Chapter Five

A Case Study of the Potential Risks Associated with Hydraulic Fracturing in Existing Oil Fields in the San Joaquin Basin

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5.1. Abstract

This case study discusses the conceivable future of hydraulic fracturing in the San Joaquin Basin and the potential consequent impacts on water and air resources, public health, and wildlife and vegetation. The rate of well stimulation in the San Joaquin Basin will likely continue over the next decade as it has over the last decade. Assessments have estimated large reserves in existing fields that have been the most productive historically, and the trends in past and current production patterns are quite likely to continue. In contrast, development of oil or gas production from source rock appears relatively unlikely. Additional production in predominantly hydraulically fractured pools can be delivered by installing new wells in existing fields, and there is sufficient remaining resource in those pools for production to continue in this manner for at least another decade.

Future oil production will continue to produce water. There are potential opportunities to reduce the amount of high-quality and low-salinity water consumed by production, and opportunities for beneficial reuse of the water produced along with the oil. One of the current methods for produced water disposal from pools with hydraulic fracturing in the San Joaquin Basin is discharge into evaporation-percolation pits. This presents a potential risk for contamination of potable groundwater resources and should be phased out in the future. Some produced water from pools with hydraulic fracturing has also been disposed of by injection into subsurface reservoirs with ground water resources that perhaps should not have been exempted from protection. Whether these injections can continue is currently undergoing review by California regulators. If it is determined

that the wastewater has been injected into protected groundwater, it is likely some of the water injected contained constituents due to stimulation that could contaminate the groundwater resources.

A general concern about hydraulic fracturing is that stimulation chemicals could leak into the environment, including drinking water wells, via potential subsurface leakage paths. The main concern identified by this investigation is the application of hydraulic fracturing at shallow depths in proximity to groundwater in some portions of the San Joaquin Basin. Most hydraulic fracturing in the San Joaquin Basin occurs shallower than 300 m (1,000 ft). This means that operators produce hydraulic fractures near the surface that can present a hazard if there is nearby protected groundwater. Two other concerns also arise. Reservoirs in the San Joaquin Basin have a high density of existing wells, which may provide potential pathways for leakage of stimulation fluids into groundwater. In addition, the density of faults in the San Joaquin Basin indicates that tens of shallow hydraulic fractures each year may intersect faults that are sufficiently large to potentially extend to protected groundwater. The presence of oil in close proximity to these faults indicates that they do not provide a leakage pathway in their natural state. However, it is unknown to what extent they might become a leakage pathway when intersected by a hydraulic fracture. No incidents of groundwater contamination due to stimulation have been found in the San Joaquin Basin to date, but there has also been no targeted monitoring of groundwater quality, nor have there been specific efforts to determine the extent of potentially compromised wellbore integrity. It is also noted that if leaks are relatively small, as can be expected for the majority of leaky wells, they are not easily detectable in the groundwater, even when dedicated monitoring is conducted.

Regarding potential air contamination, oil and gas production accounts for an appreciable portion of some air pollutants released in Kern County, but very little data have been collected to evaluate air emissions from oil and gas wells. Oil and gas production is the dominant source of hydrogen sulfide (96%) and a major contributor to emissions of benzene (9%), formaldehyde (26%), hexane (11%), and xylene (14%). Emissions from production involving well stimulation are a small portion (approximately 20%) of these emissions, but, for some pollutants, still an appreciable fraction of total emissions in Kern County (for instance nearly 20% for hydrogen sulfide and greater than 5% for formaldehyde).

The concentration of air contaminants is larger closer to the source of emissions, so those in close proximity to production wells could be exposed to higher than average concentrations. Of the population both within the San Joaquin Valley Air Pollution Control District and a county with more than one oil and gas field, 21% live within 2 km (1.2 mi.) of a well for oil and gas production. Of this population, 21% are estimated to be in such proximity to a hydraulically fractured well, which is 3.4 % of the total population. So, to the extent exposure to air contaminants from oil and gas wells is a concern, it is a concern for all wells, not just those that are hydraulically fractured.

In contrast to air-pollutant emissions, production-related greenhouse pollution per unit of oil from predominantly hydraulically fractured pools in the San Joaquin Basin is among the lowest in California. This is because most of the other oil production in the state involves energy-intensive water and steam injection, for which the energy is provided by combusting fossil fuels. Inventories indicate the production-related greenhouse pollution per unit of oil imported to California is also higher than the pollution from oil produced using hydraulic fracturing in the state. Consequently, a cessation in hydraulic fracturing could result in an increase in the use of oil produced using methods emitting more greenhouse pollution per unit of oil.

The viability of most species is inversely related to habitat fragmentation. As fragmentation increases, the population of a species increasingly consists of isolated subpopulations. Each of these subpopulations is at greater risk of complete mortality due to disease, as a consequence of less genetic diversity, or a change in environmental conditions, as a consequence of inability to migrate or change range. Habitat for wild species is largely available in some fields in the San Joaquin Basin where well stimulation is predominant. Additional development may not substantially increase fragmentation in some of these fields, because it would occur in already densely developed areas, such as in North and South Belridge. In other fields, such as Elk Hills, additional development would likely to increase fragmentation, reducing species population viability. At the landscape scale, there are currently some corridors between and through fields with predominantly fractured pools in the southwestern San Joaquin Basin that provide migration pathways between the surrounding areas. The impact of future development in these fields could be reduced by preventing the elimination of these corridors, such as by best management practices that would consolidate facilities to retain some percentage (to be tested) of undisturbed habitat in reserve areas and corridors.

5.2. Introduction

The goal of this case study is to develop an understanding of the risk from future well stimulation, with an emphasis on hydraulic fracturing, to water and air resources, public health, and wildlife and vegetation in the San Joaquin Basin. This assessment is conducted under the assumption that the future characteristics and magnitude of well stimulation are similar to what has been observed in the previous decade. Section 5.3 provides a summary of recent well stimulation trends in the San Joaquin Basin, with focus on hydraulic fracturing, and explains why these trends are expected to hold into the foreseeable future. Based on this assumption, Sections 5.4, 5.5, and 5.6 provide a brief assessment of the potential risks from hydraulic fracturing in the San Joaquin Basin to (respectively) water resources, air, and public health as possible using available sources and data.

Risk is the combination of the probability of an event occurring and the consequence of that event. This is in contrast to hazard, which only considers potential consequences without regard to the probability of occurrence. Given these definitions, a hazard may appear to present a problem, but in reality may have low risk because it is unlikely to occur. In the context of this report, risk can include both direct risk from hydraulic fracturing, such as spills of chemicals used in the process, and indirect risk from the oil and gas development enabled by hydraulic fracturing, such as air emissions from oil production from “pools” (geologically continuous zones containing oil) where a high proportion of wells are hydraulically fractured.

The possibility of hydraulic-fracturing-enabled oil and gas production from the source rocks of the Monterey Formation is not considered in this case study. Potential risks related to future source rock production, which is a highly uncertain scenario (see discussion in Volume I, Chapter 4), are considered in the Monterey Formation Case Study, provided in Chapter 3 in this volume.

The San Joaquin Basin Case Study focuses exclusively on hydraulic fracturing. Matrix acidizing and acid fracturing are not considered. No comprehensive data on the use of acid is available for the San Joaquin Basin, but existing data indicates that (1) operators use matrix acidizing one tenth as often as hydraulic fracturing, and (2) acid fracturing is hardly ever used and unlikely in the future, because it is not effective in the geologic conditions of the Basin.

5.3. Past and Future Oil and Gas Development Using Hydraulic Fracturing

This case study evaluates specific risks to water, air and public health associated with continued well stimulation in the San Joaquin Basin. The risks that may occur in the future will depend on how production in the basin develops. This section reviews well stimulation trends in the San Joaquin Basin during the last decade and defines a reasonable scenario of hydraulic-fracturing-enabled production over the next decade. This scenario forms the basis of the risk assessment.

Over 320 million m^3 (2 billion barrels) of oil were produced from the San Joaquin Basin between 2002 and 2014. This was more than three quarters of the oil produced in California during this period. A fifth of the oil produced in the San Joaquin Basin was from the predominantly hydraulically fractured pools in the four fields where 85% of the hydraulic fracturing occurs in the state: North and South Belridge, Elk Hills, and Lost Hills. Tennyson et al. (2012) assessed potential additional oil recovery from nine of the historically most productive oil fields in the San Joaquin Basin, indicated in Figure 5.3-1. These include the four fields mentioned where most hydraulic fracturing occurs. The results of the assessment indicated that 200 to 730 million m^3 (1.3 to 4.6 billion barrels (bbl)) with a mean of 410 million m^3 (2.6 billion bbl) of additional oil could be produced from these predominantly hydraulically fractured pools in the four main fields. Based on the estimated reserves and the production rates over the last decade, oil production from these pools could continue for another several decades to a century.

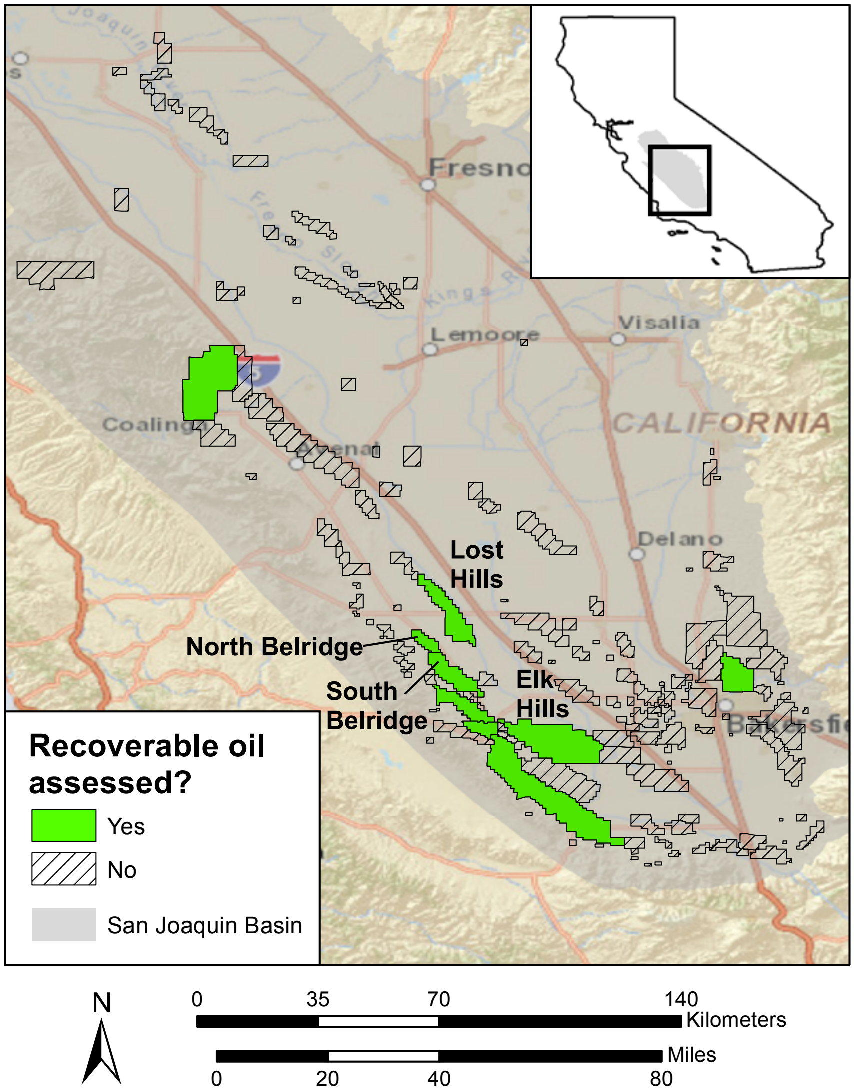


Figure 5.3-1. Oil fields assessed by Tennyson et al. (2012) for the remaining recoverable volume of oil.

The predominantly hydraulically fractured pools in the North and South Belridge fields, and in the Lost Hills field, consist of intervals of biogenic Opal A, a type of rock formed of the tests (skeletons) made of silica from single celled marine organisms, and Opal A diatomite recrystallized to Opal CT (cristobalite and tridymite) and quartz-phase, due to increased temperature and pressure resulting from deeper burial. The predominant hydraulically fractured pools in the Elk Hills field consist of sands, discussed further below.

Development of oil production from most of these reservoirs in California depends on hydraulic fracturing followed by waterflood, steam injection, or cyclic steam injection.

As such, the well stimulation within these reservoirs is different from that used in other parts of the country to develop oil and gas production from shale. In addition, about half of hydraulic fracturing in the San Joaquin Basin is shallower than 300 m (1,000 ft), which is shallower than hydraulic fracturing common in elsewhere in the country where it generally occurs at depths greater than 1,000 m (3,300 ft).

The number of hydraulic fracturing operations in the Elk Hills field each year is similar to the number in each of the North Belridge and Lost Hills fields (an operation consists of all the hydraulic fracturing stages occurring in a well with a relatively short time period, typically less than one week). Most of the Elks Hills operations occur in the Upper (Undifferentiated) pool, which includes the Scalez, Mulinia, Bittium, Wilhelm, Gusher, Calitroleum, and Olig sands in the San Joaquin, Etchegoin and Reef Ridge Formations (Division of Oil, Gas, and Geothermal Resources (DOGGR), 1998).

In addition to the prevalence of hydraulic fracturing in some pools in these fields, there are a number of other pools in the San Joaquin Basin where most of the wells are hydraulically fractured, as shown on Figure 5.3-2. Altogether, hydraulic fracturing in the San Joaquin Basin accounts for over 95% of hydraulic fracturing operations in California (Volume 1, Chapter 3).

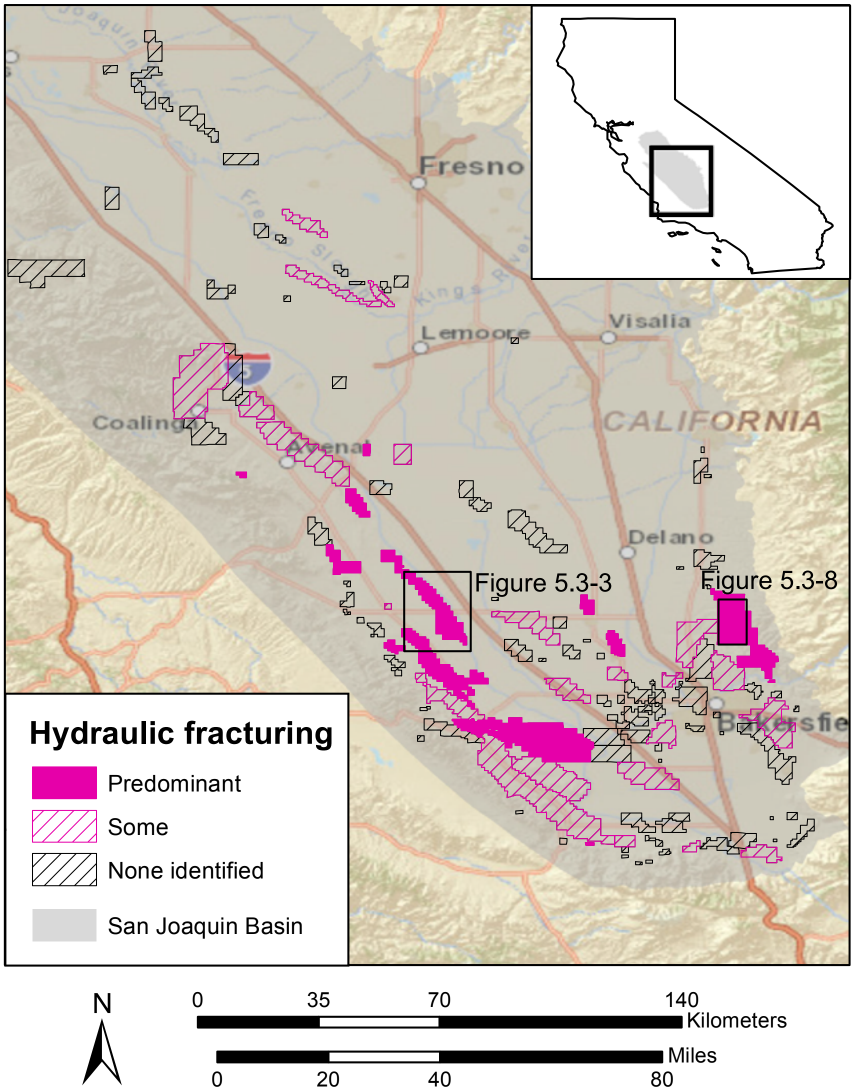


Figure 5.3-2. Oil fields containing one or more pools with where hydraulic fracturing has been conducted. "Predominant" indicates a field with at least one pool where most to all wells are estimated to have been hydraulically fractured.

Below, past and current production patterns in two fields are examined to substantiate the assessment of how hydraulic-fracturing-enabled production may continue over the next decade. Taking Lost Hills as the first example, Figure 5.3-3 shows the location of wells open to each of the two pools where hydraulic fracturing is prevalent in this field. The areal extents of the Etchegoin and Cahn pools overlap near the middle of the Lost Hills field. The Etchegoin pool consists of biogenic Opal A and recrystallized Opal CT diatomite, and the deeper Cahn pool consists of opal CT and quartz-phase developed from deeper burial of diatomite.

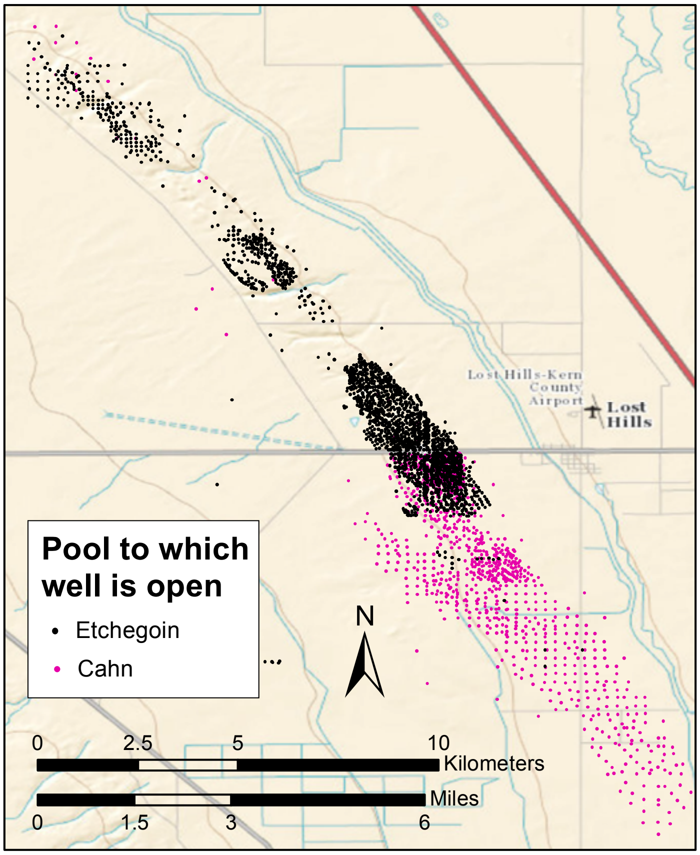


Figure 5.3-3. The location of wells open to the two pools in the Lost Hills field where most to all wells are estimated to have been hydraulically fractured. See Figure 5.3-2 for location.

Figure 5.3-4 shows the development of the Etchegoin pool in the Lost Hills field through time. There were almost no wells in this pool in 1977. Development proceeded steadily through 1989, at which time there was a grouping of oil production wells in one portion of the pool, but few injection wells for secondary recovery (water flooding). Through 1996, both the area with oil wells and the density of oil wells increased. Waterflood injection wells were also installed throughout the area with oil wells. In 1996, the east-west orientation of the northern edge of development, in combination with the sharp northwest and northeast corners of the developed area, suggests that development stopped at a survey boundary rather than a geologic boundary.

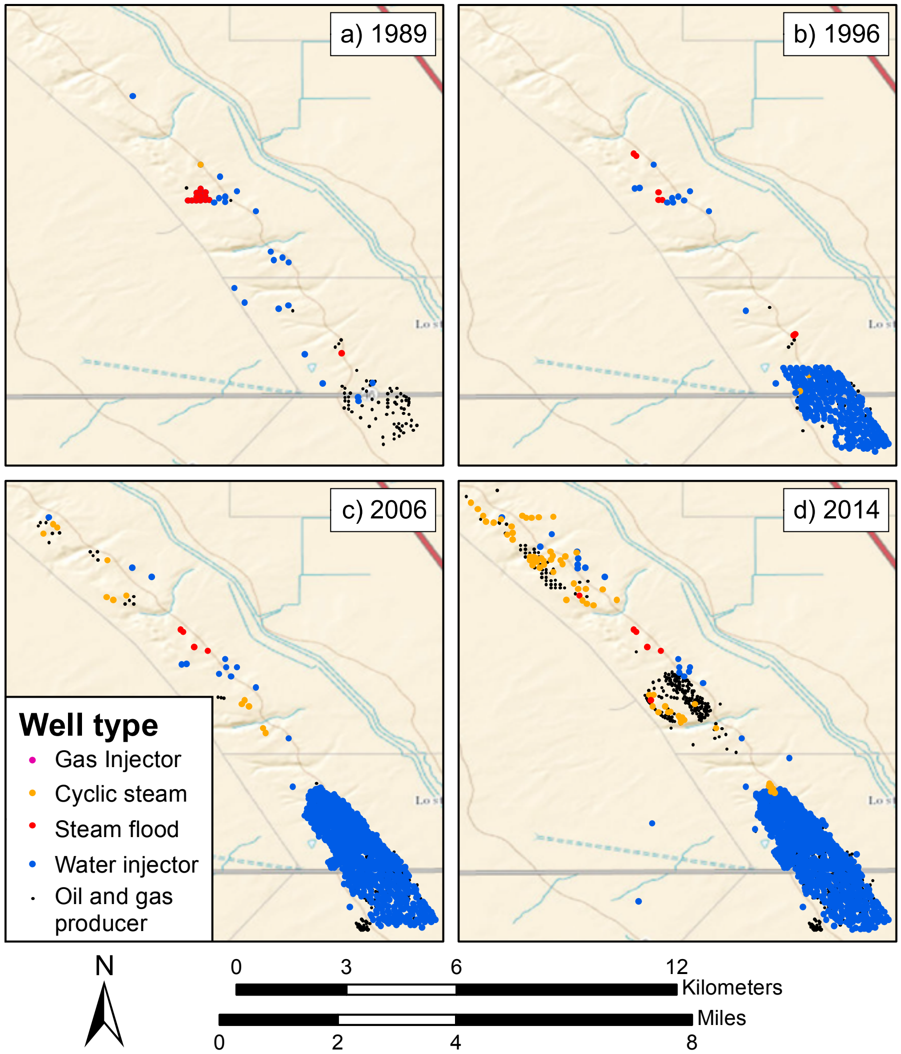


Figure 5.3-4. Wells in operation in the Etchegoin pool of the Lost Hills field in different years. Most to all of the wells shown have been hydraulically fractured.

By 2006, the dense development with oil production and waterflood wells in the southern portion of the pool shown in Figure 5.3-4 had extended further to the north. The curved northern margin of this development at this time suggests it stopped at a geologic rather than legal boundary. This is further suggested by the persistence of this development area boundary in that location through 2014. However, as of 2014, oil wells had been installed in two new areas of the pool to the northwest of the area of dense development at its southern extent. These consisted primarily of a mix of production wells and cyclic steam wells (through which steam injection alternates with oil production). The southern terminus of the northernmost pattern of oil and gas wells at this time is again east-west oriented, with sharp southwest and southeast corners, suggesting a survey rather than a geologic boundary. This in turn may suggest that development could continue to the southeast in the future.

Figure 5.3-5 shows the development of the deeper Cahn pool. A few oil wells were in operation in this pool in 1977. Development through 1986 consisted primarily of extending the productive area by installing oil wells. No injection wells were yet in operation. Through 1995, further development consisted primarily of increasing the well density in some areas and starting operation of some waterflood wells in those areas. The abrupt southern margin of the area of increased well density at that time suggested a lease rather than geologic boundary. This in turn indicates an increase in well density to the south could be productive.

