Draft Report

Well Stimulation Treatment in California: Evaluation of Disclosure Data, May 2015 – October 2019 LBNL-2001401

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Prepared by:

Mary Kay Camarillo
William T. Stringfellow

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Geochemistry Department
Earth & Environmental Sciences Area
Berkeley National Laboratory
Berkeley, CA

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1. Abstract

In this document, disclosure data from 1,228 well stimulations occurring May 2015 to October 2019 in California are evaluated. This evaluation updates a previous study that was based on 618 well stimulations occurring May 2015 to June 2016 (Stringfellow, W.T., Camarillo, M.K., and Jordan, P. 2017, Status of Well Stimulation in California Since Implementation of SB-4 Regulations, Berkeley National Laboratory, Berkeley, CA). While the goal of the previous study was to provide a summary of information obtained since passage of California Senate Bill No. 4—Oil and Gas, the goal of the current evaluation is to provide a basis for studying chemical indicators that could potentially be used to detect aquifer contamination. We evaluate chemical indicators is a separate document using the data contained herein as well as data from monitoring wells located within oil fields. Compared with the data used by Stringfellow et al. 2017, the current evaluation is based on a more diverse data set. While the previous study contained data for only two oil fields with more than 30 well stimulations, the current data set contains four oil fields with more than 30 well stimulations, making these data more ideal for comparisons using statistical tests. More producers and a new oil field, Buena Vista Nose, are represented in the current data set. Some well stimulation practices remain relatively unchanged since the previous study. Well stimulation is mostly occurring in Kern County with the exception of a single well stimulation in Orange County. Almost all well stimulations are hydraulic fracturing. The current data set contains two acid fracturing treatments and one matrix acidizing treatment. The median number of chemicals added per well stimulation—excluding water and proppant—was previously 21; the number in the expanded data set is 20. Median water added per well stimulation was previously 89,000 gallons and is now 98,000 gallons. While this water use represents a 10% increase, water use for hydraulic fracturing in California is still lower than water use in other oil and gas fields. Chemical formulations appear to have shifted since the previous study. This shift may be related to a change in the predominant service company. We identified 26 chemicals for which the frequency of use has changed by more than 30%. The total number of chemicals used has also expanded. Previously, 178 unique chemicals were identified as being added to well stimulation fluids. The total number of unique chemicals is now 205. Analytical data available for base and recovered fluids has expanded. The number of base fluid samples has increased from 12 to 35 and the number of recovered fluid samples has increased from 1,078 to 2,166. The expanded data set is more ideal for an evaluation of indicator chemicals and comparisons across different formations. The analytical data for recovered fluid samples indicates that many ions, radioactive constituents, and organics are consistently observed, making these chemicals ideal for consideration as potential indicators of aquifer contamination.

2. Introduction

The purpose of this document is to summarize information on well stimulation treatments (WST) in California, updating a previous evaluation by Stringfellow et al. (2017). Data on WST in California is collected as the result of Senate Bill No. 4 – Well Stimulation: Oil and Gas (Pavley, 2013) and regulations governing WST in California (DOGGR, 2014). Stringfellow et al. (2017) evaluated data on WST occurring between May 5, 2015 and June 29, 2016. Similar to the previous evaluation, this report includes a summary of chemicals and water volumes used, the sources of water, a summary of analytical data on sourced water, and a summary of analytical data on fluids recovered from wells undergoing WST. Here, we present an evaluation that is inclusive of that data set and extends from May 5, 2015 to October 4, 2019. While the goal of Stringfellow et al. (2017) was to evaluate WST in the context of the SB-4 Scientific Study (Long et al., 2015), the goal here was to provide a basis for evaluating chemicals that could potentially serve as indicators of aquifer contamination. The evaluation of chemical indicators is contained in a separate document (Camarillo and Stringfellow, 2021a), as is a literature review on chemical indicators of hydraulic fracturing in the environment (Camarillo and Stringfellow, 2021b). This evaluation contains a summary of WST practices in California and the accompanying water quality data sets so that these data can be compared with data from oil field monitoring wells and regional groundwater monitoring wells.

3. Data Sources and Methods

3.1. Well Stimulation Treatment (WST) Disclosure Data

The WST disclosure data evaluated herein are reported by oil and gas producers to the California Geologic Energy Management Division (CalGEM) who oversees the WST disclosure program. After screening for accuracy, CalGEM maintains the data in the WellSTAR database that can be accessed on the Department of Conservation website (DOC, 2021). The database contains information on WST dates, the number of stages stimulated, information on WST conditions, base fluid sources, base fluid volumes, base fluid analytical data, chemicals used, additive used, percent masses of chemicals used, recovered fluid volumes, and recovered fluid analytical data. The database contains analytical data for two recovered fluid samples collected for each WST: one sample is collected after three wellbore volumes have been recovered from the well and the other sample is collected approximately 30 days after commencement of production.

Electronically compiled WST disclosure data was received from James Ackerman at CalGEM. The first data transfer occurred in April 2019 and included data spanning back to the interim program, which was in place prior to the final permit program. The second data transfer occurred in June 2020 and only included data collected since the first data transfer. Latitude and longitude data were obtained by downloading a bulk data set from the WellSTAR website. The bulk data were downloaded as a *.BAK file and restored using Microsoft SQL Server Management Studio 18.

The WST reviewed as part of this project occurred May 5, 2015 – October 4, 2019. In some of the analyses, these data were compared with WST data evaluated previously by Stringfellow et al. (2017) for WST occurring May 5, 2015 – June 29, 2015.

The two data sets received from CalGEM were checked for redundancy and nine duplicate records were removed. The same analytical data for base fluid samples were reported with multiple WST permits. A subset of base fluid analytical data was created that contained base fluid results without duplication.

Multiple base fluids volumes were reported for some WST. These base fluid volumes were summed to calculate the total base fluid volume because it appeared that the water was being reported for individual stages of well stimulation. Representatives from CalGEM confirmed that for some earlier WST, multiple base fluids volumes were reported because these WST were interrupted and then resumed at a later dates, causing multiple base fluid volumes to be used.

Multiple recovered fluid volumes were also reported for some WST. These volumes were not summed because these values were identical and appeared to be duplicates. A subset of recovered fluid volumes were created that contained recovered fluid volumes without duplication. The recovered fluid data set also contained records where no samples were collected but a gross alpha measurement was made and records were oil and gas samples were collected—these records were not included in the subset of recovered fluid volumes.

The analytical data for base fluids and recovered fluids were standardized to have consistent units (e.g., mg/L and not a mix of ug/L and mg/L). Parameter names were standardized for consistent capitalization.

WST practices and recovered fluid water quality data were evaluated using field-area-pool (FAP) codes to characterize geology. The FAP codes are described in California Code of Regulations (CCR) Title 14 Section 1760 and 1741[k].

Chemicals were evaluated based on their Chemical Abstracts Service Registry Number (CASRN). Chemical names were standardized so that there is a single name for each CASRN.

3.2. Statistical Analyses

The software JMP version 13.0.0 (SAS Institute Inc., Cary, NC) was used to manage and evaluate the data sets.

4. Description of Well Stimulation Data

4.1. Oil Well Locations, Geology, and Dates of Well Stimulation

The WST disclosure data contained information on 1,228 interim notices and permits performed over the time period May 5, 2015 to October 4, 2019 (Figure 1). All of the WST occurred in Kern County, at the southern end of the San Joaquin Valley, with the exception of one WST that occurred in Orange County (Figure 2). The WST in Kern County occurred in seven oil fields: Buena Vista Nose, Elk Hills, Lost Hills, McKittrick, North Belridge, North Coles Levee, and South Belridge (Figure 3). The WST were performed by seven producers and three service companies (Table 1). Most of the WST were performed in South Belridge, FAP 0520020 (81.6%). Other FAP with more than 30 WST were Lost Hills in FAP 4320027 (9.9%), Buena Vista Nose in FAP 0000000 (2.9%), and North Belridge in FAP 0500007 (2.7%).

The WST were done in formations with differing geologic characteristics as indicated by the 14 FAP where WST occurred (Table 1). Geological descriptions reported by producers are aggregated here to show the range in formations where WST were performed (Table 2).

Formations are contain diatomite (e.g., in the Monterrey Formation), shale (e.g., Antelope and McDonald), and other compositions. Well depths vary by FAP (Table 3). In the FAP with the most WST, 0520020, the median well depth is 1,981 ft, while median well depth in 22 of the wells in Buena Vista Nose is 10,582 ft. The geology in Buena Vista Nose (FAP 0000000) also differs, described as being part of the Monterey Formation and containing Antelope shale while South Belridge (FAP 520020) is part of the Reef Ridge Formation and contains diatomite. Previous analyses indicated that WST chemicals and fluid volumes vary by formation (Stringfellow et al 2017). The differences in geology and well depth noted here likely influence differences in WST chemicals and volumes of stimulation fluids used.

4.2. Well Stimulation Chemicals

The WST disclosure data contained data on 1,228 interim notices and permits that disclosed chemicals added to WST fluids. Two of the 1,228 records were for acid fracturing treatments (INH15-0592 and permit 18-0068-1) and one was for a matrix acidizing treatment (INH15-0711). The remaining 1,225 records were for hydraulic fracturing treatments.

The mean number of chemicals added to hydraulic fracturing stimulation fluids, including water and proppant, was 19.4 (median = 22). The number of chemicals added per treatment ranged from two to 47. The two acid fracturing treatments had 39 and 56 chemicals per treatment, respectively, while the matrix acidizing treatment contained 29 chemicals.

There were 205 unique chemicals, identified by CASRN, added to well stimulation treatments (Table 4). In addition to water and quartz silica sand, 12 chemicals were used in more than half of all WST: guar gum, sodium hydroxide, sodium chloride, hemicellulose enzyme, lactose, sodium sulfate, sodium persulfate, monoethanolamine borate, ammonium chloride, polydimethyl diallyl ammonium chloride, 2,2 dibromo-3-nitrilopropionamide, and 2-bromo-3-nitriloproprionamide. A majority of the chemicals were used infrequently. For example, 166 out of the 207 chemicals (81%) were used in fewer than 10% of WST. Because acid fracturing WST fluid formulations differ from those of hydraulic fracturing WST, chemicals added to the acid fracturing treatment for permit 18-0068-1 are listed in Table 5. Chemical lists for the other acid fracturing treatment and the matrix acidizing treatment were previously described in Stringfellow et al. (2017).

To better characterize the chemicals added to WST and their frequency of use, the chemicals were assessed by function and chemical category. Based on the function that they serve in WST fluids, the most common types of chemicals used (in more than 50% of WST) were water, proppant, gelling agents, breakers, cross-linkers, clay control agents, mineral salts, biocides, pH adjusting chemicals, and product stabilizers (Table 6). Based on chemical category, the most common types of chemical used (in more than 50% of WST) were water, mineral solids, quaternary ammonium compounds (QACs), carbohydrates, mineral salts, oxidizing agents, enzymes, strong base, boron amine compounds, ammonium compounds (not including QACs), and amides (Table 7).

The chemicals used in formulating WST fluids appear to have shifted since the work of Stringfellow et al. (2017). Comparing the frequency of use in this data set compared with the previous data set, there are 26 chemicals that have frequency of use percentages that have changed by more than 30% (Table 8). Nine of these chemicals are being used more frequently and the remaining 17 are being used less frequently. The changes in chemical formulations of WST fluids appear to be related to choices in crosslinkers and breakers, biocides, clay control agents, and scale inhibitors. For example, the biocides used in WST appear to have shifted from 5-chloro-2-methyl-3(2H)-isothiazolone (CASRN 26172-55-4) and 2-methyl-3(2H)-isothiazolone (CASRN 2682-20-4) to 2,2 dibromo-3-nitrilopropionamide (CASRN 10222-01-2) and 2-bromo-3-nitrilopropionamide (MBNPA CASRN 1113-55-9). There has also been a shift from the clay control agent prolonium chloride (55636-09-4) to polydimethyl diallyl ammonium chloride (26062-79-3). A possible explanation for the change in chemicals used is that the predominant service company has changed (Table 1) compared with what was reported by Stringfellow et al. (2017).

Based on the list of chemicals added to WST fluids (Table 4), it is apparent that QACs are used consistently. These chemicals are of interest because of their toxicity profiles, challenges in measuring, and potential environmental persistence. The function of QACs in WST fluids vary—some are added clay control agents while others are added because they are surfactants and/or are biocides. Ten QACs were identified (Table 9). These QACs were added to 1,226 out of 1,228 WST fluids (99.8%).

Biocides were also consistently added to WST fluids (Table 4). These chemicals are also of interest because of their toxicity profiles and potential environmental persistence. Thirteen biocides were identified (Table 10). Four of the QACs are listed as biocides. Most WST fluids contained a biocide, found in 1,177 out of 1,228 WST fluids (95.8%).

Nitrogen added to WST fluids was of interest because nitrogen could potentially be used as an indicator and nitrogen is an essential element for microbial growth. Only 44 of the 205 WST chemicals contained nitrogen (not including trace nitrogen in mixtures and industrial chemicals), but these chemicals were added consistently to WST fluids, found in 1,227 out of 1,228 WST fluids (99.9%).

4.3. Well Stimulation Base Fluids

The volumes of base fluids added to WST fluids was variable by FAP (Table 11). On average, 107,000 gallons were used per treatment (median = 99,000 gallons), and the range in base fluid volume per treatment was 9,282 – 1,091,118 gallons.

Three types of water were used in formulating WST fluids. The most commonly used water source was the California Aqueduct (89.5%), but well water (8.0%) and produced water (2.5%) were also used. The sources of water were similar to what was reported by Stringfellow et al. (2017) where 88% of WST were formulated with water from the California Aqueduct. The well water was derived from different sources, including oil field wells, irrigation wells, and water from local water districts. The disclosure data contains descriptions of the well water sources, but coordinates are not provided that would confirm the sources. For example, well water included water from the Tulare Formation although no data were provided on the locations of the wells used or their depths. The sources of recycled produced water and details about pre-treatment were not specified.

