure safe disposal of produced water in percolation pits with appropriate testing and treatment or phase out this practice.

Agencies with jurisdiction should promptly ensure through appropriate testing that the water discharged into percolation pits does not contain hazardous amounts of chemicals related to hydraulic fracturing as well as other phases of oil and gas development. If the presence of hazardous concentrations of chemicals cannot be ruled out, they should phase out the practice of discharging produced water into percolation pits. Agencies should investigate any legacy effects of discharging produced waters into percolation pits including the potential effects of stimulation fluids (Volume II, Chapter 2; Volume III, Chapters 4 and 5 [Los Angeles Basin and San Joaquin Basin Case Studies]).

Conclusion 4.3. Required testing and treatment of produced water destined for reuse may not detect or remove chemicals associated with hydraulic fracturing and acid stimulation.

Produced water from oil and gas production has potential for beneficial reuse, such as for irrigation or for groundwater recharge. In fields that have applied hydraulic fracturing or acid stimulations, produced water may contain hazardous chemicals and chemical byproducts from well stimulation fluids. Practice in California does not always rule out the beneficial reuse of produced water from wells that have been hydraulically fractured or stimulated with acid. The required testing may not detect these chemicals, and the treatment required prior to reuse necessarily may not remove hydraulic fracturing chemicals.

Growing pressure on water resources in the state means more interest in using produced water for a range of beneficial purposes, such as groundwater recharge, wildlife habitat, surface waterways, irrigation, etc. Produced water could become a significant resource for California.

However, produced water from wells that have been hydraulically fractured may contain hazardous chemicals and chemical by-products. Our study found only one oil field where both hydraulic fracturing occured and farmers use the produced water for irrigation. In the Kern River field in the San Joaquin Basin, hydraulic fracturing operations occasionally occured, and a fraction of the produced water goes to irrigation (for example, Figure 1.5-7). But we did not find policies or procedures that would necessarily exclude produced water from hydraulically fractured wells from use in irrigation.

Figure 1.5-7. Produced water used for irrigation in Cawelo water district. Photo credit: Lauren Sommer/KQED (figure from Volume II, Chapter 1).

The regional water quality control boards require testing and treatment of produced water prior to use for irrigation, but the testing does not include hydraulic fracturing chemicals, and required treatment would not necessarily remove hazardous stimulation fluid constituents if they were present. Regional water-quality control boards have also established monitoring requirements for each instance where produced water is applied to irrigated lands; however, these requirements do not include monitoring for constituents specific to, or indicative of, hydraulic fracturing.

Safe reuse of produced water that may contain stimulation chemicals requires appropriate testing and treatment protocols. These protocols should match the level of testing and treatment to the water-quality objectives of the beneficial reuse. However, designing the appropriate testing and treatment protocols to ensure safe reuse of waters contaminated with stimulation chemicals presents significant challenges, because so many different chemicals could be present, and the safe concentration limits for many of them have not been established. Hydraulic fracturing chemicals may be present in extremely small concentrations that present negligible risk, but this has not been confirmed.

Limiting hazardous chemical use as described in Recommendation 3.2 would also help to limit issues with reuse. Disallowing the reuse of produced water from hydraulically fractured wells would also solve this problem, especially in the first years of production. This water could be tested over time to determine if hazardous levels of hydraulic fracturing chemicals remain before transitioning this waste stream to beneficial use.

Recommendation 4.3. Protect irrigation water from contamination by hydraulic fracturing chemicals and stimulation reaction products.

Agencies of jurisdiction should clarify that produced water from hydraulically fractured wells cannot be reused for purposes such as irrigation that could negatively impact the environment, human health, wildlife and vegetation. This ban should continue until or unless testing the produced water specifically for hydraulic fracturing chemicals and breakdown products shows non-hazardous concentrations, or required water treatment reduces concentrations to non-hazardous levels (Volume II, Chapter 2; Volume III, Chapter 5 [San Joaquin Basin Case Study]).

Conclusion 4.4. Injection wells currently under review for inappropriate disposal into protected aquifers may have received water containing chemicals from hydraulic fracturing.

DOGGR is currently reviewing injection wells in the San Joaquin Valley for inappropriate disposal of oil and gas wastewaters into protected groundwater. The wastewaters injected into some of these wells likely included stimulation chemicals because hydraulic fracturing occurs nearby.