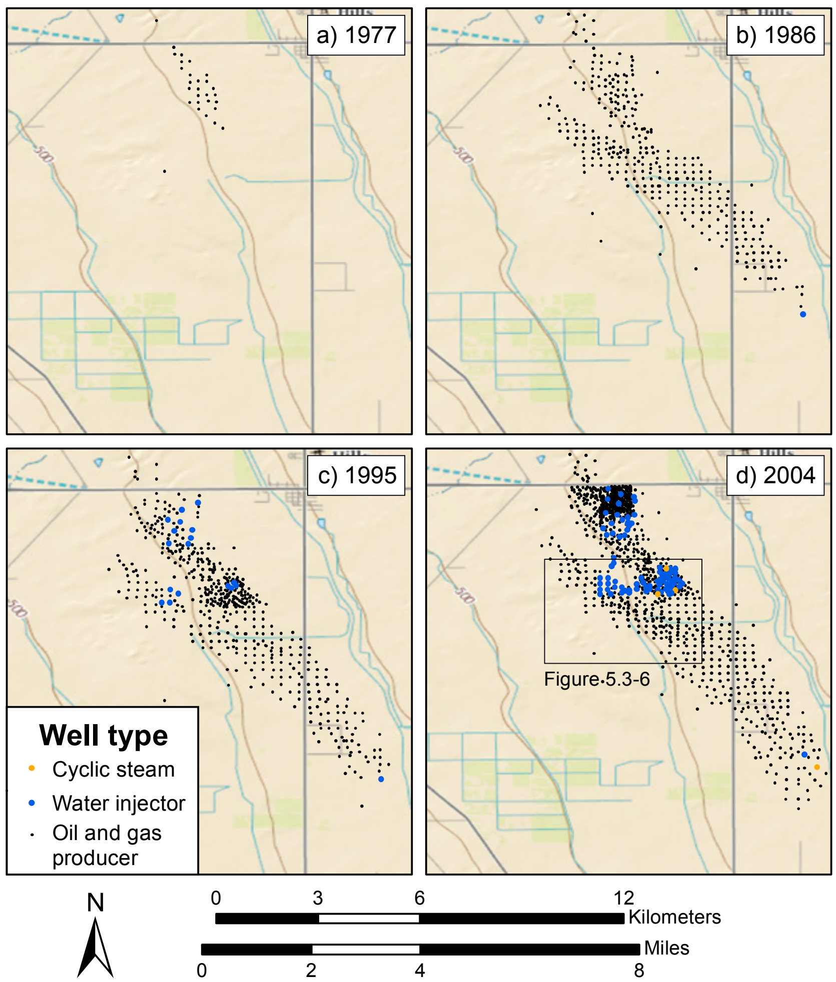


Figure 5.3-5. Wells in operation in the Cahn pool of the Lost Hills field in different years. Most to all of the wells shown have been hydraulically fractured.

By 2014, the well field in the Cahn pool had been extended north, with a relatively abrupt boundary at a highway suggesting a lease rather than geologic boundary. This abrupt boundary suggests further development to the north could be productive. In addition, far more injector wells were in operation for water flooding in the areas of greater well density.

In order to gain more quantitative insight into the likelihood and opportunity for further oil development utilizing hydraulic fracturing, past production was assessed from a region of the Cahn pool with wells in adjacent leases, as indicated by the box marked Figure 5.3-6 in Figure 5.3-5d. To provide an estimate of the productive area for each lease, the area closest to each well was assigned to the lease occupied by that well. Then, all the areas assigned to a lease were aggregated. Leases with aggregated areas relatively constrained to within the productive area of the pool were selected for study. The aggregated areas for these leases are shown in Figure 5.3-6.

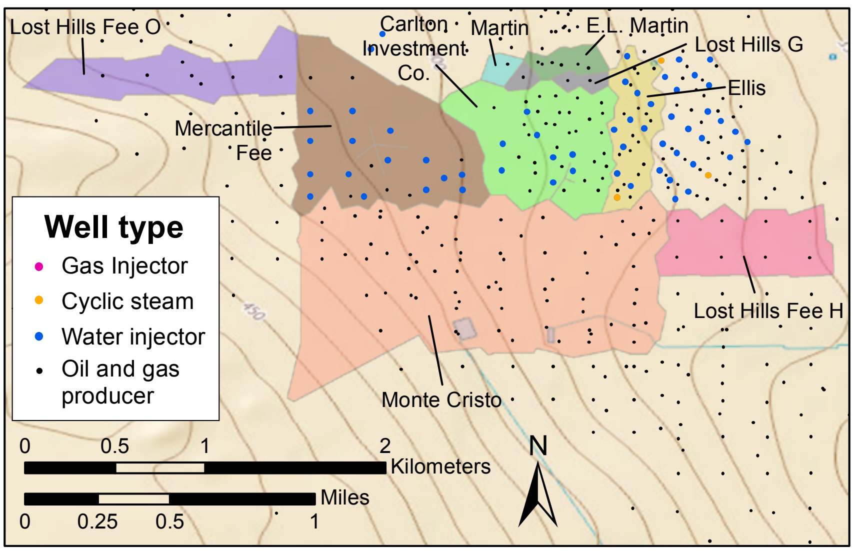


Figure 5.3-6. Lease study area in the Cahn pool of the Lost Hills field. See Figure 5.3-5d for location of figure relative to the entire Cahn pool.

The amount of oil and gas production from 1977 through May 2014 in each lease was summed from DOGGR's production database. Produced gas was converted to oil equivalent energy assuming 1,070 m^3 of gas per m^3 of oil (6,000 cubic feet/bbl), and the result was summed with the oil produced. This was divided by the aggregate area for each lease and the number of calendar years during which production occurred, to provide average equivalent oil energy produced per unit area per year in each lease. The average density of wells operating in 2013 in each lease was computed. Figure 5.3-7 shows production per area per year plotted against the well density for each lease.

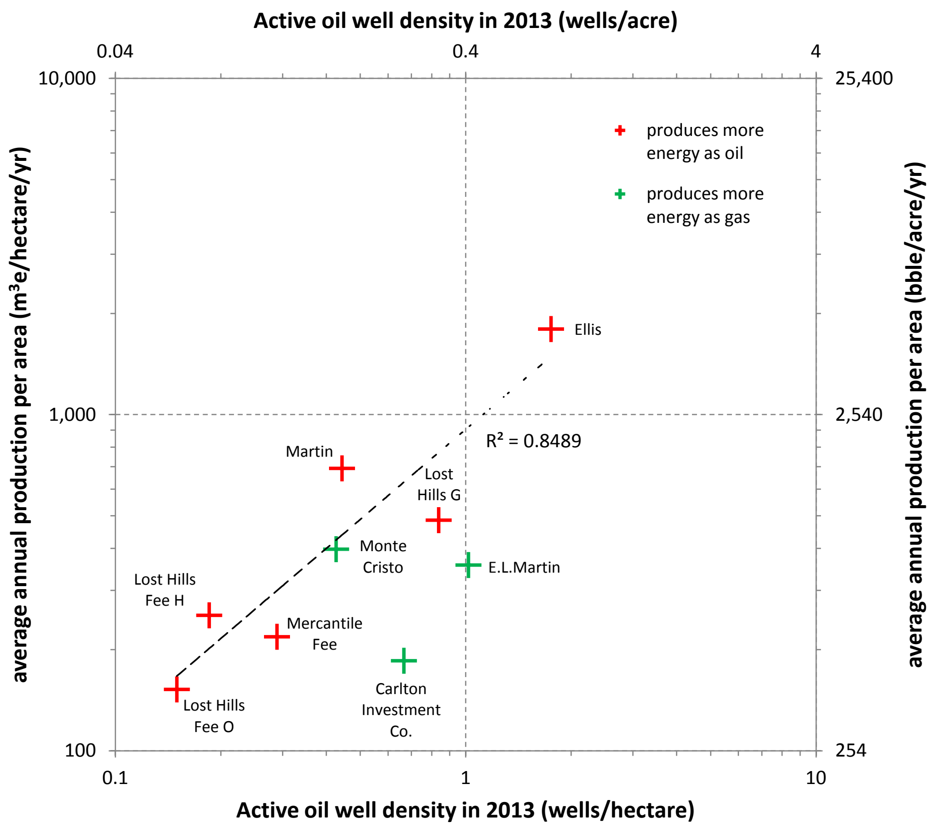


Figure 5.3-7. Scatter Plot depicting the relationship between annual equivalent oil production per area and well density across the study leases in the Cahn pool of the Lost Hills field. See Figure 5.3-6 for location of study leases. The dashed line indicates a least-squares regression line based upon the leases producing energy mostly as oil, with calculated coefficient of determination of $r^2 = 0.8489$.

Figure 5.3-7 shows how the average annual production per area is related to the well density for leases where production of energy is oil dominated. The regression line is based only on leases producing energy mostly as oil, because the energy density of gas per unit volume is substantially less. The scatter plot indicates that increasing well density by a factor of ten increases production per area per year by about a factor of ten. The pattern in the scatter plot extends to the highest well densities in Figure 5.3-7, suggesting that even at the closest spacing, production from one well is not likely interfering with production from adjacent wells. The average well spacing in the densest lease is about 75 m (250 ft). This is more than two times the average horizontal fracture length reported by hydraulic fracturing operators to the California Division of Oil, Gas, and Geothermal Resources (DOGGR; Volume II, Chapter 2), further indicating limited well interference.

The results in Figure 5.3-7 are consistent with the finding of Tennyson et al. (2012) that a considerable volume of oil can yet be produced from the assessed fields. Figure 5.3-5 suggests development over most of the Cahn pool has not progressed from the initial well pattern to infill drilling. Figure 5.3-4 indicates further increases in well density in the northern part of the Etchegoin pool are supportable. Consequently, there is opportunity for installing additional wells across both of these pools. This is further supported by the animation of wells in operation each year in the Cahn pool in Appendix 5.A.

The historical development of oil production in the smaller pools where most (to all) wells are estimated to have been hydraulically fractured (Volume I, Appendix N) provides further support and insight regarding how development will continue in the future. Figure 5.3-8 shows the wells in operation in the Pyramid Hill-Vedder pool of the Main area in the Mount Poso field. In the earlier period, production was from an initial pattern of wells enhanced with intervening steam flooding along the margins and cyclic steam focused on the Vedder portion of the pool. In the later period, production had shifted to the eastern portion of the pool with considerable infill well installation, cessation of most cyclic steaming and half of the steam flooding along that margin, and initiation of water flooding in the Pyramid Hill portion of the pool. This suggests water flooding may be initiated progressively to the south in the future, along with further infill installation of hydraulically fractured wells.

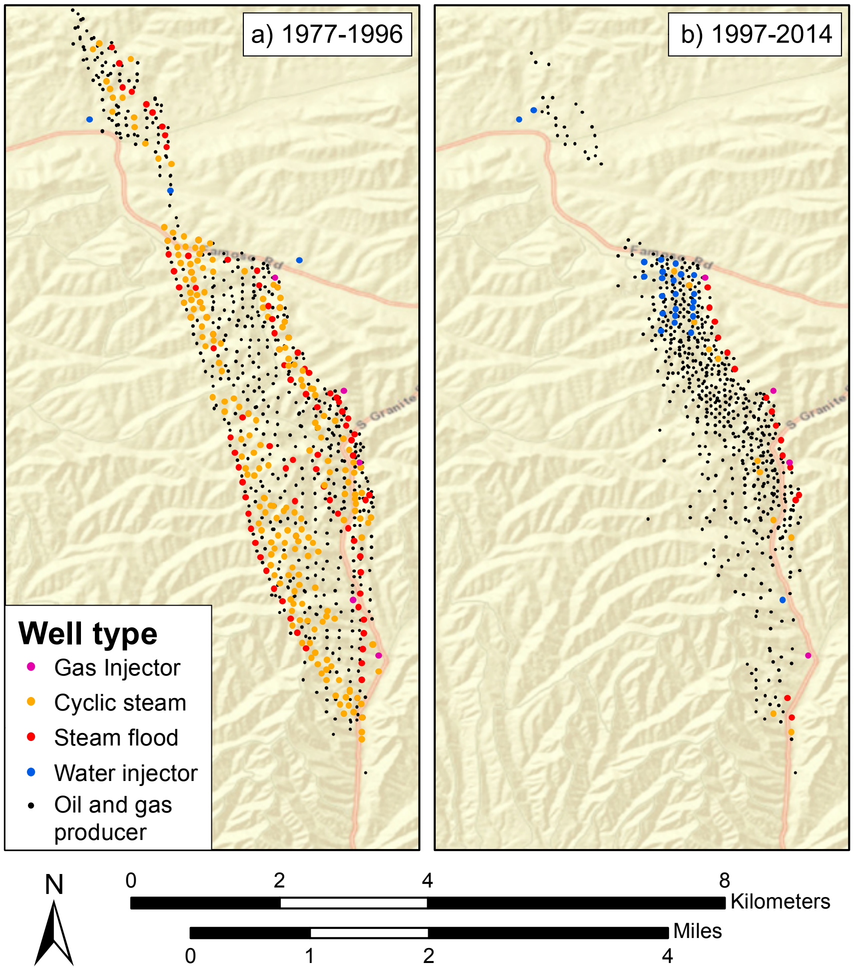


Figure 5.3-8. Wells in operation in the Pyramid Hill-Vedder pool of the Mount Poso field in different years. Most to all of the wells shown have been hydraulically fractured.

The three examples above indicate that additional production involving hydraulic fracturing can be achieved in part by installing additional wells in the existing fields, thereby increasing well density. More broadly, the baseline scenario assumed in this chapter is that the rate of well stimulation in the San Joaquin Basin will continue over the next decade as it has over the last decade, unless there is a substantial change in economic conditions. This assumption is based on (1) the large reserve estimates for existing fields that have been the most productive historically (Tennyson et al., 2012), (2) the analysis of trends in past and current production patterns in selected fields, and (3) the small likelihood of substantial, if any, development of oil or gas production from deeper shale source rock (Volume I, Chapter 4). In predominately hydraulically fractured pools, additional oil reserves and recovery in existing fields may be achieved with (a) infill well development, (b) the addition of new reservoir intervals to well completions, or (c) development area extensions (e.g., down the flanks into poorer quality rock). There is likely sufficient remaining resource in those pools for production to continue in this manner for several decades.

Given this continuation, the future risk of production enabled by hydraulic fracturing is likely to be similar to the present risk. The remainder of this case study primarily assesses this present risk.

5.4. Potential Risk to Water

Hydraulic fracturing can create risks to water supplies owing to competing demand for freshwater, and risks to water quality owing to potential releases of stimulation constituents, degradation products, mobilized natural constituents, and natural constituents in water associated with oil. Well stimulation requires water for making stimulation fluids. In some pools in the San Joaquin Basin, waterflooding or enhanced oil recovery (EOR) with steam is used after wells are hydraulically fractured, which requires additional water. (Such injection can push oil and/or, in the case of steam, reduce the viscosity of the oil, both of which results in more oil production.)

Hazards associated with well stimulation include degradation of water resources through the potential release of produced water (water that is produced along with oil and gas) that would not otherwise occur, as well as the potential release of well stimulation constituents via various potential release pathways. The potential pathways considered here are discharges of produced water to evaporation-percolation pits, disposal of produced water via injection into protected groundwater, beneficial reuse of produced water containing hazardous concentrations of stimulation constituents, and release of well stimulation constituents to groundwater via induced fractures, faults, and wells. In terms of potential subsurface pathways, the focus of this case study of the San Joaquin Basin is on induced fractures, wells, and faults. For the following reasons, the risk of leakage via natural fractures is judged to be lower than the other hazards considered in this report, and so is not further assessed. Natural fractures intersecting oil accumulations are not leakage pathways in their natural state, as evidenced by the presence of trapped oil. Natural fractures tend to be short relative to the distance between oil accumulations and protected groundwater, making them unlikely pathways even if a hydraulic fracture intersection props them open.

Some of these pathways also create risk to receptors other than water. For instance, a well blowout can release fluids to the surface that affect people, animals, and plants directly, rather than just through ingesting water contaminated with constituents used in stimulation that leak from the hydrocarbon-bearing zone into groundwater. (Note that this particular example is rare, in part because standard drilling and completion techniques require the use of a blowout preventer.)

5.4.1 Water Demand

Water used for making hydraulic fracturing fluids in the San Joaquin Basin is almost entirely high quality, meaning suitable for domestic or irrigation use (Volume II, Chapter 2). Therefore, one of the potential risks to public water availability is that the water demand for hydraulic fracturing could reduce valuable resources for other water uses. In some areas, produced water is treated, for example by reverse osmosis (RO), and then re-used for oil and gas operations, domestic purposes, or irrigation. Re-use of produced water is discussed in Section 5.4.2 below.

Some of the production enabled by hydraulic fracturing also uses “freshwater,” as coded in DOGGR records, for enhanced oil recovery (EOR), such as for water and steam flooding and cyclic steaming. Freshwater in this context in California is defined by DOGGR as water having less than 3,000 mg/L total dissolved solids (TDS) (Walker, 2011). This appears to reflect State Water Resources Control Board Resolution 88-63, as revised by Resolution 2006-0008, which defines water suitable, or potentially suitable, for domestic or municipal supply as, in part, water with less than 3,000 mg/L TDS.

The majority of solids dissolved in groundwater are generally salts. In other words, the water quality metric “total dissolved solids” is often equivalent to “salinity.” Water with low TDS has low salinity; water with high TDS has high salinity. In general, water with salinities exceeding 1,000 mg/L TDS is not considered suitable for drinking (Cal. Cod. Reg. § 64449) or for irrigating many crops, and so in this chapter, water with less than 3,000 mg/L TDS is referred to as low salinity rather than freshwater. Some portion of the water coded as low-salinity in DOGGR’s injection database may be high quality (i.e., appropriate for domestic or irrigation use), but DOGGR’s injection database does not make this distinction.

The use and potential use of low-salinity water in 2013 for EOR in hydraulic-fracturing-enabled production is broken out by pool in Table 5.4-1. This consists of water listed in DOGGR’s injection database as coming from sources other than an oil and gas well or the ocean, and consisting of other than salt water.

Table 5.4-1. Use and potential use of low-salinity water for EOR in 2013 in pools where most to all wells are hydraulically fractured. "Other" source is a designation in DOGGR's injection database. "Unknown" refers to water whose source code is not available in the database. "Maybe" low salinity includes water coded as c: "combined with chemicals", a: "another kind" beside salt, fresh, or with chemicals, and u: uncoded.

Field	Area	Pool	Source	Low salinity	Water volume	
					m^3	bbl
Belridge, North	Any	Diatomite	Other	Maybe-a	22,600	142,075
Elk Hills	Any	Stevens (31S)	Unknown	Maybe-u	368,000	2,314,947
Elk Hills	Any	Stevens (31S)	Water well	Maybe-u	39,100	245,752
Elk Hills	Any	Stevens (31S)	Water well	Yes	1,820,000	11,475,680
Elk Hills	Any	Stevens (31S)	Other	Maybe-a	95,800	602,296
Lost Hills	Any	Cahn	Other	Maybe-a	37,000	232,910
Lost Hills	Any	Etchegoin	Unknown	Maybe-c	2,210,000	13,887,373
Lost Hills	Any	Etchegoin	Other	Maybe-a	8,460	53,235
Mount Poso	Main	Pyramid Hill-Vedder	Unknown	Maybe-u	104,000	654,535
Total					4,710,000	29,608,803

Table 5.4-1 indicates that the 1.8 million m^3 (11.5 million bbl) of water from a groundwater well in one of the Elk Hills pool was definitely low-salinity and supplied to a pool with hydraulic-fracture-enabled production for EOR in 2013. For comparison, 13.4 million m^3 (84.3 million bbl) of such low-salinity water was used for EOR in all fields in the San Joaquin Basin in 2013. So 14% of the total volume of low-salinity water used for EOR in the Basin was used in pools where most to all wells are hydraulically fractured. This is less than the 22% of oil production in the San Joaquin Basin enabled by hydraulic fracturing (Volume II, Chapter 3). As obvious from Table 5.4-1, there are many entries with "Other" and "Maybe" classification, meaning that the water sources of several pools are unknown and could potentially be from high-quality water supplies.

The question arises whether the use of groundwater pumping for oil and gas production enabled by hydraulic fracturing has adversely affected groundwater levels. California's GeoTracker GAMA (Groundwater Ambient Monitoring & Assessment) provides access to water level data (http://geotracker.waterboards.ca.gov/gama/). There are no data for wells within the Elk Hills field to judge if pumping of low-salinity water in the area for EOR use in a hydraulic-fracture-enabled production pool has caused groundwater levels to decline. There is a cluster of monitoring wells in McKittrick to the east (Well ID L10008917084). Average annual water levels in these wells varied by two feet during the period covered (2006 to 2014). Levels declined in most wells and rose in some. The level in one well in Dustin Acres just south of the field rose 8 feet from 2001 through 2009 (ID 31S24E28Q002M), and rose by a few feet from 2000 through 2014 in another well in the area (ID 31S24E28B001M). Levels in three wells just east of the field near the Buena Vista Golf course varied by a couple feet or less from 2003 to 2009 (IDs 31S24E13P064M, 31S24E13K061M, 31S24E13J062M). Levels in the closest wells just north of the field have declined by more than 30 feet (ID 30S24E14M002M) and 20 feet (ID 30S24E06B002M) from 2011 to 2014.

The two wells north of the field with large water-level declines are in an area used for agriculture, while the wells to the west, south, and east with relatively stable water levels are not. This suggests that activities in the Elk Hills field are not affecting water levels in the surrounding shallow aquifers screened by these wells, but rather levels are more likely declining to the north due to groundwater withdrawal for irrigation during the drought.

Table 5.4-2 provides estimates of the total annual demand for low-salinity water in the San Joaquin Basin, which is the sum of demand for hydraulic fracturing fluids and for EOR in hydraulic fracturing-enabled production (modified from Volume II, Chapter 2, to account for only hydraulic fracturing and enabled EOR in the Basin). Note that only the demand that is coded as definitely low-salinity water supplied to the pool from Table 5.4-1 is shown in Table 5.4-2. In total, this demand is less than a thousandth of a percent of the high-quality water usage in the water resource Planning Areas in the San Joaquin Basin where hydraulic fracturing occurs, and is less than 0.2% in any individual Planning Area (total water use in each Planning Area from Department of Water Resources (2014)).

Table 5.4-2. The estimated annual volume of high-quality water demand for hydraulic fracturing and low-salinity water demand for hydraulic-fracturing-enabled EOR by water resources planning area in 2013.

Planning Area	Estimated annual hydraulic fracturing		Annual supply for enabled EOR (m^3)	Estimated annual water use		% of water use in Planning Area
	Operations	Water demand (m^3)		(m^3)	(acre-feet)	
Semitropic (Kern)	1,600	850,000	1,800,000	2,700,000	2,200	0.17
Kern Delta (Kern)	4	2,100		2,100	1.7	0.00011
Kern Valley Floor (Kern, Tulare)	34	18,000		18,000	15	0.0017
Uplands (Fresno, Tulare, Kern)	18	9,500		9,500	7.7	0.015
Western Uplands (San Benito, Fresno, Kings, Kern)	6	2,900		2,900	2.4	0.1
San Luis West Side (Fresno, Kings)	1	270		270	0.22	0.000017
Lower Kings-Tulare (Fresno, Kings)	1	740		740	0.6	0.00003
Total	1,700	880,000	2,000,000	3,000,000	2,500	0.0057

Table 5.4-2 shows that the volume of low-salinity water supplied to fields for hydraulic-fracturing-enabled EOR in the Semitropic Planning Area is about two times the volume of high-quality water needed for making hydraulic fracturing fluids in this area. Taking

the total volume of potential low-salinity water supplied to fields for hydraulic-fracturing-enabled EOR (i.e., 4,710,000 m^3, or 29.6 million bbl in Table 5.4-1) and comparing it to the total water demand for making hydraulic fracturing fluids in Table 5.4-2 (880,000 m^3, or 5.5 million bbl) gives a factor of roughly five. In other words, in the San Joaquin Basin, EOR enabled by hydraulic fracturing requires a larger volume of supplied low-salinity water than the actual stimulation requires high-quality water. While altogether the hydraulic fracturing-related demand in the Semitropic planning area is small relative to all demand, it occurs in an area of constrained supply.