Analytical data was provided for 35 samples of base fluids (Table 12). These samples consisted of 22 samples from the California Aqueduct, nine samples from well water, and four samples of recycled produced water. There were a total of 221 parameters reported for base fluid samples.

Only parameters that were consistently measured or are of particular interest are shown in Table 12. The data are summarized by source: California Aqueduct water, recycled produced water, and well water. The three different sources of base fluids can be distinguished by the total dissolved solids (TDS) measurements. Median values of TDS are 340 mg/L for water from the California Aqueduct, 1,550 mg/L for water pumped from wells, and 12,000 mg/L for produced water used to formulate WST fluids. Other water quality measurements that distinguish the three types of water are alkalinity, barium, boron, bromide, calcium, chloride, fluoride, iron, magnesium, methane, radium 226 and 228, sodium, strontium, and sulfate. For most constituents, the California Aqueduct water has the lowest concentrations followed by the well water and then the produced water. A notable exception is sulfate where concentrations are highest in well water (median = 200 mg/L) and lower in both aqueduct samples and produced water (median = 27.5 and 40.5 mg/L, respectively). The components of BTEX (benzene, toluene, ethylbenzene, and xylene) are predominantly found in produced water with trace amounts measured in the well water. Methane is similarly found in produced water (median = 0.22 mg/L) and in well water in lower amounts (median = 0.078 mg/L).

4.4. Recovered Fluids from Wells Undergoing Well Stimulation

The volume of recovered fluids collected prior to collection of the first sample was variable by FAP (Table 13). On average, 16,100 gallons were collected (median = 4,030 gallons), and the range in base fluid volume per treatment was 0 – 408,282 gallons. Recovered fluid volumes were reported for 1,217 of the 1,228 WST. In most cases, the total volume collected was identical to the volume collected as of the first sample.

There were 1,189 WST with recovered fluid analytical data. Of these, 951 had data for two samples, 225 had data for one sample, and 13 had data for three samples. The total number of recovered fluid samples was 2,166. There were 172 unique parameters measured.

Analytical data for the recovered fluids is presented in Table 14. Only parameters that were consistently measured or are of particular interest are shown in Table 14. Only data from the four FAP with more than 30 WST are summarized in Table 14. These data demonstrate variability in the water quality of fluids recovered from wells.

In some of the recovered fluid samples guar gum was measured while total carbohydrates was measured in others (Table 14). Based on the information provided, both guar gum and total carbohydrates were measured using the Anthrone method. The results; however, were kept separate and not combined because we could not verify that the analytical methods were identical. We suspect that different calibration methods were used in the Anthrone measurements and that this is why the parameters were labeled differently. Since the calibration methods could not be verified, the results were not combined.

Some of the variability in recovered fluid water quality (Table 14) can be attributed to differences in geology, as indicated by FAP, and sample order. A good example of this variability is the gross alpha measurement where the median values in samples from Buena Vista

Nose were 140 and 74 pCi/L for the first and second samples, respectively. Median gross alpha values for samples collected in the other three FAPs were lower and ranged from 18.7 to 59.9 pCi/L. In Buena Vista Nose, North Belridge, and Lost Hills samples, the median gross alpha concentrations were higher in the first sample than in the second sample. As an example, the median gross alpha for first samples from Lost Hills was 24.8 pCi/L and the median gross alpha for second samples was 18.7 pCi/L.

Variability in recovered fluid chemistry by FAP and sample order was also apparent in gross beta measurements (Table 14). The median gross beta for samples from Buena Vista Nose was 4,355 pCi/L for the first sample and 940 pCi/L for the second sample. Median gross beta measurements in Lost Hills were much lower: 245 pCi/L for the first sample and 134 pCi/L for the second sample. However, the highest gross beta value was observed in Lost Hills, 41,000 pCi/L, whereas the highest observation in Buena Vista Nose samples was 11,000 pCi/L.

While gross alpha and beta measurements indicate differences by FAP and tend to be higher in first samples, the results for radium are different (Table 14). Buena Vista Nose, North Belridge, and South Belridge have similar median values for radium-226, ranging from 23.8 to 31.1 pCi/L. The median radium-226 values in Lost Hills are lower: 9.3 pCi/L for first sample and 10.4 pCi/L for second sample. There are few data for radium-228 in North and South Belridge. In Buena Vista Nose the median values for first and second samples are 30.1 and 28.5 pCi/L, respectively. The radium-228 values in Lost Hills are lower: 6.7 and 6.3 pCi/L for first and second samples, respectively.

The higher concentrations of gross alpha, gross beta, and radium observed in the first sample, relative to the second sample, may be the result of a “first flush” phenomenon occurring following WST where formation minerals are scoured from the formation rock and pumped to the surface with the recovered fluids (Stringfellow and Camarillo, 2019). This first flush appears brief and results in initially high concentrations of radioactive ions and scale-forming minerals such as calcium. Other researchers have observed elevated concentrations of boron and lithium following hydraulic fracturing that they suggest may be the result of ion exchange with formation clays (Warner et al., 2014). Here, median boron values of the second sample were consistently higher than for the first sample. Median lithium concentrations were similar for the first and second samples. However, mean lithium concentrations were higher in the first sample than in the second sample in the South Belridge and Lost Hills formations.

There are apparent difference in total dissolved solids among the FAP, with North Belridge samples having higher TDS than samples from the other FAP (median TDS is 32,500 and 34,000 mg/L for the first and second sample, respectively). Median TDS from the other FAP are 20,500 – 28,000 mg/L, including both first and second samples. The main components of TDS also appear to vary among the FAP (e.g., calcium, magnesium, chloride). As an example, barium appears higher in North Belridge (median for the second sample is 17 mg/L) than in the other three FAP shown in Table 14 (median values for the second sample are 4.5 – 8). The components of BTEX appear lower in Lost Hills than in the other FAP.

The sulfate results indicate differences by FAP (Table 14). Buena Vista Nose, North Belridge, and South Belridge had median sulfate values that were higher for the first sample compared with the second sample; significant differences between the first and second samples were confirmed by statistical tests ($p<0.05$). While the median sulfate concentration in first samples from Lost Hills were higher than the median sulfate concentrations for the second samples, the difference was not significant ($p>0.05$). The initially high sulfate concentrations could be the result of sulfate in the base fluids used to formulate stimulation fluids (Table 12). California Aqueduct samples had median sulfate concentration of 27.5 mg/L while the recycled produced water had a median sulfate concentration of 40.5 mg/L and median sulfate for well water was 200 mg/L. The WST fluids also contain chemicals that contain sulfate and other forms of sulfur (Table 4). Three sulfur-containing WST chemicals are used extensively: sodium sulfate (51.6% WST), sodium persulfate (51.6% WST), and ammonium persulfate (45.4% WST). Other WST chemicals containing sulfur are used less frequently: sodium bisulfite (12.2% WST), tetrakis hydroxymethyl phosphonium sulfate (3.7% WST), zinc sulfate (2.3% WST), dodecylbenzene sulfonic acid (0.2% WST), dioctyl sulfosuccinate sodium salt (0.1% WST), sulferized polyolefin (0.1% WST), sulfonic acids alkane sodium salts (0.1% WST), sulfuric acid (0.1% WST), and calcium sulfate (0.1% WST). It is unlikely that there are high concentrations of sulfate in the formation fluids because formation conditions are anaerobic and highly reducing environments. It is possible that recovered fluids have measureable concentrations of sulfate because of base fluids or WST chemicals. It is also possible that the introduction of oxidants in the WST fluids are oxidizing reduced sulfur to sulfate in formation fluids. It is also possible that recovered fluid samples are oxidized in holding tanks or during the sampling process, and that this oxidation is causing sulfate to be present in recovered fluid samples. Dissolved sulfide and hydrogen sulfide were both measured in recovered fluids, and were typically below detection limits (Table 14). These results should be verified as hydrogen sulfide and sulfide are difficult to measure since hydrogen sulfide is volatile and can exit the solution during sampling, transport of the sample, and storage. The analytical method for sulfide species is often colorimetric and may not provide accurate results in flow-back and produced water samples that can have interfering compounds.

Based on the recovered fluid water quality (Table 14), it is apparent that some constituents are not consistently observed and would likely not be appropriate as indicators of aquifer contamination. Constituents consistently measured but typically below detection limits are antimony, beryllium, cadmium, chromium, copper, dissolved sulfide, fluoride, hydrogen sulfide, lead, mercury, molybdenum, nickel, nitrate, nitrite, selenium, thallium, vanadium, and zinc. The low concentrations of nitrate and nitrite may be the result of nitrogen being present in another form (e.g. ammonium). Total nitrogen and total Kjeldahl nitrogen measurements are more appropriate for assessing nitrogen in anaerobic samples. Another constituent included in Table 14 and not typically found is 2,2-dibromo-3-nitrilopropionamide (DBNPA). A colorimetric assay was used for these measurements. It is not clear that the method being used is appropriate for the produced water matrix; further testing is recommended.

Another observation of the recovered fluid water quality data (Table 14) is that there are some outliers that should not be included in subsequent analyses. These outliers are likely the result of an analytical error or, more likely, the result of the sample collection procedure. There are very few apparent outliers. Examples include some of the TDS measurements such as an observation of 890,000 mg/L for one of the first samples collected in South Belridge. One of the samples from South Belridge had a reported barium concentration of 11,000 mg/L; none of the other measurements for this sample were unusually high. Outlier analysis will be completed as part of the indicator evaluation (Camarillo and Stringfellow, 2021a).

A summary of gross alpha radiation testing is presented in Table 15. These data were reported separately from the analytical data (Table 14). Similar to the analytical data for recovered fluid samples, there is variability by FAP.

5. Discussion

The current data set contains information on almost twice as many WST as compared to the data set evaluated by Stringfellow et al. (2017). The additional records are useful for better establishing the variability and range of conditions and practices under which WST is performed in California. The expanded data set is also more ideal for performing statistical analyses where it is advisable to have more than 30 observations.

The expanded data set evaluated here has many advantages compared with the one evaluated by Stringfellow et al. (2017). In the previous evaluation, there were only two FAP with more than 30 WST. In the current data set there are four FAP with more than 30 WST: South Belridge (FAP 0520020), Lost Hills (FAP 4320027), Buena Vista Nose (FAP 0000000), and North Belridge (FAP 0500007). The current data set also contains information on WST in Buena Vista Nose that was not part of the previous data set, allowing us to observe the impact of WST practices in a different formation. The current data set also contains more producers compared with the previous data set. Two new producers performed WST in the current data set and were not part of the previous data set. Here, there are analytical data for 35 base fluid samples compared with 12 in the previous data set. The analytical data for recovered fluids is also expanded. In Stringfellow et al. (2017), there were 618 WST and a total of 1,078 recovered fluid samples. Here, there are 2,166 recovered fluid samples for the 1,228 WST. The larger analytical data sets are useful for the chemical indicator evaluation conducted as part of a separate report (Camarillo and Stringfellow, 2021a).

A comparison of the current data set with that evaluated by Stringfellow et al. (2017) confirms that some WST practices remain relatively unchanged. Most WST are still occurring in South Belridge by the same producers. The median number of chemicals added to stimulation fluids was 21 as reported by Stringfellow et al. (2017) and 20 here (excluding water and proppant). Water from the California Aqueduct is predominately used as a base fluid. The median water used per WST is 98,000 gallons here, slightly higher than the 89,000 gallons reported by Stringfellow et al. (2017), but still lower than the 140,000 gallons reported in the SB-4 Scientific Study (Stringfellow et al., 2015). These quantities of water are much lower than what is used in other oil and gas fields in other parts of the U.S.; the average water volume used per hydraulic fracturing treatment is 2.4 million gallons (Jackson et al., 2015).

Although the number of chemicals and volumes of water being used are relatively unchanged, the chemicals used has shifted since the evaluation by Stringfellow et al. (2017). In that evaluation, there were 178 chemicals used in WST in California. Here, 205 chemicals were identified. The choice of chemicals has also shifted and this may be the result of a shift in service company used.

While a toxicity evaluation was not done on the current data set—as was done by Stringfellow et al. (2017)—it is worthwhile to continually evaluate the chemicals being used and their toxicity profiles and environmental persistence characteristics. Tracking of the WST chemicals is important considering that many of the most frequently used chemicals are biocides, quaternary ammonium compounds, strong oxidants (persulfates) that can trigger subsurface reactions with halides, and solvents that are environmentally persistent. Periodic review of chemical masses and water volumes is also recommended to confirm existing practices or identify any changes.

The data summary contain herein is important in completing an evaluation of chemicals that could potentially serve as indicators of aquifer contamination (Camarillo and Stringfellow, 2021a). Knowing the sources and water quality of base fluids as well as the identity and masses of chemical used in formulating stimulation fluids is essential for evaluating recovered fluids and their potential impacts. Knowledge of chemical additives is important as these lists should guide measurements in oil field monitoring wells. As shown in this evaluation, the selection of WST chemicals can change and knowledge of these changes is essential for keeping monitoring plans relevant. In addition, having data on each field (FAP) where WST is occurring is important because there is variability between the fields in terms of water and chemical and, probably more importantly, variability in formation geology that influences the final water quality of fluids recovered from the wells.

6. Conclusion

The current evaluation characterizes WST practices in California, as based on a data set for WST occurring May 5, 2015 to October 4, 2019. In addition to WST practices, analytical data are summarized for base fluids used in formulating WST fluids and for the fluids recovered from oil wells after stimulation and during production. This evaluation confirms that the number of chemicals used per WST and water volumes used are relatively unchanged; however, the chemicals used has changed. An updated toxicity analysis and review of environmental persistence data is recommended for the revised list of chemicals. This analysis should reflect the shift in chemicals used. Validation of methods for recovered fluids should continue for measurements such as sulfides and biocides (e.g., DBNPA).