In 2014, DOGGR began to evaluate injection wells in California used to dispose of oil field wastewater. DOGGR found that some wells inappropriately allowed injection of wastewater into protected groundwater and subsequently shut them down. DOGGR's ongoing investigation will review many more wells to determine if they are injecting into aquifers that should be protected.

Figure 1.5-8 is a map of the Elks Hills field in the San Joaquin Basin showing one example where hydraulically fractured wells exist near active water disposal wells. The DOGGR review includes almost every disposal well in this field for possible inappropriate injection into protected water. Some of the produced water likely came from nearby production wells that were hydraulically fractured. Consequently, the injected wastewater possibly contained stimulation chemicals at some unknown concentration.

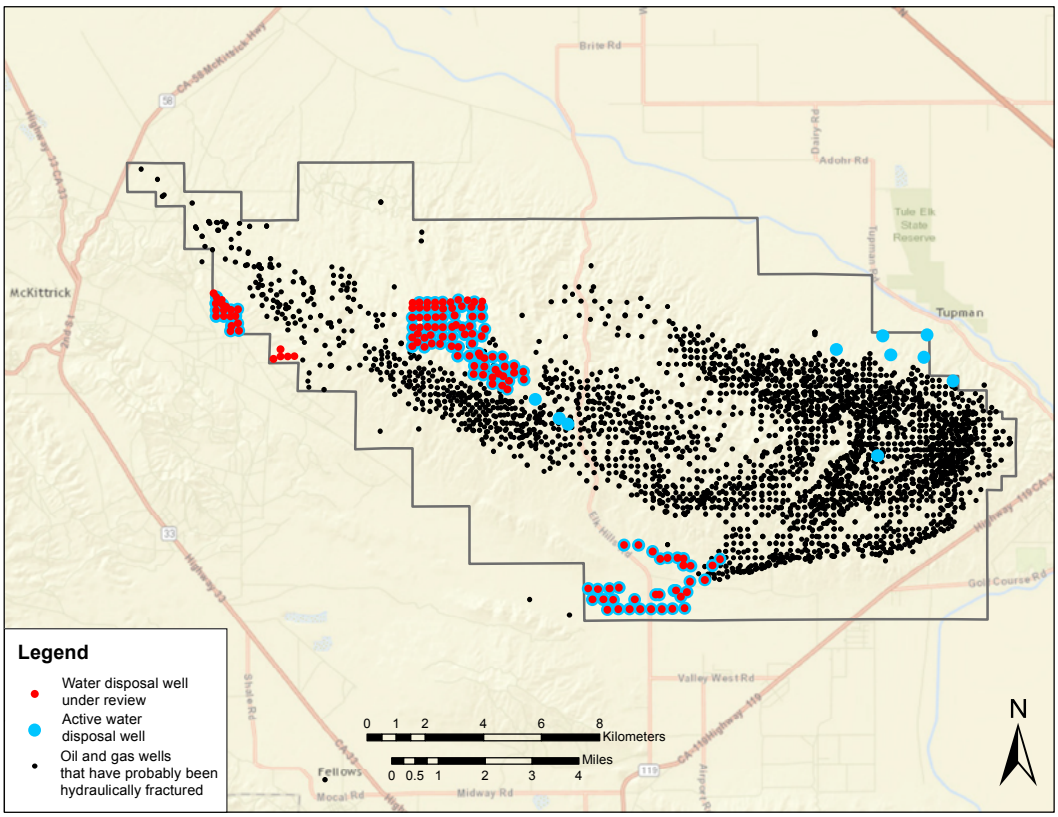

Figure 1.5-8. A map of the Elk Hills field in the San Joaquin Basin showing the location of wells that have probably been hydraulically fractured (black dots). Blue dots are the location of active water disposal wells, and blue dots with a red center are the location of disposal wells under review for possibly injecting into groundwater that should be protected (figure from Volume II, Chapter 1).

Recommendation 4.4. In the ongoing investigation of inappropriate disposal of wastewater into protected aquifers, recognize that hydraulic fracturing chemicals may have been present in the wastewater.