As suggested in Section 5.4.2 below, it may be possible to reduce the use of high-quality water in hydraulic fracturing fluids by using brines higher in TDS, such as those available from produced water (Lebas et al., 2013; Kakadjian et al., 2013). However, it is not clear that the economic benefits would justify the cost in the San Joaquin Basin. Unlike in basins elsewhere in the country where hydraulic fracturing is conducted in, or near, source rock, and where there is typically less availability of pipeline infrastructure, hydraulic fracturing in California is conducted in migrated oil accumulations in fields with produced water pipelines to every well, and to nearby water supply pipelines. Consequently, water transport to and from the site is much less expensive than the longer distance transportation by truck common in production from source rock elsewhere.

5.4.2. Water Demand Reduction and Supply Increase

Oil production does not just use water; it also produces water along with the oil. There are potential opportunities to reduce the amount of water consumed by oil production and opportunities for beneficial reuse of the water produced along with the oil.

The volume of water produced with oil is more than ten times the volume of oil produced in California. For instance, DOGGR's production database indicates over 500 million m^3 (3 billion bbl) of water were produced along with over 30 million m^3 (200 million bbl) of oil in 2013, which is a ratio of 16 to 1. A total of 40% of this produced water is used for water flooding, steam flooding, and cyclic steam injection. The remainder of this water is disposed of via other means, mostly via subsurface injection into disposal wells.

At the same time, as indicated in the previous section, the largest demand for low-salinity water in hydraulic-fracturing-enabled production is not for making fracturing fluids, but rather for EOR. The source of this water is either low-salinity water produced along with oil within the field, or is supplied from other sources. Figure 5.4-1 shows the low-salinity supplied water for EOR in hydraulic-fracturing-enabled production, along with the amount of low-salinity produced water that is disposed of by injection in each field. More low-salinity produced water could be used to satisfy the water demand in other fields, thereby reducing the need for supply of potential high-quality water that could otherwise be used for municipal supplies or irrigation. After adequate treatment, such water is suitable for any domestic or irrigation use. If treatment with reverse osmosis (RO) is used, the higher-concentration brines that are generated as a waste fluid after RO treatment can be injected into disposal wells. The volume of this brine would be only a fraction of the total produced water volume, reducing impacts associated with injection wells.

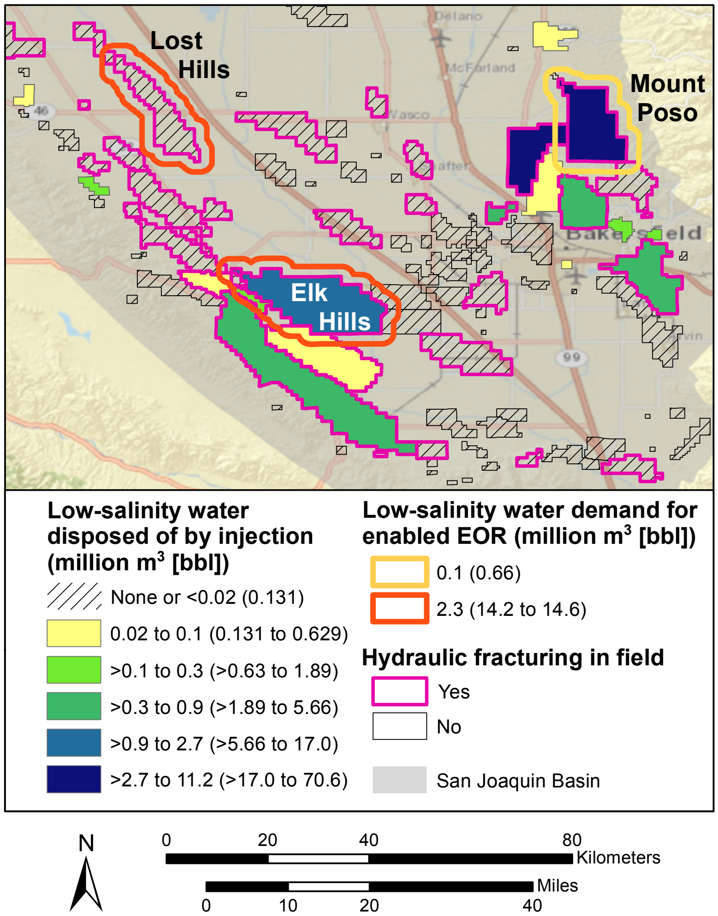


Figure 5.4-1. Produced low-salinity water disposed by injection in each field along with hydraulic fracture-enabled EOR demand for supplied low-salinity water in 2013

As an example, in the Elk Hills field, 1.1 million m³ (7.0 million bbl) of low-salinity water was disposed of by injection in 2013. This was about half of the demand for low-salinity water of approximately 2.3 million m³ (14.5 million bbl) supplied from outside oil and gas reservoirs for EOR in hydraulic-fracture-enabled pools. The simultaneous demand for supply of low-salinity water and disposal of low-salinity produced water in the same field may be because the quality of the low-salinity water that is disposed by injection is not sufficient for the EOR. If this is the case, it should be possible to treat the low-salinity water disposed of in Elk Hills so that it can instead be used for EOR. There is also low-salinity water disposed of in nearby fields that may be of sufficient quality to displace some of the demand for this water in Elk Hills.

The volume of low-salinity water disposed by injection in the Mount Poso field is much greater than demanded from supplies for EOR in the hydraulic-fracture-enabled pool. Again, this may result from a quality mismatch within the field. If so, and it is not practical to improve the water sufficiently with treatment, there is also a considerable amount of low-salinity water disposed by injection in surrounding fields that may be of sufficient quality for this use.

More generally, the total amount of low-salinity water disposed of by injection as shown in Figure 5.4-1 was 18.0 million m^3 (131 million bbl) in 2013. This is sufficient to meet the entire 2013 EOR demand for low-salinity water supply to fields of 13.4 million m^3 (84.3 million bbl), if the location and quality of sources can be matched to the location and quality of demand. If this were done, there would still be about 5 million m^3 (31 million bbl, 4,000 acre feet) of disposed low-salinity water that could be directed to other beneficial uses. However, because this water is presumably produced in the field in which it is disposed, and all the fields where larger volumes of this water are disposed also have a record of hydraulic fracturing, care would have to be taken to assure that the quality of the water is suitable for the beneficial use. Some perspective on this is offered below regarding use of this water for irrigation, for instance.

There may be additional low-salinity water resource opportunities in the San Joaquin Basin oil fields, because the quality of the water produced in each field is not coded in DOGGR's data, only the quality of the water disposed of by injection. Consequently, there may be low-salinity produced water disposed of by means other than injection, such as by percolation in unlined pits.

The disposal of low-salinity water suggests a detailed analysis of the spatial relationship and water quality between sources of this water and the location of supplied low-salinity water used for EOR would be useful. This could determine if the disposed water is suitable for EOR, or can be economically treated to make it suitable, and if it could economically be transferred to where it is needed for EOR. To the extent that this type of beneficial reuse could occur, it would reduce the demand for low-salinity water from sources outside oil pools. This would in turn make more water available for other uses in the San Joaquin Basin.

5.4.3. Produced Water Disposal

As discussed in Volume II, Chapter 2, there are various mechanisms by which produced water disposal can potentially degrade the quality of waters otherwise suitable for use, particularly groundwater. The risk from the two main methods of disposal of produced water from predominantly hydraulically fractured pools, percolation pits and injection, as well as from beneficial reuse of water at the surface from pools with some hydraulic fracturing, is discussed below.

5.4.3.1. Disposal to Percolation Pits

Hydraulic fracturing chemicals in the produced water may contaminate potable water supplies if not handled appropriately. According to DOGGR's production database, one of the methods currently used for produced water disposal in the San Joaquin Basin is discharge into evaporation-percolation pits (Volume I, Appendix N). These facilities vary from single, unlined pits to large complexes consisting of multiple pits. In the large complexes, the produced water enters smaller pits that provide for floatation and skimming of any remaining undissolved oil, with the water then flowing on to larger pits for evaporation and percolation. In practice, the year-round flow of water to these pits indicates most of it percolates, because evaporation rates in the winter are low. Figure 5.4-2 shows the location of percolation pits in the San Joaquin Basin relative to the minimum concentration of TDS in groundwater in 5 km by 5 km (3 mi. by 3 mi.) square areas. Most of the TDS data are from water supply wells. Consequently, the percolation of produced water into the shallow subsurface is a potential risk for contamination of potable groundwater resources.

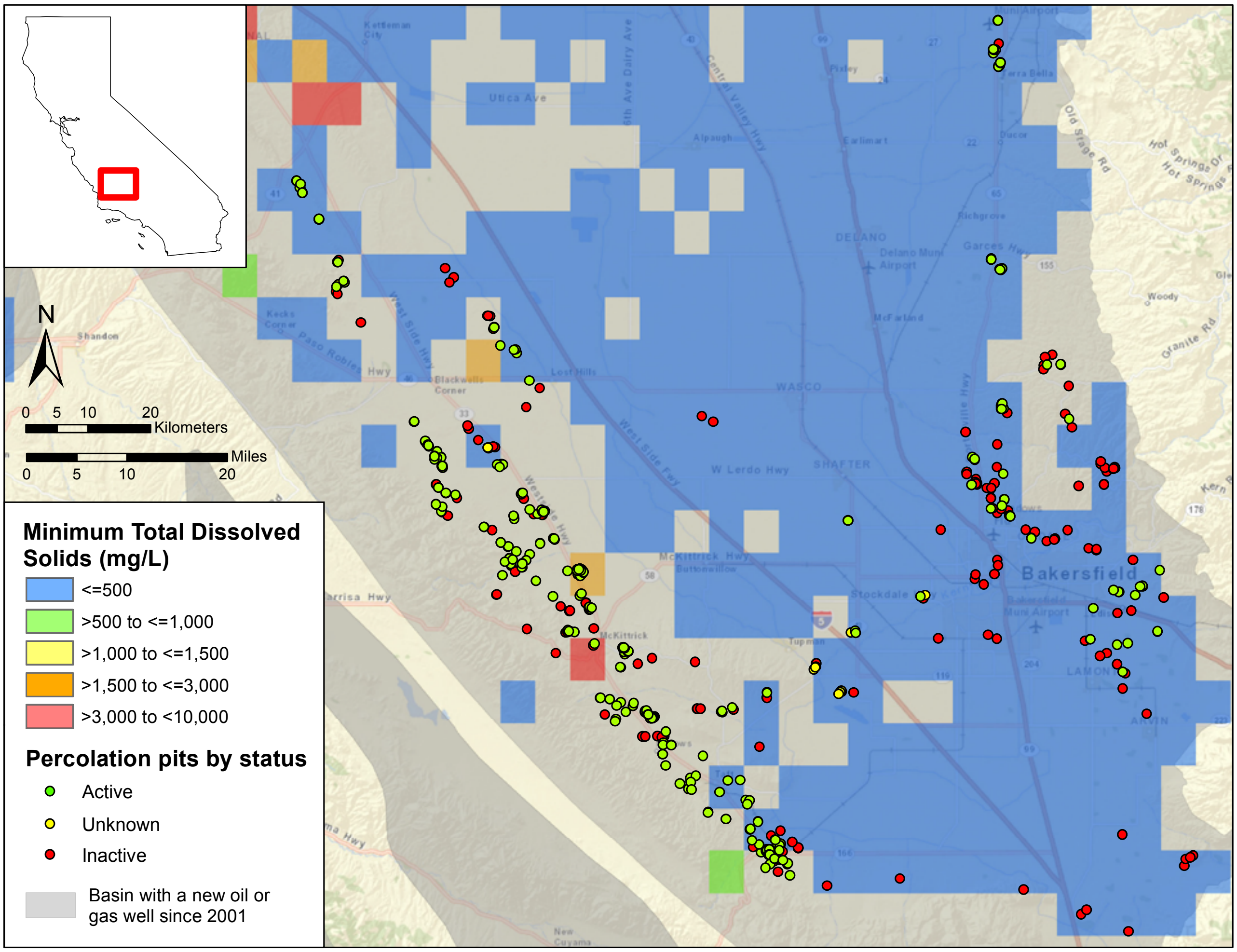


Figure 5.4-2. Minimum total dissolved solids concentration from GeoTracker GAMA[1] in 5 km by 5 km (3 mi.by 3 mi.) square areas in the southern San Joaquin Basin as of October 14, 2014, with the location of and location of percolation pits used for produced water disposal[2] overlain.

Table 5.4-3 provides the estimated number of hydraulic fracturing operations per year per pool in fields with more than 100 operations in total, and the percentage of produced water from each pool discharged to evaporation-percolation pits for disposal in 2013. The percentage of water from several of these pools discharged to pits is high. An important caveat, noted in Volume II, Chapter 2, is that some operators have communicated they no longer dispose of the water they produce in these fields in evaporation-percolation

1. http://geotracker.waterboards.ca.gov/gama/
2. http://www.waterboards.ca.gov/rwqcb5/water_issues/oil_fields/information/disposal_ponds/2015_0415_prod_pond_list.pdf

pits, but rather they dispose of the water by injection. The analysis in Table 5.4-3 is based upon the publicly available data, which in part is contradicted by the information communicated by some operators. The analysis below also assumes all the produced water from hydraulically fractured wells fully commingles with all the produced water from a field, and so is not specific to the method of disposal. This is because treatment of water produced in most fields is typically handled in central facilities, leading to the assumption that all the produced water from the stimulated pools is commingled with produced water from the entire field. For simplicity, the return of fracturing chemicals in produced water is also assumed constant, which is supported by the large number of hydraulic fracturing operations per month in the pools shown in Table 5.4-3.

Table 5.4-3. Estimated number of hydraulic fracturing operations per year per pool in fields with more than 100 estimated operations, and percentage of produced water from those pools discharged to evaporation-percolation pits for disposal in 2013.

Field	Pool	Estimated # of fracturing operations per year	% of produced water discharged to evaporation-percolation pond(s)
Belridge, North	Diatomite	139	83%
Belridge, South	Diatomite	996	90%
	Monterey (Undifferentiated)	1	0%
Elk Hills	Stevens (31S)	26	99%
	Upper (Undifferentiated)	129	98%
	Carneros	6	97%
Lost Hills	Etchegoin	179	59%
	Cahn	33	22%
	Antelope/McDonald	1	0%

Table 5.4-4 gives the estimated number of, and water volume used for, hydraulic fracturing operations per year in the four fields with the greatest number of operations. The estimated water volume for the hydraulic fracturing operations results from multiplying the estimated number of operations per year with the average water volume used for operations in that field from Volume I, Appendix O. As described in Volume II, Chapter 2, most stimulation-fluid returns are commingled and co-managed with water from the oil reservoir as produced water, so Table 5.4-4 also shows the water volume produced from each field in 2013. Finally, the table gives a dilution factor, calculated for each field as the ratio of the total produced water divided by the total water used for hydraulic fracturing. This “dilution” assumes as a conservative estimate that the entire volume of hydraulic fracturing fluid returns in the produced water.

Table 5.4-4. Estimated number of hydraulic fracturing operations and volume of water used per year per field with more than 100 estimated operations, water volume produced from each field in 2013, and dilution factor.

Field	Estimated fracturing operations per year			Water produced in 2013		Dilution factor (produced water/water for fracturing)
	#	Water volume				
		(m³)	(bbl)	(m³)	(bbl)	
Belridge, North	139	53,100	334,000	4,350,000	27,337,084	82
Belridge, South	997	347,000	2,180,000	49,300,000	310,278,910	140
Elk Hills	161	108,000	678,000	24,800,000	156,108,579	230
Lost Hills	213	107,000	675,000	21,100,000	132,840,719	200

The amount of each hydraulic fracturing fluid constituent, degradation product, and mobilized natural constituent subsequently produced with the water, oil, and gas from a well is not known in the San Joaquin Basin, because it is not reported in available databases, nor has it been determined from produced water analysis. In the absence of this information, the potential upper-limit concentration of each constituent in the produced water, excluding proppants, was estimated to provide some perspective on the potential risks (excluding proppant). The calculated total mass of each constituent injected was divided by the produced water mass for the field. This resulted in an approximate upper bound concentration of hydraulic fracturing fluid constituents in the produced water in each field as a whole, which are available in Appendix 5.B. The concentrations of degradation products and natural constituents mobilized by stimulation are obviously not considered in this first-order estimate approach.

The average mass of each chemical used recently in stimulations in the fields listed in Table 5.44 was calculated from the chemical dataset assembled from FracFocus (Volume II, Chapter 2). For each field, the mean mass of each constituent per record in the database was multiplied by the number of records in the database for that constituent, divided by the number of hydraulic fracturing operations in the database, to provide the mean mass per hydraulic fracturing operation. This accounted for the occurrence of more than one record for some constituents for some operations, such as if the same constituent was a component of more than one additive mixture. The mean mass per operation was multiplied by the estimated number of operations per year in Table 5.4-3, to provide the total estimated mass of each chemical injected per year.

The concentrations resulting from this approach are termed “potential upper-limit,” for a number of reasons. The approach overestimates the concentration for constituents that react with each other or the water or rock in the reservoir, or are adsorbed onto the rock. It overestimates the concentration for constituents that are removed, in whole or part, by oil-water-gas separators and subsequent treatment systems. It may overestimate the concentration due to dilution with produced water from other fields disposed to the same percolation and evaporation pond. It overestimates or underestimates the concentration at any given time by assuming a uniform return of constituents with the produced water. The concentrations are highest when production begins after stimulation. It may underestimate concentrations in some produced water by erroneously assuming all produced water in a field is commingled, such as because there is more than one operator in a field, each with its own treatment plant.

With regard to concentration overestimation due to interaction with (including adsorption on) reservoir rock minerals, this seems likely to be less in California than other parts of the country. Fracturing fluids in California typically have the highest viscosity of fracturing fluid formulations available, and fracturing operations in California are designed to produce simple, bi-wing fractures with apertures at the largest end of the range for hydraulic fractures. Consequently, it is likely there is less interaction between hydraulic fracturing fluid and reservoir rock in California than elsewhere in the country on average, and consequently a higher fraction of the hydraulic fracturing fluid constituent mass returns in water produced after the hydraulic fracturing operation.

Figure 5.4-3 compares the potential upper limit concentrations in produced water to concentrations that are acutely toxic to half the individuals of three aquatic species during a two- to four-day exposure. Measures of these acutely toxic concentrations are only available for about a fourth to a third of the constituents for each of the three species, and only about two fifths of the constituents for one or more species.

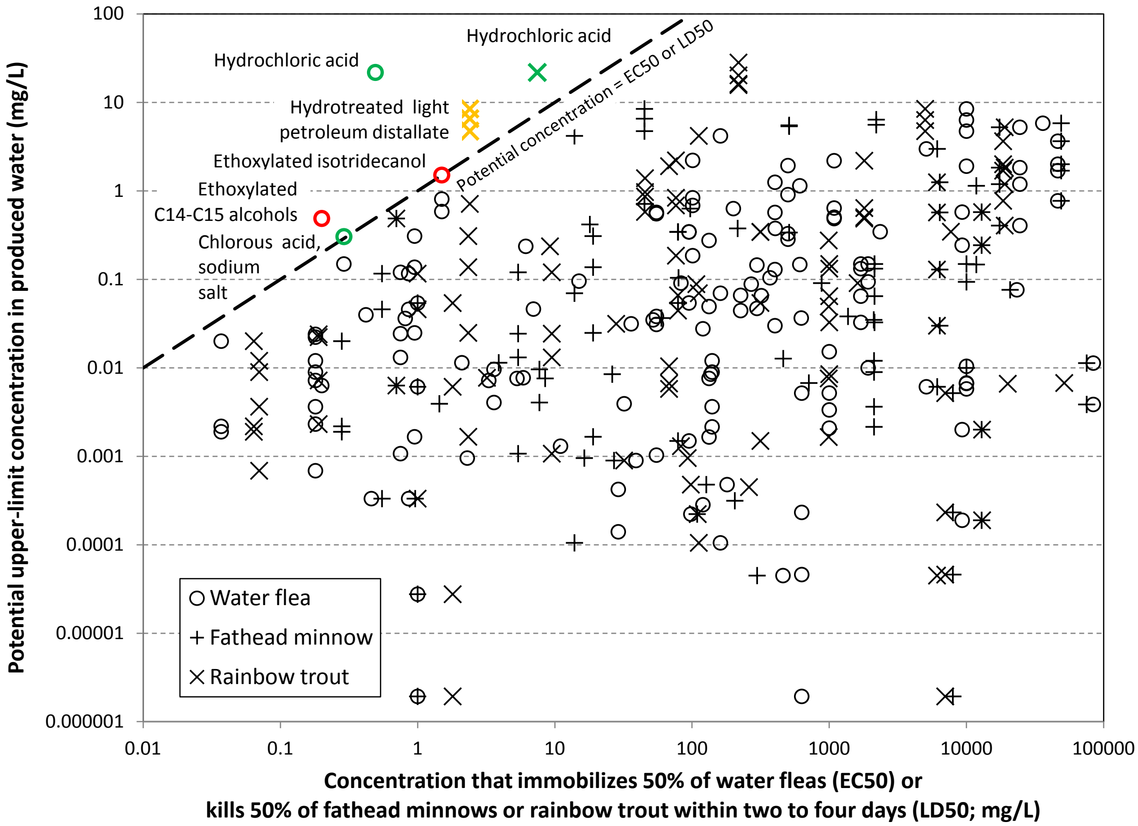


Figure 5.4-3. Comparison of potential hydraulic fracturing fluid constituent upper limit concentrations in produced water from the North and South Belridge, Elk Hills, and Lost Hills fields to the concentrations that are acutely toxic to more than half the individuals of a species during a two to four day exposure. Potential acutely toxic concentrations occur above the dashed line. See text for explanation of the symbol colors.

Some potential upper limit concentrations are acutely toxic to half the individuals of one or more of the three aquatic species. These concentrations consist of hydrochloric acid, hydrotreated light petroleum distillate, ethoxylated isotridecanol, and ethoxylated C14-C15 alcohols. Of these, hydrochloric acid almost certainly would not occur at a toxic concentration, because it would be neutralized by reactions with rock during stimulation. The concentrations of hydrotreated light petroleum distillate would likely be lower in the treatment plant effluent from a field, because it has low solubility. Consequently, it may be removed along with other hydrocarbon phases during oil-gas-water separation and subsequent water treatment. However, this may not occur, depending upon the interaction between this constituent and surfactants also typically added to hydraulic fracturing fluids. The ethoxylated constituents are miscible with water and not obviously reactive with rock, so these may occur at the potential upper-limit concentrations shown.

Assessing which, if any, concentrations have acute or chronic effects on terrestrial animals is more difficult. Acute toxicity measurements are available for rats, mice, or rabbits for many of the constituents. These measurements consist of a dose per body weight. Consequently, they are not readily comparable to potential upper-limit concentrations.

Regulatory agencies manage the deleterious health effects of water contamination for humans by proscribing maximum allowable concentrations of a contaminant, and a desirable concentration goal. The maximum allowable concentration is usually based upon limiting chronic health conditions, such as cancer, that some portion of individuals (such as one out of a million) will experience if they consume the water for a lifetime. In contrast, the desirable concentration goal is that at which no individuals are expected to experience health effects.