The data set evaluated contains more records than the data set previously evaluated. The WST were performed in more fields and by more producers. The expanded data set is useful in completing an evaluation of chemical indicators that could potentially serve as indicators of aquifer contamination. Continued collection of water quality data for base fluid and recovered fluid samples is recommended to monitoring these data—along with regional groundwater data—to detect potential environmental impacts.

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Table 14. Water quality summary of produced water from oil wells undergoing well stimulation treatment in California, May 5, 2015 – October 4, 2019. Data from the following oil fields is shown: Buena Vista Nose (FAP 0000000), North Belridge (FAP 0500007), South Belridge (FAP 0520020), and Lost Hills (FAP 4320027).

Table 15. Gross alpha radiation reported for fluids recovered from oil wells undergoing well stimulation treatment (WST). The measurements were made using a gas flow proportional counting system. The WST occurred May 5, 2015 – October 4, 2019.

Table 1. Number of well stimulation treatments (WST) occurring within each field-area-pool (FAP) by producer and service company. The WST occurred May 5, 2015 – October 4, 2019.

FAP	Field	Producer	Service company	WST
0000000	Buena Vista Nose	California Resources Elk Hills	Halliburton	35
0500007	North Belridge	BreitBurn	Halliburton	2
		Aera	Baker Hughes/Halliburton	31
0500020	North Belridge	Aera	Halliburton	3
0520000	South Belridge	Aera	Baker Hughes	1[a]
0520020	South Belridge	Aera	Baker Hughes/Halliburton/ Schlumberger	894
		Berry Petroleum	Halliburton	78
		BreitBurn	Halliburton	2
		Linn	Schlumberger	28
0520050	South Belridge	Aera	Halliburton	1[a]
0700000	Brea-Olinda	Linn	Schlumberger	1
1560025	North Coles Levee	Central Resources	Halliburton	2
2280015	Elk Hills	California Resources Elk Hills	Schlumberger/ Halliburton	9
2280022	Elk Hills	California Resources Elk Hills	Schlumberger/ Halliburton	3[b]
2280024	Elk Hills	California Resources Elk Hills	Schlumberger	1
4320027	Lost Hills	Aera	Baker Hughes/ Halliburton	58
		Chevron	Halliburton	64
4320050	Lost Hills	Aera	Baker Hughes/Halliburton	11
4540610	McKittrick	Chevron	Halliburton	4

[a]Acid fracturing treatment.
[a]Matrix acidizing treatment.

Table 2. Description of field-area-pool codes (FAP), including descriptions of the formations within each FAP. The WST occurred May 5, 2015 – October 4, 2019.

FAP	Field	Area	Pool	Formation
0000000	Buena Vista Nose	Any area	No pool breakdown	Monterey-Antelope
0700000	Brea-Olinda	Any area	No pool breakdown	Puente
2280022	Elk Hills	Any area	Stevens (29R)	Monterey-Antelope-Stevens
2280024	Elk Hills	Any area	Stevens (31S)	Monterey-Antelope
2280015	Elk Hills	Any area	Upper (Undifferentiated)DG	Etchegoin
4320050	Lost Hills	Any area	Antelope/McDonald	Monterey-Antelope-McDonald
4320027	Lost Hills	Any area	Etchegoin	Etchegoin-Reef Ridge-Diatomite-Monterey-McDonald-Antelope
4540610	McKittrick	Northeast	Antelope Shale	Monterey-Antelope
0500020	North Belridge	Any area	Belridge 64	Reef Ridge-Diatomite
0500007	North Belridge	Any area	Diatomite	Reef Ridge-Diatomite
1560025	North Coles Levee	Any area	Stevens (Undifferentiated)	Monterey-Antelope-Stevens
0520020	South Belridge	Any area	Diatomite	Reef Ridge-Diatomite
0520050	South Belridge	Any area	Monterey (Undifferentiated)	Monterey-Antelope
0520000	South Belridge	Any area	No pool breakdown	Monterey-Antelope

Table 3. Well stimulation treatments (WST) in California by oil field and a summary of well depth within these fields (N=1,228). Of the 1,228 WST, 1,189 have data for recovered fluid samples. The WST occurred May 5, 2015 – October 4, 2019.

Field	WST	FAP	Total vertical depth (ft)				
			N[a]	Min	Max	Mean	Median
South Belridge	1,004[b]	0520000	1	12,872	12,872	12,872	12,872
		0520020	822	1,009	3,103	2,001	1,981
		0520050	1	7,698	7,698	7,698	7,698
Lost Hills	133[c]	4320027	102	1,750	2,969	2,327	2,436
		4320050	9	5,004	5,210	5,058	5,026
North Belridge	36	0500007	29	1,534	2,453	1,676	1,623
		0500020	3	1,569	1,608	1,588	1,587
Buena Vista Nose	35	0000000	22	9,699	10,935	10,508	10,582
Elk Hills	13	2280015	9	3,869	7,483	4,493	4,118
		2280022	3	7,097	8,544	7,833	7,857
		2280024	1	6,672	6,672	6,672	6,672
McKittrick	4	4540610	4	5,679	5,946	5,815	5,817
North Coles Levee	2	1560025	2	9,221	9,949	9,585	9,585
Brea-Olinda	1	0700000	1	3,485	3,485	3,485	3,485

[a]Not all WST disclosures contained data on well depth, so the number of WST and N are different.
[b]967 of the WST have recovered fluid data.
[c]131 of the WST have recovered fluid data.

Table 4. Chemicals used in formulating well stimulation treatment (WST) fluids. There were a total of 1,228 WST and 205 unique chemicals added to the WST fluids. The WST reviewed as part of this project occurred May 5, 2015 – October 4, 2019.

Chemical	CASRN	Number of WST	WST (%)
Water	7732-18-5	1,228	100.0%
Crystalline silica (quartz)	14808-60-7	1,225	99.8%
Guar gum	9000-30-0	1,225	99.8%
Sodium hydroxide	1310-73-2	1,122	91.4%
Sodium chloride	7647-14-5	897	73.0%
Hemicellulase enzyme	9012-54-8	656	53.4%
Lactose	63-42-3	634	51.6%
Sodium sulfate	7757-82-6	634	51.6%
Sodium persulfate	7775-27-1	634	51.6%
Monoethanolamine borate	26038-87-9	633	51.5%
Ammonium chloride	12125-02-9	628	51.1%
Polydimethyl diallyl ammonium chloride	26062-79-3	626	51.0%
2,2 Dibromo-3-nitrilopropionamide	10222-01-2	620	50.5%
MBNPA (2-bromo-3-nitrilopropionamide)	1113-55-9	620	50.5%
Ammonium persulfate	7727-54-0	558	45.4%
Isotridecanol, ethoxylated	9043-30-5	535	43.6%
Hydrotreated light petroleum distillate	64742-47-8	534	43.5%
Crystalline silica (cristobalite)	14464-46-1	500	40.7%
2-Butoxypropan-1-ol	15821-83-7	500	40.7%
1-Butoxy-2-propanol	5131-66-8	500	40.7%
Prolonium chloride	55636-09-4	500	40.7%
Paraffinic petroleum distillate, hydrotreated light	64742-55-8	500	40.7%
Magnesium nitrate	10377-60-3	499	40.6%
5-Chloro-2-methyl-3(2H)-isothiazolone	26172-55-4	499	40.6%
2-Methyl-3(2H)-isothiazolone	2682-20-4	499	40.6%
Magnesium chloride	7786-30-3	499	40.6%
Diatomaceous earth, calcined	91053-39-3	499	40.6%
Sodium tetraborate decahydrate	1303-96-4	476	38.8%
Ethylene glycol	107-21-1	432	35.2%
Phosphonic acid	13598-36-2	392	31.9%
Nitrilotris (methylene phosphonic acid)	6419-19-8	391	31.8%
Glycerol	56-81-5	279	22.7%
Hemicellulase enzyme concentrate	9025-56-3	276	22.5%
Beta mannanases	37288-54-3	223	18.2%
Methanol	67-56-1	195	15.9%
Acetic acid	64-19-7	192	15.6%
Sodium polyacrylate	9003-04-7	154	12.5%
Sodium bisulfite	7631-90-5	150	12.2%
Glutaraldehyde	111-30-8	123	10.0%
Ethanol	64-17-5	114	9.3%
Alkyl dimethylbenzyl ammonium chloride	68424-85-1	113	9.2%
Phosphoric acid	7664-38-2	113	9.2%
Laurl hydrosultaine	13197-76-7	97	7.9%

Chemical	CASRN	Number of WST	WST (%)
Isopropanol	67-63-0	96	7.8%
Potassium carbonate	584-08-7	85	6.9%
Boric acid	10043-35-3	76	6.2%
Methyl borate	121-43-7	76	6.2%
Potassium bicarbonate	298-14-6	76	6.2%
Castor oil, ethoxylated	61791-12-6	64	5.2%
Non-crystalline silica (impurity)	7631-86-9	58	4.7%
Potassium chloride	7447-40-7	57	4.6%
Calcium magnesium sodium phosphate frit	65997-18-4	51	4.2%
Choline chloride	67-48-1	51	4.2%
Phenolic resin	9003-35-4	48	3.9%
Orange terpenes	68647-72-3	47	3.8%
Tetrakis hydroxymethyl phosphonium sulfate	55566-30-8	46	3.7%
Hexamethylenetetramine	100-97-0	45	3.7%
1,2-benzisothiazolin-3-one	2634-33-5	44	3.6%
Polysorbate 40	9005-66-7	44	3.6%
Ulexite	1319-33-1	38	3.1%
Chlorous acid,sodium salt	7758-19-2	36	2.9%
Propylene carbonate	108-32-7	35	2.9%
Sorbitan trioleate	26266-58-0	35	2.9%
Quaternary ammonium compounds, bis(hydrogenated tallow alkyl)dimethyl, salts with bentonite	68953-58-2	35	2.9%
Arsenic	7440-38-2	34	2.8%
Potassium hydroxide	1310-58-3	32	2.6%
Triethanolamine	102-71-6	31	2.5%
Ammonium acetate	631-61-8	30	2.4%
Cobaltous acetate	71-48-7	30	2.4%
Potassium metaborate	13709-94-9	28	2.3%
Propylene glycol	57-55-6	28	2.3%
Zinc sulfate	7733-02-0	28	2.3%
Sodium citrate	68-04-2	24	2.0%
Xanthan gum	11138-66-2	23	1.9%
Polyurethane resin	57029-46-6	21	1.7%
Triethylene glycol	112-27-6	20	1.6%
Sorbitan stearate	1338-41-6	20	1.6%
2-Propenoic acid, 2-ethylhexyl ester, polymer with 2-hydroxyethyl 2-propenoate	36089-45-9	20	1.6%
Tetrahydro-3,5-dimethyl-1,3,5-thiadiazine-2-thione	533-74-4	20	1.6%
Dimethyl siloxanes and silicones	63148-62-9	20	1.6%
Siloxanes and silicones, dimethyl, reaction products with silica	67762-90-7	20	1.6%
Alcohols, C12-15 ethoxylated	68131-39-5	20	1.6%
Fatty acids, C18-unsatd., dimers, ethoxylated propoxylated	68308-89-4	20	1.6%
1,2-Ethanediamine, N1-(2-aminoethyl)-N2-(2-((2-aminoethyl)amino)ethyl)-, polymer with 2-methyloxirane and oxirane	68815-65-6	20	1.6%

Chemical	CASRN	Number of WST	WST (%)
Siloxanes and Silicones, di-Me, 3-hydroxypropyl Me, ethoxylated propoxylated	68937-55-3	20	1.6%
Pigment red 48 calcium salt	7023-61-2	20	1.6%
Poly(oxy-1,2-ethanediyl), -[2,4,6-tris(1-phenylethyl)phenyl]- -hydroxy-	70559-25-0	20	1.6%
Sodium nitrite	7632-00-0	20	1.6%
Sodium carboxymethylcellulose	9004-32-4	20	1.6%
Sorbitan monooleate, ethoxylated	9005-65-6	20	1.6%
Polyoxyethylene (12) polyoxypropylene	9082-00-2	20	1.6%
Citrus terpenes	94266-47-4	18	1.5%
Citric acid	77-92-9	16	1.3%
Kyanite	1302-76-7	14	1.1%
Aluminum oxide	1344-28-1	14	1.1%
Polypropylene glycol	25322-69-4	9	0.7%
D-limonene	5989-27-5	8	0.7%
2-Propenoic acid, butyl ester, polymer with ethenylbenzene and 2-propenamide	25037-33-6	7	0.6%
Alcohols, C6-12, ethoxylated propoxylated	68937-66-6	7	0.6%
Alcohols, C10-16, ethoxylated propoxylated	69227-22-1	7	0.6%
1,4-Dioxane-2,5-dione, 3,6-dimethyl-, (3R,6R)-,polymer with rel-(3R,6S)-3,6-dimethyl-1,4-dioxane-2,5-dione and (3S,6S)-3,6-dimethyl-1,4-dioxane-2,5-dione	9051-89-2	7	0.6%
Magnesium silicate hydrate (talc)	14807-96-6	6	0.5%
Acetic acid etheynl ester, polymer with ethene	24937-78-8	5	0.4%
Vinylidene chloride/methylacrylate copolymer	25038-72-6	5	0.4%
Polyethylene glycol monohexyl ether	31726-34-8	5	0.4%
Diatomaceous earth, natural (kieselguhr)	61790-53-2	5	0.4%
Heavy aromatic naphtha	64742-94-5	5	0.4%
Olefin/maleic ester	68188-50-1	5	0.4%
Mineral oil	8042-47-5	5	0.4%
Naphthalene	91-20-3	5	0.4%
1,2,4-Trimethylbenzene	95-63-6	5	0.4%
Acrylonitrile	107-13-1	4	0.3%
2-Butoxyethanol	111-76-2	4	0.3%
Potassium acetate	127-08-2	4	0.3%
Potassium borate	1332-77-0	4	0.3%
4-Chlorobenzophenone	134-85-0	4	0.3%
Formaldehyde, polymer with phenol and 1,3,5,7-tetraazatricyclo(3.3.1.13,7)decane	37337-65-8	4	0.3%
Hydrochloric acid	7647-01-0	4	0.3%
Polytetrafluoroethylene	9002-84-0	4	0.3%
2-propenoic acid, polymer with 2-propenamide	9003-06-9	4	0.3%
2-Ethylhexan-1-ol	104-76-7	3	0.2%
1,4-Dibromobenzene	106-37-6	3	0.2%
Propargyl alcohol	107-19-7	3	0.2%
1-Tetradecene	1120-36-1	3	0.2%
1-Octadecene	112-88-9	3	0.2%