In the ongoing process of reviewing, analyzing, and remediating the potential impacts of wastewater injection into protected groundwater, agencies of jurisdiction should include the possibility that hydraulic fracturing chemicals may have been present in these wastewaters (Volume II, Chapter 2; Volume III, Chapter 5 [San Joaquin Basin Case Study]).

Conclusion 5.1. Shallow fracturing raises concerns about potential groundwater contamination.

In California, about three quarters of all hydraulic fracturing operations take place in shallow wells less than 600 m (2,000 ft) deep. In a few places, protected aquifers exist above such shallow fracturing operations, and this presents an inherent risk that hydraulic fractures could accidentally connect to the drinking water aquifers and contaminate them or provide a pathway for water to enter the oil reservoir. Groundwater monitoring alone may not necessarily detect groundwater contamination from hydraulic fractures. Shallow hydraulic fracturing conducted near protected groundwater resources warrants special requirements and plans for design control, monitoring, reporting, and corrective action.

Hydraulic fractures produced in deep formations far beneath protected groundwater are very unlikely to propagate far enough upwards to intersect an aquifer. Studies performed for high-volume hydraulic fracturing elsewhere in the country have shown that hydraulic fractures have propagated no further than 600 m (2,000 ft) vertically, so hydraulic fracturing conducted many thousands of feet below an aquifer is not expected to reach a protected aquifer far above. In California, however, and particularly in the San Joaquin Basin, most hydraulic fracturing occurs in relatively shallow reservoirs, where protected groundwater might be found within a few hundred meters (Figure 1.5-9). A few instances of shallow fracturing have also been reported in the Los Angeles Basin (Figure 1.5-10), but overall much less than the San Joaquin Basin. No cases of contamination have yet been reported, but there has been little to no systematic monitoring of aquifers in the vicinity of oil production sites.

Shallow hydraulic fracturing presents a higher risk of groundwater contamination, which groundwater monitoring may not detect. This situation warrants additional scrutiny. Operations with shallow fracturing near protected groundwater could be disallowed or be subject to additional requirements regarding design, control, monitoring, reporting, and corrective action, including: (1) pre-project monitoring to establish a base-line of chemical concentrations, (2) detailed prediction of expected fracturing characteristics prior to starting the operation, (3) definition of isolation between expected fractures and protected groundwater, providing a sufficient safety margin with proper weighting of subsurface uncertainties, (4) targeted monitoring of the fracturing operation to watch for and react to

evidence (e.g., anomalous pressure transients, microseismic signals) indicative of fractures growing beyond their designed extent, (5) monitoring groundwater to detect leaks, (6) timely reporting of the measured or inferred fracture characteristics confirming whether or not the fractures have actually intersected or come close to intersecting groundwater, (7) preparing corrective action and mitigation plans in case anomalous behavior is observed or contamination is detected, and (8) adaption of groundwater monitoring plans to improve the monitoring system and specifically look for contamination in close proximity to possible fracture extensions into groundwater.