Agencies have established the maximum allowable concentration for only one of the hydraulic fracturing constituents disclosed (acrylamide), and a component of only one other has a concentration goal set by regulation (chloride). The Office of Environmental Health Hazard Assessment (OEHHA) provided screening criteria for additional constituents in Volume II, Appendix 6.B, but those are units relevant to inhalation and oral dosing, rather than the concentrations in water considered here. A comparison of the potential upper-limit concentrations of hydraulic fracturing fluid constituents to the maximum allowable concentrations in water for other constituents with similar acute toxicity in rats, rabbits, and mice suggests that some of the potential upper-limit concentrations would exceed the maximum allowable concentration for that concentration, if one were established. Further details of this analysis and its results are available in Appendix 5.C.

Ascertaining if any of the hydraulic fracturing fluid constituents actually occur at hazardous concentrations (for either acute or chronic effects) in produced water requires more detailed investigation via chemical analysis of produced waters from stimulated pools. In the absence of such data, given the comparison to concentrations acutely toxic to half the individuals in three aquatic species, and to maximum allowable concentrations for human consumption for similar acutely toxic constituents, it cannot be ruled out that some of the constituents would occur at concentrations of concern. Consequently, if usable groundwater is present, there is some likelihood that these constituents could percolate into the subsurface and eventually reach and degrade the groundwater resource. This evaluation of hazard does not account for the dilution of the constituents in groundwater and any chemical reactions that may occur.

Unless chemical analysis of produced water demonstrates low concentrations that pose no hazard, the most appropriate means to reduce the likelihood of groundwater degradation occurring due to the use of unlined pits in the future is to dispose of produced water from hydraulic fracturing pools by some other means, such as injection below the base of protected groundwater.

As mentioned in Volume II, Chapter 2, a means to reduce concern about release of stimulation constituents is to move toward the North Sea compact/OSPAR Convention (Oslo and Paris Convention) approach to constituent selection for stimulation fluids, which requires testing of chemicals for environmentally relevant parameters (such as acute toxicity and biodegradability) and meeting certain performance criteria prior to use. In California, a similar program could be built upon the U.S. Environmental Protection Agency's Designed for Environment program, which is voluntary at the national level (U.S. Environmental Protection Agency (U.S. EPA), 2011). This would result in utilization of constituents with among the lowest potential environmental impacts for each purpose (such as corrosion and bacterial growth inhibition).

As also mentioned in Volume II, Chapter 2, some operators have communicated that they have transitioned from produced water disposal in unlined pits to disposal by injection, despite data they have submitted to DOGGR to the contrary. So the risk from surface disposal appears to be less than indicated by the produced water disposition data available from DOGGR. However, there are other operators in these fields that have not been contacted whose produced water is also coded as being disposed of in unlined pits. In addition, there may still be a legacy risk of groundwater contamination from the past practice of operators who no longer discharge produced water to these facilities for disposal. Operators should be contacted and required to correct erroneous data submitted in the past. Even if disposal in unlined pits is phased out in the future, investigations should be conducted to determine if past disposal to such pits has impacted groundwater in the vicinity, and if so, site characterization and remediation should follow.

5.4.3.2. Injection Into Groundwater That Potentially Should Be Protected

Another common method for disposing of produced water in the San Joaquin Basin is injection into aquifers with low quality groundwater above 10,000 mg/L TDS. This is termed water disposal injection, in contrast to injection for EOR. Water disposal injection is regulated under the US Safe Drinking Water Act by DOGGR acting on behalf of the U.S. EPA, and can minimize the risk of contaminants entering protected water if carried out in compliance with the underground injection control regulations. In the San Joaquin Basin, water disposal injection is frequently being used for disposing of produced water. However, in June of 2014, DOGGR issued orders to cease water disposal injection in 11 wells that may have been inappropriately permitted for injection into protected groundwater. (Protected groundwater according to EPA has less than 10,000 mg/L TDS and is not in an exempt aquifer. Aquifers may be exempted for several reasons—for example, because they contain commercially producible minerals or hydrocarbons, or because they are too deep for economic water production.) Injection in some of these wells was subsequently determined allowable and restarted, while others remained closed. DOGGR is currently reviewing many more wells to determine if it inappropriately permitted injection into aquifers that should be protected (DOGGR and State Water Resources Control Board (SWRCB), 2015). Below, the wells in review are assessed to determine if they may have received wastewater from nearby stimulated production wells, in which case the injected water may also have contained stimulation chemicals at unknown concentrations.

The first component of the assessment is a statistical analysis regarding produced water disposed of by injection in pools where most wells are hydraulically fractured and where there are more than 100 fracturing operations per year. Table 5.4-5 shows the percentage of produced water from these pools disposed of by injection. The table indicates relatively little of the water is disposed of by injection; however, as mentioned in Section 5.4.3.1, some operators have indicated they do not dispose of produced water in the fields listed in Table 5.4-3 and 5.4-5 to evaporation-percolation pits any longer, despite submitting data to DOGGR to the contrary. They instead dispose of the produced water by injection (Volume II, Chapter 2). This is particularly true in the Elk Hills field, which Table 5.4-5 indicates has little produced water injection, but where the operator indicates that all produced water is now injected. In other words, the percentages of produced water disposed by injection given in Table 5.4-5 could be higher for more recent operational practices.

Table 5.4-5. Estimated number of hydraulic fracturing operations per year per pool in fields with more than 100 estimated operations, and percentage of produced water from those pools injected in 2013.

Field	Pool	Estimated # of fracturing operations per year	% of produced water injected in disposal wells
Belridge, North	Diatomite	139	16%
Belridge, South	Diatomite	996	8%
	Monterey (Undifferentiated)	1	0%
Elk Hills	Stevens (31S)	26	0%
	Upper (Undifferentiated)	129	0%
	Carneros	6	1%
Lost Hills	Etchegoin	179	13%
	Cahn	33	54%
	Antelope/McDonald	1	100%

The potential upper limit concentrations of hydraulic fracturing fluid constituents in produced water that were calculated in the previous section can also be used to evaluate potential concerns about inappropriate injection of produced water. DOGGR is currently reviewing if the zones into which wells have been injecting are exempt from protection, as required in order for injection of produced water to occur. Groundwater can be exempt from protection if the TDS concentration is greater 10,000 mg/L, the TDS concentration is over 3,000 mg/L and the water co-occurs with a quantity of oil or gas that is economical to produce, or if the TDS concentration is greater than 3,000 mg/L and the water is not economical to produce and treat to drinking water standards— such as due to location, depth, and/or naturally occurring contaminants in the water. As a result of this review, DOGGR has identified thousands of injection wells for more detailed consideration (DOGGR, 2015).

Of the 2,552 injection wells under review by DOGGR, 468 were active or idle water-disposal wells.[3] Figure 5.4-4 shows that many of the fields where hydraulic fracturing has occurred have a substantial percentage of water disposal wells under review. In particular, this is the case for three of the four main fields where these hydraulic fracturing operations take place: South Belridge, Lost Hills, and Elk Hills. To the extent these wells are determined to have been injecting into zones that should not have been exempted from protection, the estimated hydraulic fracturing constituent concentrations suggest such constituents could be detected, potentially at hazardous concentrations, in the zones.

3. DOGGR (2015) includes two lists of wells for review: one stated as water disposal wells and the other stated as EOR wells. Comparison of the water disposal well list to DOGGR's AllWells file (DOGGR, 2014) indicated some of the wells on the list are not water disposal wells. Consequently, the water disposal and EOR well review lists were combined in order to select all the wells under review that are water disposal wells according to DOGGR (2014). This determined there was one well included on both lists. One record was included for this well in the combined list.

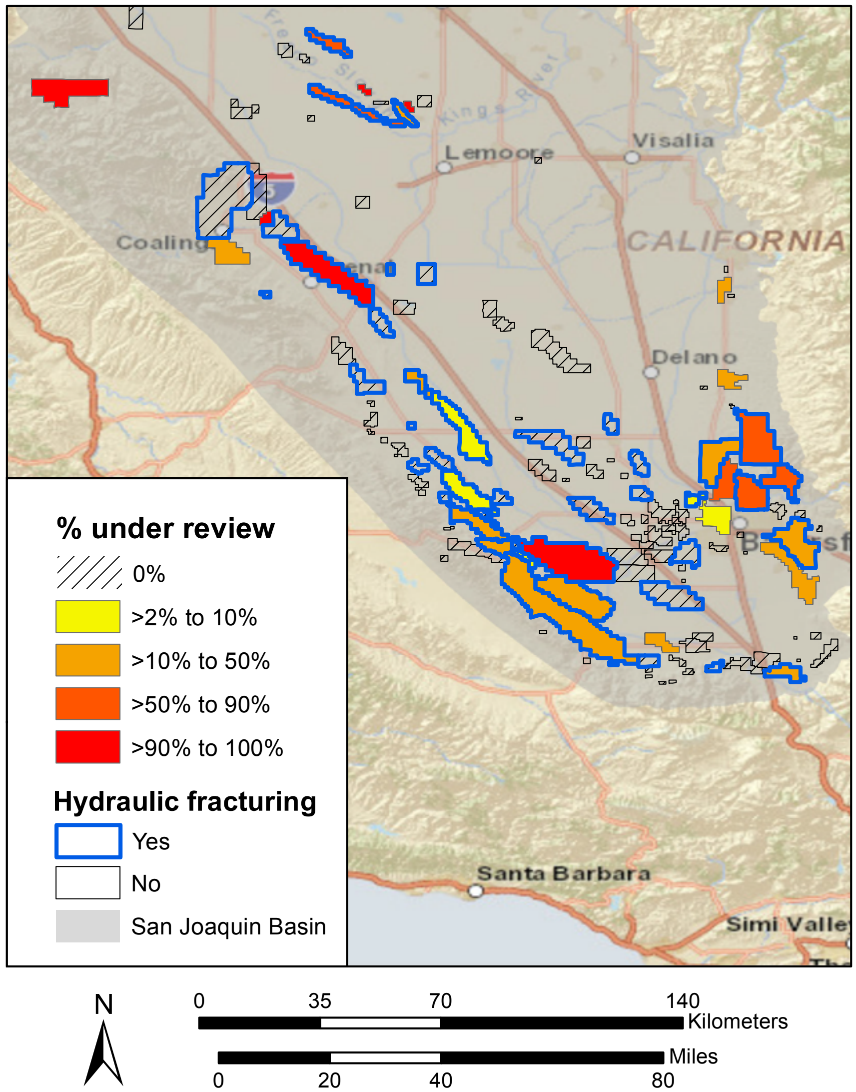


Figure 5.4-4. Percentage of water disposal wells in each field undergoing review by DOGGR for appropriateness of its permitting relative to the quality of the groundwater in the injection zone.

The percent of disposal wells under review in South Belridge and Lost Hills is relatively small, suggesting it might be possible to relatively rapidly redirect disposal to other wells in the event the wells under review are shut down. Almost all the disposal wells at Elk Hills are under review, indicating considerably more difficulty assessing potential impacts to the receiving zones if it is determined they contain groundwater that should be protected.

The Safe Drinking Water Act and the Underground Injection Control program provide a regulatory and technical basis for protecting underground sources of drinking water. As such, a more methodical system for permitting water disposal injections would arguably decrease the potential for disposal of contaminated produced water in protected groundwater. The state should establish the boundaries of water to be protected, and through the Underground Injection Control program, only allow injection into saline, non-potable aquifers that are sufficiently isolated from overlying groundwater resources to protect those resources. Currently, these boundaries are uncertain, because protected groundwater (for instance, water with TDS content up to 10,000 mg/L) has not been mapped systematically.

5.4.3.3. Beneficial Reuse Involving Release to the Surface

Some produced water is used for irrigation and groundwater recharge in parts of the San Joaquin Basin. After appropriate treatment, such reuse has benefits in areas with water scarcity. However, if this water is produced from fields that have applied well stimulation technologies, and if the treatment process is insufficient with regards to stimulation chemicals, then use for irrigation creates a potential pathway for humans to be exposed to chemicals in produced water from stimulated wells through agricultural products, as well as direct exposure of wildlife and vegetation. Where produced water has been used for irrigation and groundwater recharge, and how this relates to fields with hydraulic fracturing operations, is assessed below.

Produced water from two fields where hydraulic fracturing has occurred is permitted for agricultural usage: the Mount Poso and the Kern River fields (Volume II, Chapter 2). For the Mount Poso field, a search of the Central Valley Regional Water Quality Control Board (CVRWQCB) records suggests only water produced by SOC Resources, Inc., was permitted for irrigation (CVRWQCB, 2006). DOGGR's production database indicates that SOC Resources produced water in the Dominion area, but not the Main area, at the time and extending back to at least 2000. The integrated hydraulic fracturing data set (Volume I, Appendix M) does not include any operations in the Dominion area, nor are there any matrix acidizing operations listed in the CVRWQCB data set (described in Volume I, Chapter 3). Consequently, it is unlikely stimulation chemicals entered this water stream and ended up in irrigation water. However, water in the Vedder portion of the Pyramid Hill-Vedder pool has a TDS content of 1,000 to 1,500 mg/L (DOGGR, 1998), suggesting it could potentially be used for irrigation at some point in the future (it was primarily disposed by injection in 2013 according to DOGGR's production and injection database). The predominance of hydraulic fracturing in that pool suggests that hydraulic fracturing fluid constituents could be present in water produced from that pool.

In addition to irrigation, produced water from the Kern River field is used for groundwater recharge in the winter time when agricultural water demand is low. Prior to this, the water was released to Poso Creek (CVRWQCB, 2012). A search of CVRWQCB records indicates that at Kern River Field only Chevron USA, Inc. (Chevron), was permitted to discharge produced water for irrigation and groundwater recharge (CVRWQCB, 2012). Three of the wells identified as hydraulically fractured in the Kern River field in the integrated set (Volume I, Appendix M) are operated by Chevron. One of these was identified only from the well record search. Due to the small proportion of well records searched, this record suggests approximately one to two hydraulic fracturing operations per year occurred in the Kern River field on average between 2002 and 2013. The calculation of the estimated number of annual hydraulic fractures per field is explained in Volume II, Appendix 5.E.

CVRWQCB (2012) indicates the facility operated by Chevron that treats produced water subsequently discharged for irrigation can process 143,000 m^3 (900,000 bbl) per day, but the average treated was 83,000 m^3 (520,000 bbl) per day. This is a significant fraction of the total water produced by Chevron in the Kern River field, which was 150,000 m^3 (950,000 bbl) per day on average from 1990 through 2013. The treatment facility uses the same components as the Kern Front No. 2 facility, which will not remove most stimulation fluid constituents (Volume II, Chapter 2).

Produced water from one of the two wells identified as hydraulically fractured operated by Chevron is disposed of by injection according to DOGGR's production database. The database has no disposition data for produced water from the second well. It is not known if produced water from this well is used for irrigation and groundwater recharge. Given the uncertainty regarding the accuracy of produced water disposition data in DOGGR's production database, it is not known if water from the other two wells is used for these purposes rather than disposed of by injection. It is also not known if water from unidentified hydraulically fractured wells operated by Chevron is used for these purposes. Given the high proportion of Chevron's produced water in this field that does go through the treatment facility, providing water for irrigation and groundwater recharge, it is likely that produced water from some well or wells goes to this facility. Further, and perhaps more importantly, there has been and is currently no regulatory control on produced water from hydraulically fractured wells being used for irrigation and groundwater recharge.

No data regarding stimulation fluid constituents for operations in the Kern River field are available. Of constituents that occur in more than 5% of the operations for which the constituents were disclosed (at least in part), the largest median mass for any single, soluble constituent with a Globally Harmonized System (GHS) acute aquatic toxicity category of 1 (the most toxic category) is 135 kg (ethoxylated C14-15 alcohols; GHS acute aquatic toxicity category 1 encompasses the most toxic constituents). This mass dissolved in the average daily volume of produced water used for irrigation would result in a concentration of 1.6 mg/L. This is several times the concentration that kills or disables 50% of the individuals of certain aquatic species in two to four days.

However, it is unlikely the entire mass of a stimulation chemical would be produced back from a hydraulically fractured well, and it is unlikely that whatever portion of the mass is ultimately produced back would be produced back in one day. Further, some downstream dilution with water from other sources does occur, although, according to information in CVRWQCB (2012), only minimal dilution appears to be necessary to meet the quality goals of the irrigation district receiving the water.

On the other hand, the concentration that would not have an acute effect on any individuals is less than that considered. In addition, acute aquatic toxicity measurements for the animals and algae considered are not available for more than half and a bit less than half of the constituents, respectively. The synergistic effects of exposure to the concentrations of multiple constituents at once are not accounted for in the acute toxicity measurements that are available. Other constituents in lower acute aquatic toxicity categories may be used in greater masses, also resulting in potentially acutely toxic concentration spikes in produced water.

The above reasoning indicates that the current practice of treatment and dilution of produced water utilized for irrigation may not be sufficient to reduce concentrations of all stimulation constituents to levels that are less than acutely toxic, or even to levels less than what can cause chronic effects for aquatic species on a continuous basis. In addition, the human exposure pathway involving consumption of food irrigated with produced water containing hydraulic fracturing fluid constituents is not considered. However, no known instances of such contamination have been observed. Further investigations are needed to ensure that environmental or human health concerns as a result of these practices can be ruled out. If risk of contamination is found to be unacceptably high, hydraulic fracturing in reservoirs that produce water used for irrigation or other beneficial purposes should be reconsidered until the produced waters are demonstrated to be safe for agricultural use. If concentrations are inconsistent with agricultural use, then treatment systems should be considered that remove stimulation fluid constituents or reduce their concentrations to acceptable levels, or use of the produced water for irrigation should cease. The latter would require determining what levels are acceptable, which is not known for almost all of the chemicals used in hydraulic fracturing.

5.4.4. Leakage Via Subsurface Pathways

Fluid leakage from an oilfield production interval into other zones can potentially occur via subsurface pathways, including induced and natural fractures, faults, and wells. A driving force is required for leakage via such pathways, whether preexisting or created by the stimulation. This can be provided by a vertical upward hydraulic gradient and/or buoyancy force due to fluids in the pool less dense than those overlying the pool.

Leakage of non-buoyant liquids, such as hydraulic fracturing fluids containing well stimulation chemicals, generally requires a pressure sufficient to cause them to flow upward towards protected groundwater resources. Gas leakage only requires a transmissive pathway, because gases are much less dense than water and migrate under buoyancy. Most oils are also less dense than water, and so could flow upward due to buoyancy. However, the buoyancy forces are smaller because oil is closer to the density of water than is gas, and the mobility of oil is much smaller than that of gas due to its much higher viscosity. As a result, leakage of oil is generally much less of a concern than leakage of gas, but it cannot be ruled out. Further, studies suggest leakage of buoyant fluids will be limited both by production in the reservoir and the capillary entry pressure to permeable features (Reagan et al., 2015).

This section focuses on the possibility of hydraulic fracturing fluids leaking into protected groundwater resources, which means the driving force of concern is the hydraulic gradient rather than buoyancy. In areas with oil and gas production, the natural hydraulic gradient can be strongly affected by production-related pressure changes in the reservoir rocks relative to the overlying fresh groundwater systems. This has certainly been the case in the San Joaquin Basin: In 2013, only about 3% of the oil produced from the 28 pools in the Basin where most to all wells are estimated as hydraulically fractured, flowed from the well due to reservoir pressure in 2013. About 90% is coded as produced using artificial-lift, mostly by rod-pump, with most of the rest coded as other or not coded. This is up from over 20% produced by artificial lift in 1980, early in the production from most of these pools, over 50% in 1990, and over 80% in 2000. In other words, past oil and gas production in the San Joaquin Basin has reduced the pressure in producing reservoirs to the extent that the driving force for potential leakage has diminished or reversed in most pools. Just a few of the 28 pools with hydraulic-fracture-enabled production continued to produce a significant portion of the oil by flow in 2013. All pools with more than 3% oil production by flow rather than lift are shown on Table 5.4-6.

General guidance to maximize production using pumping is to maintain the bottom-hole pressure at less than 10% of the static reservoir pressure (McCoy et al., 2003). This results in a large downward vertical head gradient from overlying aquifers to the pool. Due to this gradient, there is no driving force for upward leakage of liquids as dense as or denser than water during production, and thus little risk of fracturing fluids or formation water migrating upward from hydraulically fractured pools during production.

Table 5.4-6. Predominantly hydraulically fractured pools in the San Joaquin Basin with more than 3% of the oil flowed to the surface in 2013 rather being lifted, such as by a pump.

Field	Area	Pool	Oil produced		% flowing
			m^3	bbl	
Shafter, North	Any Area	McClure	150,000	940,893	66%
Lost Hills, Northwest	Any Area	Antelope Shale	420	2,642	27%
Rose	Any Area	McClure	73,700	463,643	19%
Kettleman Middle Dome	Any Area	Kreyenhagen	2,790	17,552	9%
Elk Hills	Any Area	Stevens (31S)	327,000	2,059,961	7%
Monument Junction	Main Area	Antelope	14,300	89,680	4%
McKittrick	Northeast Area	Point of Rocks	14,700	92,612	4%

While there is little risk of liquids leaking upward during production due to the general lack of a driving force, there may be some hazard of upward-leaking liquids during the hydraulic fracturing operations due to the pressure applied during fracturing. This possibility is analyzed below for the San Joaquin Basin regarding leakage of stimulation fluids via induced fractures, pre-existing natural fractures, wells, and fault pathways.

Aside from the risk of liquid leakage, the development of these pools does increase the probability of gas leakage via subsurface pathways due to buoyancy, as observed in several studies for various areas with and without hydraulic fracturing elsewhere in the country (Volume II, Chapter 2). The portion of these potential emissions that are caused by hydraulic-fracturing-enabled production is assessed in the section regarding risk to air in the San Joaquin Basin in this case study.

5.4.4.1. Shallow Fracturing

Most hydraulic fracturing in the San Joaquin Basin occurs shallower than 300 m (1,000 ft). This means that operators produce hydraulic fractures near the surface that can present a hazard if there is nearby protected groundwater. Hydraulic fracturing at these shallow depths has been permitted in at least one field where the California State Water Resources Control Board (SWRCB) has recently required a groundwater monitoring plan (Lost Hills), indicating the presence of protected groundwater (Volume I, Chapter 3, and Volume II, Chapter 2). Figure 5.4-5 shows the minimum depth of fracturing relative to the minimum TDS concentration in groundwater in 5 km by 5 km (3 mi. by 3 mi.) square areas, which suggests there are other fields with shallow hydraulic fracturing near protected groundwater. Consequently, the planned separation between the base of protected groundwater and the top of the shallowest induced fracture is in the tens to (at most) hundred meters. Given the uncertainty about the vertical extent of hydraulic fractures, this creates a potential for the induced fractures to encounter protected groundwater and release stimulation fluids as well as oil and gas into this groundwater. Further, because the TDS data were predominantly from water supply wells, Figure 5.4-5 also suggests that shallow fracturing creates a potential for release near existing sources of water supply.