Chemical	CASRN	Number of WST	WST (%)
Disodium octaborate tetrahydrate	12008-41-2	3	0.2%
1-bromo-3,5-dichlorobenzene	19752-55-7	3	0.2%
Poly(dimethylaminoethylmethylacrylate) dimethyl sulphate quat.	27103-90-8	3	0.2%
2,5-Dibromothiophene	3141-27-3	3	0.2%
1-Eicosene	3452-07-1	3	0.2%
1-Bromo-4-iodobenzene	589-87-7	3	0.2%
Dicoco dimethyl quaternary ammonium chloride	61789-77-3	3	0.2%
Fatty acids, tall-oil	61790-12-3	3	0.2%
4-Iodotoluene	624-31-7	3	0.2%
1,3,5-Tribromobenzene	626-39-1	3	0.2%
1-Hexadecene	629-73-2	3	0.2%
2,4,6-Tribromotoluene	6320-40-7	3	0.2%
1,2,4,5-Tetrabromobenzene	636-28-2	3	0.2%
1-Chloro-4-iodobenzene	637-87-6	3	0.2%
Benzoic acid	65-85-0	3	0.2%
Ethoxylated alcohol C6-12	68439-45-2	3	0.2%
Thiourea, polymer with formaldehyde and 1-phenylethanone	68527-49-1	3	0.2%
Alcohols, C14-C15, ethoxylated	68951-67-7	3	0.2%
Ethoxylated alcohol C11-14	78330-21-9	3	0.2%
1-Iodonaphthalene	90-14-2	3	0.2%
Ethoxylated alcohol C6	104780-82-7	2	0.2%
Ammonium fluoride	12125-01-8	2	0.2%
Corundum	1302-74-5	2	0.2%
Aluminosilicate	1327-36-2	2	0.2%
3,5-Dibromotoluene	1611-92-3	2	0.2%
Dodecylbenzene sulfonic acid	27176-87-0	2	0.2%
2,4,5-Tribromotoluene	3278-88-4	2	0.2%
Hydroxylamine hydrochloride	5470-11-1	2	0.2%
1,2-Diiodobenzene	615-42-9	2	0.2%
Amines, hydrogenated tallow alkyl, acetates	61790-59-8	2	0.2%
Alkenes, C>10 a-	64743-02-8	2	0.2%
Copper dichloride	7447-39-4	2	0.2%
Ethylene oxide	75-21-8	2	0.2%
Hydrofluoric acid	7664-39-3	2	0.2%
Zirconium dichloride oxide	7699-43-6	2	0.2%
Tricalcium phosphate	7758-87-4	2	0.2%
Ethoxylated alcohol C7-9-iso, C8	78330-19-5	2	0.2%
Polyethylene, polypropylene ether glycol copolymer	9003-11-6	2	0.2%
Poly(oxy-1,2-ethandiyl), a-(nonylphenyl)-w-hydroxy-	9016-45-9	2	0.2%
Calcium chloride	10043-52-4	1	0.1%
Quaternary ammonium compound	100765-57-9	1	0.1%
Cinnamaldehyde	104-55-2	1	0.1%
1-Methoxy-2-propanol	107-98-2	1	0.1%
Methyl isobutyl ketone	108-10-1	1	0.1%
Diethanolamine	111-42-2	1	0.1%

Chemical	CASRN	Number of WST	WST (%)
2,2"-oxydiethanol (impurity)	111-46-6	1	0.1%
Oleic acid	112-80-1	1	0.1%
2-Propenoic acid, polymer with sodium phosphinate	129898-01-7	1	0.1%
Bauxite	1318-16-7	1	0.1%
Ammonium bifluoride	1341-49-7	1	0.1%
Potassium oleate	143-18-0	1	0.1%
Diethylenetriaminepenta(methylenephosphonic) acid	15827-60-8	1	0.1%
2-Iodobiphenyl	2113-51-1	1	0.1%
5-Iodo-m-xylene	22445-41-6	1	0.1%
Polyethylene oxide	25322-68-3	1	0.1%
Etidronic acid	2809-21-4	1	0.1%
4-Iodo-o-xylene	31599-61-8	1	0.1%
Sodium carbonate	497-19-8	1	0.1%
Aziridine, polymer with methyloxirane and oxirane	52501-07-2	1	0.1%
9-Bromophenanthrene	573-17-1	1	0.1%
Dioctyl sulfosuccinate sodium salt	577-11-7	1	0.1%
2-Bromonaphthalene	580-13-2	1	0.1%
3-aminopropyl (sileanetriol)	58160-99-9	1	0.1%
Fatty acids, tall-oil, ethoxylated	61791-00-2	1	0.1%
Formic acid	64-18-6	1	0.1%
Alcohols, C10-14, ethoxylated	66455-15-0	1	0.1%
Sulferized polyolefin	68037-13-8	1	0.1%
Phenol, 4,4'-(1-methylethylidene) bis-, polymer with 2-(chloromethyl)oxirane, 2-methyloxirane and oxirane	68123-18-2	1	0.1%
Silanetrio; (3-aminopropyl, homopolymer	68400-07-7	1	0.1%
Alcohols, C12-16, ethoxylated	68551-12-2	1	0.1%
Ethoxylated alcohol C8-10	68603-25-8	1	0.1%
Sulfonic acids, alkane, sodium salts	68608-15-1	1	0.1%
2,4-Dibromomesitylene	6942-99-0	1	0.1%
Tar bases, quinoline derivs., benzyl chloride quaternized	72480-70-7	1	0.1%
Sulfuric acid	7664-93-9	1	0.1%
Potassium Iodide	7681-11-0	1	0.1%
Triisobutylene (mixed isomers)	7756-94-7	1	0.1%
Calcium sulfate	7778-18-9	1	0.1%
Polyethylene glycol trimethyl nonyl ether	84133-50-6	1	0.1%
Erythorbic acid	89-65-6	1	0.1%

Table 5. Acid fracturing treatment reported in this data set: WST Permit No. 18-0068-1 occurring in FAP 0520050. An additional acid fracturing treatment and an acid matrix treatment were previously reported by Stringfellow et al. 2017.

Constituent	CASRN	Concentration (% mass)
Water	7732-18-5	84.516897
Hydrochloric acid	7647-01-0	8.798746
Ammonium chloride	12125-02-9	2.867002
Ammonium fluoride	12125-01-8	1.719254
Dodecylbenzene sulfonic acid	27176-87-0	0.376596
Ethylene glycol monobutyl ether	111-76-2	0.352744
Acetic acid	64-19-7	0.256242
Laryl dimethyl hydroxysulfobetaine	13197-76-7	0.1695
Citric acid	77-92-9	0.154716
Methanol	67-56-1	0.122144
Isopropanol	67-63-0	0.118332
Ethoxylated hexanol	68439-45-2	0.099448
Alcohols, C14-C15, ethoxylated	68951-67-7	0.06087
Mixture of dimer and trimer fatty acids of indefinite compostion derived from tall oil	61790-12-3	0.06087
Reaction product of acetophenone, formaldehyde, thiourea and oleic acid in dimethyl formamide	68527-49-1	0.06087
Polylactide resin	9051-89-2	0.057751
Tricalcium phosphate	7758-87-4	0.028702
Sodium chloride	7647-14-5	0.028298
Hydroxylamine hydrochloride	5470-11-1	0.025122
Poly(oxy-1,2-ethanediyl), alpha-hexyl-omega-hydroxy	31726-34-8	0.021368
Propargyl alcohol	107-19-7	0.020328
Sodium carbonate	497-19-8	0.014438
2-Ethyl hexanol	104-76-7	0.010684
1-Hexadecene	629-73-2	0.010164
1-Octadecene	112-88-9	0.010164
Alkenes, C >10 alpha-	64743-02-8	0.010164
Castor oil, ethoxylated	61791-12-6	0.005313
Terpenes and Terpenoids, sweet orange-oil	68647-72-3	0.005313
Poly(oxy-1,2-ethandiyl), a-(nonylphenyl)-w-hydroxy-	9016-45-9	0.003581
Amines, hydrogenated tallow alkyl, acetates	61790-59-8	0.002888
Silica, amorphous - fumed	7631-86-9	0.002137
1-Eicosene	3452-07-1	0.002079
1-Tetradecene	1120-36-1	0.002079
Ethylene glycol	107-21-1	0.00179
Sorbitan, monohexadecanoate,poly(oxy-1,2-ethanediyl) derivs.	9005-66-7	0.00179
2,2 Dibromo-3-nitrilopropionamide	10222-01-2	0.00104
Copper dichloride	7447-39-4	0.000462
2-Monobromo-3-nitrilopropionamide	1113-55-9	0.000058
Ethylene oxide	75-21-8	0.000058

Table 6. Frequency of the types of chemicals used in formulating well stimulation treatment (WST) fluids, as expressed by chemical function. There were 1,228 WST and 205 unique chemicals added to WST fluids. The WST reviewed as part of this project occurred May 5, 2015 – October 4, 2019.

Chemical function	Number of WST	WST (%)
Water	1228	100.0%
Proppant	1227	99.9%
Gelling agent	1225	99.8%
Breaker	1224	99.7%
Crosslinker (boron)	1224	99.7%
Clay control	1222	99.5%
Mineral salt	1202	97.9%
Biocide	1176	95.8%
pH adjustment	1128	91.9%
Product stabilizer	661	53.8%
Surfactant, nonionic	577	47.0%
Solvent	546	44.5%
Carrier fluid	534	43.5%
Solvent, glycol ethers	502	40.9%
Carrier solid	499	40.6%
Scale inhibitor	452	36.8%
Solvent, glycol	304	24.8%
Scale inhibitor (incl iron control)	202	16.4%
Friction reducer	154	12.5%
Reducing agent	150	12.2%
Biocide, viscosity modifier	113	9.2%
Polymer production	113	9.2%
Surfactant, zwitterionic	97	7.9%
Polymer	95	7.7%
pH adjustment, buffering	86	7.0%
Surfactant	84	6.8%
Curing agent for resins used to coat proppants	45	3.7%
Corrosion inhibitor	44	3.6%
Solvent, ester	35	2.9%
Use to produce polymers	34	2.8%
Chelating agent (e.g., for zirconium)	31	2.5%
Tracer	28	2.3%
Surface treatment	21	1.7%
Carrier	20	1.6%
Solvent, aliphatic hydrocarbon	18	1.5%
Carrier, mineral solid	11	0.9%
Carrier fluid for tracer chemicals	8	0.7%
Carrier fluid for active surfactants	5	0.4%
Solvent, aromatic hydrocarbon	5	0.4%
Solvent, hydrocarbon	5	0.4%
Acidizing, pH adjustment	4	0.3%
Biocide and surfactant	4	0.3%
Monomer used to produce polymers	4	0.3%
Solvent, alcohol	4	0.3%

Chemical function	Number of WST	WST (%)
Surfactant, anionic	4	0.3%
Corrosion inhibitor, used to produce "emulsifiers, oil-wetting agents and lubricants"	3	0.2%
Hydrocarbon (used to produce polymers)	3	0.2%
Surfactant, cationic	3	0.2%
Viscosity modifier	3	0.2%
Acidizing	2	0.2%
Crosslinker (zirconium)	2	0.2%
Iron control	2	0.2%
Breaker, iron control	1	0.1%
Fatty acids are used to make "emulsifiers, oil-wetting agents and lubricants"	1	0.1%
Solvent, ether	1	0.1%
Solvent, ketone	1	0.1%

Table 7. Frequency of the types of chemicals used in formulating well stimulation treatment (WST) fluids, as expressed by chemical category. There were 1,228 WST and 205 unique chemicals added to WST fluids. The WST reviewed as part of this project occurred May 5, 2015 – October 4, 2019.