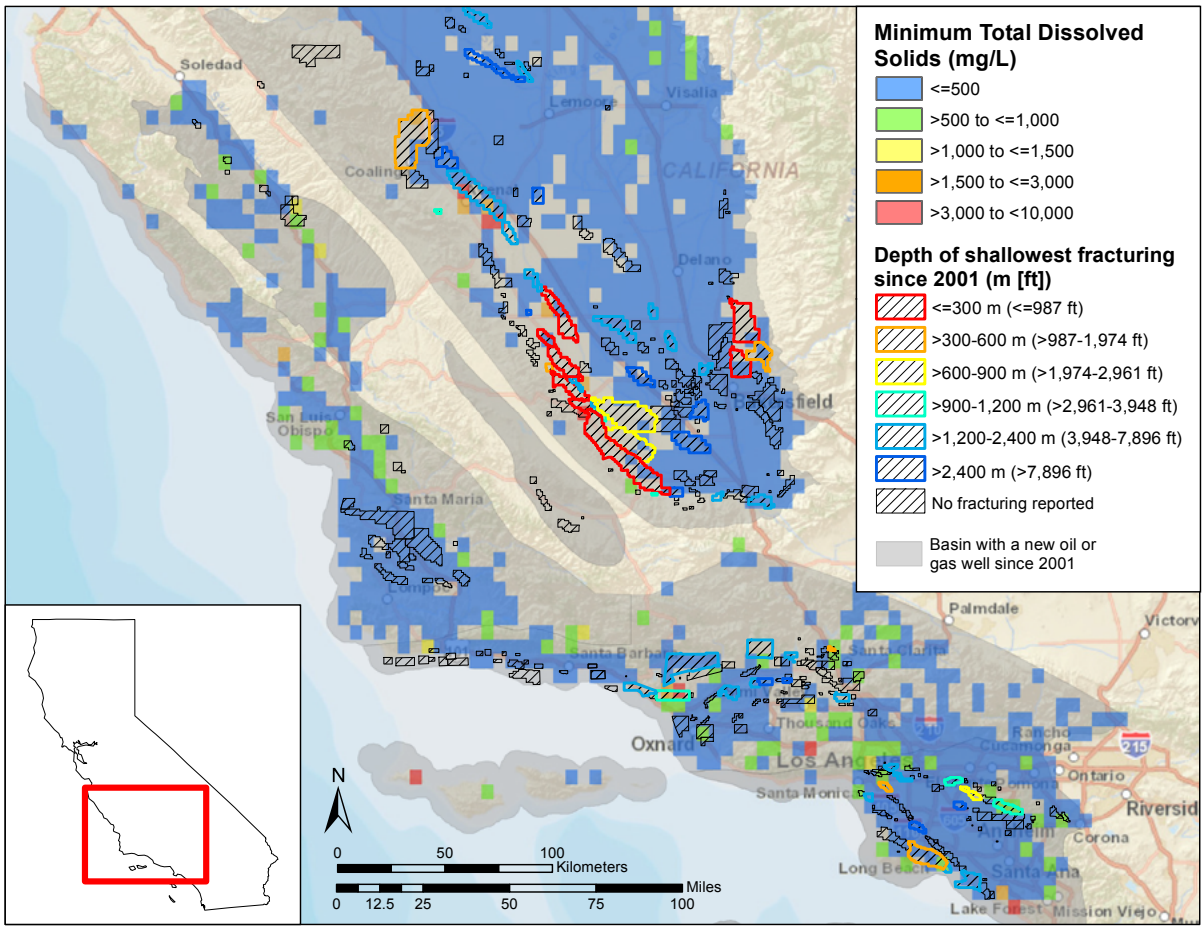

Figure 1.5-9. Shallow fracturing locations and groundwater quality in the San Joaquin and Los Angeles Basins. Some high quality water exists in fields that have shallow fractured wells (figure from Volume II, Chapter 2).