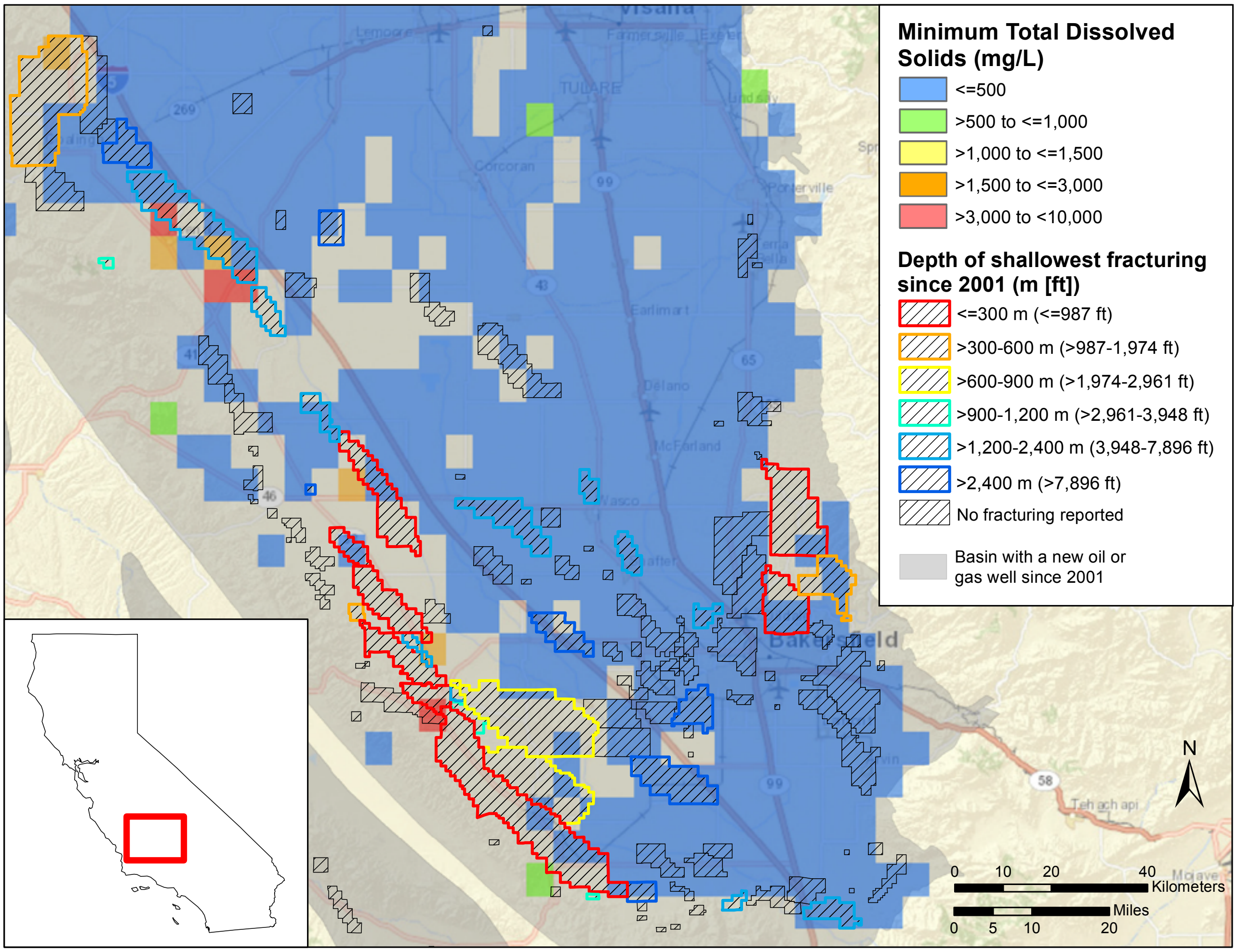


Figure 5.4-5. Minimum total dissolved solids concentration from GeoTracker GAMA[4] in 5 km by 5 km (3 mi.by 3 mi.) square areas in the southern San Joaquin Basin as of October 14, 2014, with the available minimum depth of hydraulic fracturing in each field available in Volume 1, Appendix M is shown. For most fields, this is the depth of a well in which hydraulic fracturing occurred, so the upper limit of the hydraulic fracture may be in a shallower category.

An important factor for the likelihood of induced fractures entering groundwater is their orientation, which in turn is a function of subsurface stress conditions and hydraulic fracturing operational choices. Flewelling and Sharma (2014) found that shallow formations are more likely to fracture horizontally rather than vertically; however, these results are from settings outside of California. Engineering of fractures from shallow

4. http://geotracker.waterboards.ca.gov/gama/

horizontal wells in California indicates they are typically vertical, at least in the southwest San Joaquin Basin, where most shallow fracturing occurs in the state, as discussed further in the next paragraph.

Emanuele et al. (1998) measured the orientation of fractures resulting from tens of stages in three horizontal wells in the Lost Hills field at a depth of ~600 m (2,000 ft), using surface tiltmeter measurements for each along with subsurface tiltmeter measurements for a few. The orientation of all the fractures was within 10 degrees of vertical. Hejl et al. (2007) reported vertical fracturing at depths as shallow as 425 m (1,400 ft) measured with downhole tiltmeters in the Lost Hills field. Allan et al. (2010) reported on testing of longitudinal versus transverse fracturing in horizontal wells at a depth of approximately 300 m (1,000 ft) in the South Belridge field. The tests determined wells oriented to create longitudinal fractures were considerably more productive. If fractures propagated horizontally, it would not be possible to create transverse fractures from a horizontal well, and the well orientation would be less relevant to the volume of oil it produced. In addition, Allan et al. (2010) reported that the fractures were vertical, as indicated by surface and downhole tiltmeter measurements. Figure 5.4-6 shows a representation of vertical fracturing from vertical wells in diatomite in the South Belridge field included in a history of the South Belridge field (Allan and Lalicata, 2007).

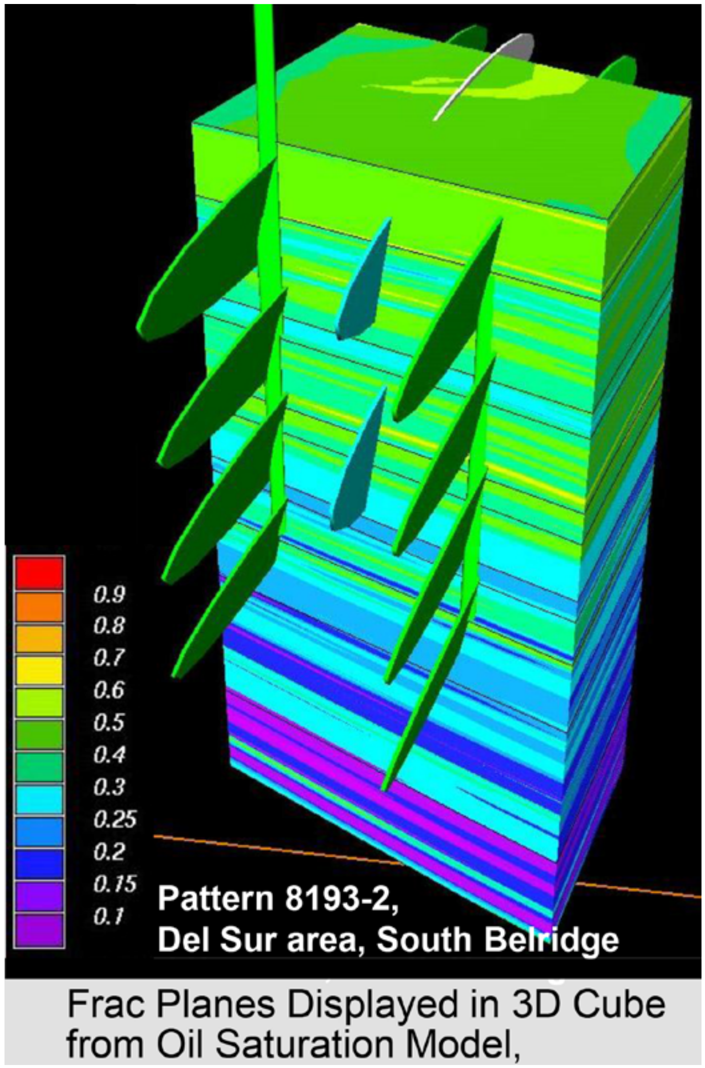


Figure 5.4-6. Representation of vertical fracturing from vertical wells in the diatomite in the South Belridge field (Allan and Lalicata, 2007).

Consequently, there are indications that fracturing at shallow depths in the San Joaquin Basin is predominantly vertical, which means fracturing is more likely to extend upward and encounter protected groundwater. Determining the probability of one of these fractures encountering protected groundwater requires a field-verified data set regarding the upward extent of induced shallow fractures, relative to the base of protected groundwater, which is sufficiently large to draw statistical inferences. Such a data set regarding upward extent is not known to exist in the public domain, although it may be available in hydraulic fracture completion reports prepared by the oil field service provider. Data sufficient to determine the position of protected groundwater may exist in the public domain. If so, it requires assembly and interpretation.

In the absence of such publicly available information, further investigation is recommended. A statistical understanding of the relationship of shallow fracturing to protected groundwater could provide the basis for judging if and what mitigation measures are needed in addition to standard practice. This analysis could be done with data already held by operators if this were made available. If the data cannot be made available, or turn out to be insufficient, then a field program monitoring the upward extent of shallow hydraulic fractures should be pursued to generate such data.

In the meantime, for operations with shallow fracturing near protected groundwater, additional recommendations to decrease the probability of groundwater resources being degraded by intersection with a hydraulic fracture include:

1. Detailed prediction of expected fracturing characteristics prior to starting the operation;

2. Minimum separation distance between expected fractures and protected groundwater, providing a sufficient safety margin with proper weighting of subsurface uncertainties;

3. 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;

4. Ongoing monitoring of groundwater quality and levels (hydraulic head) to detect leaks and evidence of hydraulic connection to underlying reservoir;

5. Timely reporting of the measured or inferred fracture characteristics confirming whether or not the fractures have actually intersected or come close to intersecting groundwater;

6. Preparing corrective action and mitigation plans in case anomalous behavior is observed or contamination is detected;

7. Adapting groundwater monitoring plans as part of the corrective action, to improve the monitoring system and specifically look for contamination in close proximity to possible fracture extensions into groundwater.

5.4.4.2. Leakage Via Wells

Leakage of stimulation fluids during hydraulic fracturing could occur via well defects, including breaches in the casing and gaps in the cement sealing the space between the casing and the rock. Fluids migrating along this pathway could enter groundwater, the unsaturated soil zone above groundwater, and the atmosphere, and can spill onto the ground surface. The capacity of a well to prevent such migration is referred to as its integrity.

Well leakage can broadly be considered as acute or chronic. The difference is largely in how soon a leak is observed after it starts, and how soon mitigation commences. Leaks that are observed shortly after they commence (seconds to days) and for which mitigation activities start virtually immediately are acute. These are termed “well blowouts” in this study. They typically occur due to the sudden failure of vital well elements, such as well casing. In contrast, chronic leaks are typically caused by defects or deficiencies in well seals, such as incomplete cementing. Because the leakage rates are smaller, chronic leaks may not ever be observed, or, if observed, do not necessarily trigger immediate mitigation action in practice (e.g. Chilingar and Endres, 2005).

5.4.4.2.1. Injection Well Leakage

The wells undergoing hydraulic fracturing can provide a leakage path to the environment if the casing or cement of the well is flawed or breaks down, or if there is a breach in the casing. With regard to acute leakage, Jordan and Benson (2008) collated and assessed blowout data for oil, associated gas, and the small amount of non-associated gas operations in California Oil and Gas District 4. This district includes Kern County, where most of the hydraulic fracturing in the San Joaquin Basin and the state occurs. Analysis of the blowout data provided in Jordan and Benson (2008) for this case study finds that it does not contain any records of blowouts related to hydraulic fracturing during the period studied (1991 to 2005). The well-record search results reported in Volume I, Chapter 3, indicated 900 hydraulic fracturing operations per year from 2002 through 2006. Comparison to other data sets suggested that the actual number of operations per year is ~1,500, for a total of ~7,500 from 2002 through 2005. The literature review in Volume I, Chapter 3, also indicated that substantial hydraulic fracturing activity began in the early 1980s in the four fields where it is most common. Thus, even if the average number of operations per year from 1991 through 2001 was only half that from 2002 through 2005, the total number of operations during the 1991 through 2005 study period would have exceeded 15,000.

This suggests that the frequency of blowouts during hydraulic fracturing events is less than 1 per 15,000 operations, which is equivalent to about a decade of operations at the rate estimated in Volume I, Chapter 3. Consequently, even though the potential leakage flow rates during a blowout would be quite high, perhaps as high as the injection flow rates during the hydraulic fracturing operation, these events would occur infrequently. It is possible the total rate of well blowouts is somewhat higher than given in the database, because not all blowouts have surface expressions (i.e., they may be restricted to the subsurface). However, Jordan and Benson (2008) found that two thirds of the steam-injection-well blowouts were from the ground surface away from the well head, indicating a subsurface release that fractured to the surface due to the pressure. Consequently, at least some portion of subsurface blowouts of highly pressurized fluids would manifest themselves as surface blowouts, from which it can be concluded that the overall rate of well blowouts from hydraulic fracturing in California has been low.

The frequency and potential magnitude of chronic leakage of stimulation fluids from wells into the subsurface in the San Joaquin Basin, anywhere in California, and apparently anywhere in the world, is not well known. Kell (2011) suggests that no groundwater contamination incidents were reported from 16,000 multi-stage hydraulic fracturing operations in horizontal wells occurring in Texas from 1993 to 2008. Aside from this study, focused on the potential migration of stimulation fluids or brines into groundwater, most other analyses of well integrity have looked into the frequency of leakage along wells via monitoring of methane and other gases at the surface. A study conducted by Watson and Bachu (2009), in an area of Alberta where monitoring of gas leakage in the subsurface around each well was mandated, found 5.7% of these wells showed evidence of such leakage. Watson and Bachu (2009) furthermore found that 0.6% of wells across all of Alberta exhibited leaks to the subsurface. Davies et al. (2014), examining records from 2005 to 2013 for wells installed in the Marcellus shale in Pennsylvania from 1958 to 2013, found evidence that 1.27% had showed evidence of gas leakage to the ground surface. Vidic et al. (2013) is cited in Davies et al. (2014) as finding that 0.27% of wells whose borings drilled into the Marcellus Shale from 2008 to 2013 leaked to the surface.

There is a discrepancy between the finding of no groundwater contamination resulting from the hydraulic fracturing of 16,000 wells in Texas, and other studies finding 1 in 400 to 1 in 20 wells manifesting gas leakage at the surface from migration along wells. One reason for this is the difference in driving forces between non-buoyant subsurface fluids (such as stimulation fluids or deep reservoir brines) and buoyant gases such as natural gas, as previously mentioned.

Another reason for this discrepancy may be the difficulty of detecting subsurface leakage by monitoring groundwater quality. For instance, Carroll et al. (2014) presented the results of a risk assessment modeling study concerning geologic storage of carbon dioxide. The project assessed consisted of injecting 5 million metric tons (5.5 million tons) of carbon dioxide (CO^2) per year for 50 years. The resulting area with a pressure increase in the reservoir contained 48 legacy oil and gas wells with a 2% to 10% probability of chronic leakage. Groundwater monitoring was conducted for 200 years from one well per square kilometer over the entire pressure increase area. Given these conditions, the study found a less than 5% probability of detecting groundwater contamination when the location of leakage pathways into groundwater is unknown.

The findings of Carroll et al. (2014) indicate that it is not clear to what degree leakage causing an adverse impact to groundwater quality could be detected by monitoring. Theoretically any intrusion of contaminants, no matter how small, constitutes an impact to groundwater. As a practical matter, however, it is not possible to definitively measure and prove zero leakage. For instance, even if a sample of groundwater with quality altered by a leak is analyzed, natural variability in groundwater quality can mask that result. Only concentrations exceeding one of a variety of statistical thresholds of significance will be flagged for further investigation to determine if the concentration is due to leakage (Last et al., 2013).

Regulations recognize that assuring zero leakage is not possible, and consequently inherently find a certain amount of leakage acceptable. For instance, injection well casings in California are periodically pressure tested. The casing passes the test if the pressure declines less than 10% in fifteen minutes. The minimum final pressure is 1.4 MPa (200 psi), so the minimum acceptable pressure loss is 0.14 MPa (20 psi; Walker, 2011). A typically sized casing of a relatively shallow well (several hundred meters [a couple thousand feet] deep) can hold thousands of gallons. This combination of volume, size of acceptable pressure decline, test duration, and water compressibility indicates an allowable leak on the order of 3 L (1 gallon) per hour. At this rate, an injection well would leak 0.3 m^3 (2 bbl) within a week. Consequently, this amount of leakage is implicitly allowed by testing requirements in California.

Currently approved groundwater monitoring plans for some hydraulic fracturing operations in California provide another perspective. These plans specify monitoring for leakage via analysis of samples collected from groundwater supply wells or monitoring wells. The monitoring wells are typically located hundreds of meters from some of the hydraulically fractured wells they propose to monitor. For example, Figure 5.4-7 shows the location of 42 planned hydraulic fracture operations in relation to planned monitoring wells from one groundwater monitoring plan developed for operations in the Lost Hills field. The apparent average distance from a stimulated well to a monitoring well is 400 m (1/4 mi.). The monitoring well density is similar to that investigated by Carroll et al. (2014).

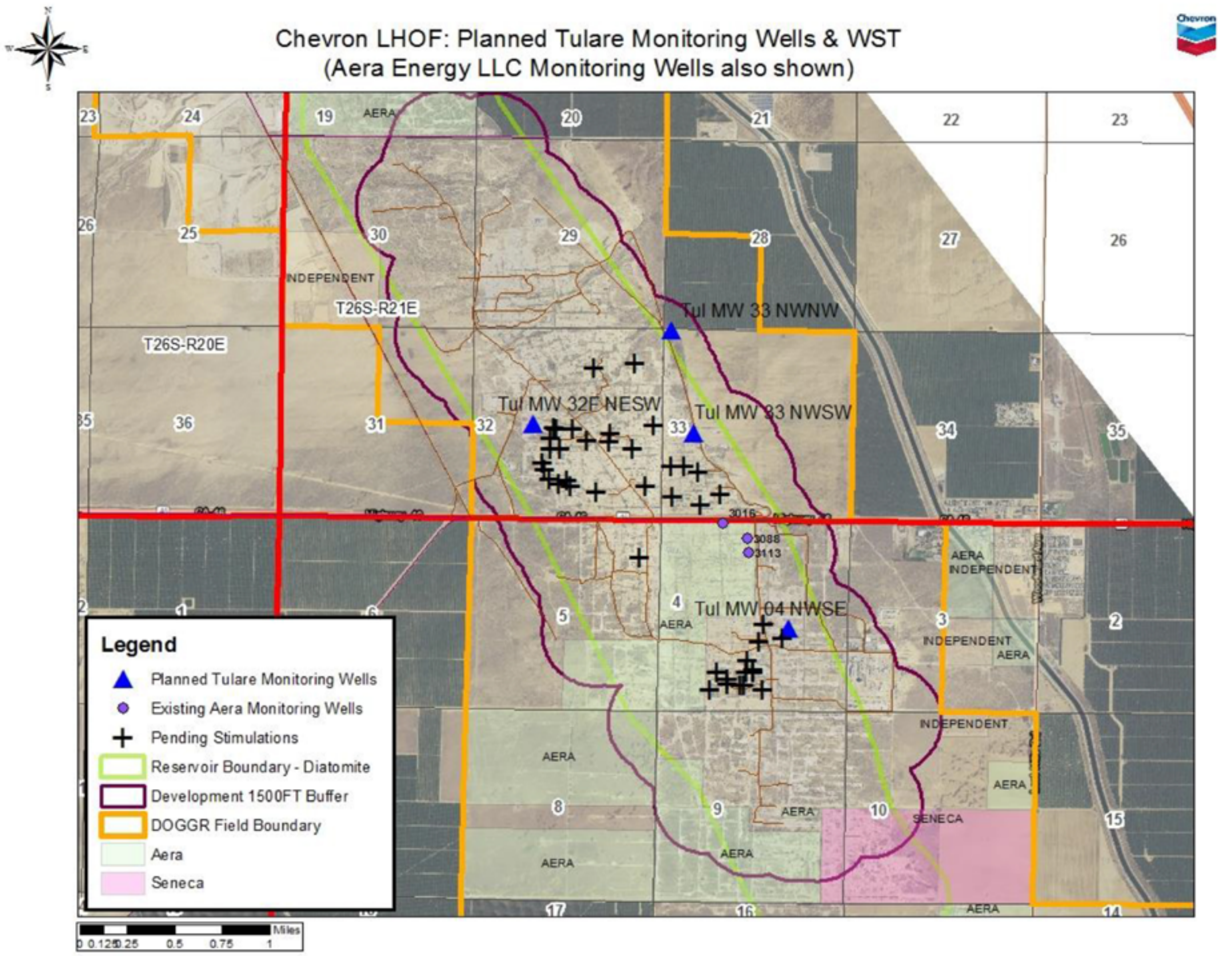


Figure 5.4-7. Location of planned hydraulic fracturing and monitoring wells in a portion of the Lost Hills field. The stimulation locations are shown by crosses and the planned monitoring wells by blue triangles (Chevron USA Inc., 2015).

Locating monitoring wells closer to stimulated wells would increase the likelihood of detection; however, this would require a geometrically larger increase in the number of monitoring wells. For instance, decreasing the average distance from a stimulated well to the nearest monitoring well by a factor of four would increase the number of monitoring wells by ~16. While this may be possible, the probability of detecting a leak would still depend on a monitoring well being in a zone into which a leak occurs, along a flow line from where leaking fluid entered the zone, and in sufficiently close proximity to where the leak entered the zone to allow its detection within a reasonable time of when the leak occurred. This is dependent upon proper prediction of the location of the leakage into the zone, and characterization of hydraulic gradients and the hydrogeological conditions in the zone, such as heterogeneity and anisotropy of the geologic materials. It is known that leakage pathways in the subsurface can be quite complex and irregular as a result of subsurface heterogeneities. For example, Jordan and Benson (2008) found that steam well blowouts can occur up to 200 m (600 ft) from the source well, presumably resulting from the steam fracturing through the subsurface from the well at some depth. It is not known how the extent of this horizontal spatial distribution shrinks at flow rates progressively less than blowout flow rates.

The above discussion, summarized as follows, illustrates the potential difficulty in developing appropriate groundwater monitoring plans that strike a balance between leakage detectability and the resources needed for multiple monitoring wells. The highest likelihood of detection is for the largest leaks, such as acute flow rates during well blowouts, which appear to occur in the San Joaquin Basin with a frequency of less than 1 per 15,000 hydraulic fracturing operations. Small leaks resulting from chronic flow along wells is considered more likely based on studies conducted elsewhere; however, these studies were mostly done for gas leakage and not for non-buoyant fluids. Groundwater contamination due to leakage of stimulation fluids or reservoir brines caused by hydraulic fracturing operations has rarely been reported. If leakage occurred, on the other hand, the leakage rates may be too low to be detected even with well-designed groundwater monitoring plans. It would be useful to conduct a study on leakage detectability like that reported by Carroll et al. (2014) to better inform the design of groundwater monitoring plans, so that they are as effective as possible. In addition, improved monitoring design could be achieved via dedicated field study areas where monitoring and data collection can be much more intense and ubiquitous than is possible in general industry operations. The field study areas would be monitored with more-than-usual resolution and frequency, which allows for testing of monitoring practices and provides for lessons learned in terms of what is useful or not.

It should be noted that the studies on chronic well leakage cited above are all from regions outside of California (e.g., Texas, Alberta, Pennsylvania); comparable studies have not been conducted in California. It is unknown if the well failure rates from elsewhere in the country provide reasonable approximations for the San Joaquin Basin. Such rates depend on factors like the regulations at the time of well construction, the degree to which those regulations were followed, the type of well (such as vertical versus horizontal), and the age of the well. For instance, land subsidence related to groundwater extraction and oil production in California might be more pronounced than where the studies have been conducted elsewhere, possibly resulting in a higher chronic leakage well leakage frequency in California. It is also possible the greater seismic activity in California and use of steam injection in pools overlying stimulated pools could also affect the chronic well leakage frequency. Thus, bounding this frequency in the state requires a California-specific study. It is important that further studies are conducted to assess the integrity of legacy wells and their susceptibility for chronic leakage.

5.4.4.2.2. Offset Well Leakage

Somewhat similar to leakage of stimulation fluid via wells that are themselves hydraulically fractured, leakage could also occur via an existing well, known as an offset well, that is intersected by a hydraulic fracture generated from a neighboring well. This intersection could result in leakage of fluids from the fracture via the well if the offset well is transmissive, or becomes transmissive as a result of the hydraulic fracture intersection. The hydraulic fracturing operations in the San Joaquin Basin are largely located in reservoirs with high well density that have been in production for a long time. For instance, the well density maps in Volume II, Chapter 5, indicate the average spacing between wells in the most of the North and South Belridge, and Lost Hills fields is about 100 m (330 ft) or less, and in the Elk Hills field is about 250 m (820 ft) or less. Thus, there may be many older offset wells in the vicinity of hydraulic fracturing operations, and these wells may not always be designed for, or have the integrity to withstand, the high pressures used in hydraulic fracturing. It is important in such conditions to assess the integrity and leakage risk of existing wells that might be encountered by a hydraulic fracture, and to remediate wells with a higher risk of leakage.