Chemical Category	Number of WST	WST (%)
Water	1,228	100.0%
Mineral solid	1,227	99.9%
Quaternary ammonium compounds (QAC)	1,226	99.8%
Carbohydrate	1,225	99.8%
Mineral salt	1,203	98.0%
Oxidizing agent	1,189	96.8%
Enzyme	1,155	94.1%
Strong base	1,127	91.8%
Boron compound, amine	633	51.5%
Ammonium compound	628	51.1%
Amide	621	50.6%
Boron compound	593	48.3%
Surfactant, nonionic	577	47.0%
Isothiazolones	543	44.2%
Solvent, hydrocarbon	543	44.2%
Solvent, glycol	507	41.3%
Solvent, glycol ethers	506	41.2%
Organophosphorus compound	438	35.7%
Polymer	264	21.5%
Carboxylic acid	252	20.5%
Solvent, alcohol	238	19.4%
Reducing agent	206	16.8%
Aldehyde	124	10.1%
Phosphoric acid	113	9.2%
Amine	97	7.9%
Carbonate	86	7.0%
Surfactant	84	6.8%
Solvent	52	4.2%
Solvent, ester	35	2.9%
Organosilicon	21	1.7%
Dithiocarbomates	20	1.6%
Organic salt	20	1.6%
Solvent, aliphatic hydrocarbon	18	1.5%
Solvent, aromatic	8	0.7%
Solvent, aromatic hydrocarbon	5	0.4%
Polymer, amide	4	0.3%
Strong acid	4	0.3%
Surfactant, anionic	4	0.3%
Ether	2	0.2%
Phosphoric acid (base)	2	0.2%
Amine, organophosphorous compound	1	0.1%
Solvent, ether	1	0.1%
Solvent, ketone	1	0.1%

Table 8. Well stimulation treatment (WST) chemicals that had frequency of use that changed by more than 30% from the data reported by Stringfellow et al. 2017 to the current data set. The WST reviewed as part of this project occurred May 5, 2015 – October 4, 2019. The WST reviewed by Stringfellow et al. 2017 occurred May 5, 2015 – June 29, 2015.

Chemical	CASRN	WST reported by Stringfellow et al. 2017	WST reported in this evaluation
Hemicellulase enzyme	9012-54-8	9.9%	53.4%
Lactose	63-42-3	6.3%	51.6%
Sodium sulfate	7757-82-6	6.5%	51.6%
Sodium persulfate	7775-27-1	6.5%	51.6%
Monoethanolamine borate	26038-87-9	6.3%	51.5%
Ammonium chloride	12125-02-9	6.5%	51.1%
Polydimethyl diallyl ammonium chloride	26062-79-3	6.3%	51.0%
2,2 Dibromo-3-nitrilopropionamide	10222-01-2	1.1%	50.5%
MBNPA (2-bromo-3-nitrilopropionamide)	1113-55-9	1.3%	50.5%
Ammonium persulfate	7727-54-0	93.4%	45.4%
Isotridecanol, ethoxylated	9043-30-5	84.5%	43.6%
Hydrotreated light petroleum distillate	64742-47-8	84.3%	43.5%
Crystalline silica (cristobalite)	14464-46-1	84.3%	40.7%
2-Butoxypropan-1-ol	15821-83-7	84.5%	40.7%
1-Butoxy-2-propanol	5131-66-8	84.5%	40.7%
Prolonium chloride	55636-09-4	84.5%	40.7%
Paraffinic petroleum distillate, hydrotreated light	64742-55-8	84.5%	40.7%
Magnesium nitrate	10377-60-3	84.3%	40.6%
5-Chloro-2-methyl-3(2H)-isothiazolone	26172-55-4	84.3%	40.6%
2-Methyl-3(2H)-isothiazolone	2682-20-4	84.3%	40.6%
Magnesium chloride	7786-30-3	84.3%	40.6%
Diatomaceous earth, calcined	91053-39-3	84.3%	40.6%
Sodium tetraborate decahydrate	1303-96-4	79.8%	38.8%
Ethylene glycol	107-21-1	72.3%	35.2%
Phosphonic acid	13598-36-2	66.5%	31.9%
Nitrilotris (methylene phosphonic acid)	6419-19-8	66.3%	31.8%

Table 9. Quaternary ammonium compounds (QACs) identified in well stimulation treatment (WST) fluids. The WST occurred May 5, 2015 – October 4, 2019.

CASRN	Chemical description
100765-57-9	Quaternary ammonium compound
13197-76-7	Laurl hydrosultaine
26062-79-3	Polydimethyl diallyl ammonium chloride
27103-90-8	Poly(dimethylaminoethylmethylacrylate) dimethyl sulphate quat.
55636-09-4	Prolonium chloride
61789-77-3	Dicoco dimethyl quaternary ammonium chloride
67-48-1	Choline chloride
68424-85-1	Alkyl dimethylbenzyl ammonium chloride
68953-58-2	Quaternary ammonium compounds, bis(hydrogenated tallow alkyl)dimethyl, salts with bentonite
72480-70-7	Tar bases, quinoline derivs., benzyl chloride quaternized

Table 10. Biocides identified in well stimulation treatment (WST) fluids. The WST occurred May 5, 2015 – October 4, 2019.

CASRN	Chemical description
100765-57-9	Quaternary ammonium compound
10222-01-2	2,2 Dibromo-3-nitrilopropionamide
111-30-8	Glutaraldehyde
1113-55-9	2-Monobromo-3-nitrilopropionamide
26172-55-4	5-Chloro-2-methyl-4-isothiazolin-3-one
2634-33-5	1,2-Benzisothiazolin-3-one
2682-20-4	2-Methyl-4-isothiazolin-3-one
533-74-4	Tetrahydro-3,5-dimethyl-1,3,5-thiadiazine-2-thione
55566-30-8	Tetrakis(hydroxymethyl)phosphonium sulfate
61789-77-3	Dicoco dimethyl quaternary ammonium chloride
68424-85-1	Quaternary ammonium compounds, benzyl-C12-16-alkyldimethyl chlorides
68953-58-2	Quaternary ammonium compounds, bis(hydrogenated tallow alkyl)dimethyl, salt with bentonite
75-21-8	Ethylene oxide

Table 11. Base fluid volume used in well stimulation treatment (WST) fluids. The WST occurred May 5, 2015 – October 4, 2019.

Field	FAP	Base fluid total (gallons)				
		N	Mean	Min	Max	Median
Buena Vista Nose	0000000	35	312,228	93,492	1,091,118	208,908
Brea-Olinda	0700000	1	45,948	45,948	45,948	45,948
Elk Hills	2280015	9	111,048	30,198	220,416	89,460
	2280022	3	153,300	17,304	279,846	162,792
	2280024	1	227,178	227,178	227,178	227,178
Lost Hills	4320027	121[a]	137,424	63,588	298,872	122,388
	4320050	11	151,452	90,804	228,270	135,660
McKittrick	4540610	4	907,914	862,890	1,005,144	881,790
North Belridge	0500007	33	106,680	51,912	274,008	96,726
	0500020	3	103,236	97,440	110,040	102,228
North Coles Levee	1560025	2	280,644	226,002	335,244	280,644
South Belridge	0520000	1	258,132	258,132	258,132	258,132
	0520020	1,002	91,350	9,282	288,960	91,686
	0520050	1	161,658	161,658	161,658	161,658

[a]One base fluid record was missing in this FAP.

Table 12. Water quality summary of water used to formulate well stimulation fluids in California, May 5, 2015 – October 4, 2019. Data from source water used in all fields is shown (N=35).

Parameter	Source Water	N	Min	Max	Mean	Median
Alkalinity (mg/L as $CaCO_3$)	CA Aqueduct	20	44	91	62	59
	Produced Water	4	270	1,000	593	550
	Well Water	9	15	580	141	73
Alpha, gross (pCi/L)	CA Aqueduct	11	-3.07	7.98	2.3	2
	Produced Water	4	0.996	134	55.7	44
	Well Water	4	9.69	14.9	12.9	13.5
Antimony (mg/L)	CA Aqueduct	20	0	0.047	0.0029	0
	Produced Water	4	0	0.002	0.0005	0
	Well Water	8	0	0.046	0.0099	0
Barium (mg/L)	CA Aqueduct	20	0	0.15	0.039	0.0305
	Produced Water	4	0.031	4.3	2.5	2.75
	Well Water	9	0.019	1.6	0.29	0.093
Benzene (mg/L)	CA Aqueduct	22	0	0	0	0
	Produced Water	4	0.0014	5.1	1.3	0.0855
	Well Water	9	0	0.043	0.0056	0
Beryllium (mg/L)	CA Aqueduct	20	0	0	0	0
	Produced Water	4	0	0	0	0
	Well Water	8	0	0	0	0
Beta (pCi/L)	CA Aqueduct	10	-0.289	6.42	2.4	1.67
	Produced Water	3	-5.85	96.7	30.8	1.64
	Well Water	4	0.911	28.9	17.6	20.35
Boron (mg/L)	CA Aqueduct	20	0.07	0.38	0.16	0.135
	Produced Water	4	1.1	45	26.3	29.5
	Well Water	9	0.002	7.6	2.2	0.59
Bromide (mg/L)	CA Aqueduct	20	0	0.84	0.20	0.115
	Produced Water	3	43	160	111	130
	Well Water	9	0	15	4.7	2.4
Calcium (mg/L)	CA Aqueduct	20	13	54	24.7	18.5
	Produced Water	4	9.8	1,300	390	125
	Well Water	9	16	360	145	150
Chloride (mg/L)	CA Aqueduct	20	17	160	66	57.5
	Produced Water	4	79	22,000	8,620	6,200
	Well Water	9	20	3,200	904	500
Chromium (mg/L)	CA Aqueduct	20	0	0.019	0.0016	0
	Produced Water	4	0	0.0011	0.00028	0
	Well Water	8	0	0	0	0
Chromium VI (mg/L)	CA Aqueduct	18	0	0.004	0.00047	0.000059
	Produced Water	3	0	0	0	0
	Well Water	5	0	0.00008	0.000025	0

Parameter	Source Water	N	Min	Max	Mean	Median
Copper (mg/L)	CA Aqueduct	20	0	0.21	0.013	0.0029
	Produced Water	4	0	0.023	0.0058	0
	Well Water	8	0	0.013	0.0026	0
Dissolved sulfide (mg/L)	CA Aqueduct	11	0	0	0	0
	Produced Water	3	0	0.062	0.021	0
	Well Water	0				
Ethylbenzene (mg/L)	CA Aqueduct	22	0	0	0	0
	Produced Water	4	0	0.064	0.021	0.01085
	Well Water	9	0	0.0061	0.00081	0
Fluoride (mg/L)	CA Aqueduct	13	0	0.18	0.090	0.073
	Produced Water	3	0	1.7	0.76	0.58
	Well Water	4	0	0.68	0.25	0.15
Guar gum (mg/L)	CA Aqueduct	0				
	Produced Water	1	0	0	0	0
	Well Water	1	0	0	0	0
Hydrogen sulfide (mg/L)	CA Aqueduct	11	0	0	0	0
	Produced Water	2	0	0	0	0
	Well Water	2	0	0.2	0.1	0.1
Iron (mg/L)	CA Aqueduct	12	0	29	3.0485	0.22
	Produced Water	4	0.43	14	4.7975	2.38
	Well Water	4	0	1.3	0.695	0.74
Lead (mg/L)	CA Aqueduct	20	0	0.039	0.0022	0
	Produced Water	4	0	0	0	0
	Well Water	8	0	0.011	0.0014	0
Lithium (mg/L)	CA Aqueduct	20	0	0.018	0.0036	0
	Produced Water	4	0.07	4.8	2.0	1.65
	Well Water	9	0	0.98	0.21	0
Magnesium (mg/L)	CA Aqueduct	20	0.183	18	6.9	6.4
	Produced Water	4	1.6	600	180	58.5
	Well Water	9	0.21	140	30	6.6
Manganese (mg/L)	CA Aqueduct	12	0	0.41	0.055	0.0155
	Produced Water	4	0	0.8	0.24	0.0865
	Well Water	5	0	0.7	0.31	0.36
Mercury (mg/L)	CA Aqueduct	20	0	0.000045	8.15E-06	0
	Produced Water	4	0	0.00021	0.000053	0
	Well Water	8	0	0	0	0
Methane (mg/L)	CA Aqueduct	12	0	0.002	0.00048	0
	Produced Water	3	0.17	4.6	1.7	0.22
	Well Water	4	0	4.6	1.2	0.078
Molybdenum (mg/L)	CA Aqueduct	20	0	0.004	0.00082	0
	Produced Water	4	0	0.04	0.013	0.0065
	Well Water	8	0	0.058	0.018	0.01

Parameter	Source Water	N	Min	Max	Mean	Median
Nickel (mg/L)	CA Aqueduct	20	0	0.025	0.0019	0
	Produced Water	4	0	0.00047	0.00012	0
	Well Water	8	0	0.0025	0.00031	0
Nitrate (mg/L)	CA Aqueduct	17	0	9.47	3.10	1.9
	Produced Water	3	0	0	0	0
	Well Water	7	0	4	0.61	0
Nitrite (mg/L)	CA Aqueduct	12	0	0.59	0.065	0
	Produced Water	3	0	0	0	0
	Well Water	3	0	0.002	0.00067	0
pH	CA Aqueduct	14	7.27	8.12	7.68	7.69
	Produced Water	4	7.11	7.96	7.45	7.36
	Well Water	1	7.54	7.54	7.54	7.54
Potassium (mg/L)	CA Aqueduct	20	0	4.1	2.1	1.9
	Produced Water	4	3.1	100	55.8	60
	Well Water	9	0.5	24	6.7	1.8
Radium-226 (pCi/L)	CA Aqueduct	11	0	6.41	1.07	0.481
	Produced Water	4	3.82	9.13	5.53	4.59
	Well Water	4	0.0785	3.29	1.30	0.911
Radium-228 (pCi/L)	CA Aqueduct	1	0.204	0.204	0.20	0.204
	Produced Water	2	0.47	10.1	5.3	5.285
	Well Water	4	-0.16	1.86	1.1	1.365
Radon (pCi/L)	CA Aqueduct	4	-77	108.2	16.8	17.9
	Produced Water	2	54	156	105	105
	Well Water	1	721	721	721	721
Radon-222 (pCi/L)	CA Aqueduct	6	-74	80.9	27.0	46.5
	Produced Water	1	50.8	50.8	50.8	50.8
	Well Water	1	96	96	96	96
Selenium (mg/L)	CA Aqueduct	20	0	0	0	0
	Produced Water	4	0	0.0007	0.00018	0
	Well Water	8	0	0	0	0
Sodium (mg/L)	CA Aqueduct	20	18	140	62	64.55
	Produced Water	4	170	11,000	4,818	4050
	Well Water	9	20	1,900	607	320
Strontium (mg/L)	CA Aqueduct	20	0	0.8	0.27	0.195
	Produced Water	4	0.14	14	7.1	7.2
	Well Water	9	0.00067	5.6	2.0	0.73
Sulfate (mg/L)	CA Aqueduct	20	9.9	200	60	27.5
	Produced Water	4	0.5	170	63	40.5
	Well Water	9	11	1,400	392	200
Thallium (mg/L)	CA Aqueduct	20	0	0	0	0
	Produced Water	4	0	0	0	0
	Well Water	8	0	0.01	0.0013	0