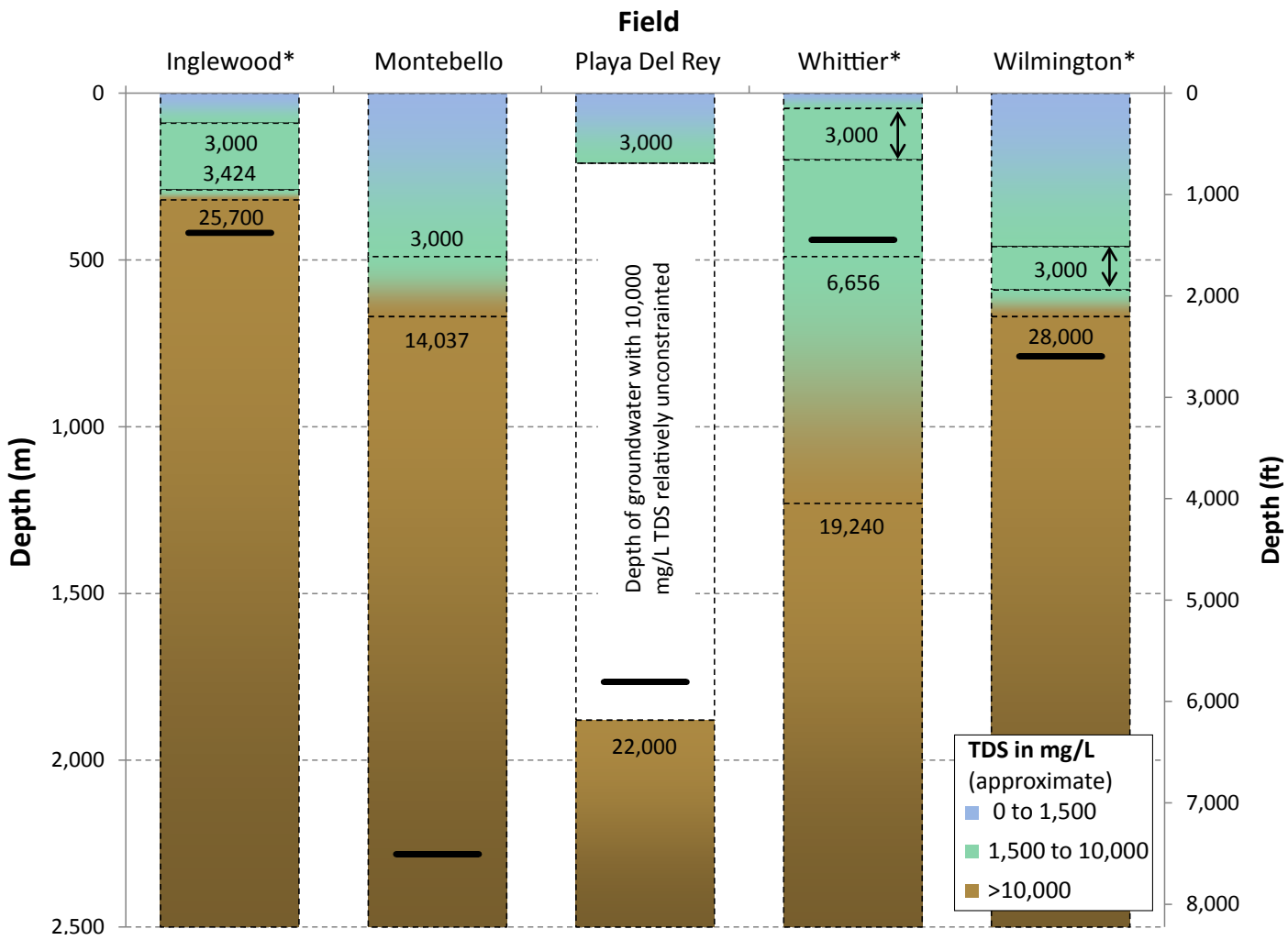

Figure 1.5-10. Depths of groundwater total dissolved solids (TDS) in mg/L in five oil fields in the Los Angeles Basin. The numbers indicate specific TDS data and the colors represent approximate interpolation. The depth of 3,000 mg/L TDS is labeled on all five fields. Blue (<3,000 mg/L) and aqua (between 3,000 mg/L and 10,000 mg/L) colors represent protected groundwater. Depth of 10,000 mg/L TDS is uncertain, but it is estimated to fall in the range where aqua transitions to brown. The heavy black horizontal line indicates the shallowest hydraulically fractured well interval in each field. (Asterisks denote the fields of most concern for the proximity of hydraulic fracturing to groundwater with less than 10,000 mg/L TDS.) (figure from Volume III, Chapter 4 [Los Angeles Basin Case Study]).

The potential for shallow hydraulic fractures to intercept protected groundwater requires both knowing the location and quality of nearby groundwater and accurate information about the extent of the hydraulic fractures. Maps of the vertical depth of

protected groundwater with less than 10,000 mg/L TDS for California oil producing regions do not yet exist. Analysis and field verification could identify typical hydraulic fracture geometries; this would help determine the probability of fractures extending into groundwater aquifers. Finally, detection of potential contamination and planning of mitigation measures requires integrated site-specific and regional groundwater monitoring programs.

The pending SB 4 well stimulation regulations, effective July 1, 2015, require operators to design fracturing operations so that the fractures avoid protected water, and to implement appropriate characterization and groundwater monitoring near hydraulic fracturing operations. However, groundwater monitoring alone does not ensure protection of water, nor will it necessarily detect contamination should it occur. The path followed by contamination underground can be hard to predict, and may bypass a monitoring well. Groundwater monitoring can give false negative results in these cases,5 and does nothing to stop contamination from occurring in any case.

Recommendation 5.1. Protect groundwater from shallow hydraulic fracturing operations.