Jordan and Benson (2008) found that no blowouts occurred from offset wells during the minimum estimated 15,000 hydraulic fracturing operations conducted during the study period. Wright et al. (1997) stated that there were no offset wells intersected by hydraulic fractures observed prior to infilling with wells on a 1/4 hectare (5/8 acre) pattern in the South Belridge field. After about three years of infilling with 4 to 5 wells a week, 16 such intersections had been observed. This is a frequency of about one intersection per 50 hydraulically fractured wells. Applying this rate to the minimum number of estimated hydraulic fracturing operations during the study period considered by Jordan and Benson (2008) suggests that up to 300 offset wells were intersected by hydraulic fractures during this period. Jordan and Benson (2008) did not find any blowouts from such offset wells—this implies that the blowout frequency from offset wells intersected by a hydraulic fracture is certainly less than 1 per 300. Jordan and Benson (2008) found that the steam blowout rate from shut-in and abandoned wells was on the order of 1 per 100,000 well years, suggesting that the blowout rate from offset wells intersected by a hydraulic fracture is much less than 1 per 300.

5.4.4.2.3. Leakage Via Wells to Groundwater with 3,000 to 10,000 mg/L TDS

Per regulations, wells are constructed in the United States with surface casings extending beyond the base of groundwater aquifers that need to be protected. The annulus between the casing and the well-bore surface is filled with cement prior to deeper drilling. This increases protection of the groundwater by assuring there is a cement seal isolating it from fluids deeper in the boring, such as oil, and providing an additional layer of casing isolating it from fluids in the well.

In California, DOGGR's groundwater protection program has been oriented to fresh groundwater, defined as having TDS of 3,000 mg/L or less (Walker, 2011). However, another classification of groundwater that is typically found deeper than fresh groundwater, called underground sources of drinking water (USDWs), has not received the same regulatory protection in California as elsewhere in the country. This leads to increased risk of contamination of USDWs compared with fresh groundwater as defined by DOGGR. As mentioned before, USDWs are defined by the U.S. Environmental Protection Agency, with some exceptions, as groundwater having TDS of 10,000 mg/L or less. Consequently, wells in California have not been constructed to be protective of groundwater that is of USDW quality but above the 3,000 mg/L TDS limit. In other words, surface casings have been set and cemented below the 3,000 mg/L TDS limit rather than below the 10,000 mg/L TDS limit, which may create a leakage hazard.

As an example, the field rules for the Lost Hills field diatomite (Etchegoin) pool indicate there is no low-salinity ("fresh") groundwater (DOGGR, 2007b). The surface casing is only required to extend to 10% of the total well depth, which is only about 30 m (100 ft) given the 300 m (1,000 ft) depth of the pool (DOGGR, 1998). As mentioned above, a groundwater monitoring plan has been required for hydraulic fracturing in this pool under the new requirements imposed by California Senate Bill 4 (SB 4). This indicates a USDW with between 3,000 and 10,000 mg/L TDS is considered to be present. The field rules for this pool require cementing all casing, including the production casing, to the surface. The field rules for the deeper Cahn pool require cementing 150 m (500 ft) above all oil, gas, and anomalous pressure zones (DOGGR, 2007a). So the likelihood of a hydraulic fracture encountering an open annulus in an offset well is low. However, these wells do not have the additional layer of surface casing and cement protecting typically required to protect all USDW. The lack of this layer suggests the chronic leakage volume frequency to USDW may be higher than the 5% of wells discussed in the previous section, because there are fewer barriers in some wells between the fractured interval and the USDW.

The risk of leakage via wells to groundwater above the 3,000 mg/L TDS limit can be decreased in the future via a number of actions. Future wells should be constructed with casings extending through USDWs. This may require the addition of an intermediate casing, depending upon the depth separation between the base of groundwater with less than 3,000 mg/L TDS and groundwater with less than 10,000 mg/L TDS. Past wells within the search area around a stimulated well should be reviewed to determine if they are protective of USDWs. This determination likely requires research regarding the permeability distribution along wells from fractured pools to USDWs. One approach would be to install monitoring wells screened near the base of USDWs near offset wells known to have been encountered by hydraulic fractures. Another would be to hydraulically test well cement via ports cored through production casings to determine well seal permeability, such as just prior to well abandonment.

5.4.4.3. Leakage via Faults

The San Joaquin Basin has abundant faults, which present potential paths for leakage out of hydraulically fractured pools. The probability of leakage via faults has two components: first, the probability that a hydraulic fracture will encounter a fault; second, the probability that fluids can migrate via the fault from the hydraulic fracture to a USDW. Most faults in the oil reservoirs do not act as permeable conduits; they are sealing and often function as hydrocarbon traps.

The probability of a hydraulic fracture intersecting a fault can be roughly estimated from an assessment of fault density and typical hydraulic fracture geometry (Jordan et al., 2012). Figure 5.4-8 shows the fault density measured for a portion of the eastern San Joaquin Basin from Jordan et al. (2012). Fault density is typically found to be a power function of throw truncation. This is the density of faults with a vertical displacement across the fault greater than a particular value. Structure maps of some of the oil fields in the eastern portion of the San Joaquin Basin provided the data from which the correlation in Figure 5.4-8 was developed. Fault throw in turn has been demonstrated to correlate with fault height. These correlations are used below to explore the relationship between fault density, fault size, and the likelihood of hydraulic fractures encountering faults in the western portion of the San Joaquin Basin, where most of the hydraulic fracturing operations take place.

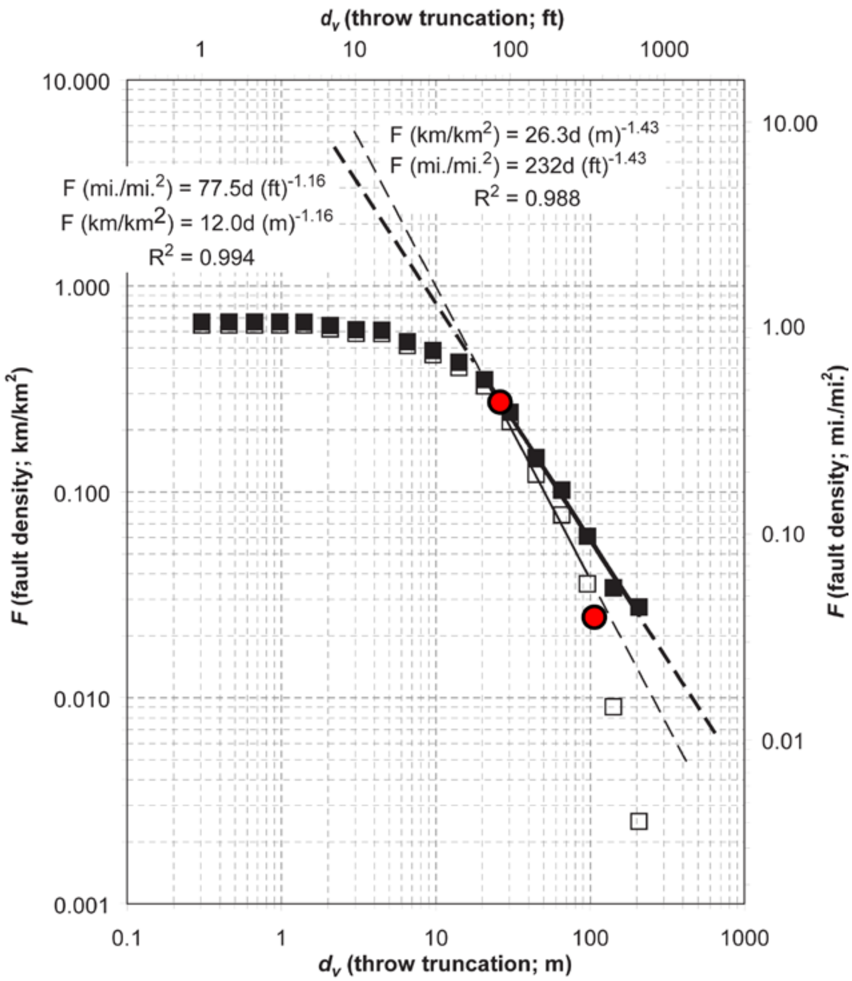


Figure 5.4-8. The red dots are fault densities measured by this study from structure maps for the four fields in the western San Joaquin Basin where 85% of the hydraulic fracturing in the state occurs: North and South Belridge, and Lost and Elk Hills (DOGGR, 1998).These match the underlying raw data from a portion of the eastern San Joaquin Basin, indicating the heavy line is the best estimate of the density of faults with throw (vertical displacement) greater than the throw truncation value (Jordan et al., 2012). The heavy line adjusts the raw data for censoring caused by map edges (Pickering et al. 1995).

Because nearly 90% of the hydraulic fracturing in the San Joaquin Basin occurs in four fields in the western Basin (North and South Belridge, and Lost and Elk Hills), the fault density analysis conducted for the eastern Basin (Jordan et al., 2012) needed to be extended to the western Basin. The length of faults in these four western fields was measured from the structure maps in DOGGR (1998), the area covered by each map was measured, and the fault length was divided by the map area to arrive at the fault density.

The resulting fault densities measured for these fields are plotted as two points on Figure 5.4-8. In the earlier study, Jordan et al. (2012) found that all faults with a throw (vertical displacement) greater than two thirds of the structure map contour interval typically are mapped. So the measured fault densities are plotted at these values. The red point shown on Figure 5.4-8 with a throw truncation of about 100 m (330 feet) is from the Elk Hills field alone, because it had a much larger structure contour interval than the maps for the other fields. The red point shown on Figure 5.4-8 at a throw truncation of about 25 m (80 ft) is from the other three fields combined, their maps having similar structure contour intervals.

The fault densities measured for the western San Joaquin Basin fields lie on the raw data trend from the eastern Basin. Consequently, the heavy line in Figure 5.4-8 (which was developed from the raw data in the eastern San Joaquin Basin) is also considered a good estimate of the fault density in the portion of the western Basin where the fields are located. Fault height worldwide averages about 100 times the maximum displacement on a fault. This ratio ranges from 20 to 1,000 (Cowie and Scholz, 1992). Thus, faults with 4 m (13 ft) of throw encountered by hydraulic fractures are likely to extend at least 200 m (660 ft) vertically above the point of encounter (ignoring possible mechanical heterogeneity and the absence of some overlying strata at the time of fault movement). At the shallow depths where most hydraulic fracturing is conducted, a fault of this height is likely to intersect a USDW.

From Figure 5.4-8, the density of faults with at least 4 m (13 ft) of throw is 2 km/km^2 (3 mi/mi^2). The probability of a hydraulic fracture with an average length of 30 m (100 ft; Volume II, Chapter 2) encountering a fault with at least this much throw is 6% (presuming the fracture is perpendicular to the fault). However, operators are likely to make an effort to avoid having hydraulic fractures encounter faults where they are known to exist. Presuming operators are able to map all faults where they have at least 10 m (30 ft) of throw, the probability of a hydraulic fracture encountering faults with at least 10 m (30 ft) of throw should be subtracted. From Figure 5.4-8, the density of these faults is 0.8 km/km^2 (1 mi./mi^2), which gives an encounter probability of 2.4%. Subtracting this from the previous probability gives a 3.6% probability of a hydraulic fracture encountering an unknown fault with sufficient extent to encounter a USDW. With over 1,500 wells hydraulically fractured each year in the western San Joaquin Basin, it is possible that tens of hydraulic fractures encounter such a fault each year.

How far stimulation fluids may propagate along such a fault once it is encountered is unknown. As mentioned above, faults in oil pools generally do not provide a pathway for fluids to migrate upward; otherwise the oil would have leaked out of the pool due to its buoyancy. However, the hydraulic fracturing process itself could cause the fault to open (Rutqvist et al., 2013). In addition, there is the possibility that once stimulation fluid starts opening a fault, it might cause slip beyond the stimulation fluid extent, which can increase fault permeability and provide a pathway for the stimulation fluid to migrate further. This could also provide a pathway for migration of gases after cessation of fracturing that would not otherwise exist. More research is needed to better understand fault permeabilities and how they might be affected by high fluid pressure if intersected by a hydraulic fracture. Given these uncertainties, it is important to ensure that site characterization efforts are designed to ensure a reasonable chance of detecting existing faults of a given size before a hydraulic fracturing operation is conducted.

5.5. Potential Risk to Air

Air emissions in the San Joaquin Basin were discussed in Volume II, Chapter 3, of this report. In that volume, emissions of criteria air pollutants, toxic air contaminants (TACs), and greenhouse gases were discussed. All emissions were assessed statewide, and the pollutant emissions were also assessed by air district. Emissions can be even more localized, resulting in more localized impacts. This section assesses emissions in Kern County, the western portion of which has the vast majority of the population and emissions in the county and is part of the San Joaquin Valley Air Pollution Control District. Because most of the oil and gas production in the San Joaquin Valley is in Kern County rather than spread out more uniformly across the air district, assessing emissions at the county level allows more detailed understanding of emissions from oil and gas production in the local context. The next section, which concerns potential risk to human health (Section 5.6), regards emissions at the scale of a single well, which is relevant to single households, facilities, and neighborhoods.

5.5.1. Air Pollutants

This analysis takes a more detailed look at the pools where most to all wells within the San Joaquin Basin are hydraulically fractured, aligning datasets from DOGGR with California Air Resources Board (CARB) air-pollution inventories. Because DOGGR regional jurisdictions do not align with CARB air districts, the analysis was performed using counties as the regions of interest. For this reason, only emissions in Kern County were considered, since 71% of all statewide production and most of the production in the San Joaquin Basin occurred there.

Total criteria air pollutants in the San Joaquin region are shown in Table 5.5-1. TAC emissions for four indicator TACs that are released by oil and gas operations are shown in Table 5.5-2.

Table 5.5-1. Anthropogenic emissions of criteria air pollutants and reactive organic gases in Kern County (San Joaquin Basin), 2012.

Pollutant	Metric tonnes/day	Tons/day
Reactive organic gases (ROG)	82.4	90.6
Nitrogen oxides (NO_x)	98.0	107.8
Sulfur oxides (SO_x)	4.8	5.3
PM_{10}	53.8	59.2
$PM_{2.5}$	17.8	19.6

Table 5.5-2. Emissions of toxic air contaminants from all sources in Kern County (San Joaquin Basin), 2010. Data from California Toxics Inventory.

Species	Emissions (kg/y)	Emissions (lb/yr)
1,3-Butadiene	30,575	67,326
Acetaldehyde	2,802,503	6,171,112
Benzene	267,163	588,293
Carbonyl sulfide	0	0
Ethyl Benzene	70,974	156,285
Formaldehyde	486,080	1,070,348
Hexane	423,110	931,688
Hydrogen Sulfide	146,942	323,566
Toluene	550,514	1,212,232
Xylenes (mixed)	117,249	258,182

The portion of these emissions due to the portion of oil and gas production enabled by hydraulic fracturing in Kern County was estimated. A variety of sources in the criteria pollutants inventory and facility-level toxics database can be linked to the oil and gas industry. In order to estimate criteria pollutant emissions from the oil and gas sector in Kern County, emissions from the following sectors were summed (see Volume II, Chapter 3, for more detail):

1. Stationary sources > Petroleum production and marketing > Oil and gas production > All subsectors and sources

2. Stationary sources > Fuel combustion > Oil and gas production (combustion) > All subsectors and sources

3. Mobile sources > Other mobile sources > Off-road equipment > Oil drilling and workover

The oil and gas sector will also have some use of on-road light and heavy-duty trucks in non-drilling operations. These are not able to be differentiated using reported inventory results (on-road vehicles are classified by weight class rather than industry using them). Table 5.5-3 below shows the result of summing oil and gas sources in Kern County. As shown, oil and gas production emits a significant fraction of criteria pollutants in the San Joaquin region, especially reactive organic gases (ROG), which are involved in ground level ozone formation, and sulfur oxides (SO_x). This is because most of the oil production in the state occurs in Kern County, and there is a lack of other heavy industry in the area. These results differ from results presented in Volume II, Chapter 3 due to their being compiled for Kern County rather than San Joaquin Unified Air Pollution Control District. This was done because most of the oil and gas production in the San Joaquin Basin, and well stimulation in particular, is located in Kern County at the south end of the basin.

Table 5.5-3. Emissions of criteria air pollutants from oil and gas production in metric tonnes/day, and these emissions as a percent of total emissions in Kern County in 2012. ROG = reactive organic gases; NO_x = nitrogen oxides; SO_x = sulfur oxides; PM_{10} = particulates smaller than 10 microns; $PM_{2.5}$ = particulates smaller than 2.5 microns.

	ROG	NO_x	SO_x	PM_{10}	$PM_{2.5}$
Stationary oil and gas	22.5	1.80	0.96	1.48	1.48
Mobile oil and gas	0.02	0.17	0.00	0.01	0.01
Total anthropogenic	82.4	98.0	4.8	53.8	17.8
Percentage	27.3%	2.0%	19.8%	2.8%	8.3%

The contribution of oil and gas sources to TAC emissions was estimated by searching for facility-level emissions by Standard Industrial Classification (SIC) codes. Using the five SIC codes identified as comprising the upstream oil and gas sector (Volume II, Chapter 3), it is possible to compute the fraction of TAC emissions for select pollutants that are due to the oil and gas industries. Because total TAC emissions from all sources are only available from 2010, this table compares TAC emissions by oil and gas facility in 2010 to overall TACs reported in 2010. Table 5.5-4 below shows the oil and gas contribution to select TACs in the San Joaquin region. As shown on the table, oil and gas production is the dominant source of hydrogen sulfide (96%) and a major contributor to emissions of benzene (9%), formaldehyde (26%), hexane (11%), and xylene (14%).

Table 5.5-4. Emissions of toxic air contaminants from oil and gas production in kg/yr, and these emissions as a percent of total emissions in Kern County in 2010.

	Total: Stationary oil and gas	Total: All stationary	Total: All sources	Fraction stationary oil and gas
1,3-Butadiene	67	133	30,575	0.2%
Acetaldehyde	10,605	15,651	2,802,503	0.4%
Benzene	23,765	28,177	267,163	8.9%
Carbonyl sulfide	0	1	1	0.0%
Ethyl Benzene	2,266	6,280	70,974	3.2%
Formaldehyde	124,708	139,499	486,080	25.7%
Hexane	46,777	140,030	423,110	11.1%
Hydrogen Sulfide	141,662	143,565	146,942	96.4%
Toluene	17,173	54,679	550,514	3.1%
Xylenes (mixed)	16,832	42,475	117,249	14.4%

A comparison of Tables 5.5-3 and 5.5-5 indicates that criteria air-pollutant emissions from mobile sources involved in oil and gas production is accounted for, but TACs emissions are not. While stationary and mobile emissions sources in oil and gas operations can be separated for criteria pollutants, this is not the case for TACs inventories. TACs reporting for stationary sources is available in detailed databases that can be queried by economic sector. In contrast, TACs emissions from mobile sources are presented in aggregate form and are not able to be separated into oil and gas and other sources. Because most criteria pollutants from oil and gas sources come from stationary sources, it is likely that the majority of TACs from oil and gas sources are also counted in the stationary source inventory. For further discussion, see Volume II, Chapter 3.

The pools in Kern County where most or all of the wells are hydraulically fractured, as listed in Volume I, Appendix N, produced 23.2% of the oil in the county in 2013—and 30.0% of the wells starting production that year accessed those pools. These activity factors were used to scale the stationary source and mobile source emissions from the oil and gas sector as a whole to capture those emissions enabled or facilitated by well stimulation. All stationary source emissions (combustion and non-combustion) were scaled by the fraction of oil production from the hydraulic-fracturing-enabled pools, and mobile source off-road emissions were scaled by the fraction of wells commencing production in enabled pools. The results are shown in Tables 5.5-5 and 5.5-6. These results do not take into account differences in emissions from heavy oil production facilitated by steam injection, and lighter oil production enabled by hydraulic fracturing. The first involves production of more viscous oil with lower volatile hydrocarbon concentrations at higher temperatures compared to second, which involves production of less viscous oil with higher volatile hydrocarbon content at lower temperatures. Based on the differences in temperature and volatile content, it is not clear which would have the higher relative emissions.

Table 5.5-5. Percent of criteria air pollutant and reactive organic gases emissions from hydraulic fracturing enabled production in Kern County in 2012.

ROG	NO_x	SO_x	PM_{10}	$PM_{2.5}$
6.3%	0.5%	4.6%	0.6%	1.9%

Table 5.5-6. Toxic air contaminant emissions from hydraulic fracturing enabled production as a percent of total emissions in Kern County in 2010.

TAC species	Percentage Well Stimulation (WS)-related
1,3-Butadiene	0.1%
Acetaldehyde	0.1%
Benzene	2.1%
Carbonyl sulfide	0.0%
Ethyl Benzene	0.7%
Formaldehyde	6.0%
Hexane	2.6%
Hydrogen Sulfide	22.4%
Toluene	0.7%
Xylenes (mixed)	3.3%

Table 5.5-5 shows about a fifteenth of the ROG emissions in Kern County are from oil and gas production enabled by hydraulic fracturing. As mentioned, ROG is involved in the formation of ground-level ozone (as opposed to ozone in the troposphere). Due to regular high ozone concentrations, the portion of Kern County in the San Joaquin Valley is designated by the EPA as extremely out of compliance with the 8-hour ozone standards, meaning ozone concentrations regularly exceed health standards (U.S. Environmental Protection Agency (U.S. EPA), 2012). In this context, the portion of ROG emissions due to hydraulic-fracturing-enabled oil and gas production is substantial, although obviously not uniquely so compared to other sources.

Table 5.5-6 shows that a substantial percentage of some TAC species emissions in Kern County are caused by hydraulic-fracturing-enabled production, especially hydrogen sulfide. This is because oil and gas production as a whole is responsible for the majority of these emissions, as shown in Table 5.5-4. Consequently, measures that can reduce these emissions should be considered.

5.5.2. Greenhouse Pollutants

CARB also issues annual inventories of the greenhouse pollution emitted during oil production and transportation to a refinery on a field-by-field basis for the more productive fields. This does not include greenhouse pollution from refining the oil or combusting the final product.

The amount of pollution is expressed as units of carbon equivalent emissions per unit of energy produced, which is termed carbon intensity (CI). Figure 5.5-1 shows all the CIs available in the 2013 inventory versus the volume of oil produced 2013 from DOGGR's production database (CARB, 2014). Each symbol indicates whether the field had water flooding or steam injection, and whether it had a pool with hydraulic-fracturing-enabled production. If it did have such a pool, the shading of the symbol indicates the fraction of the field's production coming from such a pool (or pools), with darker shading indicating a higher fraction.