Parameter	Source Water	N	Min	Max	Mean	Median
Toluene (mg/L)	CA Aqueduct	22	0	0.00011	0.000005	0
	Produced Water	4	0.0028	2.2	0.62	0.135
	Well Water	9	0	0.031	0.0039	0
Total carbohydrates (mg/L)	CA Aqueduct	13	0	19	2.0	0
	Produced Water	2	41	61	51	51
	Well Water	3	0	4.5	1.5	0
Total dissolved solids (mg/L)	CA Aqueduct	20	110	540	304	340
	Produced Water	4	500	38,000	15,625	12,000
	Well Water	8	140	6,200	2,514	1,550
Uranium (mg/L)	CA Aqueduct	1	1.4	1.4	1.4	1.4
	Produced Water	0				
	Well Water	2	0	0.018	0.009	0.009
Vanadium (mg/L)	CA Aqueduct	20	0	0.022	0.0060	0.0041
	Produced Water	4	0	0	0	0
	Well Water	8	0	0.0092	0.0025	0
Xylenes (mg/L)	CA Aqueduct	22	0	0.00057	2.6E-05	0
	Produced Water	4	0.0033	0.61	0.19	0.073
	Well Water	9	0	0.018	0.0030	0
Xylene, Isomers m & p (mg/L)	CA Aqueduct	16	0	0.00045	0.000028	0
	Produced Water	4	0.0018	0.41	0.12	0.0415
	Well Water	5	0	0.0051	0.0010	0
o-Xylenes (mg/L)	CA Aqueduct	16	0	0.00012	0.0000075	0
	Produced Water	4	0.0014	0.2	0.066	0.0315
	Well Water	4	0	0.0024	0.00060	0
Zinc (mg/L)	CA Aqueduct	20	0	0.051	0.012	0.0059
	Produced Water	4	0	0.047	0.017	0.011
	Well Water	8	0	0.05	0.0080	0

Table 13. Recovered fluid volume at the time that the first sample was collected at wells undergoing well stimulation treatment (WST). The WST occurred May 5, 2015 – October 4, 2019.

Field	FAP	Volume (gallons)				
		N	Mean	Min	Max	Median
Brea-Olinda	0700000	1	16,800	16,800	16,800	16,800
Buena Vista Nose	0000000	35	22,554	16,800	84,000	21,000
Elk Hills	2280015	9	7,560	4,200	10,584	7,098
	2280022	3	18,396	11,046	23,100	21,000
	2280024	1	21,000	21,000	21,000	21,000
Lost Hills	4320027	122	19,446	42	308,154	5,208
	4320050	11	53,088	7,098	263,382	8,736
McKittrick	4540610	4	13,650	13,314	13,986	13,650
North Belridge	0500007	33	3,990	2,730	9,660	3,822
	0500020	3	69,930	3,906	201,936	3,906
North Coles Levee	1560025	2	15,120	15,120	15,120	15,120
South Belridge	0520000	1	37,800	37,800	37,800	37,800
	0520020	991	15,372	0	408,282	3,906
	0520050	1	14,868	14,868	14,868	14,868

Table 14. Water quality summary of produced water from oil wells undergoing well stimulation treatment in California, May 5, 2015 – October 4, 2019. Data from the following oil fields is shown: Buena Vista Nose (FAP 0000000), North Belridge (FAP 0500007), South Belridge (FAP 0520020), and Lost Hills (FAP 4320027).

Parameter	Oil field	Sample Order	N	Min	Max	Mean	Median
Alkalinity (mg/L as CaCO3)	Buena Vista Nose	One	35	730	1,700	988	950
	Buena Vista Nose	Two	35	1,100	3,400	1,649	1,600
	North Belridge	One	31	1	3,400	2,296	2,400
	North Belridge	Two	33	1,800	3,600	2,488	2,400
	South Belridge	One	894	1	5,100	2,449	2,700
	South Belridge	Two	841	300	5,200	3,008	3,100
	Lost Hills	One	104	74	5,600	3,046	3,500
	Lost Hills	Two	120	320	5,000	3,502	3,800
Alpha, gross (pCi/L)	Buena Vista Nose	One	35	-101	968	143	140
	Buena Vista Nose	Two	35	-77	222	82.7	74
	North Belridge	One	30	-48.8	212	65.4	59.9
	North Belridge	Two	33	-171	199	49.2	55.9
	South Belridge	One	892	-830	2,483	88.4	55
	South Belridge	Two	841	-366	1,555	63.0	56.7
	Lost Hills	One	103	-315	1,588	41.8	24.8
	Lost Hills	Two	120	-630	416	9.3	18.7
Antimony (mg/L)	Buena Vista Nose	One	35	0	0.13	0.0037	0
	Buena Vista Nose	Two	35	0	0.021	0.00060	0
	North Belridge	One	30	0	0.42	0.041	0
	North Belridge	Two	33	0	0.36	0.034	0
	South Belridge	One	894	0	180	0.22	0
	South Belridge	Two	841	0	0.81	0.016	0
	Lost Hills	One	104	0	0.17	0.0035	0
	Lost Hills	Two	120	0	0.17	0.0033	0
Barium (mg/L)	Buena Vista Nose	One	35	2.8	17	6.4	6.1
	Buena Vista Nose	Two	35	3.2	8.8	6.4	6.6
	North Belridge	One	30	3.9	49	17	15
	North Belridge	Two	33	7.35	54	19	17
	South Belridge	One	894	0	11,000	20	7.4
	South Belridge	Two	841	0.33	23	8.5	8
	Lost Hills	One	104	0.49	24	4.7	4
	Lost Hills	Two	120	0.23	18	4.9	4.5
Benzene (mg/L)	Buena Vista Nose	One	35	1.2	7	3.13	3
	Buena Vista Nose	Two	35	0.56	5	2.84	2.8
	North Belridge	One	30	0.22	11	4.07	4.1
	North Belridge	Two	33	0.13	17	5.27	3.6
	South Belridge	One	893	0	25	0.77	0.49

Parameter	Oil field	Sample Order	N	Min	Max	Mean	Median
	South Belridge	Two	840	0	6	0.96	0.77
	Lost Hills	One	104	0	6.5	0.93	0.385
	Lost Hills	Two	120	0	4.8	1.02	0.68
Beryllium (mg/L)	Buena Vista Nose	One	35	0	0.0054	0.00035	0
	Buena Vista Nose	Two	35	0	0	0	0
	North Belridge	One	30	0	0.015	0.00093	0
	North Belridge	Two	33	0	0.0065	0.00038	0
	South Belridge	One	894	0	0.1	0.00045	0
	South Belridge	Two	841	0	0.17	0.00063	0
	Lost Hills	One	104	0	0	0	0
	Lost Hills	Two	120	0	0	0	0
Beta, gross (pCi/L)	Buena Vista Nose	One	35	8	11,000	5,191	4,355
	Buena Vista Nose	Two	35	185	2,800	1,002	940
	North Belridge	One	30	46	420	232	225
	North Belridge	Two	33	39	2,250	270	223
	South Belridge	One	892	-345	8,064	293	136
	South Belridge	Two	841	-166	3,845	162	127
	Lost Hills	One	103	16	41,000	1,014	245
	Lost Hills	Two	120	-1,109	6,100	238	134
Boron (mg/L)	Buena Vista Nose	One	35	33	85	63.6	64
	Buena Vista Nose	Two	35	51	120	90.2	92
	North Belridge	One	30	12	120	83.1	83
	North Belridge	Two	33	67	130	91.2	88
	South Belridge	One	894	0	220	91.5	95
	South Belridge	Two	841	0.1	230	105	100
	Lost Hills	One	103	1	170	77.6	77
	Lost Hills	Two	120	13	140	77.8	82
Bromide (mg/L)	Buena Vista Nose	One	35	0	95	47.3	45
	Buena Vista Nose	Two	35	55	100	79.3	80
	North Belridge	One	30	31	180	127	125
	North Belridge	Two	33	83	230	138	130
	South Belridge	One	894	0	670	100	100
	South Belridge	Two	841	1.7	250	117	120
	Lost Hills	One	104	0	160	53.2	50.5
	Lost Hills	Two	119	0	150	53.6	50
Cadmium (mg/L)	Buena Vista Nose	One	35	0	0	0	0
	Buena Vista Nose	Two	35	0	0	0	0
	North Belridge	One	30	0	0	0	0
	North Belridge	Two	33	0	0.031	0.0027	0
	South Belridge	One	894	0	0.12	0.00039	0
	South Belridge	Two	841	0	0.051	0.00033	0

Parameter	Oil field	Sample Order	N	Min	Max	Mean	Median
	Lost Hills	One	104	0	0.03	0.00068	0
	Lost Hills	Two	120	0	0.013	0.00011	0
Calcium (mg/L)	Buena Vista Nose	One	35	98	680	196	160
	Buena Vista Nose	Two	35	58	190	106	98
	North Belridge	One	30	160	9,200	568	240
	North Belridge	Two	33	170	420	256	240
	South Belridge	One	894	4.7	190,000	3,833	200
	South Belridge	Two	841	2.9	93,000	353	200
	Lost Hills	One	104	12	170,000	4,726	180
	Lost Hills	Two	120	16	15,000	348	160
Chloride (mg/L)	Buena Vista Nose	One	35	10,000	53,000	17,971	15,000
	Buena Vista Nose	Two	35	9,500	15,000	12,214	12,000
	North Belridge	One	30	13,000	26,000	19,600	19,500
	North Belridge	Two	33	14,000	27,000	19,485	20,000
	South Belridge	One	894	54	360,000	23,770	15,000
	South Belridge	Two	841	310	230,000	15,186	15,000
	Lost Hills	One	104	420	310,000	21,180	10,000
	Lost Hills	Two	120	2,400	170,000	16,874	9,200
Chromium (mg/L)	Buena Vista Nose	One	35	0	0.29	0.037	0.015
	Buena Vista Nose	Two	35	0	0.41	0.047	0.034
	North Belridge	One	30	0	0.2	0.021	0
	North Belridge	Two	33	0	0.18	0.028	0
	South Belridge	One	894	0	1.2	0.012	0
	South Belridge	Two	841	0	3.5	0.023	0
	Lost Hills	One	104	0	0.3	0.016	0
	Lost Hills	Two	120	0	0.11	0.0082	0
Chromium VI (mg/L)	Buena Vista Nose	One	35	0	0	0	0
	Buena Vista Nose	Two	35	0	0	0	0
	North Belridge	One	30	0	0	0	0
	North Belridge	Two	33	0	0.025	0.00076	0
	South Belridge	One	894	0	0.61	0.0018	0
	South Belridge	Two	841	0	0.036	0.00044	0
	Lost Hills	One	45	0	0.029	0.0012	0
	Lost Hills	Two	54	0	0	0	0
Copper (mg/L)	Buena Vista Nose	One	35	0	1.3	0.0487	0
	Buena Vista Nose	Two	35	0	1.6	0.0764	0
	North Belridge	One	30	0	0.33	0.0304	0
	North Belridge	Two	33	0	0.13	0.0183	0
	South Belridge	One	894	0	5.6	0.0702	0
	South Belridge	Two	841	0	37	0.0758	0
	Lost Hills	One	104	0	2.4	0.0743	0

Parameter	Oil field	Sample Order	N	Min	Max	Mean	Median
	Lost Hills	Two	120	0	0.52	0.0219	0
2,2-dibromo-3-nitrilopropionamide, DBNPA (mg/L)	Buena Vista Nose	One	0				
	Buena Vista Nose	Two	0				
	North Belridge	One	0				
	North Belridge	Two	2	0	0	0	0
	South Belridge	One	39	0	15	1.03	0
	South Belridge	Two	35	0	10	0.29	0
	Lost Hills	One	0				
	Lost Hills	Two	0				
Dissolved sulfide (mg/L)	Buena Vista Nose	One	35	0	3.29	0.24	0
	Buena Vista Nose	Two	35	0	2.16	0.25	0
	North Belridge	One	30	0	0	0	0
	North Belridge	Two	33	0	0	0	0
	South Belridge	One	881	0	32	0.11	0
	South Belridge	Two	841	0	37	0.40	0
	Lost Hills	One	45	0	0	0	0
	Lost Hills	Two	54	0	3.2	0.069	0
Ethylbenzene (mg/L)	Buena Vista Nose	One	35	0	0.66	0.28	0.24
	Buena Vista Nose	Two	35	0.068	1.6	0.30	0.24
	North Belridge	One	30	0.13	2.2	0.53	0.455
	North Belridge	Two	33	0.089	1.9	0.50	0.47
	South Belridge	One	894	0	5.3	0.28	0.215
	South Belridge	Two	841	0.0041	5.1	0.30	0.27
	Lost Hills	One	104	0	3.7	0.29	0.18
	Lost Hills	Two	120	0	1.2	0.24	0.21
Fluoride (mg/L)	Buena Vista Nose	One	35	0	53	5.33	0
	Buena Vista Nose	Two	35	0	12	1.09	0
	North Belridge	One	30	0	0	0	0
	North Belridge	Two	33	0	0	0	0
	South Belridge	One	894	0	34	0.47	0
	South Belridge	Two	841	0	16	0.068	0
	Lost Hills	One	104	0	23	0.57	0
	Lost Hills	Two	120	0	1.4	0.012	0
Guar gum (mg/L)	Buena Vista Nose	One	21	0	3,500	1,264	1,100
	Buena Vista Nose	Two	17	0	130	56	54
	North Belridge	One	0				
	North Belridge	Two	0				
	South Belridge	One	0				
	South Belridge	Two	0				
	Lost Hills	One	36	0	250	122	109
	Lost Hills	Two	48	0	300	107	115