Agencies with jurisdiction should act promptly to locate and catalog the quality of groundwater throughout the oil-producing regions. Operators proposing to use hydraulic fracturing operation near protected groundwater resources should be required to provide adequate assurance that the expected fractures will not extend into these aquifers and cause contamination. If the operator cannot demonstrate the safety of the operation with reasonable assurance, agencies with jurisdiction should either deny the permit, or develop protocols for increased monitoring, operational control, reporting, and preparedness (Volume I, Chapter 3; Volume II, Chapter 2; Volume III, Chapter 5 [San Joaquin Basin Case Study]).

Conclusion 5.2. Leakage of hydraulic fracturing chemicals could occur through existing wells.

California operators use hydraulic fracturing mainly in reservoirs that have been in production for a long time. Consequently, these reservoirs have a high density of existing wells that could form leakage paths away from the fracture zone to protected groundwater or the ground surface. The pending SB 4 regulations going into effect July 1, 2015 do address

5. Chemical tracers (non-reactive chemicals that can be detected in small concentrations) can be added to hydraulic fracturing fluids and, if groundwater samples contain these tracers, it is evidence that the stimulation fluid has migrated out of the designed zone. However, the use of tracers does not guarantee that leaks to groundwater will be detected. Groundwater flow can be highly channelized and it can be difficult to place a monitoring well in the right place to intersect a possible plume of contaminant. The use of tracers is good practice, but does not “solve” the problem of detecting contamination.

concerns about existing wells in the vicinity of well stimulation operations; however, it remains to demonstrate the effectiveness of these regulations in protecting groundwater.

In California, most hydraulic fracturing occurs in old reservoirs where oil and gas has been produced for a long time. Usually this means many other wells (called "offset wells") have previously been drilled in the vicinity of the operation. Wells constructed to less stringent regulations in the past or degraded since installation may not withstand the high pressures used in hydraulic fracturing. Thus, in California, as well as in other parts of the country, existing oil and gas wells can provide subsurface conduits for oil-field contamination to reach protected groundwater. Old wells present a risk for any oil and gas development, but the high pressures involved in hydraulic fracturing can increase this risk significantly. California has no recorded incidents of groundwater contamination due to stimulation. But neither have there been attempts to detect such contamination with targeted monitoring, nor studies to determine the extent of compromised wellbore integrity.

Historically, California has required placement of well casings and cement seals to protect groundwater with a salinity less than 3,000 mg/L total dissolved solids (TDS). Now, SB 4 requires more stringent monitoring and protection from degradation of non-exempt groundwater with less than 10,000 mg/L TDS. Consequently, existing wells may not have been built to protect groundwater between 3,000 mg/L and 10,000 mg/L TDS. For instance, there may be no cement seal in place to isolate the zones containing water that is between 3,000 and 10,000 mg/L TDS from deeper zones with water that is higher than 10,000 mg/L TDS.

The new well stimulation regulations going into effect in July 1, 2015 require operators to locate and review any existing well within a zone that is twice as large as the expected fractures. Operators need to design the planned hydraulic fracturing operation to confine hydraulic fracturing fluids and hydrocarbons within the hydrocarbon formation. The pressure buildup at offset wells caused by neighboring hydraulic fracturing operations must remain below a threshold value defined by the regulations.

The new regulations for existing wells are appropriate in concept, but the effectiveness of these requirements will depend on implementation practice. For example: How will operators estimate the extent of the fractures, and how will regulators ensure the reliability of these calculations? Is the safety factor provided by limiting concern to an area equal to twice the extent of the designed fractures adequate? How will regulators assess the integrity of existing wells when information about these wells is incomplete? How will regulators determine the maximum allowed pressure experienced at existing wells? Will the regulators validate the theoretical calculations to predict fracture extent and maximum pressure with field observations?

Recommendation 5.2. Evaluate the effectiveness of hydraulic fracturing regulations designed to protect groundwater from leakage along existing wells.

Within a few years of the new regulations going into effect, DOGGR should conduct or commission an assessment of the regulatory requirements for existing wells near stimulation operations and their effectiveness in protecting groundwater with less than 10,000 TDS from well leakage. This assessment should include comparisons of field observations from hydraulic fracturing sites with the theoretical calculations for stimulation area or well pressure required in the regulations (Volume II, Chapter 2; Volume III, Chapters 4 and 5 [Los Angeles Basin and San Joaquin Basin Case Study]).