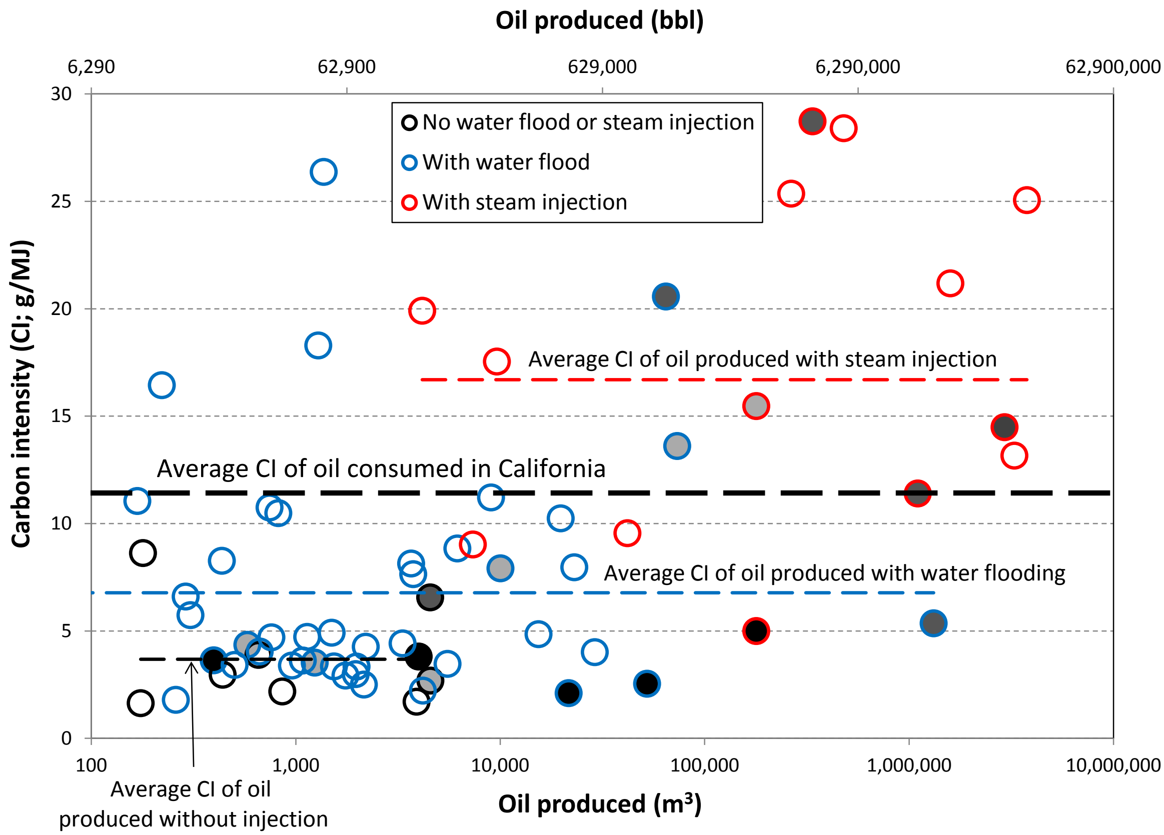


Figure 5.5-1. Greenhouse pollution, as carbon intensity (CI), from producing and transporting a unit of oil from California fields to a refinery (CARB, 2014) versus oil production in 2013 from DOGGR. Open symbols indicate no hydraulically fracture-enabled production. Black indicates more than two thirds of the production was enabled. Averages are weighted by production in each field.

Figure 5.5-1 indicates the CI of oil from fields with hydraulic-fracturing-enabled production is generally less than from fields without such production. The average CI for oil from fields with hydraulic-fracturing enabled production, but without water flooding or steam injection, are near the average CI for all fields without water flooding or steam injection. For fields with water flooding and steam injection, the greater the production fraction from predominantly hydraulically fractured pools, the lower the CI in general. Most of the fields with higher fractions of production from such pools have CIs below the average for all fields with either water flooding or steam injection. This is presumably because in those fields, stimulation requires additional effort to produce a unit of oil, whereas in fields with water or steam injection, stimulation reduces this effort.

CARB (2014) indicates the average CI of oil used in California is 11.39 g/MJ. Figure 5.5-1 indicates the average CI for oil produced in California using hydraulic fracturing is less than this value. This analysis indicates that if hydraulic fracturing were disallowed, the average greenhouse pollution per unit of oil consumed in California due to production and transportation could actually increase if well stimulation was stopped. If stimulation was stopped and consumption remained constant, more oil would be required from non-stimulated California fields or regions outside of California, greenhouse pollution due to oil consumption in California could increase.

5.6. Potential Risk to Public Health From Proximity to Oil Production

Many features, events, and processes associated with oil production can create risk to public health, such as air-pollutant emissions, water quality degradation, and light and noise pollution. This section focuses on the potential risk from air-pollutant emissions in the San Joaquin Basin. Other health risks are assessed in Volume II, Chapter 6.

The concentration of air contaminants is largest at the source emitting those contaminants. The concentration declines rapidly with distance from the source. Consequently, risk to public health due to air pollution from production wells is sensitive to a population's proximity to the well. Studies of the distribution of air pollutant concentrations around other point sources indicate that these typically decline to background at a distance of one to two km (0.6 to 1.2 mi.) from the source (references and further discussion are available in Volume II, Chapter 6).

The only air-pollutant emission data available is the aggregate total for all oil and gas production in a given area. Statistics for air-pollutant emissions from a single well in California are not available. In addition, most pollutants emitted during oil and gas production are not associated with well stimulation chemicals. Rather they are due to production of petroleum, whether or not that production is enabled by well stimulation (full discussion available in Chapter 4 of this volume). Exposure to these chemicals will be a function of the proximity of the population to any production well, although without statistics on the emission per well, the consequence of this exposure cannot be determined.

Below, the proximity of population to all production wells and the subset in proximity to hydraulically fractured wells is assessed, to emphasize the point that the health impact is only indirectly related to hydraulic fracturing. It is production in general aside from well stimulation that may cause an impact. These points, with supporting data and citations, are elaborated on in Appendix 4.B to Chapter 4 of this volume. The analysis calculates the size and character of the population, as well as sensitive receptor sites such as schools and senior care facilities, occurring within various distances of a production well. Details on the analysis approach are available in Appendix 4.B to Chapter 4 of this volume.

The extent of this analysis was limited to the CARB San Joaquin Valley Air Basin (SJVAB) without Merced, San Joaquin, and Stanislaus Counties, as shown in Figure 5.6-1 (CARB, 2009). Merced and Stanislaus Counties were removed because little to no oil and gas production occurs in them. San Joaquin County was removed because it actually resides outside of the San Joaquin geologic basin, and no well stimulations are reported to have occurred there.

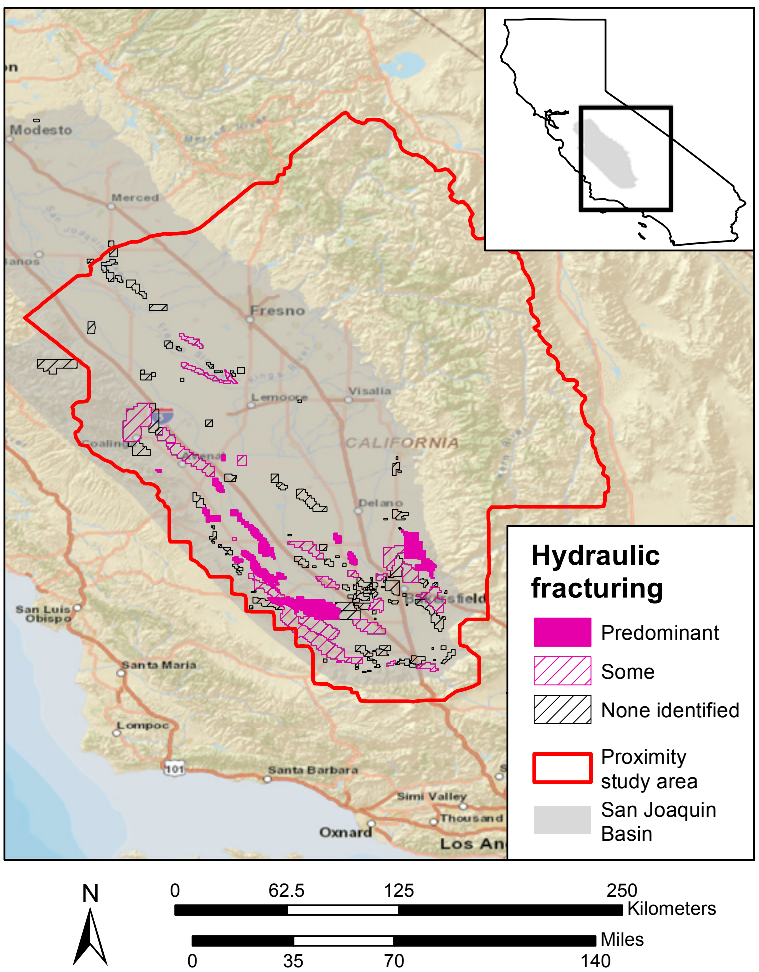


Figure 5.6-1. Study area for analysis of population and households in proximity to hydraulically fractured wells and all active wells.

Decennial census data was downloaded from American Fact Finder via Census.gov for the entire state of California at the census block and block group level (U.S. Census Bureau, 2012). The demographic data found in Summary File 1 for the 2010 census were used, including details collected from every household, such as "sex, age, race, Hispanic or Latino origin, household relationship, household type, household size, family type, family size, and group quarters." Data on housing included occupancy status, vacancy status, and tenure (whether a housing unit is owner-occupied or renter-occupied; U.S. Census Bureau, 2012)."

In addition to demographic profiles, the spatial analysis included four types of facilities frequented or inhabited by more sensitive members of the population. The proximity of residential elderly care homes, schools, permitted daycare facilities, and playgrounds in the San Joaquin Basin were included to provide additional perspective on the population of elderly and children in proximity to stimulated wells.

The analysis used data regarding residential care homes from the California Health Care Facility Dataset (HLTHFAC, undated); a dataset of over 4,000 facilities in California. The dataset was limited to only residential elderly care facilities. Student enrollment demographics data was downloaded from the California Department of Education web site. The location of schools was downloaded from a California Department of Education Portal (California Department of Education, undated), cleaned, and the locations verified for elementary, secondary, and unified school districts. Then, 2013/2014 enrollment demographic data for each school were taken from the United States Census Bureau's 2014 TIGER file (U.S. Census Bureau, 2014). Schools with no student enrollment were removed from the dataset. Quality control techniques identified enrollment demographics for schools that did not match the schools listed in the Geographic Information Systems (GIS) files, which were eliminated from the analysis. The location of licensed childcare, preschool, and day care facilities was extracted from a larger dataset of all childcare facilities, which also included child group homes (California Department of Social Services, undated).

The results of the proximity analysis of this data in the SJVAB are shown in Table 5.6-1. The proximity of facilities with sensitive populations (such as schools and elder care) and other demographics, including low education populations, unemployed populations, and low-income households, are listed in tables in Appendix 5.D.

Table 5.6-1. Total and percent of population, population by age, Hispanic, and Non-Hispanic minority in proximity to hydraulically fractured (HF) wells and all wells in the study area (based on the Census block level).

Proximity to a well (m; ft)	All active or HF wells?	Metric	Category population	Under 18 years of age	5 years of age and younger	Over 75 years of age	Minority (Non-Hispanic)	Hispanic
100 (330)	HF	Population.	76	20	6	4	14	20
		% of total pop..	<0.01%	<0.01%	<0.01%	<0.01%	<0.01%	<0.01%
	All	Population	3,640	985	341	214	953	1,499
		% of total pop..	0.15%	0.13%	0.14%	0.21%	0.10%	0.12%
		HF pop % of total pop.	2.1%	2.0%	1.8%	1.9%	1.5%	1.4%
400 (1,300)	HF	Population.	1,542	472	159	75	411	533
		% of total pop..	0.06%	0.06%	0.06%	0.07%	0.04%	0.04%
	All	Population	32,917	9,631	3,220	1,378	9,708	14,498
		% of total pop..	1.4%	1.3%	1.3%	1.4%	1.1%	1.1%
		HF pop % of total pop.	4.7%	4.9%	4.9%	5.4%	4.2%	3.7%
800 (2,600)	HF	Population.	9,908	2,984	1,011	413	3,194	3,819
		% of total pop..	0.42%	0.41%	0.40%	0.41%	0.35%	0.30%
	All	Population	101,103	29,906	10,128	3,952	31,815	44,896
		% of total pop..	4.2%	4.1%	4.1%	4.0%	3.5%	3.5%
		HF pop % of total pop.	9.8%	10%	10%	10%	10%	8.5%
1,600 (5,300)	HF	Population.	51,689	16,368	5,546	1,776	16,432	19,970
		% of total pop..	2.17%	2.24%	2.22%	1.78%	1.79%	1.56%
	All	Population	289,112	87,311	29,449	10,707	96,132	130,687
		% of total pop..	12.1%	12.0%	11.8%	10.7%	10.4%	10.2%
		HF pop % of total pop.	18%	19%	19%	17%	17%	15%
2,000 (6,600)	HF	Population.	81,153	26,017	8,877	2,415	27,227	32,846
		% of total pop..	3.4%	3.6%	3.5%	2.4%	3.0%	2.6%
	All	Population	381,665	116,772	39,693	14,055	129,723	175,000
		% of total pop..	16%	16%	16%	14%	14%	14%
		HF pop % of total pop.	21%	22%	22%	17%	21%	19%
		Total population	2,386,959	730,050	250,065	99,957	920,404	1,278,020

Table 5.6-1 and those in Appendix 5.D show that about 4% or less of the population in general, and subpopulations assessed (e.g., all households, household types, and daycare centers and schools), are estimated to reside within 2 km (1.2 mi.) of a hydraulically fractured well in the San Joaquin Basin. For these same groupings, 17% or less are estimated to reside within 2 km (1.2 mi.) of an active oil or gas well. Consequently, a bit less than about a fifth of the populations, households, and schools that are in proximity to an active oil and gas well are in proximity to a hydraulically fractured well. This is about the same as hydraulic-fracture-enabled production as a fraction of all production in the

San Joaquin Basin, and suggests to the extent air emissions due to hydraulic fracturing are small compared to all other emissions to install and produce a well, the majority of exposure in the Basin is not due to hydraulically fractured wells, but rather to other wells.

Table 5.6-1 and those in Appendix 5.D show that the percentage of almost every selected demographic and household group in proximity to both hydraulically fractured and all active wells is smaller than the percentage of the general population and households. In other words, people and households in proximity to a hydraulically fractured well and all active oil wells are on average more young adult to middle aged, better educated, and have higher incomes than populations away from these wells.

However, because the density of hydraulically fractured wells is typically high where they do occur, people and households that are in proximity are likely in proximity to a large number of such wells. This is shown for the town of Shafter in Figure 5.6-2. Consequently, the threshold of emissions for any single well to have an acceptable impact is smaller than the threshold for a well among a grouping of wells. For instance, in the Shafter area the threshold for a well among the group would be about one hundredth of the threshold for a single well, based on a proximity of 1.6 km.

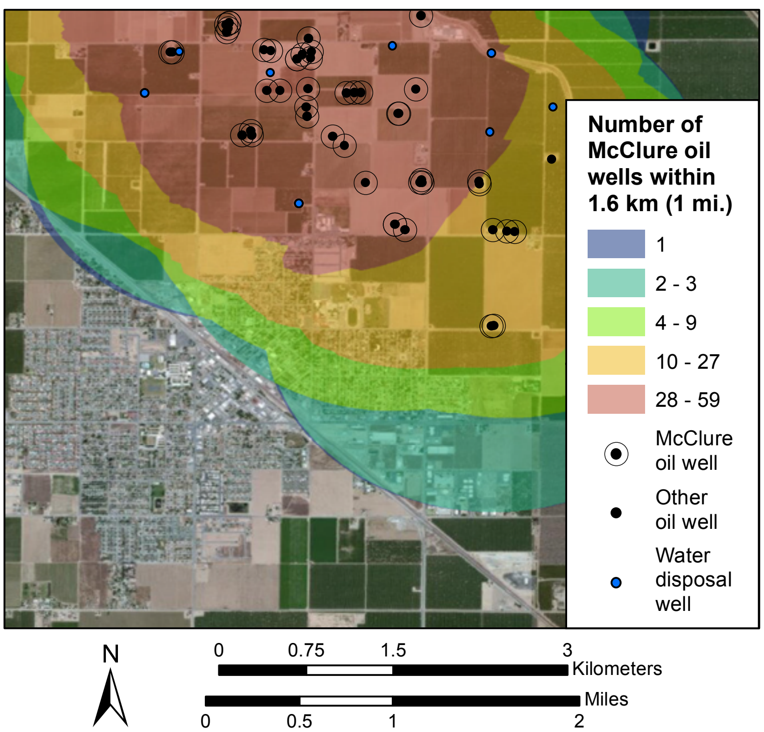


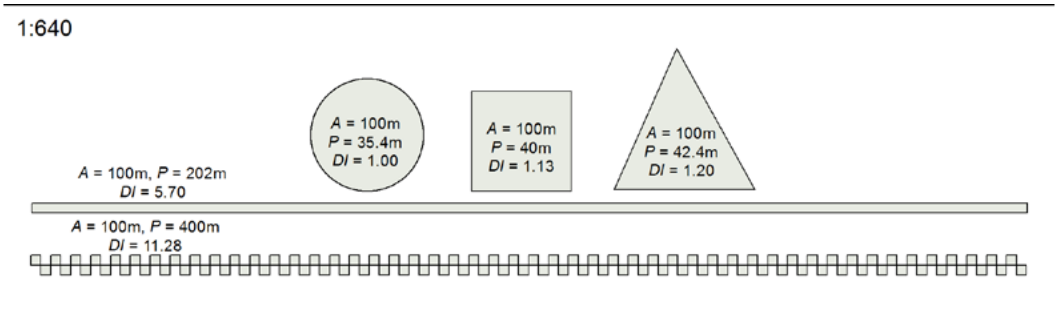
Figure 5.6-2. Number of oil wells in the McClure pool in proximity to a location in the town of Shafter. Oil wells in this pool are generally hydraulically fractured. Other wells in this area are generally not hydraulically fractured. The well type during 2014 is shown.

5.7 Potential Risk to Wildlife and Vegetation From Habitat

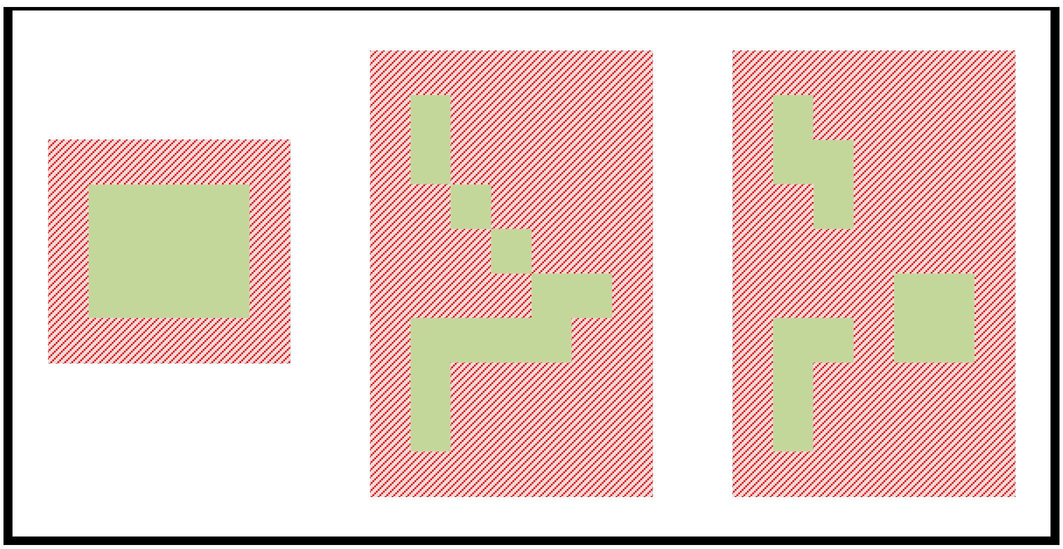
While habitat loss, as discussed in Volume II, Chapter 5, denotes a decrease in the total area of suitable habitat, fragmentation is a change in configuration of that habitat. The two are related, but fragmentation has distinct aspects: an increase in the proportion of perimeter to interior, and the change from one large to many small areas, as shown on Figure 5.7-1. An increase in the ratio of perimeter to interior results in increased exposure to disturbance at the fringe of the habitat, commonly referred to as “edge effects.” A change from one large to many small areas of habitat, also referred to as loss of connectivity or corridors, splits populations of an organism from one large population into many smaller subpopulations. It is important to maintain connectivity between subpopulations to prevent inbreeding and enable recolonization after local extinctions (Pimm and Gilpin, 1989). These two aspects of fragmentation are referred to simply as edge effects and loss of connectivity in the following discussion.

Most of the hydraulic-fracturing-enabled production in the San Joaquin Basin takes place against a backdrop of rangeland habitat, mostly saltbush scrub and non-native grasslands (Volume II, Chapter 5). Almost 90% of the hydraulic fracturing reported in the state is concentrated in six fields clustered in the southwestern portion of the valley: North and South Belridge, Lost Hills, Elk Hills, Midway-Sunset, and Buena Vista fields (Volume I, Chapter 3, Table 3-1). The southwestern San Joaquin also happens to be one of the largest locales of remaining saltbush scrub habitat in the state and is a high regional priority for conservation (Volume II, Chapter 5).

Many populations of native species in the San Joaquin Valley are endangered because of habitat loss and fragmentation (Kelly et al., 2005; Kucera et al., 1995). While the main drivers of habitat loss in the valley as a whole are agriculture and urbanization, in the southwestern portion, a large proportion of land is occupied by oil fields (see Volume II, Chapter 5’s section on “Kern County: Ecology, Oil and Gas Development, and Well Stimulation”). Maintaining linkages between small, fragmented populations is important for survival of native species, such as the San Joaquin Kit Fox (Cypher et al., 2007; Harrison et al., 2011).



a)



b)

Figure 5.7-1. Fragmentation. a) Edge effects: a comparison of five shapes with low to high edge effects. The shapes have the same area but different configurations, progressing from the shape with the lowest ratio of perimeter to area (the circle) to a shape with a very high ratio of perimeter to area (a string of many small squares). The DI metric increases as the ratio of perimeter to area increases. b) Loss of connectivity: a comparison of connected and disconnected areas. Green represents suitable habitat and red hatching represents unsuitable habitat. The portion marked in green is the same total area in all three, but progressing from greatest connectivity on the left (one continuous block), through reduced connectivity (minimal connection points between habitat), to loss of connectivity (three isolated patches with no corridors).

5.7.2. Fragmentation Analysis Methodology

Two approaches were taken to assess fragmentation in the San Joaquin Valley. First, a metric for edge effects called the Diversity Index (DI) was used (Patton, 1975). As illustrated in Figure 5.7-1a, an area with a higher DI is more fragmented. Details on the calculation of DI are provided in Appendix 5.E.

DI was calculated for six fields: North Belridge, South Belridge, Mount Poso, Elk Hills, Midway-Sunset, and Buena Vista. It was calculated from three categories of land use: barren/highly disturbed oil field, other developed (urban or agriculture), and vegetated. The vegetated areas are habitat (nearly all non-native grasslands and Valley saltbush scrub). The DI was calculated for the perimeter of the vegetated area, which includes the edges between vegetated area and the two other land-use categories, as well as the perimeter of the field. Data was acquired from the Geographical Information Center (2014).

Second, corridors in the southwestern San Joaquin Valley were identified, and whether they could be lost due to expanding oil and gas development was assessed. Four criteria were used to identify a viable corridor. First, a corridor needed to have a well density no greater than 77 wells per square kilometer, based on studies showing that most native organisms do not use areas at higher well densities[5] (Fiehler and Cypher, 2011). Second, corridors needed to be more than 2 (1 mi.) wide to be viable, based on expert opinion (Garcia and Associates, 2006). Corridors needed to connect areas of shrubland/grassland (as opposed to urban or agricultural areas). Finally, while areas that are extremely wide do allow migration, they are not "corridors" in the sense that they are not relatively narrow pathways connecting patches of habitat. Our fourth criteria for identifying an area as a corridor was that it be less than 3 km (2 mi.) wide, in order to identify relatively narrow pathways that could be eliminated by relatively small geographic expansions or intensifications of oil development.

5.7.2. Fragmentation Analysis Results

The six fields assessed had different degrees of fragmentation. Elk Hills had the highest DI, followed by Midway-Sunset, then Mount Poso, Buena Vista, South Belridge and North Belridge, as shown in Table 5.7-1. Figure 5.7-2 shows the land use types and fragmentation in each field. Note that DI is calculated based on the length of contact between vegetation and developed areas, including oil and gas, urban, and agriculture areas. Only a portion of the oil and gas development can be attributed to hydraulic-fracturing-enabled production (column A/B).