Parameter	Oil field	Sample Order	N	Min	Max	Mean	Median
Hydrogen sulfide (mg/L)	Buena Vista Nose	One	35	0	0	0	0
	Buena Vista Nose	Two	35	0	0.1	0.0029	0
	North Belridge	One	30	0	0.097	0.0070	0
	North Belridge	Two	33	0	0	0	0
	South Belridge	One	879	0	4.7	0.021	0
	South Belridge	Two	841	0	10	0.066	0
	Lost Hills	One	104	0	2	0.133	0
	Lost Hills	Two	120	0	5	0.179	0
Iron (mg/L)	Buena Vista Nose	One	35	17	190	66	58
	Buena Vista Nose	Two	35	4	190	38	21
	North Belridge	One	30	4.1	160	50	37
	North Belridge	Two	31	2.8	220	54	48
	South Belridge	One	894	0	660	34	18.0
	South Belridge	Two	841	0	300	22	5.8
	Lost Hills	One	104	1.1	460	64	30
	Lost Hills	Two	120	0	350	28	6.8
Lead (mg/L)	Buena Vista Nose	One	35	0	0.08	0.0061	0
	Buena Vista Nose	Two	35	0	0.29	0.0157	0
	North Belridge	One	30	0	0.13	0.0080	0
	North Belridge	Two	33	0	0.11	0.0033	0
	South Belridge	One	894	0	2.1	0.0238	0
	South Belridge	Two	841	0	0.22	0.0027	0
	Lost Hills	One	104	0	1.2	0.0335	0
	Lost Hills	Two	120	0	0.065	0.0026	0
Lithium (mg/L)	Buena Vista Nose	One	35	1.2	6.3	2.8	2.5
	Buena Vista Nose	Two	35	1.2	6.5	2.6	2.6
	North Belridge	One	30	6.7	26	12.2	12
	North Belridge	Two	33	5.6	19	12.5	13
	South Belridge	One	894	0	540	15.9	6.2
	South Belridge	Two	841	0.0062	260	7.0	6.2
	Lost Hills	One	104	0.28	410	18.3	6.65
	Lost Hills	Two	120	0	47	7.3	6.35
Magnesium (mg/L)	Buena Vista Nose	One	35	16	150	35	27
	Buena Vista Nose	Two	35	12	150	21	15
	North Belridge	One	30	110	510	231	215
	North Belridge	Two	33	140	400	231	220
	South Belridge	One	894	0	9,300	303	130
	South Belridge	Two	841	0	4,800	135	130
	Lost Hills	One	104	16	4,600	271	110
	Lost Hills	Two	120	15	700	131	110
Manganese (mg/L)	Buena Vista Nose	One	35	0.25	3.2	1.12	0.96

Parameter	Oil field	Sample Order	N	Min	Max	Mean	Median
	Buena Vista Nose	Two	35	0.056	2.9	0.73	0.53
	North Belridge	One	30	0.16	4.1	1.17	1.1
	North Belridge	Two	31	0.12	2.8	0.95	0.71
	South Belridge	One	894	0	45	1.47	0.63
	South Belridge	Two	841	0	23	0.50	0.31
	Lost Hills	One	104	0	11	1.43	0.715
	Lost Hills	Two	120	0	13	0.61	0.275
Mercury (mg/L)	Buena Vista Nose	One	35	0	0.0007	3.0E-05	0
	Buena Vista Nose	Two	35	0	0.00022	1.9E-05	0
	North Belridge	One	30	0	0.001	9.0E-05	0.000019
	North Belridge	Two	33	0	0.00055	4.0E-05	0
	South Belridge	One	894	0	0.005	7.6E-05	0
	South Belridge	Two	841	0	0.01	8.3E-05	0.000045
	Lost Hills	One	104	0	0.00028	1.7E-05	0
	Lost Hills	Two	120	0	0.00095	4.1E-05	0
Methane (mg/L)	Buena Vista Nose	One	35	0.178	4.32	1.45	1.21
	Buena Vista Nose	Two	35	0	4.6	1.03	0.76
	North Belridge	One	30	0.31	4	1.58	1.35
	North Belridge	Two	33	0.21	6	1.66	1.2
	South Belridge	One	894	0	12	0.83	0.48
	South Belridge	Two	841	0	8.2	0.91	0.62
	Lost Hills	One	104	0	7.1	1.51	1.38
	Lost Hills	Two	120	0	9.5	1.75	1.5
Molybdenum (mg/L)	Buena Vista Nose	One	35	0	0.23	0.030	0.014
	Buena Vista Nose	Two	35	0	0.19	0.0091	0
	North Belridge	One	30	0	0	0.0000	0
	North Belridge	Two	33	0	0.27	0.022	0
	South Belridge	One	894	0	0.26	0.0053	0
	South Belridge	Two	841	0	0.24	0.0051	0
	Lost Hills	One	104	0	0.62	0.019	0
	Lost Hills	Two	120	0	0.16	0.0035	0
Nickel (mg/L)	Buena Vista Nose	One	35	0	3	0.121	0.03
	Buena Vista Nose	Two	35	0	4.1	0.256	0.025
	North Belridge	One	30	0	0.25	0.027	0
	North Belridge	Two	33	0	0.069	0.004	0
	South Belridge	One	894	0	3	0.026	0
	South Belridge	Two	841	0	0.55	0.015	0
	Lost Hills	One	104	0	0.24	0.015	0
	Lost Hills	Two	120	0	0.87	0.043	0
Nitrate (mg/L)	Buena Vista Nose	One	28	0	12	0.43	0
	Buena Vista Nose	Two	32	0	12	0.38	0

Parameter	Oil field	Sample Order	N	Min	Max	Mean	Median
	North Belridge	One	30	0	0	0.00	0
	North Belridge	Two	33	0	0	0.00	0
	South Belridge	One	894	0	800	5.92	0
	South Belridge	Two	841	0	310	1.44	0
	Lost Hills	One	104	0	220	4.41	0
	Lost Hills	Two	120	0	0	0.00	0
Nitrite (mg/L)	Buena Vista Nose	One	28	0	1.6	0.0696	0
	Buena Vista Nose	Two	32	0	0.044	0.0014	0
	North Belridge	One	30	0	0.16	0.0189	0
	North Belridge	Two	33	0	0.75	0.0607	0
	South Belridge	One	894	0	10	0.1132	0
	South Belridge	Two	837	0	4.7	0.0700	0
	Lost Hills	One	104	0	0.63	0.0338	0
	Lost Hills	Two	120	0	0.051	0.0015	0
pH	Buena Vista Nose	One	25	6.29	7.45	6.83	6.87
	Buena Vista Nose	Two	22	6.58	8.02	7.54	7.655
	North Belridge	One	27	6.59	7.84	7.48	7.49
	North Belridge	Two	29	7.15	7.8	7.51	7.57
	South Belridge	One	740	4.61	27.785	7.52	7.62
	South Belridge	Two	722	5.92	8.81	7.68	7.7
	Lost Hills	One	34	6.06	8.79	7.27	7.41
	Lost Hills	Two	40	7.07	8.84	7.57	7.535
Potassium (mg/L)	Buena Vista Nose	One	35	1000	18,000	6,923	6,300
	Buena Vista Nose	Two	35	190	3,600	1,398	1,100
	North Belridge	One	30	220	620	382	385
	North Belridge	Two	33	170	580	398	400
	South Belridge	One	894	1.2	13,000	462	210
	South Belridge	Two	841	5.7	6,500	230	200
	Lost Hills	One	104	12	52,000	1,428	305
	Lost Hills	Two	120	46	1,500	284	235
Radium-226 (pCi/L)	Buena Vista Nose	One	35	6.93	78.6	33.9	31
	Buena Vista Nose	Two	35	4	63.9	25.5	23.8
	North Belridge	One	30	4.89	73.1	33.6	31.1
	North Belridge	Two	33	16.9	67.4	33.3	30.8
	South Belridge	One	891	-4.66	917	42.6	24.5
	South Belridge	Two	841	-4.111	589	27.6	26.4
	Lost Hills	One	101	-4.375	450	27.8	9.3
	Lost Hills	Two	119	-0.83	109	13.1	10.4
Radium-228 (pCi/L)	Buena Vista Nose	One	31	-6.5	65	34.6	30.1
	Buena Vista Nose	Two	30	0.08	56.8	27.5	28.5
	North Belridge	One	0				

Parameter	Oil field	Sample Order	N	Min	Max	Mean	Median
	North Belridge	Two	0				
	South Belridge	One	1	9.59	9.59	9.6	9.59
	South Belridge	Two	1	0.128	0.128	0.13	0.128
	Lost Hills	One	58	-0.1	515	27.6	6.69
	Lost Hills	Two	66	-8.73	91.2	10.0	6.31
Radon (pCi/L)	Buena Vista Nose	One	16	-3.4	459	84	56.75
	Buena Vista Nose	Two	17	-35	503	50	1.2
	North Belridge	One	9	-99	225	109	151
	North Belridge	Two	10	36	375	162	166.5
	South Belridge	One	201	-484	3,572	92	34.2
	South Belridge	Two	187	-277	2,417	147	111.1
	Lost Hills	One	43	-145	1,011	23	-1.5
	Lost Hills	Two	52	-80.3	3,894	158	46.25
Radon-222 (pCi/L)	Buena Vista Nose	One	19	-200	663	71	31
	Buena Vista Nose	Two	18	-198	65	-4.0	10.65
	North Belridge	One	21	-74	892	170	172
	North Belridge	Two	23	-68	666	141	110
	South Belridge	One	683	-36,570	250,690	1,135	64
	South Belridge	Two	651	-554	29,540	231	69
	Lost Hills	One	60	-170	2,821	153	10.5
	Lost Hills	Two	67	-250	1,524	0.3	-11.5
Selenium (mg/L)	Buena Vista Nose	One	35	0	0.75	0.20	0.2
	Buena Vista Nose	Two	35	0	0.34	0.10	0.09
	North Belridge	One	30	0	1.1	0.059	0
	North Belridge	Two	33	0	0.31	0.016	0
	South Belridge	One	894	0	15	0.14	0
	South Belridge	Two	841	0	2	0.040	0
	Lost Hills	One	104	0	1	0.058	0
	Lost Hills	Two	120	0	0.47	0.039	0
Sodium (mg/L)	Buena Vista Nose	One	35	3,700	31,000	7,243	5,700
	Buena Vista Nose	Two	35	920	11,000	7,329	7,500
	North Belridge	One	30	1,900	16,000	11,120	11,000
	North Belridge	Two	33	8,700	16,000	11,744	12,000
	South Belridge	One	894	51	110,000	9,915	9,100
	South Belridge	Two	841	170	40,000	9,363	9,200
	Lost Hills	One	104	190	82,000	8,348	6,850
	Lost Hills	Two	120	1,700	120,000	11,032	7,200
Strontium (mg/L)	Buena Vista Nose	One	35	12	31	20.0	20
	Buena Vista Nose	Two	35	9.3	25	16.4	16
	North Belridge	One	30	11	210	23.9	16.5
	North Belridge	Two	33	11	34	18.2	18

Parameter	Oil field	Sample Order	N	Min	Max	Mean	Median
	South Belridge	One	894	0.01	3,300	79.4	11
	South Belridge	Two	841	0.29	1,700	13.5	11
	Lost Hills	One	104	0.47	3,400	94.9	4.85
	Lost Hills	Two	120	0.82	310	8.6	4.6
Sulfate (mg/L)	Buena Vista Nose	One	35	0	280	104.9	100
	Buena Vista Nose	Two	35	0	87	17.9	0
	North Belridge	One	30	0	100	25.6	26
	North Belridge	Two	33	0	65	14.8	0
	South Belridge	One	894	0	12,000	91.6	37
	South Belridge	Two	841	0	2,100	24.7	22
	Lost Hills	One	104	0	1,300	115.9	59
	Lost Hills	Two	120	0	4,400	145.3	21
Thallium (mg/L)	Buena Vista Nose	One	35	0	0	0	0
	Buena Vista Nose	Two	35	0	0	0	0
	North Belridge	One	30	0	0	0	0
	North Belridge	Two	33	0	0	0	0
	South Belridge	One	894	0	6.4	0.011	0
	South Belridge	Two	841	0	7	0.0094	0
	Lost Hills	One	104	0	3.1	0.047	0
	Lost Hills	Two	120	0	0.25	0.0031	0
Toluene (mg/L)	Buena Vista Nose	One	35	0.87	6.6	2.74	2.7
	Buena Vista Nose	Two	35	0.72	5.1	2.67	2.5
	North Belridge	One	30	0.84	14	4.96	4.15
	North Belridge	Two	33	0.34	22	6.22	5
	South Belridge	One	894	0	61	2.01	1.6
	South Belridge	Two	841	0.02	9.5	2.37	2.3
	Lost Hills	One	104	0	16	1.26	0.465
	Lost Hills	Two	120	0	5.8	1.10	0.665
Total carbohydrates (mg/L)	Buena Vista Nose	One	14	230	4400	911	635
	Buena Vista Nose	Two	18	0	650	230	235
	North Belridge	One	30	8.8	270	97	74.5
	North Belridge	Two	33	13	430	85	63
	South Belridge	One	893	0	3,300	171	100
	South Belridge	Two	841	0	11,000	174	100
	Lost Hills	One	45	0	780	108	57
	Lost Hills	Two	54	0	880	118	68.5
Total dissolved solids (mg/L)	Buena Vista Nose	One	35	11,000	180,000	38,771	31,000
	Buena Vista Nose	Two	35	22,000	50,000	25,286	24,000
	North Belridge	One	30	22,000	52,000	33,933	32,500
	North Belridge	Two	33	25,000	44,000	33,242	34,000
	South Belridge	One	894	300	890,000	51,173	28,000

Parameter	Oil field	Sample Order	N	Min	Max	Mean	Median
	South Belridge	Two	841	700	560,000	27,927	27,000
	Lost Hills	One	104	1,000	740,000	51,669	24,000
	Lost Hills	Two	120	5,700	310,000	33,766	20,500
Vanadium (mg/L)	Buena Vista Nose	One	35	0	0	0	0
	Buena Vista Nose	Two	35	0	0	0	0
	North Belridge	One	30	0	0	0	0
	North Belridge	Two	33	0	0	0	0
	South Belridge	One	894	0	0.15	0.0027	0
	South Belridge	Two	841	0	0.89	0.0049	0
	Lost Hills	One	104	0	0.014	0.00013	0
	Lost Hills	Two	120	0	0.094	0.00078	0
Xylenes (mg/L)	Buena Vista Nose	One	35	0.41	3.7	1.32	1.1
	Buena Vista Nose	Two	35	0.34	7.5	1.44	1.1
	North Belridge	One	30	0.14	11	2.36	1.65
	North Belridge	Two	33	0.1	9	2.51	1.8
	South Belridge	One	894	0	12	1.47	1.1
	South Belridge	Two	841	0.03	6.7	1.58	1.4
	Lost Hills	One	104	0	19	1.13	0.465
	Lost Hills	Two	120	0	6	0.93	0.53
Xylene, Isomers m & p (mg/L)	Buena Vista Nose	One	4	0.26	1.1	0.69	0.695
	Buena Vista Nose	Two	5	0.33	5.2	1.68	1
	North Belridge	One	30	0.084	6.9	1.57	1.15
	North Belridge	Two	33	0.051	6.3	1.73	1.1
	South Belridge	One	894	0	8.8	1.00	0.7
	South Belridge	Two	841	0	5	1.08	0.96
	Lost Hills	One	45	0	13	0.82	0.44
	Lost Hills	Two	54	0	4.1	0.72	0.685
m-Xylene (mg/L)	Buena Vista Nose	One	31	0.26	2.7	0.92	0.72
	Buena Vista Nose	Two	30	0.21	2.5	0.84	0.745
	North Belridge	One	0				
	North Belridge	Two	0				
	South Belridge	One	0				
	South Belridge	Two	0				
	Lost Hills	One	0				
	Lost Hills	Two	0				
o-Xylene (mg/L)	Buena Vista Nose	One	35	0.15	1.1	0.43	0.37
	Buena Vista Nose	Two	35	0.13	2.3	0.47	0.36
	North Belridge	One	30	0.059	4.1	0.78	0.56
	North Belridge	Two	33	0.05	2.7	0.79	0.69
	South Belridge	One	894	0	5.4	0.47	0.36
	South Belridge	Two	841	0	3.5	0.50	0.45

Parameter	Oil field	Sample Order	N	Min	Max	Mean	Median
	Lost Hills	One	45	0	5.7	0.44	0.33
	Lost Hills	Two	54	0	3.1	0.47	0.455
Zinc (mg/L)	Buena Vista Nose	One	35	0	37	1.66	0.13
	Buena Vista Nose	Two	35	0	9.2	0.77	0.11
	North Belridge	One	30	0	1.8	0.14	0
	North Belridge	Two	33	0	0.061	0.0036	0
	South Belridge	One	894	0	15	0.19	0
	South Belridge	Two	841	0	350	0.48	0
	Lost Hills	One	104	0	9	0.26	0
	Lost Hills	Two	120	0	2.1	0.049	0

Table 15. Gross alpha radiation reported for fluids recovered from oil wells undergoing well stimulation treatment (WST). The measurements were made using a gas flow proportional counting system. The WST occurred May 5, 2015 – October 4, 2019.

Field	FAP	Gross alpha (pCi/L)				
		N	Min	Max	Mean	Median
Brea-Olinda	0700000	1	131	131	131	131
Buena Vista Nose	0000000	35	-101	349	121	140
Elk Hills	2280015	9	-14	240	40.4	13
	2280022	3	-53	368	123	54.8
	2280024	1	173	173	173	173
Lost Hills	4320027	122	-594	1,588	37.6	21.0
	4320050	11	41.2	937	324	246
McKittrick	4540610	4	5.66	25.0	15.6	15.9
North Belridge	0500007	33	-48.8	212	60.2	46.5
	0500020	3	55.5	206	138	153
North Coles Levee	1560025	2	15.6	92.2	53.9	53.9
South Belridge	0520000	1	-1,156	-1,156	-1,156	-1,156
	0520020	982	-830	2,483	83.1	51.5
	0520050	1	144	144	144	144

10. Figures

List of Figures

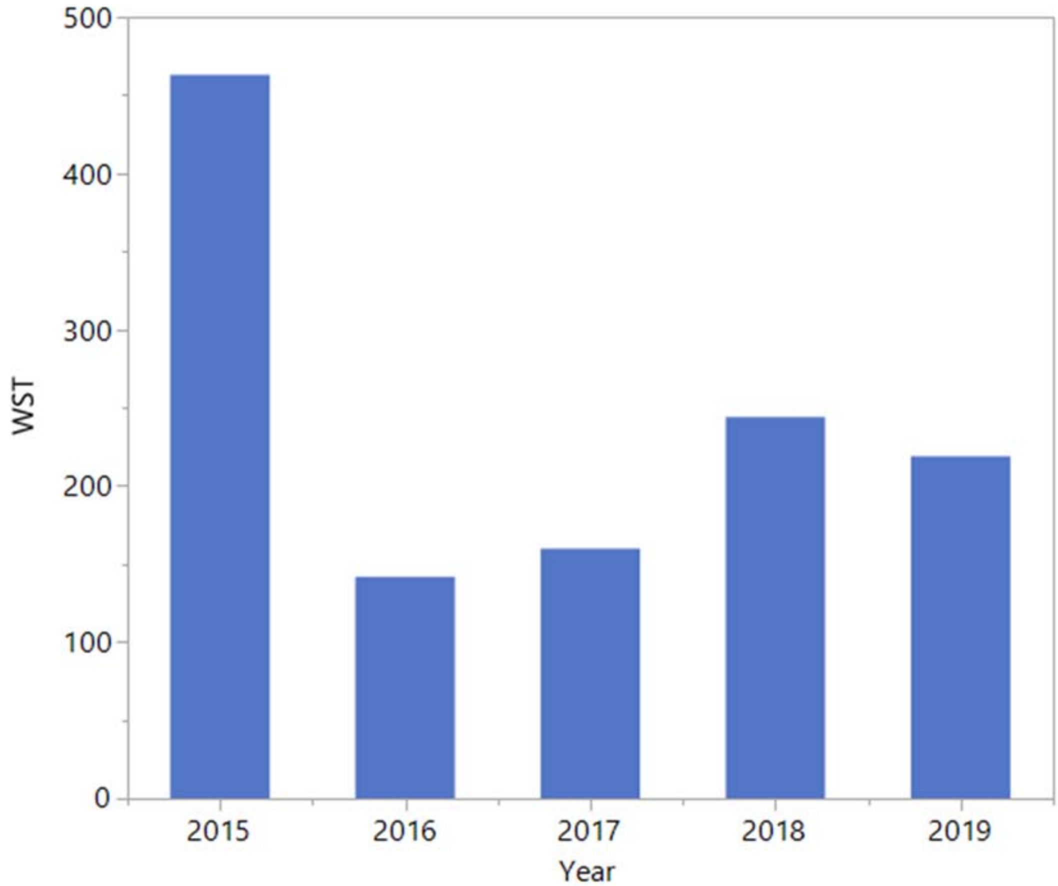

Figure 1. Number of well stimulation treatments (WST) reported per year based on WST occurring May 5, 2015 – October 4, 2019.

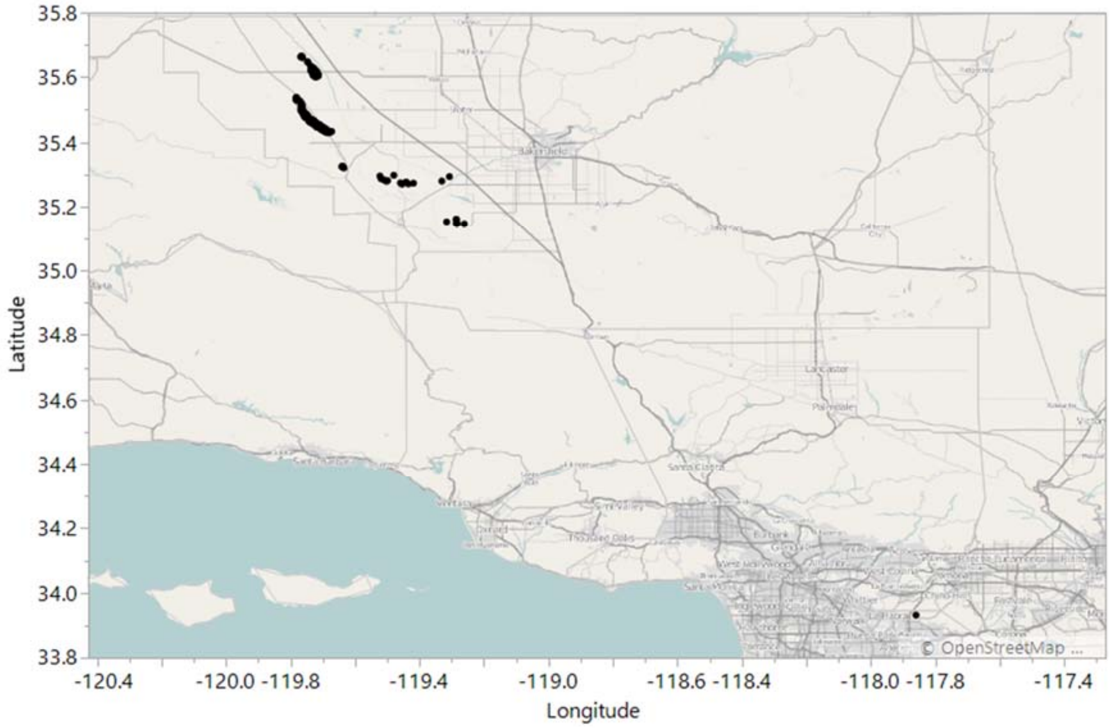

Figure 2. Locations of oil wells where well stimulation treatments (WST) were completed in California, May 5, 2015 to October 4, 2019.

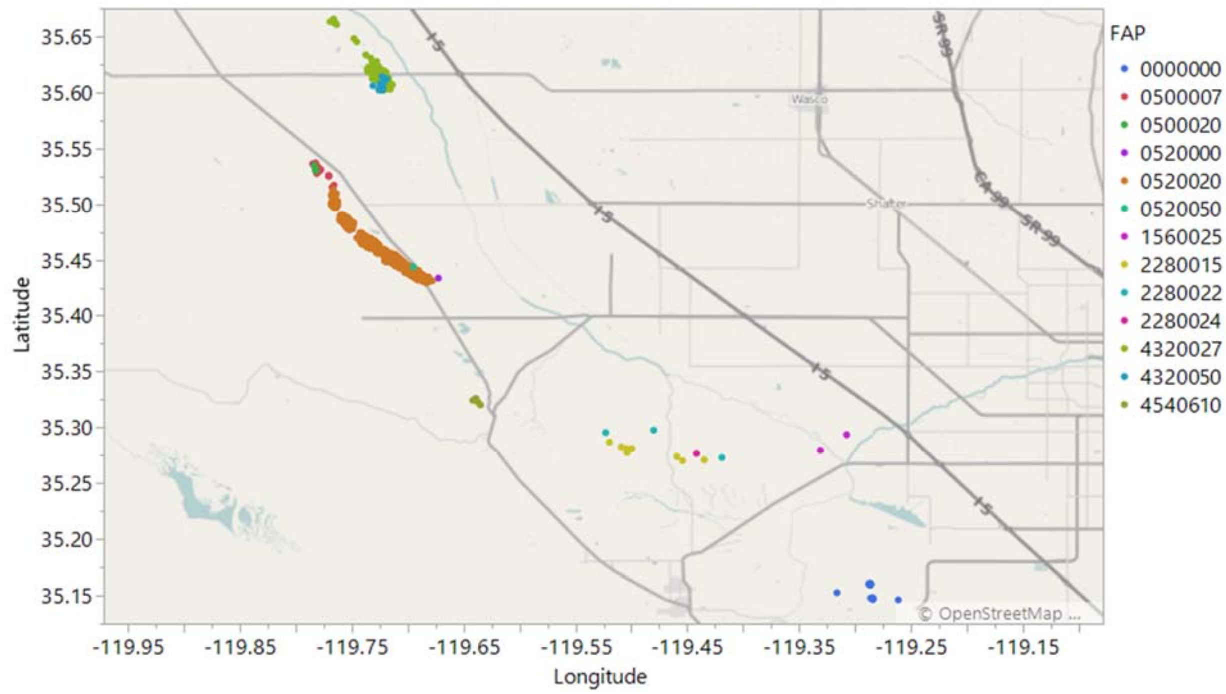

Figure 3. Locations of oil wells where well stimulation treatments (WST) were completed in Kern County, May 5, 2015 to October 4, 2019, with locations labelled by field-area-pool (FAP) code.