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5. Well density is highly predictive of habitat disturbance from all infrastructure in an area. See Volume II, Chapter 5, Appendix 5.C for details.

Table 5.7-1. Edge effects in six southern San Joaquin Basin oil fields, ranked from greatest to least DI. Note that DI is calculated based on the length of contact between vegetation and developed areas, including oil and gas, urban and agriculture areas. Only a proportion of the oil and gas development can be attributed to hydraulic fracturing-enabled production (column A/B).

Field	A Hydraulic Fracturing-Enabled Alteration to Habitat (km²)	B All Oil & Gas Alteration to Habitat (km²)	A/B Proportion of Alteration to Habitat Due to Hydraulic Fracturing (%)	Vegetated Area (km²)	Vegetated Perimeter (km)	DI
Elk Hills	53	146	36%	160	1836	40.88
Midway - Sunset	7	181	4%	201	1595	31.75
Mount Poso	18	48	37%	112	506	13.51
Buena Vista	10	90	11%	112	506	13.51
Belridge, South	5	46	10%	27	172	9.41
Belridge, North	4	15	30%	18	107	7.08

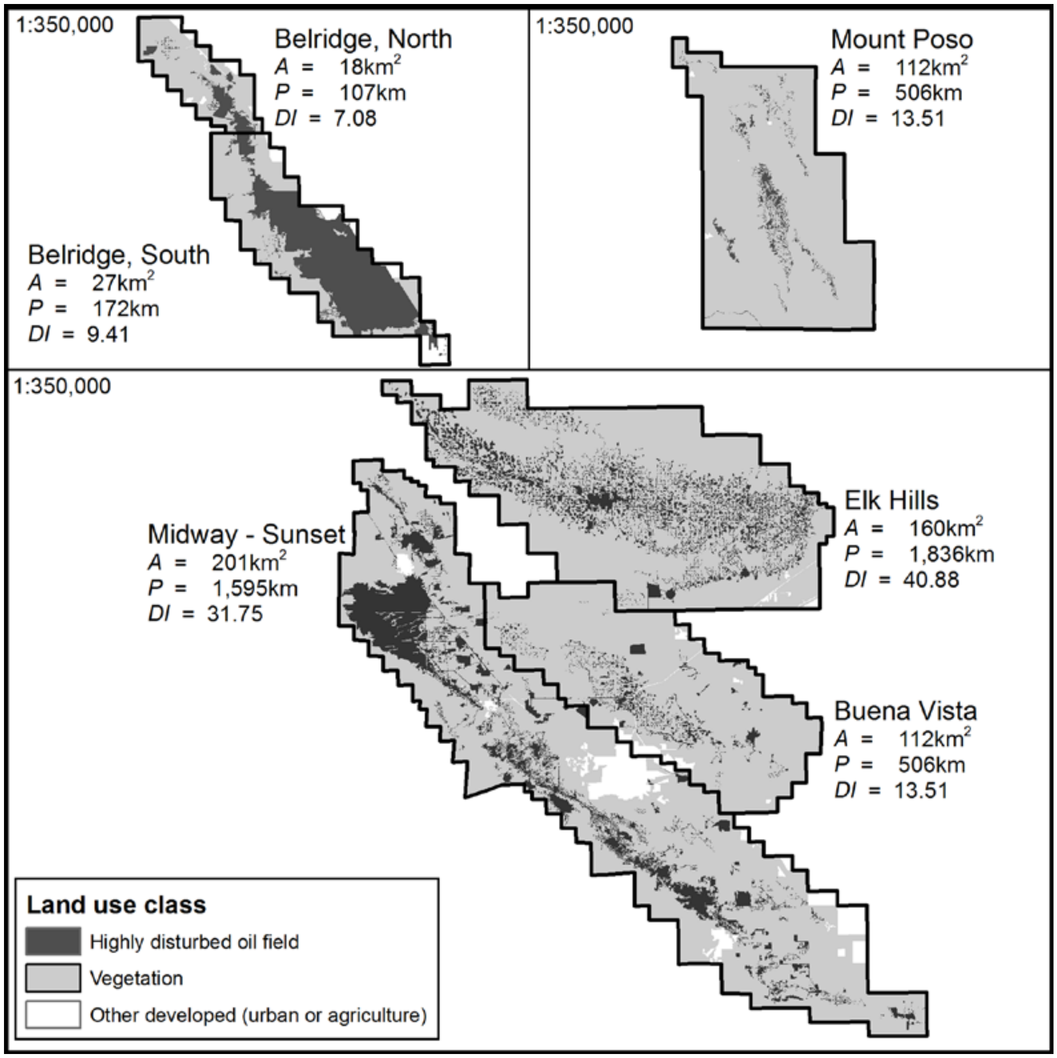

Figure 5.7-2. Land use categories and fragmentation in six oil fields in the San Joaquin Basin with the greatest number of hydraulic fractures.

Different patterns of development have very different impacts on habitat loss and fragmentation; for example, while North and South Belridge have a much smaller amount of vegetated area remaining than Elk Hills, that area is much less fragmented, because development in the Belridge fields is highly clustered. It is also worth noting that while North and South Belridge have much higher numbers of reported hydraulic fractures than Elk Hills, the newly drilled and stimulated wells in the Belridge fields are generally located in areas that have already been intensively developed. It is also important to note that the analysis of fragmentation did not attempt to parse out the impact of hydraulic-fracturing-enabled development. Column “A/B” in Table 5.7-1 gives the proportion of habitat altered due to hydraulic-fracturing-enabled development compared to all oil and gas development in each field. Only a portion of the fragmentation of habitat by oil and gas production can be attributed to development enabled by hydraulic fracturing. In some fields in particular, such as Midway-Sunset, this portion is likely quite small, although the exact contribution to fragmentation will depend on the location of the altered habitat.

The ratio of edge to interior habitat can be minimized by clustering facilities as much as possible: for example, building a network of main roads, pipelines, and powerlines rather than many small ones; using centralized staging and storage equipment; and placing multiple directionally drilled wells on one well pad rather than placing individual vertical wells on each well pad (Getches-Wilkinson Center for Natural Resources, Energy, and the Environment, 2015).

Eight locations were identified in the southwest San Joaquin Basin that met the definition of a corridor. These are shown in Figure 5.7-3. These connected the relatively small islands of habitat that lie between the vast expanses of agricultural fields and the highly developed oil and gas areas with the open land to the south and west of the oil fields. These eight corridors lie between areas of high-density oil patches in the Midway Sunset field (3 corridors), McKittrick/Elk Hills field (2), Elk Hills (2), and South Belridge/Cymric (1). All of these fields except the McKittrick were identified as having pools where production is predominantly facilitated by hydraulic fracturing (Volume I Appendix N). These corridors are high-value areas that should be targets for conservation and implementation of best management practices, habitat thresholds, and/or regulated mitigation measures that maintain sustainable populations of rare species within the oil field landscape.

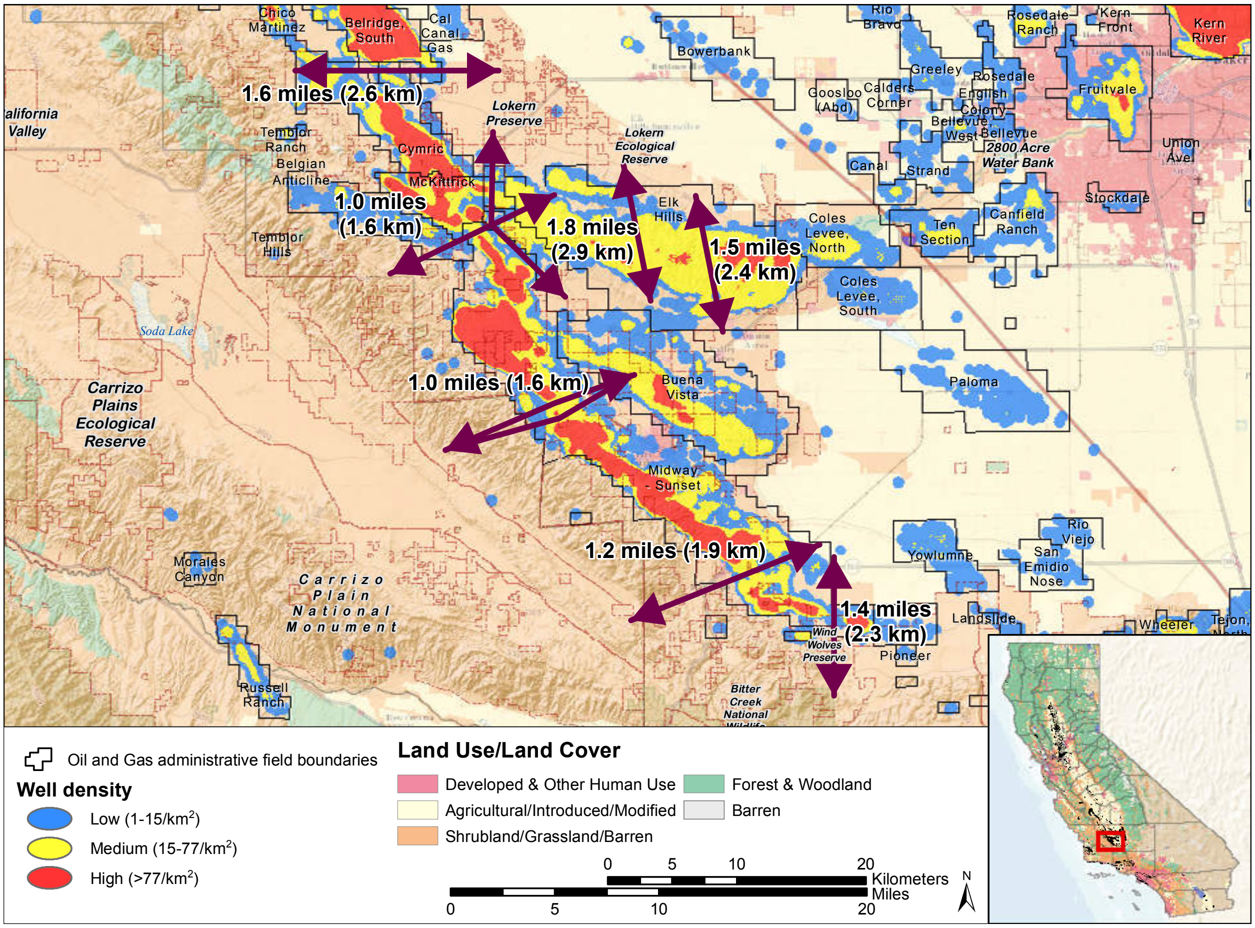

Figure 5.7-3. Corridors between high-density oil developments in the southwestern San Joaquin Valley.

From the standpoint of habitat conservation, how much new development is enabled by well stimulation is less important than where that new development occurs. Well stimulation in California has enabled production from pools that were formerly uneconomical to produce (Volume I, Chapter 3). In some cases, these pools underlie regions at the surface that have already been intensively developed for human use—either for oil and gas production tapping into other pools, or for agriculture or cites. If well stimulation spurs development of pools that underlie habitat, it results in loss and fragmentation of that habitat. When well stimulation enables new development in pools that underlie already developed areas, the marginal impact to habitat loss and fragmentation is much smaller. It is possible that the co-occurring unstimulated pools could cease production before the stimulated ones, in which case stimulation could extend the duration of an impact to the field. However, in the limited number of studies of long-term habitat impacts after a well is abandoned, the habitat did not reconverge to pre-disturbance quality within the timeframe of the studies (on the scale of a few to approximately ten years after a well was abandoned) (Hinshaw et al., 1998). This suggests that while extending the duration of production at a site may have some ecological impacts, the major impact is in the initial development.

Oil and gas production as a whole has contributed to habitat fragmentation in California, although the proportion of fragmentation caused specifically by hydraulic-fracturing-enabled production is most likely fairly minor, in line with the proportion of habitat loss it has caused. However, in certain key areas, particularly the southwestern San Joaquin Basin, hydraulic-fracturing–enabled production is an important contributor to fragmentation in an ecologically sensitive area. In particular, there are only a few corridors connecting the islands of habitat remaining between farmland and oil fields to each other and the habitat to the south and west of the oil fields. These relatively small areas are vulnerable to expanded production, given that most native species do not generally use high-density oil fields. Fragmentation from future development can be minimized by focusing on infill areas, and minimizing new development in corridors can reduce the impacts of fragmentation resulting from future oil and gas development.

5.8. Data Gaps

Many of the sections above have identified data gaps regarding each assessment, which are summarized below together with recommendations for assessing and collecting additional data.

- The disposal method for water produced from the fields with the most hydraulic fracturing is uncertain. Data submitted to the public database by at least some operators disagree with statements from them regarding how they dispose of water. In order to understand the historic disposition of these waters, an effort should be made to correct this data set. Aside from providing an accurate understanding of current practice, this is relevant to characterizing potential legacy contamination, discussed below in the conclusions. Going forward, adequate reporting procedures should be implemented with data quality assurance and control to increase data integrity.

- The concentration of well stimulation chemicals, their degradation products, and natural constituents mobilized by stimulation in produced water streams from central treatment plants is unknown. This is particularly a concern for produced water from pools with hydraulic fracturing operations that is disposed of in percolation pits or potentially injected into protected groundwater. The composition of produced water should be analyzed in order to characterize this possible source of contamination. Even if the recommendations above to phase out such disposal are implemented, this source characterization is needed to inform the recommended next step of investigating potential legacy contamination at and beneath percolation pits and around disposal wells injecting into groundwater that is determined to require protection.

- The statistical likelihood of shallow hydraulic fractures encountering protected groundwater resources is currently unknown, or at least not estimable from publicly available data. It may well be that operators have data sufficient to develop this understanding if it is released, perhaps in response to a regulatory request. If these data do not exist, cannot be released, or are insufficient, field research is recommended to develop these statistics. In addition, a theoretical basis should be developed for limiting the likely maximum size of shallow hydraulic fractures to support appropriate regulations to prevent intersecting protected water.

- The frequency of chronic well leakage in California is not known. This information is critical to estimating the frequency of fluid volumes leaking from wells. While information regarding this frequency exists for other parts of North America, the frequency in California could be different for a variety of reasons (such as sedimentary consolidation and ground settlement, use of thermal recovery methods, and seismic activity). If an understanding of the chronic well-leakage frequency in California cannot be developed from existing public data sources, this understanding should be developed through new field research, such as soil gas monitoring around statistical samples of existing wells, and testing of behind-casing well permeability as part of plugging orphaned wells.

- Data regarding the concentration of TACs and criteria pollutants in the vicinity of stimulated wells, and oil and gas wells in general in the San Joaquin Basin, appears to be lacking. Air quality data should be collected in the vicinity of such wells, particularly where communities are located in proximity to high well densities, given the high percentage of criteria pollutant emissions in the San Joaquin Basin by oil production.

- Assessments of greenhouse gas pollution from oil production, transportation, and refining from pools where most wells are hydraulically fractured versus pools developed using other technologies are not available. Consequently, understanding the amount of pollution from different production methods, with greatly varying greenhouse pollution profiles, is difficult. Assessments of greenhouse gas pollution should be conducted for individual pools, at least some that are representative of different production methods used in California, because production methods are more consistent across a pool than they are within a field consisting of multiple pools.

- Our understanding of key parameters for conservation in the southwestern San Joaquin Basin is limited. Key questions for further research are: what is the minimum width for a viable corridor? What level of human disturbance can the native species tolerate in a corridor, and in viable habitat? What is the minimum amount of area and degree of connectivity that must be maintained in order for native species to sustain their populations? How will continuing changes in the region—such as from oil field development, agriculture, urbanization, and climate change—affect native species? These are classic questions in conservation biology, but relatively little research has been done on these issues for the suite of species that inhabit the southwestern San Joaquin Basin.

5.9. Conclusions and Recommendations

The following summarizes the conclusions from each potential risk assessed in this case study. Recommendations to reduce some risks in the San Joaquin Basin are also included, along with some additional general recommendations.

Water Supply: In the San Joaquin Basin, high-quality water is used for hydraulic fracturing, and low-salinity supplied water is used for EOR in some fields, while produced low-salinity water is disposed of in other fields. There may be opportunities for switching from using supplied water to low-salinity produced water that is currently disposed of in the same or nearby fields. This could both reduce demand for supplied low-salinity and high-quality water and reduce subsurface disposal volumes, which in turn would reduce the induced-seismicity risk created by disposing of produced water by injection. It is currently unknown what barriers exist to using produced water for this purpose. They may be technical, such as a mismatch between the quality of the produced water and the water quality needed for hydraulic fracturing and EOR. It might be possible to address such a barrier, for instance with incentives to apply an appropriate treatment technology to improve the quality of the produced low-salinity water. The barriers may be legal, such as restrictions on operators cooperating on transfers of produced water between them within the same field or between different fields, or the liability associated with such transfers. These could potentially be addressed through legislation.

Disposal of Produced Water in Percolation Pits: Analysis of available data suggests the concentrations of hydraulic fracturing fluid constituents in produced water from fields with substantial hydraulic fracturing are sufficiently high that it should not be disposed of by percolation, because of the risk of groundwater contamination this creates.

Produced Water Used for Irrigation: Analysis of available data suggests occasional hydraulic fracturing in fields from which produced water is used for irrigation. While there are central treatment facilities for produced water, these may not be designed to remove or reduce stimulation-fluid constituents, their degradation products, and any natural constituents mobilized by stimulation or reduce the concentration of those constituents to acceptable levels. Thus, there is a possibility that hydraulic fracturing fluid constituents could be at concentrations of concern in the produced water stream from central treatment facilities, in particular shortly after a well is put on production after stimulation. In the absence of appropriate treatment systems and a determination of what are acceptable concentrations, which are unknown for many possible constituents, hydraulic fracturing should not be allowed in fields that supply produced water for use in the environment, such as irrigation. Alternatively, use of produced water for irrigation from fields with hydraulic fracturing should be prohibited.

Constituents Used for Stimulation: One means of reducing concerns about the release of stimulation constituents is to move to a constituent selection approach similar to that of the North Sea compact/OSPAR Convention. In California, a similar program could be built upon the U.S. Environmental Protection Agency's Designed for Environment program, which is voluntary at the national level (U.S. EPA, 2011). This would result in utilization of constituents with among the lowest potential environmental impacts, and would allay the current situation involving use of numerous chemicals without a complete environmental profile, which precludes a complete assessment of risk to the environment and human health. In the meantime, a risk assessment regarding those constituents for which OEHHA provided screening criteria in Volume II, Appendix 6.B should be carried out, ideally based upon measurements of constituent concentrations in produced water at the point of disposal. But if those are unlikely to be collected in the near term, it is advised to use the potential upper-bound concentrations derived in this report in the meantime.

Site Characterization: Site characterization is needed in order to assess the risk of leakage to groundwater via subsurface pathways. This includes characterizing the extent and quality of groundwater with less than 10,000 mg/L TDS, horizontal hydraulic gradients and flow directions in this zone, vertical gradients through the section from the reservoir to the ground surface, and hydrostratigraphy throughout the section in the vicinity of a hydraulic fracturing operation, as well as potential leakage paths (such as wells and faults). A particular focus for the San Joaquin Basin is determining the extent of and hydraulic head distribution within groundwater with less than 10,000 mg/L TDS, which has not historically been methodically determined and mapped. This information is necessary to designing monitoring for all protected groundwater.

Shallow Hydraulic Fracturing Operations: Most hydraulic fracturing in the San Joaquin Basin occurs in relatively shallow subsurface reservoirs, which increases the potential for created fractures encountering protect groundwater. Shallow fracturing should only be permitted if (1) there is a detailed prediction of the expected fracturing extent, (2) the separation distance between this extent and protected groundwater provides a sufficient safety margin given appropriate weighting of uncertainties, (3) operations are monitored to infer if the fracture has intersected or come near groundwater, (4) a corrective action plan is in place if this occurs, and (5) the groundwater monitoring plan includes appropriate adjustments to monitor groundwater in close proximity to any possible fracture extensions into or near groundwater.

Leakage Detection and Groundwater Monitoring: SB 4 now requires operators to implement appropriate monitoring near well stimulation operations. However, groundwater monitoring will not necessarily detect contamination should it occur, in particular if leakage frequencies are low and rates are small. It would be beneficial to conduct further studies on leakage detectability specific to the conditions in the San Joaquin Basin to assess the cost versus the benefit of different monitoring approaches, and to optimize monitoring strategies to adequately account for potential higher risk stimulations, such as hydraulic fracturing in close proximity to protected groundwater.

While similar studies have been conducted in other settings, the depth of stimulation in the San Joaquin Basin is one unique feature that warrants studies specific to the practice in the state. In addition, improved monitoring design could be achieved via dedicated field study areas where monitoring and data collection can be much more intense and ubiquitous than is possible in general industry operations. The field study areas would be monitored with more-than-usual resolution and frequency, which allows for testing of monitoring practices and provides for lessons learned in terms of what types of monitoring is useful.

Well Construction: Current well construction requirements in the San Joaquin Basin are not designed to protect groundwater with 3,000 to 10,000 mg/L TDS that is not otherwise exempt from protection. These requirements should be modified to protect this water, such as by requiring full-length cementing of casing into an aquitard below the base of the deepest water with <10,000 mg/L TDS. A statistical understanding of the existing wells relative to protecting this groundwater from potential migration of stimulation fluids should be developed, both through an assessment of available well construction records and field research in the vicinity of selected legacy wells of concern. Wells that do not have seals behind casing positioned to protect groundwater with less than 10,000 mg/L TDS should be remediated with cement squeeze operations.

Faults as Leakage Pathways: The San Joaquin Basin has a high density of faults, which present potential paths for leakage out of hydraulically fractured pools. The presence of oil generally suggests that faults intersecting oil reservoirs do not provide leakage paths. However, the likelihood of leakage of stimulation fluids or reservoir gases via faults opened during hydraulic fracturing is not known. This likelihood should be investigated further, perhaps in simulation assessments and/or dedicated field studies. In the meantime, it is important to ensure that site characterization efforts conducted will detect existing faults of a size sufficient to connect the reservoir to protected groundwater before a hydraulic fracturing operation is conducted.

Proximity Analysis: About 3 to 4% of the total population in the San Joaquin Basin lives within 2 km (1.2 mi.) of a hydraulically fractured well, and about 16% live within this distance from an active oil and gas production well. Consequently, about a fifth of people in proximity to an active oil production well are in proximity to a hydraulically fractured well. This is about the same as the portion of oil production that is enabled by hydraulic fracturing. The population within the vicinity of both hydraulically fractured wells and all active wells is younger, more educated, and has higher incomes than populations further away.

Habitat Fragmentation: Habitat fragmentation is related to both an increase in the proportion of edge to interior habitat, and a loss of connectivity between areas of high-quality habitat. An increase in edge habitat tends to be deleterious for species that are intolerant of human disturbance. Loss of connectivity tends to reduce the long-term viability of populations of native species. Conserving large patches of habitat with a relatively low ratio of edge to interior, and preserving corridors for connectivity between patches of habitat, are important for conservation of native species. Edge effects can be minimized by clustering facilities as much as possible: for example, building a network of main roads, pipelines, and power lines rather than many small ones; using centralized staging and storage equipment; and placing multiple wells on one well pad. Connectivity can be preserved by maintaining corridors between patches of habitat. Eight major corridors were identified in the vicinity of the oil fields with the most hydraulic fracturing in the San Joaquin Basin. These should be preserved by focusing development elsewhere or by drilling directional and horizontal wells from well pads outside these corridors to reach locations beneath the corridors. The agencies of jurisdiction should identify quantifiable objectives for habitat conservation (in terms of minimum width of corridors, maximum disturbance levels, total area conserved and configuration) that could be applied in high priority reserves and corridors in the southwestern San Joaquin Basin to maintain sustainable populations of special status species in the corridors and oil field landscape.

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